PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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August 14, 2020

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

RE: UE 374—PacifiCorp's Surrebuttal Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Surrebuttal Testimony and Exhibits of Ms. Etta Lockey, Ms. Nikki L. Kobliha, Ms. Ann E. Bulkley, Mr. Michael G. Wilding, Mr. Frank Graves, Mr. Richard T. Link, Mr. Robert Van Engelenhoven, Mr. James Owen, Mr. Dana M. Ralston, Mr. Richard A. Vail, Ms. Julie Lewis, and Ms. Shelley E. McCoy.

Included with this filing are CDs containing the confidential and non-confidential electronic testimony, exhibits and workpapers.

In accordance with the Commission's COVID-19 filing procedures, the Company will serve a copy of this filing to parties via encrypted email. Due to file size, the supporting workpapers will be served to parties via Huddle. Confidential material in support of the filing will be provided to qualified parties under Order No. 20-040.

Please direct any informal correspondence and questions regarding this filing to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosure

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Surrebuttal Testimony** on the parties listed below via encrypted email and supporting workpapers via Huddle, in compliance with the Commission's COVID-19 filing instructions for confidential information.

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UE 374

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Dated this 14th day of August, 2020.

Mary Penfield
Adviser, Regulatory Operations

REDACTED
Docket No. UE 374
Exhibit PAC/3300
Witness: Etta Lockey

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Redacted Surrebuttal Testimony of Etta Lockey

August 2020

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Q. Are you the same Etta Lockey who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

Q. Did you file reply testimony in this proceeding?

A. No. However, I am adopting certain portions of the reply testimony of Mr. Michael G. Wilding, PAC/2000, submitted on behalf of the Company, that are related to general policy issues. Specifically, I am adopting the following from Exhibit PAC/2000:

- Page 2, lines 7 through 12;
- Page 2, lines 17 through page 51, line 16.

I. PURPOSE OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. In my testimony, I summarize the Company's surrebuttal case reflecting certain updates, respond to various Public Utility Commission of Oregon (Commission) Staff and Intervenor (collectively, Filing Parties) positions in rebuttal testimony, provide recommendations to the Commission for their decision in this proceeding, and introduce Company witnesses submitting surrebuttal testimony. Specifically, I respond to Filing Parties' rebuttal positions regarding:

- disallowances related to the Company's investments in transmission and selective catalytic reduction (SCR) systems;
- attestations requested for certain capital investments;
- cost recovery recommendations for Energy Vision 2020 new wind projects, repowering the Foote Creek I wind facility, and Pryor Mountain Wind Project;
- decommissioning costs;

- Exit Dates and Exit Orders for the Company's coal-fired generating units;
- the Generation Plant Removal Adjustment (GPRA);
- the Company's proposal to buy down the undepreciated plant balance and closure costs for Cholla Unit 4 with Tax Cuts and Jobs Act (TCJA) deferred tax benefits; and
- the Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism.

Q. Please provide a summary of PacifiCorp's case, as updated by its surrebuttal filing.

A. When combined with the 2021 Transition Adjustment Mechanism (TAM), PacifiCorp is now requesting an overall net rate **decrease** of $8.8 million, or 0.7 percent, effective January 1, 2021. This is the first general rate change PacifiCorp has sought since its 2013 rate case, docket UE 263 (2013 Rate Case), in which PacifiCorp agreed to only a two-year stay-out.[1] After keeping rates stable for seven years, PacifiCorp is now seeking to reduce overall rates, while at the same time delivering significant new investments to both transform the power supply to Oregon customers and provide reliable, safe electric service.

As outlined in this case, the Company has worked hard to maintain stable rates through innovative investments and improved efficiencies. With the filing of this case and the TAM, the Company is able to bring to its customers the benefits of low-cost new and repowered wind resources that lower net power costs and pass along the savings of federal production tax credits.

[1] In its 2013 Rate Case, the Company committed to not filing a rate case prior to January 1, 2016. *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 263, Order No. 13-474, at 6 (Dec. 18, 2013). In a letter to its Oregon customers, PacifiCorp further committed not to file a general rate case prior to January 1, 2018.

The updated revenue requirement in this filing is $47.5 million, which is offset by the stipulated revenue requirement decrease of $49.8 million in the 2021 TAM, based on the latest update. Also offsetting the revenue requirement increase is the amortization of the remaining TCJA tax benefits after the buy down of the Cholla Unit 4 undepreciated plant balance and closure costs, a credit to customers of $6.9 million, and an increase of $0.4 million related to the rate mitigation adjustment (RMA).

Q. Has COVID-19 impacted the Company's customers and their communities?

A. Yes. The COVID-19 pandemic threatens the health and safety of the Company's customers, and also impacts the economy of the communities the Company serves. Even though there has been some movement to reopen the state, there remains uncertainty as to when large portions of the state and the country will return to "business as usual."

Q. As PacifiCorp proceeds with this general rate case, is the Company mindful of the impacts of COVID-19 to its customers?

A. Yes. The Company's evolving positions and reductions in revenue requirement in this general rate case directly respond to the current circumstances of our customers and the state. I note that the Company's direct case, when combined with the impacts of the TAM, reflected a modest increase in rates of $21.6 million, or an average rate increase of 1.6 percent. In reply testimony, the Company took further action to lessen the impacts on customers with its proposal to buy down the undepreciated plant balance and closure costs associated with the retirement of Cholla Unit 4. Further, in this surrebuttal filing, the Company has reduced its requested return on equity (ROE) to 9.8 percent, which is its current authorized ROE. As noted above, when combined with the TAM, the Company is now proposing an overall *decrease* in rates of 0.7 percent. The Company is providing exceptional value in the form of a rate decrease while maintaining the financial health of the Company as it continues its transition to a cleaner, more renewable resource mix.

Q. Please describe PacifiCorp's efforts to support its customers during the pandemic.

A. First, the Company is working to keep the lights on. The Company's provision of safe and reliable electric service is important now more than ever to support families that stay at home during the pandemic and to support important community services, such as hospitals. While many of its personnel can work remotely, the Company's essential employees, such as linemen, generation plant employees, and grid operators continue to report to work on site with social distancing guidelines and enhanced sanitation measures to ensure the provision of safe and reliable electric service.

Second, the Company has suspended residential disconnections for non-payment and late payment fees and is helping accommodate all customers with payment plans. On July 23, 2020, the Company announced it was extending help for customers.[2]

Third, the Company is also actively participating in the Commission's series of COVID-19 workshops to collaboratively identify ways to transition to "business as usual" while mitigating customer impacts.

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[2] https://www.pacificpower.net/about/newsroom/news-releases/pp-extends-help-for-customers-behind-on-bills.html.

Fourth, since the onset of the pandemic, the Pacific Power Foundation[3] has donated $374,500 to community food banks and other critical organizations in Oregon specifically for COVID-19 community support.

The Company is committed to working with its customers and communities so we can all emerge from this historic situation stronger; the implications that the Company has not acted to aid its customers during the pandemic are untrue.[4]

Q. What recommendations do you make in your surrebuttal testimony?

A. In addition to approving the overall decrease in revenue requirement that I describe above, I recommend that the Commission:

1. Approve the Exit Dates and Exit Orders for the Company's coal-fired generating plants, except for Hunter Units 1, 2, and 3, Huntington Units 1 and 2, and Wyodak, which the Company will request in a future proceeding;

2. Approve the Company's investments in transmission and SCR systems at Jim Bridger Units 3 and 4 and Hayden Units 1 and 2;

3. Approve the recovery approach set forth by Staff regarding possible delays in the commercial operation dates (COD) for the EV 2020 new wind projects, repowering the Foote Creek I wind facility, and the Pryor Mountain Wind Project;

4. Approve the estimated decommissioning costs in the studies prepared by Kiewit Engineering Group, Inc. (Kiewit) (Decommissioning Studies) for inclusion in rates, or in the alternative, approve the Decommissioning Studies for inclusion in rates and open a proceeding for a further review of the Decommissioning Studies subject to true-up;

5. Approve the Company's proposal to buy down the undepreciated plant balance and closure costs related to the retirement of Cholla Unit 4; and

6. Approve the Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism as modified in my surrebuttal testimony.

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[3] The Pacific Power Foundation is funded with shareholder dollars.
[4] CUB/300, Jenks/2:3-4:13. (filed July 24, 2020).

Q. How is your surrebuttal testimony organized?

A. My testimony is structured as follows: Section II provides an overview of the Company's surrebuttal position and a summary of the positions in Staff and Intervenor rebuttal testimony; Section III addresses various proposals regarding the Company's capital investment, including disallowances for investments in transmission and SCR systems, requested attestations for certain capital investments, and a proposed recovery recommendation for Energy Vision 2020 new wind projects, repowering the Foote Creek I wind facility, and Pryor Mountain Wind Project; Section IV addresses depreciation and decommissioning costs; Section V addresses salaries and wages expense; Section VI addresses the Company's Oregon Energy Transition issues, including Exit Dates and Exit Orders for the Company's coal-fired generating units, the GPRA, and the Company's proposal to buy down undepreciated plant balance and closure costs for Cholla Unit 4 with TCJA deferred tax benefits; Section VII addresses the Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism; and Section VIII introduces the Company's surrebuttal witnesses.

II. PACIFICORP'S SURREBUTTAL POSITION

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I provide an overview of the rebuttal testimony filed by Staff and Intervenors in this proceeding. I also provide an overview of the Company's surrebuttal position in this proceeding.

Q. Which parties to the rate case filed rebuttal testimony?

A. Rebuttal testimony was filed by the following parties: Staff, the Alliance of Western

Energy Consumers (AWEC), Calpine Energy Solutions, LLC (Calpine), the Oregon Citizens' Utility Board (CUB), Sierra Club, and Tesla, Inc.

Q. Please provide comparison of the revenue change proposed by the Filing Parties' in their rebuttal testimony.

A. The revenue change proposed by each of the parties' as stated in their testimonies is indicated in Table 1 below. Table 1 also provides a parties' opening testimony revenue change position, where applicable.

Table 1: Filing Parties' Monetary Positions

Filing Party	Proposed Revenue Change (in millions)	Filing Parties Revenue Change- Opening (in millions)	Filing Parties Revenue Change- Rebuttal (in millions)
Company – *as filed*	$77.99		
Company – *reply*	$71.73		
Company – *surrebuttal*	$47.5		
Staff		$7.20[5]	($7.525) [6]
AWEC		$15.78[7]	

AWEC continues to support adjustments to the Company's revenue requirement but did not update its proposed revenue change. Other Filing Parties proposed adjustments but did not specify an overall proposed revenue change. For example, CUB continues to propose disallowances for the Jim Bridger SCR systems and proposes an ROE of 9.4 percent. Sierra Club continues to propose adjustments regarding the Company's investment in SCR systems at Jim Bridger Units 3 and 4, but did not rebut the Company's reply testimony on Hayden Units 1 and 2.

[5] Staff/100, Gardner/3-5, Table A.
[6] Staff/1800, Fox/4, Table A.
[7] AWEC/100, Mullins/2, Table 1. This amount does not reflect adjustments proposed by AWEC witness Dr. Lance D. Kaufman.

Q. What are the major drivers causing the divergence between the Filing Parties' positions and the Company's surrebuttal testimony?

A. The difference between the positions of the Company and the Filing Parties continues to be attributable to several key drivers: the calculation of ROE, capital structure, parties' adjustments related to SCR systems, and disallowance of a significant amount of the Company's transmission investments.[8]

Q. What are the Filing Parties' positions on ROE and the equity portion of capital structure?

A. The Filing Parties' positions on ROE and the equity portion of the capital structure are reflected in Table 2 and Table 3 below.

Table 2: Filing Parties' Positions Regarding ROE

Filing Party	Company ROE	Filing Parties-Opening ROE	Filing Parties-Rebuttal ROE
Company – *as filed and*	10.2%		
Company - *Surrebuttal*	9.8%		
Staff		9.0%	9.0%
AWEC		9.2%	9.2%
CUB[9]			9.4%
Sierra Club[10]		9.8%	

[8] Company witnesses Ms. Ann E. Bulkley and Ms. Nikki L. Kobliha address Filing Parties' recommendations regarding ROE and capital structure, respectively. Mr. James Owen, Mr. Rick T. Link, Mr. Dana M. Ralston, and Mr. Richard A. Vail address Filing Parties' recommendations concerning SCR systems. Mr. Vail addresses Staff's disallowance of transmission investment.
[9] CUB did not offer a recommendation regarding ROE in opening testimony.
[10] Sierra Club did not address ROE issues in rebuttal testimony.

Table 3: Filing Parties' Positions Regarding Capital Structure

Filing Party	Company's Capital Structure	Filing Parties Opening Capital Structure	Filing Parties Opening Capital Structure
Company – *as filed and*	53.2%		
Company - *Surrebuttal*	53.2%		
Staff		52.0%	50.64%
AWEC		50.64%	51.86%
Sierra Club[11]		52.1%	

Q. Please summarize generally PacifiCorp's positions on surrebuttal.

A. The Company is proposing certain adjustments in surrebuttal testimony. These adjustments have been incorporated in the updated revenue requirement sponsored by Ms. Shelley E. McCoy. Table 4 provides a list of all the adjustments that I will describe below.

Table 4: Adjustment to the Company's Revenue Requirement in Reply Testimony

Line Identifier	Description	Amount (in millions)
	Company Revenue Requirement – *reply position*	$71.8
A	Update ROE to 9.8%	(12.3)
B	Depreciation Study Settlement in Principle	(10.7)
C	Depreciation Rate Update – Other Adj.	(0.3)
D	Depreciation Rate Update – Protected EDIT	0.4
E	Cholla Unit 4 Decommissioning Reg. Liability	(0.7)
F	Removal of 2021 Wildfire Projects	(0.7)
G	Other Updates	(0.1)
	Total Adjustments	(24.4)
	Company Revenue Requirement – *Surrebuttal*	$47.5

Adjustments in lines A through G reflect adjustments attributable to updates due to more recent information and changes in position and are supported by various

[11] Sierra Club did not address capital structure issues in rebuttal testimony.

Company witnesses in their surrebuttal testimony. These adjustments constitute a 34.0 percent reduction to the Company's requested increase in reply testimony.

Q. How do you respond to the parties' position on ROE and capital structure?

A. The parties continue to recommend an unreasonably low ROE and improper capital structure in this proceeding. The Company has updated its ROE request to 9.8 percent, which maintains the Company's currently authorized ROE and is at the low end of the ROE range proposed by Ms. Bulkey. As explained in part by Ms. Bulkley, the Company's requested 9.8 percent ROE is supported by her updated analyses and is consistent with current and prospective market conditions. The requested ROE and capital structure proposed by Ms. Kobliha maintains the financial health of the Company as it pursues a transition of its resource portfolio at a lower cost, which benefits customers.

Q. Are the Company's proposals in this proceeding consistent with traditional ratemaking principles?

A. Yes. In this case, PacifiCorp has proposed regulatory treatments that drive the evolution, not erosion, of traditional ratemaking principles.[12] The Company's proposals work to expand the tools available to the Commission to address the dynamic circumstances utilities currently face, while operating within the Commission's established regulatory paradigm. These proposals address the fact that the Company is faced, not just in Oregon, but in many of its jurisdictions, with legislation or directives requiring compliance with certain environmental goals, such as Oregon Governor Brown's recent Executive Order 20-04. It is also faced with

[12] Staff/1800, Fox/6:7-7:16.

changing circumstances, where it must act quickly to address the security and safety of its customers, facilities, and employees, such as with the increased threat of wildfires. In its filing, the Company made discrete proposals, ranging from deferrals to recovery mechanisms that balanced the Company's ability to timely recover certain significant costs and maintain stable rates for customers.

Q. Please describe actions that PacifiCorp has taken to work with parties to this proceeding to ensure they have adequate information.

A. For the Commission to make an informed decision in a contested proceeding, a fully developed record on the issues is needed. As a result, even before PacifiCorp filed this rate case proceeding in February 2020, it began meeting with stakeholders to discuss specifics of the Company's rate case filing. This informal communication continued after the filing of the rate case. Consistent with the Commission's administrative rules that require parties to make every effort to engage in cooperative informal discovery and resolve disputes themselves,[13] PacifiCorp arranged biweekly general rate case meetings with parties to provide an opportunity to meet with the Company's subject matter experts, answer questions, walk through models, and discuss discovery issues including whether a data request response was answered with responsive information. This open communication among parties allowed the Company to provide a revised or supplemental response without the issuance of additional data requests, which can lead to further miscommunication and delay.[14]

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[13] OAR 860-001-500(5).

[14] Parties in a proceeding are also afforded a formal process to resolve discovery issues, such as discovery conferences with the Administrative Law Judge and motions to compel. *See* OAR 860-001-500.

Furthermore, internally, the Company took several steps to support continued communications with parties. First, witnesses or other technical personnel were made available to discuss data request responses with parties. Second, I communicated to all employees engaged in rate case support that timely responses to discovery was a priority.

The Company instituted these processes because absent a discussion of issues, either informally or formally, PacifiCorp is not provided the opportunity to address discovery concerns. In every contested case, the Company's goal is the development of a full factual record upon which the Commission can make a decision, and avoiding any claim that the Company has not provided sufficient information.

III. CAPITAL INVESTMENTS

Q. What is the purpose of this subsection of your surrebuttal testimony?

A. In this section of my testimony, I address proposals regarding certain capital investments. First, I address an adjustment proposed by Staff witnesses Ms. Nadine Hanhan, Mr. Yassir Rashid, and Mr. Matt Muldoon to disallow investments in transmission. Second, I respond to Sierra Club witness Dr. Jeremy Fisher's testimony regarding SCRs. Third, I address proposals made by Staff witnesses Mr. John L. Fox and Mr. Brian Fjeldheim regarding attestations requested for certain capital investments. Finally, I respond to Staff witness Mr. Steve Storm's recovery recommendation for Energy Vision 2020 new wind projects, repowering of the Foote Creek I wind facility, and Pryor Mountain Wind Project.

A. Disallowance of Transmission Investments

Q. Ms. Hanhan and Messrs. Rashid and Muldoon recommend (1) a total rate base disallowance of [redacted] for PacifiCorp's transmission investments, which is approximately [redacted] million on an Oregon-allocated basis; and (2) an investigation be opened to examine the Company's categorization of transmission, including all transmission above 100 kilovolts (kV). How do you respond?

A. Staff's recommendation is troublesome in a number of ways. First, the recommendation is contrary to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol). The recommendation also ignores that the Company allocates transmission and distribution in accordance with its Open Access Transmission Tariff (OATT). Finally, raising this issue for the first time in rebuttal testimony deprives the Company appropriate time to respond to Staff's radical departure from how the Company has consistently treated transmission assets throughout its system. For these reasons, the Commission should reject Staff's recommendations.

Q. Please explain.

A. Staff's new approach to transmission investments on rebuttal is inconsistent with the historical ratemaking treatment relied upon in the 2020 Protocol to which Staff was a signatory. In the 2020 Protocol, amounts are defined by Federal Energy Regulatory Commission (FERC) account, and the Company's transmission account has historically included all transmission investments over 46 kV.[15] By seeking to

[15] *See In the Matter of PacifiCorp dba Pacific Power Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 20-024,

reallocate the Company's transmission investments in this rate case, Staff ignores its recent commitment to a systematic and fair allocation of transmission investments in the recent 2020 Protocol settlement.

The Company's existing approach results in a fair and consistent allocation of costs across the six states in which PacifiCorp operates. As explained in the surrebuttal testimony of Mr. Vail, the Company's approach is consistent with the OATT and FERC's guidelines. If each state were to adopt different or inconsistent methodologies for allocating transmission and distribution, there would likely be orphaned investments and an incentive for states to conclude that any transmission investment incurred out of state should be situs-assigned, regardless of overall system benefits. Notably, Staff has not acknowledged the prior treatment of the Company's transmission investments in the 2020 Protocol, or presented any evidence to support either disallowance or the need for a new investigation.

Q. Do you have additional concerns regarding the timing of Staff's new transmission disallowances and investigation proposals?

A. Yes. By raising these proposals in rebuttal, Staff has undermined the Company's ability to fully respond to Staff's novel position. Indeed, Staff has since modified its proposed disallowance in discovery, though the precise impact of Staff's modification remains unclear. For instance, it is unclear whether Staff's modified proposal would allow recovery of investments that are upgrades to existing transmission assets, where the underlying base assets are already in rates. This issue is discussed in more detail in the surrebuttal testimony of Mr. Vail.

Appendix B at 4 (Jan. 23, 2020) (requiring PacifiCorp to file for approval with the Commission before seeking reclassification of facilities as transmission or distribution with FERC).

Q. Do you have any additional concerns with Staff's proposed treatment of transmission investments in this proceeding?

A. Yes. Staff's proposed methodology unfairly proposes and applies a new regulatory standard retroactively. Staff's new approach seeks, for the first time, to itemize all of the Company's pro forma transmission investments. If Staff wishes to apply a new approach to auditing transmission investments, this should happen prospectively. This would allow the Company to anticipate the kind of documentation Staff wishes to review and adopt new record-keeping practices. Without notice, it was extremely challenging to gather and present the requested data for 137 transmission projects, especially in the shortened time periods applicable at this stage of the case. Staff's proposed disallowance is also one-sided, adjusting for facilities outside Oregon, but not accepting the total costs for facilities located within Oregon.

Moreover, Staff's approach is inconsistent with Staff's own findings in its recent audit of the Company, in which Staff found that transmission investments can be appropriately investigated through a sampling approach.[16] Notably, Staff's audit report did not raise any issues regarding limiting lower voltage investments to those located in Oregon.

Q. Does Staff offer an alternative to its substantial disallowance proposal?

A. Yes. As an alternative to Staff's proposed disallowance, Staff suggests that the Commission could authorize deferred accounting to track the revenue requirement

[16] Audit Report of PacifiCorp Audit Number 2019-01 (May 12, 2020) (Table 1: Summary of Findings). PacifiCorp is not suggesting a random sampling is dictated by the Audit Report, but requesting all underlying agreements, change orders, one-line diagrams, and other detailed documentation before conducting the higher level review is extremely difficult to accomplish within the time limitation of a general rate case proceeding.

impact of the Company's transmission investments, pending resolution of Staff's proposed transmission allocation investigation.

Q. Do you believe that deferred accounting treatment would be appropriate in this case?

A. No. Staff's deferred accounting proposal would require the Company to repeat the process of demonstrating the prudence of the Company's costs—a process that PacifiCorp has already undergone in considerable depth in this case. There is no basis for establishing an ongoing tracking mechanism so that the Commission can subsequently review costs for prudence, where the prudence of these costs is already fully supported. That said, if the Commission accepts Staff's transmission adjustment and opens an investigation, PacifiCorp will need a deferred account to allow it an opportunity to recover transmission costs incurred during the investigation.

Q. Does any other witness address concerns with Staff's proposed disallowance and attempt to insert reclassification issues into this proceeding?

A. Yes. Mr. Vail's surrebuttal testimony explains that Staff's proposal misunderstands the Company's OATT, as well as the role FERC plays in the classification of transmission investments.

B. Investment in SCR Systems

Q. In an attempt to marginalize the California Public Utilities Commission (CPUC) decision to allow the Company's investment in SCR systems at Jim Bridger Units 3 and 4 and Hayden Units 1 and 2 into the Company's California rates, Dr. Fisher cites the CPUC's lack of oversight of PacifiCorp and the CPUC's withdrawal of the Company's alternative compliance mechanism for California's Emission Performance Standard (EPS).[17] How do your respond?

A. I completely disagree with Dr. Fisher's characterization of the CPUC's oversight of the Company and the implications of the change in how PacifiCorp demonstrates compliance with the EPS standard. As with all the state commissions in the jurisdictions that PacifiCorp operates, the CPUC thoroughly investigates the Company's applications and compliance with CPUC requirements and the Company maintains compliance with all regulatory requirements in California. Further, the CPUC's decision in the Company's 2019 California Rate Case, Application 18-04-002 (California Rate Case), to withdraw the Company's use of an alternative form of EPS compliance was an issue specific to that state and is irrelevant to the issues raised in this case. Dr. Fisher's claim that the CPUC's withdrawal of the Company's alternative compliance mechanism for the California EPS established that the Company "had not been acting in good faith under the EPS in California" is wholly unsupported and a gross mischaracterization of the CPUC's decision in the California Rate Case. With regard to the California EPS, the CPUC found "in the past 12 years PacifiCorp has invested in baseload energy generation facilities that exceeded the

[17] Sierra Club/400, Fisher/40:9-43:4.

1,100 [pounds] CO2/MWh EPS limit, and *it is disputed* whether those expenditures violate EPS."[18] The CPUC did not find PacifiCorp to be either acting in bad faith or in violation of California EPS standard.

Finally, I note that in finding the Company's expenditures for emissions control equipment at Jim Bridger, Hayden, and Craig coal-fired plants reasonable and necessary, the CPUC found that "[a]lthough Sierra Club questions the rational for these decisions [to install SCR systems at Jim Bridger], Sierra Club's lack of support from pricing changes and forecasting data which could have impacted these decisions raises Sierra Club's questions to nothing more than speculation."[19] The evidence presented by Sierra Club in this proceeding suffers the same flaws as discussed in the reply and surrebuttal testimony of Mr. Link, Mr. Owen, and Mr. Ralston.

Q. Dr. Fisher asserts that in the settlement entered into in the Company's Washington Rate Case filed on December 13, 2019 (Washington Rate Case), "PacifiCorp agreed to accelerate the depreciation - and then remove from rates - Washington's ratable allocation of PacifiCorp coal by year-end 2023."[20] He adds that in the Company's 2019 California Rate Case, PacifiCorp also requested accelerated depreciation for various coal units, but made no similar offer to remove coal units from rates. How do you respond?

A. Again, Dr. Fisher mischaracterizes the facts and circumstances in each instance and misrepresents the impact of accelerating depreciation on rates. With respect to the

[18] *In the Matter of the Application of PacifiCorp (U901E), and Oregon Company, for an Order Authorizing a general Rate Increase Effective January 1, 2019,* Application 18-04-002, Decision 20-02-025, pp. 51-52 (Feb. 6, 2020). (emphasis added) (footnotes omitted).
[19] Decision 20-02-025, pp. 34-35 (Feb. 6, 2020).
[20] Sierra Club/400, Fisher/45:7-46:2.

settlement of the Company's Washington Rate Case, the settlement accelerates the depreciation of the Company's Colstrip and Jim Bridger generating units to 2023, which complies with Washington law that requires the depreciation costs of all coal-fired plants to be removed from rates by the end of 2025.[21] Similarly, in this proceeding, through the proposed Exit Dates and Exit Orders, the Company has set forth a plan to remove costs of coal-fired plants from Oregon rates by 2029. I discuss the Exit Dates and Exit Orders later in my testimony. In the Company's California Rate Case, the Company proposed to accelerate depreciation on coal units to the earlier end-of-useful life of 2029.[22] Unlike Oregon and Washington, California law does not require that utilities remove costs associated with coal-fired generating plant from rates by a date certain.

C. Attestations for Capital Additions

Q. Mr. Fox continues to recommend that for non-wind and non-transmission capital additions over $1 million, the Company provide attestations for plant placed in-service near the rate effective date.[23] How do you respond?

A. In reply testimony, the Company indicated that it does not oppose providing attestations but believes that the threshold should be set at $5 million on an Oregon-allocated basis.[24] Mr. Fox states that Staff does not support the Company's proposal at this time, without further explanation. The Company continues to support the $5 million threshold as more appropriate given the small impact the non-wind and

[21] Washington Utilities and Transportation Commission v. Pacific Power & Light Company, Docket Nos. UE-191024, UE-190750, UE-190929, UE-190981, and UE-180778 (cons.), Exhibit JT-1, 38:6-39:13.
[22] Application 18-04-002, PAC/1400, 9:5-17.
[23] Staff/1800, Fox/26:7-10.
[24] PAC/2000, Wilding/19:13-18.

non-transmission projects that Mr. Fox identified in opening testimony have on Oregon-allocated rate base.[25]

Q. Does Mr. Fjeldheim revise his recommendation regarding the capital investments in PacifiCorp's Klamath Hydroelectric Facilities?

A. Yes. While no longer proposing an adjustment with respect to the capital investments, Mr. Fjeldheim asserts that these investments in the Klamath Hydroelectric Facilities, which are governed by the Klamath Hydroelectric Settlement Agreement, may be imprudent especially if the facilities are successfully deconstructed and removed in the next three years. Staff recommends that the Commission (1) order the Company provide a written attestation by a Senior Company officer affirming when capital additions currently slated to be used-and-useful in November and December 2020 are complete; and (2) exclude any capital addition that will not be used and useful by January 2021.

Q. How do you respond?

A. As an initial matter, just prior to Staff filing its rebuttal testimony, FERC denied the transfer of the licenses for the Klamath Hydroelectric Facilities. While the Company is still reviewing the implications of the FERC decision, the Company remains the licensee of these facilities and responsible for their ongoing operations as described in the reply testimony of Company witness Mr. Timothy J. Hemstreet.[26] These capital additions are appropriate to be included in rate base because they are required to ensure the continued safe and efficient operation of these facilities and compliance

[25] PAC/2000, Wilding/18, Table 4; *see also* Staff/1000, Fox/21:17-22:20.
[26] PAC/2700, Hemstreet/12:3-13:21.

with FERC requirements.[27] Further, the Company disagrees with Staff's recommendation that the Company provide attestations verifying capital additions are used and useful by the rate effective date in this proceeding. As I explain above, for attestations related to capital additions placed in-service near the rate effective date, the Commission should adopt a threshold of $5 million on an Oregon-allocated basis.

D. Cost Recovery of New Wind and Repowering Projects

Q. Does Mr. Storm revise the recommendation regarding cost recovery for Energy Vision 2020 New Wind projects, repowering the Foote Creek I wind facility, and the Pryor Mountain Wind Project?

A. Yes. In response to the Company's reply testimony, Mr. Storm proposes a middle ground, namely, that the Commission should require PacifiCorp to confer with parties to this proceeding regarding these projects if the COD, including that of necessary transmission infrastructure, is after June 30, 2021. If the project is placed in-service on or before June 30, 2021, but after December 31, 2020, Staff recommends allowing a rate effective date following the project's COD and receipt of a signed declaration from a Vice President of Pacific Power or Rocky Mountain Power attesting that the project has been placed in-service and is in commercial operation.[28]

Q. How do you respond to Mr. Storm's revised recommendation regarding cost recovery for Energy Vision 2020 New Wind projects, repowering the Foote Creek I wind facility, and the Pryor Mountain Wind Project?

A. I agree with Mr. Storm's recommendation. It provides the Company the ability to recover the costs of these projects that bring low-cost renewable energy to customers

[27] *Id.*, 13:13-21.
[28] Staff/2000, Wilding/3:3-11, 4:1-6.

while recognizing the impacts of the COVID-19 pandemic on construction.

IV. DEPRECIATION AND DECOMMISSIONING COSTS

Q. What is the purpose of this section of your surrebuttal testimony?

A. The purpose of this section of my testimony is two-fold. First, I provide an update regarding the Company's application for an accounting order authorizing a change in depreciation rates in docket UM 1968.[29] Second, I address the testimony of Staff witness Mr. Storm, CUB witness Mr. Bob Jenks, and AWEC witness Dr. Lance D. Kaufman regarding the Decommissioning Studies prepared by Kiewit.

Q. Please provide an update on PacifiCorp's application for an accounting order authorizing a change in depreciation rates in docket UM 1968.

A. The Company has reached an agreement in principle with the parties in docket UM 1968 regarding the Company depreciation rates, excluding decommissioning costs, which is being addressed in this proceeding. The parties in docket UM 1968 expect to file a stipulation and supporting joint testimony on August 17, 2020. In her surrebuttal testimony, Ms. McCoy has incorporated the agreement in the revenue requirement.

Q. What do Staff, CUB, and AWEC recommend with respect to the incorporation of decommissioning costs in depreciation rates in this proceeding?

A. Mr. Storm recommends that the Commission (1) order the Company to use the estimated decommissioning costs included in its initial filing in docket UM 1968 for each coal-fired unit in Oregon rates; and (2) allow the Company to make a filing subsequent to the rate effective-date in this proceeding to determine whether the

[29] *In the matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates,* Docket No. UM 1968, Application filed Sept. 13, 2018.

decommissioning costs set in this proceeding should be adjusted.[30] Similar to the Staff recommendation, Mr. Jenks recommends that the Company use the estimated decommissioning costs included in its initial filing in docket UM 1968[31] for each coal-fired unit in Oregon rates and either conduct further proceedings in this docket or an entirely new investigation be initiated to review the Decommissioning Studies.[32] Dr. Kaufman claims that the Commission has three options with respect to decommissioning costs: adopt the Decommissioning Studies, adopt the decommissioning study originally submitted by the Company in docket UM 1968, or adopt Dr. Kaufman's "compromise" option. Dr. Kaufman states that AWEC is not opposed to Staff's and CUB's recommendations *per se* but any additional proceedings would require additional evidence to support the Decommissioning Studies.[33]

Q. Do you agree with the recommendations of Staff, CUB, and AWEC?

A. No. As explained in further detail by Mr. Robert Van Engelenhoven, the Independent Evaluator (IE) Report's conclusions are based on a misunderstanding of the information that PacifiCorp provided Kiewit and what costs are reflected in the base estimate for decommissioning costs.

Q. What is your recommendation with respect to the incorporation of decommissioning costs in depreciation rates in this proceeding?

A. The Decommissioning Studies should be incorporated into the Company's rates in

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[30] Staff/1700, Storm/3:2-9.
[31] *In the matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates,* Docket No. UM 1968, Application filed Sept. 13, 2018.
[32] CUB/300, Jenks/7:20-8:10.
[33] AWEC/500, Kaufman/42:3-13.

this proceeding. These estimated decommissioning costs are a critical piece of the 2020 Protocol and Oregon's transition out of coal. For the coal plants that continue to operate beyond the Oregon Exit Date, Oregon customers will only pay an estimated decommissioning amount without a true-up to actual amounts. Per the 2020 Protocol, the Decommissioning Studies were meant to provide those estimated costs for allocation purposes. Additionally, the amount of decommissioning costs to be paid for by Oregon customers is of particular interest to the other states within the Company's service territory, which also agreed to this treatment as part of the 2020 Protocol, as filings will be made in those states beginning next year to determine potential reassignment of the coal plants.

However, if the Commission determines that the record should be developed further with respect to the Decommissioning Studies, the Company recommends that the Commission (1) use the Decommissioning Studies to set rates in this proceeding; and (2) open a separate proceeding to allow further review and investigation of the Decommissioning Studies, where the final decommissioning cost estimates can be trued-up to the amounts included in rates. The Company will work with stakeholders regarding additional analyses that can be performed in lieu of providing Kiewit workpapers.

The "compromise" position offered by AWEC is flawed and should be rejected. The AWEC position is unsupported and suffers from many of the misunderstandings regarding the Decommissioning Studies demonstrated by the IE Report. See Mr. Van Engelenhoven's testimony for further discussion.

Q. If the Commission determines that the Decommissioning Studies would benefit from further analysis, why use the Studies to set rates in this proceeding?

A. It is in the public interest to reflect the best estimate of decommissioning costs in rates. Reflecting the best estimate in customer rates minimizes rate pressure and maintains rate stability. If the original decommissioning study is reflected in rates and the review of the updated Decommissioning Studies deferred to a separate proceeding, following the approval of updated decommissioning costs in that separate proceeding, customer rates would need to be updated again, creating rate instability for customers and potentially increasing rate pressure for customers. The best estimate of decommissioning costs before the Commission in this proceeding are those contained in the Decommissioning Studies prepared by Kiewit and its subcontractors, independent third-parties with experience in the decommissioning, demolition, and reclamation of coal-fired plants. It would be reasonable to include the estimates contained in the Decommissioning Studies in rates, subject to review in a separate proceeding, because it minimizes rate pressure on customers and maintains rate stability.

Q. In reply testimony, the Company indicated that it did not oppose Mr. Jenks' proposal for a non-bypassable charge for incremental decommissioning costs.[34] Do you have any comments on this proposal based on the rebuttal testimony filed by AWEC and Calpine?[35]

A. Both AWEC and Calpine raise concerns regarding CUB's proposed non-bypassable charge that merit further discussion. The Company would not oppose addressing the

[34] PAC/2000, Wilding/27:10-20.
[35] AWEC/500, Kaufman/44:8-45:2; Calpine/200, Higgins/3:7-4:7.

issue in docket UM 2024 as suggested by both AWEC and Calpine.

V. SALARIES AND WAGES

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I address Ms. Cohen's proposal to apply a "sharing principle" to the Company's wage projections. Specifically, I address Ms. Cohen's proposal is to apply a "sharing principle" to wage projections whereby Staff allows the Company to share 50/50 the lesser of the difference between the wage projections as calculated by Staff and the Company or a 10 percent band around Staff's projection, applying the 28.3 Oregon-allocated percentage.[36]

Q. Do you agree with Ms. Cohen's "sharing principle"?

A. No. The Commission has found that the ratemaking formula allows it to set just and reasonable rates based on a forecast of a utility's revenue needs and is not intended to render one correct result.[37] Like all forecasts, a utility's actual costs will vary. As a result, some estimates used in rates will be too high and other too low—a utility absorbs the expenses if they are higher and benefits to the extent that they are lower.[38] This gives the utility the incentive to operate efficiently and manage its costs to attain its authorized ROE.[39] If costs deviate significantly, either the utility will file a rate case or the Commission or a customer may initiate a rate review.[40] This ratemaking principle works as the last rate case the Company filed was seven years ago. The Staff proposal seeks to pick one expense and refine an estimate with a sharing

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[36] Staff/2500, Cohen/3:1-3.
[37] Docket Nos. DR 10, UE 88, and UM 989, Order 08-487, 5 (dated Sept. 30, 2008).
[38] *Id.*
[39] *Id.*
[40] *Id.*

mechanism. Unlike net power costs or wildfire mitigation costs, or other costs where circumstances are continuing to evolve or accurate forecasting is challenging, this cherry picking by Staff is not proper as it is a disincentive to efficient operations. Furthermore, the Commission will determine either that the Company's wage projections or the Staff's wage projections are just and reasonable. Thus, the proposed sharing mechanism would function to disallow costs that have been found prudent.

VI. OREGON ENERGY TRANSITION

Q. What is the purpose of this section of your surrebuttal testimony?

A. The purpose of this section of my testimony is two-fold. First I will address the rebuttal testimony of Staff witness Ms. Rose Anderson and Sierra Club witness Dr. Ezra D. Hausman regarding the Exit Orders the Company has requested in this proceeding. Second, I address the need for the Company's proposed GPRA, if the Commission approves the Company's proposal to use the TCJA tax benefits to buy down the plant balance and closure costs of Cholla Unit 4. I also respond to Dr. Kaufman's testimony regarding the Company's proposed use of TCJA tax benefits to buy down the plant balance and closure costs of Cholla Unit 4.

A. Request for Exit Orders

Q. Ms. Anderson states that the Company's position requesting Exit Orders for Hunter Units 1, 2, and 3, Huntington Units 1 and 2, and Wyodak is inconsistent with the 2020 Protocol.[41] How do you respond?

A. I respectfully disagree with Ms. Anderson. The 2020 Protocol does not dictate when

[41] Staff/2200, Anderson/3:21-4:19.

the Company is to request a specific Exit Order, only a time frame, namely, that:

> Oregon Parties and the Company will strive to have Exit Orders issued by the Oregon Commission issued by December 31, 2023 for [Hunter Units 1, 2, and 3, Huntington Units 1 and 2, and Wyodak] to allow the Company to make the necessary filings in other States in accordance with Section 4.2 [of the 2020 Protocol].[42]

The Company requested the Exit Orders in this proceeding because it is a general rate case filing, which it believed to be the preferred proceeding-type for the Oregon parties to address the issue of Exit Orders. There is no certainty that the Company will file another rate case and receive a Commission Order prior to December 31, 2023.

Q. Is Staff still recommending that the Commission not issue Exit Orders for Hunter Units 1, 2, and 3, Huntington Units 1 and 2, and Wyodak in this proceeding?

A. Yes. Even though it continues to believe it would be appropriate for the Commission to issues Exit Orders for these units, to narrow the issues in the rate case the Company does not oppose Staff's request for additional time to consider cost allocation and economic retirement dates for these units. With the clarification that a request for Exit Orders for these units can occur outside of a rate case proceeding, the Company does not oppose Staff's recommendation to not issue Exit Orders for Hunter Units 1, 2, and 3, Huntington Units 1 and 2, and Wyodak at this time. However, I note that the Company will need to make a filing over the course of the next several years, likely outside of a rate case proceeding, to ensure it receives an

[42] *In the matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, 2020 Protocol, 22:457-461.

Order from the Commission issuing Exit Orders for these units by December 31, 2023.

Q. Does Dr. Hausman continue to recommend that the Commission issue Exit Orders for all of the Company's coal-fired units with Exit Dates no later than December 31, 2025?[43]

A. Yes. However, in his rebuttal testimony, he adds an alternative position, namely, that if the Commission declines to adopt his proposal, the Commission direct PacifiCorp to update its integrated resource plan (IRP) analysis using current load, electricity price, and gas price expectations, along with updated renewable and storage resource costs, to determine whether retaining its coal-fired units beyond December 31, 2025, is in customers' interest. He adds that this updated analysis incorporates the social cost of carbon as indicated in the Commission's report on Executive Order (EO) 20-04. I address Dr. Hausman's recommendation regarding accelerating the Exit Dates for all of the Company's coal-fired units to December 31, 2025. Mr. Link addresses Dr. Hausman's alternative recommendation regarding the IRP.

Q. Does the Company continue to oppose Dr. Hausman's recommendation that the Commission issue Exit Orders for all of the Company's coal-fired units with Exit Dates no later than December 31, 2025?

A. Yes, for all the reasons set forth in the Company's reply testimony.[44] Dr. Hausman provides no additional justification to support for his recommendation.

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[43] Sierra Club/500, Hausman/13:5-13.
[44] *See* PAC/2000 and PAC/2300.

Q. Dr. Hausman claims that in direct testimony he provided "reasons that in [his] judgement the overall impact of [his] recommendations on revenue requirements would be modest, and could result in customer savings over the long term."[45] How do you respond?

A. No Sierra Club witness, including Dr. Hausman, appears to have quantified the impact of his recommendation on customer rates nor has he provided a cost benefit analysis demonstrating that the long-term savings that "could" result from his recommendation outweighs the cost. I also take exception to Dr. Hausman's implication that PacifiCorp has the responsibility to evaluate his proposal and provide a full accounting of all costs. Specifically, Dr. Hausman asserts "However, it is PacifiCorp's ultimate responsibility to evaluate options for implementing the Governor's GHG mitigation goals and to provide a full accounting of associated cost, for comparison with the costs of its proposed plan, to the Commission."[46] As an initial matter, this is a rate case proceeding, not a proceeding evaluating a plan set forth by the Company in compliance with EO 20-04 or a Commission investigation to address EO 20-04. Setting this aside, while burden of proof will be addressed in the Company's briefs, it is my understanding that a party, once having made a proposal to the Company's direct case, has the burden of carrying it forward.

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[45] Sierra Club/500, Hausman/8:17-9:1.
[46] Sierra Club/500, Hausman/9:1-5.

Q. Dr. Hausman claims that the Company's interpretation of EO 20-04 would result in no modification of the Commission's review of the utility's planning and rates, despite the directives laid out in EO 20-04.[47] He claims that the Company's sole focus is on costs and not implementing the greenhouse gas (GHG) directives of EO 20-04.[48] How do you respond?

A. Dr. Hausman's assertions mischaracterize the Company's reply testimony, which explained the need to balance the directives in EO 20-04 with cost impacts on customers. Further, as I stated earlier, this is a rate case proceeding, not a proceeding to implement the directives in EO 20-04. The Commission will lead the effort to develop consistent policies that comply with the directives of EO 20-04 for all utilities in the state. As the Commission stated in its "Report on Executive Order 20-04,"

> This report is not a final, definitive statement on the PUC's response to EO 20-04, but rather a starting point and a set of potential directions to prioritize and carry out with stakeholder input and through public processes in the coming months and years. We have already conducted preliminary informal outreach sessions with stakeholders to help us prepare this initial report. We look forward to further dialogue with the Governor's office, as well as broader and more extensive engagement with stakeholders to shape the PUC's approach to implementing EO 20-04.[49]

The Company looks forward to participating as a stakeholder in the Commission process to determine the approach to implementing EO 20-04.

[47] Sierra Club/500, Hausman/8:2-11.
[48] Sierra Club/500, Hausman/5:4-13.
[49] Public Utility Commission of Oregon Report on Executive Order 20-04 at 1. (May 15, 2020).

Q. Based on his review of Table R.4 of Appendix R of the Company's 2019 IRP combined with lower energy prices and a decreased demand outlook, Dr. Hausman claims that the Company might reasonably retire more units early or remove them from Oregon's resource mix and significantly reduce GHG emissions, at a minimal cost to ratepayers.[50] How do you respond?

A. As modified above, the Company is requesting Exit Orders with Exit Dates for all but six of its coal-fired units; thus, the majority of the Company's gas-fired units will be removed from Oregon rates by December 31, 2027. The Company's resource mix, including whether a coal-fired unit is retired early, is driven by the Company's IRP. In the event that that a coal-fired resource is identified that also has received an Exit Order, the Company would make the appropriate filing with the Commission and work with the Commission and stakeholders to remove the coal-fired resource at the earlier date. However, any potential early retirement of a coal-fired resource is speculation. Furthermore, Dr. Hausman provides no support for his conclusion that the early retirement of a coal-fired unit could be accomplished at a minimum cost to customers. Please see Mr. Link's testimony for further discussion of the IRP.

[50] Sierra Club/500, Hausman/11:8-12:6.

B. GPRA

Q. Does Staff continue to oppose the Company's proposed GPRA mechanism, which would allow the Company to recover costs associated with the closure of or termination of its ownership interest in generation plants and provide a credit to customers for the revenue requirement associated with a generation plant that is removed between general rate cases?

A. Yes. Staff continues to recommend that such costs be recovered through an automatic adjustment clause. However, Staff supports the Company's recommendation to remove the undepreciated plant balance for Cholla Unit 4 from the proposed GPRA and offset those costs with the TCJA tax benefits.[51]

Q. Has the Company revised its position regarding the GPRA?

A. Yes. Because of Staff's support of the buy down of the Cholla Unit 4 undepreciated plant balance, the need for a recovery mechanism is not immediate. However, to clarify, the Company's proposal is to apply TCJA tax benefits to the Cholla Unit 4 undepreciated plant balance *and* closure costs. Therefore, with that understanding, in order to reduce the issues in this proceeding, the Company withdraws the GPRA from consideration. Please see Ms. McCoy's testimony for the clarification requested by Ms. Anderson as to whether decommissioning costs are included in closure costs.

Q. Is the Company's position impacted by AWEC's objections regarding the buy down of Cholla Unit 4's undepreciated capital costs and closure costs?

A. Yes. If the Commission agrees with AWEC's arguments, the Company would request that the GPRA be approved as proposed by the Company to allow the

[51] Staff/2200, Anderson/8:2-17.

Company recovery of the Cholla Unit 4 undepreciated plant balance and closure costs.

Q. Dr. Kaufman asserts that that the Company's proposed buy down of the Cholla Unit 4 undepreciated plant balance and closure costs with TCJA tax benefits is not appropriate because the TCJA tax benefits should be returned to customers as soon as possible, while the undepreciated plant balance should be recovered from customers through 2025 to match the timing of costs and benefits of early retirement of Cholla Unit 4.[52] How do you respond?

A. Dr. Kaufman's concerns are misplaced. The Company's proposal provides short-term and long-term benefits to customers. In the short term, it alleviates rate pressure as a result of this proceeding because the recovery of the undepreciated plant balance and closure costs associated with Cholla Unit 4 will not be in revenue requirement. It also benefits customers in the long term as it eliminates a significant portion of a known customer obligation from future recovery. Further, this is not a new ratemaking concept in Oregon as it was recently used in the Company's 2019 Renewable Adjustment Clause, which is discussed by Ms. McCoy. Ms. McCoy also addresses the remainder of Dr. Kaufman's testimony regarding the Company's proposal to use TCJA tax benefits to buy down the Cholla Unit 4 undepreciated plant balance and closure costs.

[52] AWEC/500, Kaufman/17:13-22.

VII. WILDFIRE MITIGATION AND VEGETATION MANAGEMENT COST RECOVERY MECHANISM

Q. What is the purpose of this subsection of your surrebuttal testimony?

A. In this section of my testimony, I address the testimony of Staff witness Mr. Mitchell Moore and AWEC witness Dr. Kaufman regarding the Company's proposed Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism.

Q. Does Staff propose an alternative Vegetation Management and Wildfire Mitigation Cost Recovery Mechanism?

A. Yes. Beginning with the mechanism the Company proposed in reply testimony, Mr. Moore proposes a number of revisions, such as the introduction of certain performance metrics and an earning test.[53] Staff also recommends the Commission approve a third-party expert to aid Staff in its evaluation of PacifiCorp's wildfire mitigation capital investment projects.[54]

Q. Does the Company agree with the revised Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism?

A. Yes, with modification.

The Company proposes the following changes to the timing of the filing to align the period in which the wildfire mitigation and vegetation management costs are incurred with the period for which the Company's reports its earnings.

- The deferral period will align with the calendar year.
- A filing date of May 5 each year.
- Rate effective date of November 5 each year.

[53] Staff/2700, Moore/7:20-10:17.
[54] Staff/2700, Moore/25:1-8.

These timing changes are necessary to incorporate the earnings test as outlined by Staff, but still allow the same amount of time for review as proposed in rebuttal testimony and agreed to by Staff.[55]

The Company proposes the entire amount of wildfire mitigation and vegetation management costs requested in this case, $33.225 million, be allowed in rates. It is inappropriate to disallow prudent costs in a rate case and make those costs subject to an earnings collar. However, PacifiCorp proposes that the first $6.645 million (the same dollar amount as Staff's proposal) of wildfire mitigation and vegetation management costs incremental to what is included in rates be subject to the performance metrics as outlined by Staff.

The Company proposes that the violation levels as outlined by Staff be normalized on a per audit miles basis. The normalized audit miles used would be equal to one-third of the overhead mileage within Oregon, with an error rate of 0.3 percent, calculated as vegetation management violations per 14,359 overhead miles (PacifiCorp's Oregon 2019 tax report miles) with an average span length of approximately 300 feet, equating to approximately 84,239 spans available to be sampled.

Lastly, PacifiCorp agrees to the use of an independent expert to review the Company's wildfire mitigation plan and performance against the plan. However, the Commission should set the criteria, scope, budget, and selection of an independent expert through the Commission's wildfire rulemaking that I understand will be opened later this month.

[55] Staff/2700, Moore/7:12-13.

Q. Dr. Kaufman recommends that the Commission reject the Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism based on the forecastability of costs, minimal harm to the Company, ratemaking principles, and that costs would only be borne by customers.[56] How do you respond?

A. In disagreeing with AWEC's arguments that deferrals are not appropriate for wildfire mitigation costs, Mr. Moore states that "[w]ildfires are an increasing risk to the safety of Oregonians, which the Governor's Executive Order demonstrates is a substantive policy issue that warrants special treatment."[57] I agree with Mr. Moore. Wildfire mitigation costs, and the related vegetation management costs,[58] proposed for recovery through the deferral mechanism addresses a substantive policy issues that ensures the safety of the Company's customers, employees, and facilities.

The argument about whether these costs can be forecasted misses the mark. Because of the substantial nature of these costs, without a deferral mechanism, the Company faces a multi-year regulatory lag on important and significant capital expenditures. As noted by the Commission in Order No. 20-147, in concluding that ORS 757.259(2)(e) empowers it to authorize deferral of capital project costs, "[d]eferral is but one of many ratemaking tools available to the Commission" but utilities should utilize the standard rate case process to recover its capital costs.[59] The significant nature of these costs and the substantive policy issue addressed makes this deferral mechanism appropriate.

[56] AWEC/500, Kaufman/32:5-16.
[57] Staff/2700, Moore/26:12-15.
[58] Staff proposed that vegetation management costs be included in the deferral related to wildfire mitigation. *See* Staff/600,Moore/12:4-13.
[59] *In the Matter of Public Utility Commission of Oregon, Investigation of the Scope of the Commission's Authority to Defer Capital Costs,* Docket No. UM 1909, Order No. 20-147, 13 (Apr. 30, 2020).

Finally, the hardening of the Company's system against wildfire threat benefits shareholders and customers. It is in the public interest to ensure the safety of the Company's customers, employees, and facilities, and ensure the Company continues to provide safe, reliable service. While the deferral mechanism allows the Company to reduce regulatory lag, the costs deferred through the mechanism are still subject to a Commission prudency review in the Company's next rate case.[60]

Q. Does AWEC propose an alternative recommendation?

A. Yes. Dr. Kaufman states that if the Commission approves the Wildfire Mitigation and Vegetation Management Cost recovery Mechanism, AWEC recommends that the Commission only allow for the recovery of these costs subject to an earning test that is set at 100 basis point below the Company's authorized return.[61]

Q. How do you respond?

A. The Company has agreed to, with modification, the Staff proposal regarding the Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism. Staff's proposal includes an earning test to which the Company does not object. AWEC's proposal should be rejected.

VIII. INTRODUCTION OF WITNESSES

Q. Please present the Company's witnesses submitting surrebuttal testimony in response to the rebuttal testimony submitted by the Filing Parties.

A. In addition to myself, the Company is presenting surrebuttal testimony from the following witnesses:

[60] As the Commission stated in Order No. 20-147, "any decision to defer capital project costs is not an authorization or determination that such amount will be necessarily be included in rates in the future." *Id.,* 13-14.

[61] AWEC/500, Kaufman/35:4-18.

- In Exhibit PAC/3400, Nikki L. Kobliha, Chief Financial Officer, responds to the Filing Parties positions regarding capital structure, Green First Mortgage Bonds, and cost of debt. She also addresses Filing Parties' recommendations regarding pension expense.

- In Exhibit PAC/3500, Ann E. Bulkley, economist and principal at Concentric Energy Advisors, supports the Company's revised recommendation for ROE. She also responds to the ROE recommendations of the Filing Parties.

- In Exhibit PAC/3600, Michael G. Wilding, Director, Net Power Costs and Regulatory Policy, responds to Filing Parties' positions regarding net power costs, the Company's proposed Annual Power Cost Adjustment (APCA), and the TAM.

- In Exhibit PAC/3000, Frank C. Graves, principal with the Brattle Group, supports the Company's request for the proposed APCA and addresses the arguments raised by Filing Parties regarding the APCA.

- In Exhibit PAC/3800, Rick T. Link, PacifiCorp's Vice President of Resource Planning and Acquisition, responds to Filing Parties' recommendations regarding the Company's decision to install SCRs at Jim Bridger Units 3 and 4 and Hunter Unit 1. He also responds to AWEC's testimony regarding emission control investments at the Hunter plant Mr. Link respond's to Sierra Club's testimony regarding the Company's requested Exit Orders for the Company's coal-fired generating plants. Finally, he also addresses Staff's recommendation regarding an investigation into the Company's Schedule 272.

- In Exhibit PAC/3900, Robert Van Engelenhoven, Director of Resource Development, provides an update related to the cost and construction of the Pryor Mountain Wind Project. He also responds Filing Parties' recommendations related to the independent Decommissioning Studies.

- In Exhibit PAC/4000, James Owen, Director, Environmental, also responds to Filing Parties' testimony regarding the Company's investment in SCRs at Jim Bridger Units 3 and 4.

- In Exhibit PAC/4100, Dana M. Ralston, Vice President of Thermal Generation and Mining, addresses Filing Parties' testimony regarding the Company's investment in SCRs at Jim Bridger Units 3 and 4. He also responds to Sierra Club's testimony regarding the impact of mine plan changes at Bridger Coal Mine on coal costs and the Company's economic analysis. Mr. Ralston addresses arguments related to the value of water rights in evaluating the Jim Bridger environmental investments. Finally, he responds to recommended disallowance associated with the closure of Deer Creek Mine.

- In Exhibit PAC/4200, Richard A. Vail, Vice President of Transmission Services, addresses Staff's recommendations regarding the Company's transmission investment. He also responds to arguments regarding SCRs installed at Jim Bridger Units 3 and 4.

- In Exhibit PAC/4300, Julie A. Lewis, Vice President, People, explains the Company's compensation philosophy and explains why certain labor-related adjustments proposed by Staff should be rejected.

- In Exhibit PAC/4400, Shelley E. McCoy, Revenue Requirement Manager, presents modifications for revenue requirement changes due to additional updates since the reply filing based on current information. She also responds to various adjustments made by parties in rebuttal testimony including adjustments to operations and maintenance expense, tax, and rate base.

IX. CONCLUSION

Q. Please summarize the conclusions you reach in surrebuttal testimony.

A. As supported by the Company in surrebuttal testimony, the Commission should approve the Company's proposed revenue requirement increase of $47.5 million, which reflects the Company's updated request of an 9.80 percent ROE, and is fully offset by the 2021 TAM rate decrease. Further, I recommend that the Commission:

1. Approve the Exit Dates and Exit Orders for the Company's coal-fired generating plants, except for Hunter Units 1, 2, and 3, Huntington Units 1 and 2, and Wyodak, which the Company will request in a future proceeding;

2. Approve the Company's investments in transmission and SCR systems at Jim Bridger Units 3 and 4 and Hayden Units 1 and 2;

3. Approve the recovery approach set forth by Staff regarding possible delays in the COD for the EV 2020 new wind projects, repowering the Foote Creek I wind facility, and the Pryor Mountain Wind Project;

4. Approve the Decommissioning Studies prepared by Kiewit for inclusion in rates, or in the alternative, approve the Decommissioning Studies for inclusion in rates and open a proceeding for a further review of the Decommissioning Studies subject to true-up;

5. Approve the Company's proposal to buy down the undepreciated plant balance and closure costs related to the retirement of Cholla Unit 4; and

6. Approve the Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism as modified in my surrebuttal testimony.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

REDACTED
Docket No. UE 374
Exhibit PAC/3400
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Redacted Surrebuttal Testimony of Nikki L. Kobliha

August 2020

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ATTACHED EXHIBITS

Confidential Exhibit PAC/3401—Regulatory Research Associates' Publication of "Major Rate Case Decisions"

Q. Are you the same Nikki L. Kobliha who previously submitted direct, supplemental direct and reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes, I am.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. I will respond to certain issues raised in the rebuttal testimony of the Public Utility Commission of Oregon (Commission) Staff witnesses Mr. Matt Muldoon, Ms. Moya Enright, Mr. John L. Fox, and Mr. Curtis Dlouhy; and Alliance of Western Energy Consumers (AWEC) witness Mr. Michael P. Gorman.

Q. Please explain how your testimony is organized and the issues you will address in your surrebuttal testimony.

A. I will comment on the following issues and recommendations and explain why my analysis continues to support the capital structure proposed in my direct testimony.

1. In Section II, I respond to the recommendations by Mr. Muldoon, Ms. Enright, Mr. Dlouhy and Mr. Gorman, on the Company's proposed capital structure and explain why the Company's proposed capital structure is reasonable and necessary.[1]
2. In Section III, I address the recommendation of Staff that the Company should issue Green First Mortgage Bonds "as soon as practicable."
3. In Section IV, I respond to Mr. Fox's testimony on pensions.[2]

[1] Staff/1900; AWEC/600.
[2] Staff/1800.

II. CAPITAL STRUCTURE

Q. Staff updated their Capital Structure to include a 50.64 percent equity and AWEC updated their Capital Structure to be 51.86 percent equity. Do you agree with these recommended updates?

A. No. While I agree with Mr. Gorman's consideration of the most recent off balance sheet debt estimates provided by Standard & Poor's (S&P) for use in his calculation, I continue to recommend a 53.52 percent common equity layer in the Capital Structure as detailed in my direct and reply testimony. At the 53.52 percent level the Company will remain financially sound and keep costs low for customers while transforming its generation portfolio.

Q. Staff references 50/50 as an optimal capital structure as depicted in a finance textbook written by Roger Morin. Does the Company agree that a 50/50 capital structure is the optimal capital structure for PacifiCorp, particularly during its current build cycle?

A. No. In an effort to maintain credit ratings and low cost access to debt markets, during this significant extended capital build cycle, the Company has demonstrated the requested 53.52 percent common equity capital structure is the optimal capital structure at this time. The simplified textbook calculations do not factor in the Company's specific circumstances that are applicable in this case. In addition, the following quote from that same textbook is representative of the Company's current position:

> The optimal capital structure ....suggests that long-term achievement of a single A credit rating is in a utility company's and its ratepayers best interests. Debt leverage targets should be set in the lower part of the range required to attain this

> optimal rating. If the company maintains its debt ratio close to the optimal range required for a single A bond rating, its overall cost of capital should be minimized.[3]

PacifiCorp currently has a Moody/S&P bond issuer credit rating of A3/A, which is considered a single A credit rating, and as suggested from the textbook will minimize its overall cost of capital.

Q. Staff also references Regulatory Research Associates' (RRA) publication of "Major Rate Case Decisions"[4] where it indicates the Company's proposed equity levels are well above the recent averages awarded. How do you respond to that data?

A. PacifiCorp's proposed equity level is indicative of the capital-intensive portfolio transition currently underway by the Company. Similar to Staff's reliance on a simplified textbook example, a simple comparison of PacifiCorp's proposed equity levels to the average equity levels awarded does not take into account the specific circumstances of PacifiCorp or the utilities referenced in the Major Rate Case Decisions documents. Reviewing the detailed support behind the averages noted in the RRA publication of "Major Rate Case Decisions" that Staff is referencing, there is a varied range in the ordered common equity percentages due to specific facts and circumstances surrounding each utility company. There are a number of utilities included in that chart who's common equity percentages are not materially different than the 53.52 percent being proposed by the Company in this case. Furthermore, a number of the utilities noted in the RRA publication with lower common equity percentages include deferred income taxes as a component of their capital structure,

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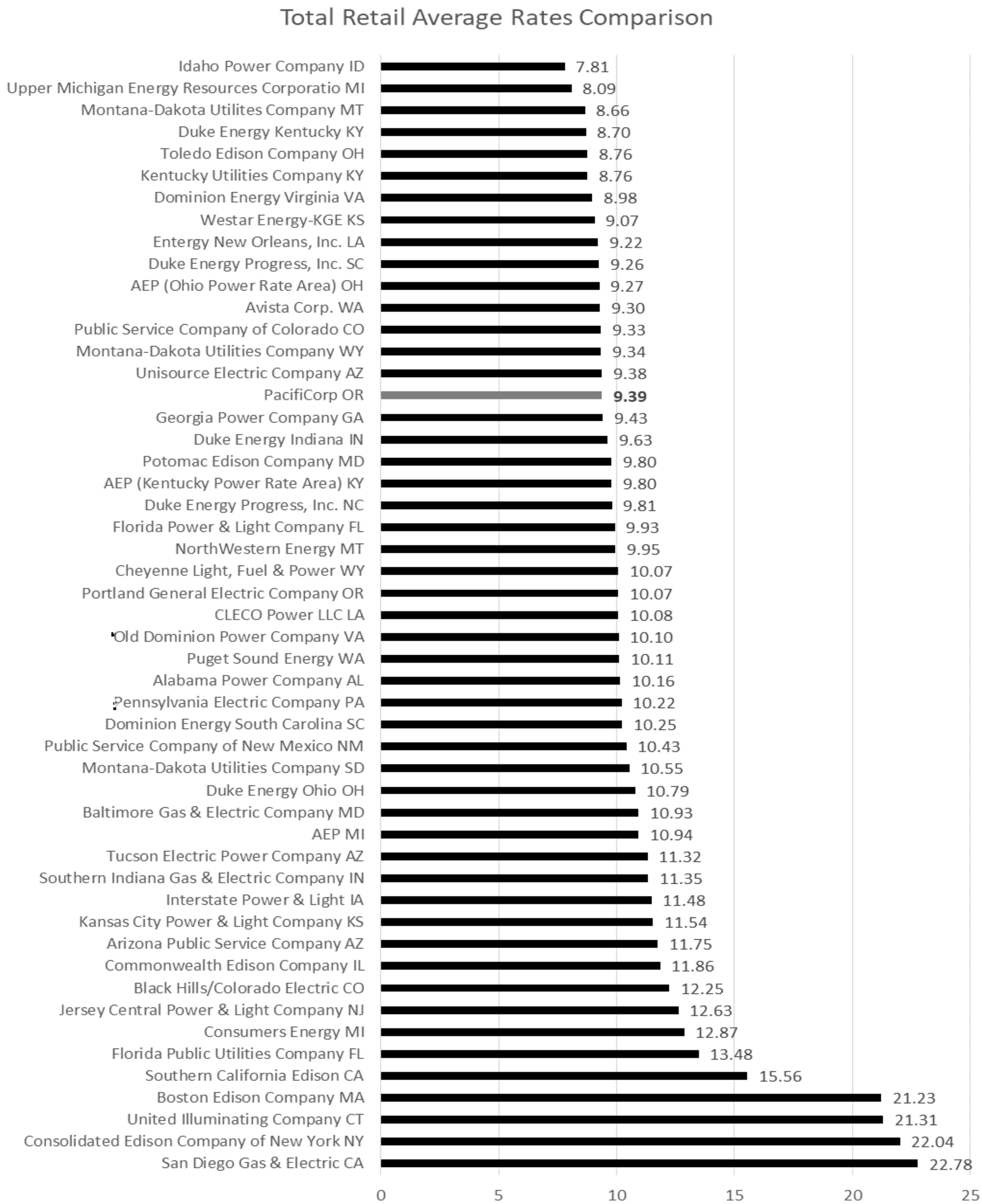
[3] Roger A. Morin, PhD, *New Regulatory Finance, Public Utilities Reports*, Inc, Virginia 2006, p.471.
[4] PAC/3401.

which reduces the overall percentage of debt and equity in the capital structure. PacifiCorp reflects deferred income taxes as a reduction to rate base rather than part of the capital structure.

Q. Staff's use of RRA's publication also indicates approving a 53.52 percent equity would result in Oregon customers paying much higher prices than customers in other states. Do you agree?

A. No. Accurately reflecting the Company's forecasted level of equity during the rate effective period provides PacifiCorp with the opportunity to earn a reasonable return on its investment and does not equate to Oregon customers paying much higher prices than customers in other states. Staff's view that a higher equity component means that customers are going to be paying higher rates than customers in other states is overly simplistic and in fact PacifiCorp rates as compared to utilities in other states, as reflected in Figure 1, are actually lower than the majority of companies.

Figure 1



Source: Edison Electric Institute Typical Bills and Average Rates Report Winter 2020

Q. Staff comments on whether or not a calculated Capital Structure will remain at its targeted equity levels. Do you agree with their comments?

A. To some extent, yes, but not entirely. I agree that the movements in debt and equity percentages can be lumpy when the Company issues debt or pays dividends but when looked at over a five-quarter average, as used for rate making purposes, that lumpiness generally gets smoothed out. The Company targets its five-quarter average common equity layer to equal the weighted average common equity level authorized across the six jurisdictions in which it operates. This enables the Company to earn its authorized return. This can be seen in Table 5 of my direct testimony where the five-quarter average common equity is near its authorized weighted average of 51.6 percent equity. Thinning the equity component of the capital structure over time to be closer to 50/50 will likely occur after the Company exits its significant capital build cycle so long as the Company is able to do so and maintain Moody's targeted cash flow from operations before changes in working capital (CFO pre-W/C) to debt metric.

Q. Do you agree with Staff's comment that the Company is too focused on Moody's CFO pre-WC to debt (also referred to as funds from operations (FFO) to Debt) credit metric?

A. No. While the Company agrees that Moody's CFO pre-WC to debt ratio may not be the only factor the rating agency relies on when determining a company's ratings, as noted from the recent ratings reports below, underperformance for this credit metric is a key factor Moody's highlights that could lead to a downgrade. In its most recent credit opinion of PacifiCorp, issued June 2020, the threshold for a potential downgrade was listed as such:

[redacted]

PacifiCorp also strives to maintain the ratio above 20 percent as has been recommended by Moody's in its June 2020 outlook of PacifiCorp:

[redacted]

[redacted]

PacifiCorp cannot sustain a CFO pre-WC to debt ratio of [redacted] or above in the current build cycle planned for the next several years with a 50/50 capital structure based revenue requirement. The Company is also not likely to achieve this metric at a 51.86 percent equity level as suggested by Mr. Gorman.

In addition, the Company recently noted a downgrade of American Electric Power Company, Inc and utility subsidiaries AEP Texas, Ohio Power and Public Service of Oklahoma by Moody's.[7] Drivers for the downgrades all reference weakened financial profiles that are driven by large capital programs and an increased use of leverage. The increased use of leverage combined with lower authorized

[5] Moody's Investor Service, Credit Opinion (June 25, 2020) at 2.
[6] Moody's Investor Service, Credit Opinion (June 25, 2020) at 2.
[7] Moody's Investor Service, Ratings Action (August 6, 2020).

revenues will cause metrics to decline below current levels. An updated credit opinion on American Electric Power Company specifically notes deterioration of its previously strong credit metrics as the primary driver behind their downgrade.[8] This action demonstrates the importance of the CFO pre-WC to debt ratio to Moody's when determining ratings.

Q. Why did the Company not provide the forecasted calculation of the FFO to Debt ratio in its reply testimony?

A. I provided only historical rating agency ratios in reply testimony as the Company cannot precisely calculate the ratio in its planning process and does not wish to speculate what the rating agency calculation may be in subsequent years.

Q. Is there a forecast of CFO pre-WC to debt ratio you can supply at this time?

A. Looking at recent historical data and estimated impacts through the remainder of 2020, I have replicated Moody's CFO pre-WC to debt ratio calculation in order to provide a high-level indicator of where this metric may land. Based on the Company's 12 months ended June 30, 2020 results, the CFO pre-WC to debt ratio is near [redacted]. The [redacted] in this metric as calculated for the most recent 12-month period compared to the calendar year 2019 period result of [redacted]

[8] Moody's Investor Service, Credit Opinion (June 29, 2020) at 2.

[redacted]. The Company's current forecast for the 12 months ended December 31, 2020 period for the Moody's CFO pre-WC to debt ratio is [redacted] and is based on a projected average common equity percentage of 51.6 percent for the period. With a low metric result reported in 2019 [redacted] without favorable regulatory support during the Company's continuing capital growth cycle.

As has been noted in both direct and reply testimony, the Company can manage the capital structure through the timing and amount of long-term debt issuances and dividend distributions, however, there are neither long term debt issuances nor dividend distributions planned for 2021. Hence, PacifiCorp must rely on continued regulatory support to recover costs and achieve a reasonable rate of return to have adequate cash from operations during this period of growth when additional debt issuance would increasingly dampen the Company's already stressed key CFO pre-WC to debt credit metric.

Q. Please address Mr. Gorman's concerns around whether the FFO to Debt ratio in 2019 of [redacted] percent is adequate to support the current bond rating.

A. The Company has provided confidential copies of the most recent credit opinion issued by Moody's in June 2020. As noted above, the June 2020 Moody's report indicates a CFO pre-WC to debt sustained below [redacted] could lead to a downgrade. Using that description it is clear that a decline in credit metrics at levels seen in 2019 could result in a downgrade if those levels were to continue.

Q. Do you agree that Mr. Gorman is referencing the most useful metric for assessing the Company's risk of downgrade?

A. No. Mr. Gorman's response in rebuttal makes projections for the Company based on S&P coverage of debt credit metric. As stated in direct and reply testimony, Moody's is the lower of the Company's ratings and the most difficult to maintain with the current equity levels during a significant current growth cycle.

Q. Do you agree with Mr. Gorman's position that your arguments "simply do not address the reasonable cost standard of establishing an overall fair rate of return?"[9]

A. No. The Company demonstrated in both direct and reply testimony that the capital structure included in this case allows the Company to maintain its credit rating, which, in turn, allows the Company to access the debt market and issue debt at a reasonable cost. If the Company's credit rating was downgraded, its cost of debt would increase and during times of economic turmoil a low credit rating could limit the Company's access to capital markets at a reasonable cost. The Company's capital structure, together with its recommended cost of equity, result in an overall rate of return that is just and reasonable, consistent with the return on enterprises of comparable risk, and appropriately balances the interests of customers and shareholders.

Q. Please comment on Staff's comparison of PacifiCorp to other Oregon utilities.

A. Staff's comparison of PacifiCorp to other Oregon utilities fails to recognize the different factors that Moody's has laid out for each utility's requirements for ratings.

[9] AWEC/600, Gorman/3.

- Portland General Electric Company, while similarly rated at A3, has a threshold of [redacted] for CFO pre-WC to debt as noted in the February 2020 Credit Opinion.[10]
- Avista, a Baa2 rated company, or two notches below PacifiCorp, has a threshold [redacted] for CFO pre-WC to debt as noted in the December 2019 Credit Opinion.[11]
- Northwest Natural Gas Company, a Baa1 rated company, or one notch below PacifiCorp, has a threshold of [redacted] as noted in the Moody's Credit Opinion from May 2020.[12]
- Cascade Natural Gas Corp had their Moody's rating withdrawn in April of 2011.[13]

To suggest that PacifiCorp is a "plane almost able to fly itself" minimizes the efforts the Company has made to maintain its higher credit rating, allowing for lower cost debt, while still providing safe, clean and reliable power for its customers. The Company is targeting equity levels that have been authorized while balancing the dividend and debt issuances, and adhering to a more stringent Moody's requirement as noted above. PacifiCorp realizes that those requirements will be difficult to achieve in the coming years as the capital spend required to provide for new clean renewable energy and transmission puts significant pressure on the Company's CFO pre-WC to debt ratio. As noted above continued regulatory support to recover costs

[10] Moody's Investor Service, Rating Action (February 25, 2020) at 1.
[11] Moody's Investor Service, Credit Opinion (December 19, 2010) at 2.
[12] Moody's Investor Service, Credit Opinion (May 29, 2020) at 2.
[13] Moody's Investor Service, Ratings Action (April 7, 2011).

and earn a reasonable return will help the Company have adequate cash flows to maintain this metric.

Q. What is your recommendation regarding the Company's capital structure?

A. For the reasons noted above, I recommend the equity component of the capital structure remain at the 53.52 percent included in my direct testimony with no update for the April 2020 bond issuance and new 2021 bond and dividend projections, which would increase the equity component of the capital structure as measured on a five-quarter average to 53.55 percent.

III. GREEN BONDS

Q. Mr. Muldoon and Ms. Enright recommend that PacifiCorp issue tranches of Green First Mortgage Bonds as soon as practicable. Please discuss.

A. The Company agrees with the recommendation to issue green bonds as soon as practical. While I don't disagree with staff that providing *"solid green securities that investors and money managers would be proud to hold,"*[14] is a worthy objective, the Company must keep in mind its key regulatory mandate of providing the lowest cost of capital to customers. There are additional costs, as noted in an article provided by Staff, involved for the issuance of green bonds related to management assertions, website postings, and external audit fees that must be considered when evaluating the issuance of green bonds. As discussed in my reply testimony, PacifiCorp will continue to evaluate the use of green bonds each time it goes to the market.

[14] Staff/1900, Muldoon-Enright-Dlouhy/47, Lines 4-5 (emphasis added).

IV. PENSION

Q. Do you agree with Mr. Fox's assertions that the Commission's definition of pension costs excludes financial accounting standards (FAS) 88 and that excluding FAS 88 costs from rates is fair, just and reasonable?

A. No, I do not. While the Company does not disagree with Mr. Fox's statements regarding Commission Order No. 15-226, Mr. Fox takes a narrow view. Mr. Fox's position is based on his belief that the pension costs included in rates by definition exclude FAS 88. While FAS 88 expense is not part of "net periodic benefit cost" as defined in FAS 87 and referenced in Order No. 15-226, it is clearly a part of pension cost. As emphasized in my reply testimony, the Commission acknowledges this in Order No. 15-226 by stating that pension contributions equal expense over time only by factoring in both FAS 87 and FAS 88 (codified as Financial Accounting Standards Board's Accounting Standards Codification Topic 715-30-Compensation-Retirement Benefits (ASC 715-30)). While the Commission in Order No. 15-226 affirmed continuing to allow recovery of pension costs on the basis of FAS 87 expense, it is unreasonable to assert that the Commission intended to preclude utilities from recovering FAS 88 expense. Whether pension costs are defined as limited to FAS 87 net periodic benefit cost does not change the fact that the full cost of providing a pension plan ultimately requires recognition of amounts contributed to satisfy the plan's obligations. As indicated in Order No. 15-226, contributions equal the combination of both FAS 87 and FAS 88 expense over the life of a plan.

It is also important to note that Order No. 15-226 was focused on whether to allow a return on the utilities' prepaid pension costs and thus was addressing *return* *on* not *recovery of* pension costs. Thus the Company does not believe the Commission intended to preclude utilities from recovering FAS 88 costs by affirming its practice of allowing recovery of pension costs based on FAS 87 expense in Order No. 15-226. As indicated in my reply testimony, settlement losses are not new or incremental costs; they are simply the same costs that would have otherwise been recognized over time if not for being triggered for immediate recognition under settlement accounting requirements. Under Mr. Fox's view, no FAS 88 gains or losses would be passed on to or recovered from customers despite being a true cost of a pension plan.

Q. Do you have additional context you would like to provide regarding Mr. Fox's reference to Commission Order No. 20-004's affirmation of the FAS 87 methodology for addressing pension costs?

A. Yes. Order No. 20-004 addressed the use of a deferral associated with the recognition of settlement losses. The Commission ultimately denied the Company's request for a deferral on the basis that the requested deferral did not meet the Commission's parameters for use of a deferral; the Commission did not deny the Company's request on the basis of the settlement losses not being part of FAS 87 or deny that they are a valid pension cost. In the Order, the Commission stated in part:

> In reviewing the undisputed facts of this case, we find that PacifiCorp has, of necessity, a high level of knowledge and sophistication in managing its employee pension benefits. We therefore conclude that the larger-than-anticipated number of employees opting to receive a lump sum payout from the retirement plans, does not fit well into either the stochastic or scenario event categories. Rather, a high number of retirees taking lump sum distributions may be viewed as being a reasonably possible outcome resulting from PacifiCorp's business decisions. It falls within the range of foreseeably possible outcomes in the then-

> existing environment of low service costs, stable interest rate and low inflation, all factors well-known to PacifiCorp at the time...[15]

Based on the Commission's conclusion that the Company should be able to foresee factors that may lead to settlement accounting, in this case the Company used the best available information to forecast settlement accounting arising during the test period.

Q. Mr. Fox states that the Company only pursues recovery when it benefits the Company and has benefited from regulatory lag and the absorption of curtailment gains. Do you agree with Mr. Fox's statements?

A. I disagree with Mr. Fox's statements. Mr. Fox's suggestion that the Company attempts to keep gains for itself while passing on losses to customers is unfounded. In 2017, the Company filed an application in docket UM 1917 to defer impacts arising from the Tax Cuts and Jobs Act that was signed into law on December 22, 2017. This application was filed on December 28, 2017, almost immediately following enactment of the legislation and captured the benefits of the Tax Cuts and Job Act for later return to customers.

Q. Do you agree with Mr. Fox's assertion that settlement costs must be excluded from rates because costs are not to be trued up between rate cases and suggestion that the Company has benefited inappropriately from regulatory lag over time?

A. No, I do not. Mr. Fox's argument ignores the fact that rates are set on a prospective basis. In this case, I have presented evidence that PacifiCorp is likely to incur settlement losses during the period of time when rates are in effect. Experiencing a curtailment gain or cost variances between rate cases is not an inappropriate benefit

[15] Commission Order No. 20-004, page 8.

of regulatory lag, rather it is a natural consequence of setting rates on a prospective basis. Here, the Company is making every effort to accurately forecast costs that it will incur during the test period. As the Company incurred a significant settlement loss in 2018 and expects to incur a significant settlement loss in 2020, the Company no longer views these as one-time or infrequent events. The Company has not unfairly benefited from regulatory lag; rather it has adhered to acceptable ratemaking principles and Mr. Fox himself has singled out pension costs in forming his conclusions.

Q. Mr. Fox suggests that your reply testimony was in conflict with information provided in docket UM 1992. How do you respond?

A. While the Company was able to produce the information requested in docket UM 1992, it did not agree that the amounts were precisely in rates.[16] As indicated in my rebuttal testimony in docket UM 1992, the Company has generally reached black box settlements and referenced the pension expense shared in docket UM 1992 as the "as-filed" amounts.[17] To call out the differences between what the Company included in its original general rate case filing and the actual pension costs later incurred is to cherry pick and isolate that one cost, while the Company would have experienced other differences between what it requested in its original filing and what later transpired. I referenced the Company's history of black box settlements in my reply testimony in docket UM 1992, clarifying that the amounts provided and referenced by parties were the "as-filed pension expense" such that while this information is available the Company does not consider such amounts as "in rates" able to be

[16] Commission Docket No. UM 1992 PAC/200, Kobliha/6 lines 15 to 21.
[17] Commission Docket No. UM 1992 PAC/200, Kobliha/6 lines 3 to 8.

compared to actual expenses in order to derive an estimate of over or under collection.

Q. Mr. Fox recommends against the Company's suggestion to establish a pension balancing account on the basis of it being "inequitable to establish" such a mechanism at this "point in the plan's lifecycle." Do you agree with the basis for Mr. Fox's recommendation?

A. No, I do not. Regardless of the Company's frozen pension plan, significant costs remain to be recognized over the remaining life of the plan and participants' lives. This stems from ASC 715-30 accounting that allows costs such as actuarial losses to be recognized over time rather than immediately, which would otherwise result in materially volatile expense from year to year. Furthermore, the fact that the Company's pension plan is frozen reduces costs to customers since no service cost is being incurred and expected asset returns often exceed interest cost.

Q. What is your recommendation regarding the Company's pension costs?

A. I recommend inclusion of projected settlement losses in base rates as they are a valid cost of providing a pension plan. Alternatively, I recommend the creation of a deferral or balancing account for prospective pension costs, including settlement costs.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

REDACTED
Docket No. UE 374
Exhibit PAC/3401
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Nikki L. Kobliha

Regulatory Research Associates' Publication of "Major Rate Case Decisions"

August 2020

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 374
Exhibit PAC/3500
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Ann E. Bulkley

August 2020

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Exhibit PAC/3505—Updated Capital Asset Pricing Model

Exhibit PAC/3506—Updated Risk Premium Approach

Exhibit PAC/3507—Updated Expected Earnings Analysis

Exhibit PAC/3508—Staff Constant Growth DCF Update (Revised)

Exhibit PAC/3509—Staff Hamada Adjustment (Re-creation)

Staff Multi-Stage DCF (Revised)

Exhibit PAC/3510—Staff Multi-Stage ROE Summary (Revised)

Q. Are you the same Ann E. Bulkley who previously submitted direct and reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of the Public Utility Commission of Oregon (Commission) Staff (Staff) witnesses Mr. Matt Muldoon, Ms. Moya Enright and Mr. Curtis Dlouhy; the Alliance of Western Energy Consumers (AWEC) witness Mr. Michael P. Gorman; and the Oregon Citizens' Utility Board (CUB) witness Mr. Bob Jenks, as it relates to the just and reasonable return on equity (ROE) and the appropriate capital structure for PacifiCorp in Oregon.

Q. Are you sponsoring any exhibits as part of your surrebuttal testimony?

A. Yes. I am sponsoring Exhibits PAC/3501 through PAC/3510, which have been prepared by me or under my direct supervision.

Q. How is the remainder of your surrebuttal testimony organized?

A. The remainder of my surrebuttal testimony is organized as follows:

- In Section II, I respond to the ROE rebuttal evidence presented by witnesses for Staff, AWEC and CUB;
- In Section III, I present my updated ROE analyses based on market data through July 31, 2020; and
- In Section IV, I summarize my conclusions and recommendations.

II. RESPONSE TO COST OF CAPITAL ISSUES RAISED IN THE REBUTTAL TESTIMONY OF STAFF, AWEC AND CUB WITNESSES

Q. Staff notes the significant risk and economic uncertainty due to COVID-19,[1] yet Staff reports that its updated Multi-Stage Discounted Cash Flow (DCF) analysis produces the same ROE recommendation of 9.0 percent and only a slightly higher range of results. Please comment.

A. I agree with Staff that the COVID-19 pandemic has resulted in economic uncertainty and significant risk for equity investors. This uncertainty and risk is evident in indicators such as elevated levels of market volatility and elevated credit spreads, and substantial increases in Beta coefficients for electric and natural gas utilities. Higher uncertainty, higher volatility and higher risk are normally associated with higher required returns among investors. However, Staff reports that when its Multi-Stage DCF model is updated to reflect market data during the COVID-19 pandemic, the model continues to produce midpoint results of approximately 9.0 percent.[2] Financial models used to estimate the cost of equity should reflect the greater risk and economic uncertainty caused by the COVID-19 pandemic. If those models do not produce higher return estimates under such market conditions, then one must question whether or not the inputs and assumptions used in those models are reasonable.

Q. Are there any differences in the inputs used in Staff's updated Multi-Stage DCF model as compared with Staff's model filed in its opening testimony?

A. Setting aside my concerns with Staff's proxy group that were discussed in my reply testimony, the one important difference that I have noted is that in its opening

[1] Staff/1900, Muldoon-Enright-Dlouhy/6-18.
[2] Staff/1900, Muldoon-Enright-Dlouhy/38.

testimony, Staff used my long-term Gross Domestic Product (GDP) growth rate of 5.53 percent as the highest terminal growth rate in its Multi-Stage DCF model, whereas in its rebuttal testimony, Staff has changed its methodology to develop a lower estimate of the high terminal growth rate of 5.05 percent for the Multi-Stage DCF analysis. This lower long-term growth rate explains why the upper end of Staff's range of results is essentially the same despite the fact that other factors point toward a higher cost of equity. If Staff had used my long-term GDP growth rate of 5.56 percent as of June 30, 2020, as the terminal growth rate in its updated Multi-Stage DCF model, the high end of Staff's range would be 9.82 percent, rather than 9.42 percent.[3]

Q. Has Staff also updated its Constant Growth DCF analysis and its Capital Asset Pricing Model (CAPM) analysis?

A. Yes. As shown in Staff's updated ROE analysis, the results of Staff's Constant Growth DCF model have increased from 8.90 percent to 9.50 percent, and the results of Staff's CAPM analysis have increased from 7.70 percent to 9.30 percent. Both of these models demonstrate that the cost of equity for Staff's proxy group companies has increased by 60 to 160 basis points as compared with the results in Staff's opening testimony, which were based almost entirely on market data from before the COVID-19 pandemic. These updated Constant Growth DCF and CAPM results support a return toward the upper end of Staff's Multi-Stage DCF analysis. It is unclear how Staff can ignore these changes in its model results and market conditions and continue to recommend an ROE of 9.0 percent for PacifiCorp based on the midpoint results of its Multi-Stage DCF analysis.

[3] *See* PAC/3510.

Q. Do you agree with how Staff has addressed low outliers in its ROE analysis?[4]

A. No, I do not. While Staff recognizes that there is a need to remove low-end outliers, it has applied a low-end outlier test only to the results of its CAPM analysis. Staff has not removed similar low outliers from its Constant Growth or Multi-Stage DCF analysis. Staff does not explain why it is only necessary to remove low outliers from the CAPM analysis. As shown in Exhibit PAC/3508, had Staff applied the same outlier test to its DCF models, the results of Staff's Constant Growth DCF model would have increased from 9.50 percent to 10.12 percent within a range from 8.80 percent to 11.60 percent. The Multi-Stage DCF results (using Staff's composite long-term growth rate of 3.94 percent) would increase from 8.57 percent to 8.98 percent, while the results using my long-term growth rate of 5.56 percent (as of June 30, 2020) would not change from 9.82 percent. As a result, the midpoint of Staff's Multi-Stage DCF analysis excluding outliers below 8.0 percent would be 9.40 percent, as shown in Exhibit PAC/3510.

Q. Do you agree with Staff that the 2008/2009 financial crisis and Great Recession is not a valid point of comparison with today's market conditions?[5]

A. No, I do not. While the cause of the market dislocation in 2020 is obviously not the same as in 2008/2009, the market's response has been very similar. As discussed in my reply testimony, market volatility spiked in March 2020 to similar levels as were experienced in October 2008. Likewise, credit spreads widened substantially as investors required higher yields on lower rated bonds to compensate for the potential default risk during a severe recession. Further, on August 5, 2011, Standard and

[4] Staff/1900, Muldoon-Enright-Dlouhy/104.
[5] Staff/1900, Muldoon-Enright-Dlouhy/14.

Poor's (S&P) downgraded the long-term credit rating for U.S. government debt from AAA to AA+ due to concerns over high unemployment and high budget deficits, while on July 31, 2020, FitchRatings (Fitch) reduced the outlook for U.S. government debt to Negative, citing "the ongoing deterioration in the U.S. public finances and the absence of a credible fiscal consolidation plan, issues that were highlighted in the agency's last rating review on March 26, 2020."[6]

One significant difference between the current market dislocation and that in 2008/2009 is that the Federal Reserve implemented a comprehensive monetary policy response within six weeks, whereas in 2008/2009 it took 18 months for the Federal Reserve to develop its full policy response. Due to the Federal Reserve's rapid and aggressive response in March 2020, market volatility was mitigated more rapidly.

Q. Staff observes that corporate bond credit spreads have fallen to their lowest level since the pandemic, while volatility in equity markets remains higher than normal.[7] How do you interpret these market data?

A. While I agree with Staff that credit spreads are lower in July 2020 than in March 2020, due primarily to the rapid and aggressive economic stimulus provided by the Federal Reserve and the U.S. Congress, both equity market volatility and credit spreads remain well above their long-term historical averages. The daily average Chicago Board Options Exchange Volatility Index (CBOE VIX) in July 2020 was 26.84, which is more than 66 percent higher than the daily long-term historical median for the CBOE VIX of 16.12 since January 2003. Similarly, the 30-day average spread between 30-year U.S. Treasury bonds and Moody's Baa-rated utility

[6] FitchRatings, Fitch Revises United States Outlook to Negative; Affirms at AAA, July 31, 2020.
[7] Staff/1900, Muldoon-Enright-Dlouhy/11, and 16-18.

bonds as of July 31, 2020, was 1.84 percent compared to the long-term historical average daily credit spread of 1.72 percent since 2013, when PacifiCorp's last rate case was filed in Oregon. The Commission is setting the return on common equity for PacifiCorp, so the volatility in equity markets is a more important indicator of equity costs for the Company than are bond yields or credit spreads, both of which have fallen due to the aggressive policy response of the Federal Reserve and the U.S. Congress in March and April 2020.

Q. Are very low yields on government bonds an indication that the cost of equity has decreased for regulated utilities, as suggested by Staff?[8]

A. No. The very low yields on government bonds are a result of the aggressive steps taken by the Federal Reserve to stabilize financial markets and to stimulate the U.S. economy during the period of unprecedented economic uncertainty. These low interest rates are not a sign that equity risk has decreased or that the cost of equity capital has declined for regulated utilities. On the contrary, the very conditions that have caused the Federal Reserve and U.S. Congress to respond with such aggressive measures are an indication of the magnitude of the risk associated with owning common equity when such uncertain conditions prevail.

Q. Please summarize Mr. Gorman's testimony on the relationship between utility bond yields and utility stock yields.

A. Mr. Gorman once again comments on the relationship between utility bond yields and utility dividend yields, noting that utility stock yields have generally tracked utility bond yields, but at a discount. However, in the current market environment, Mr. Gorman observes that there is very little spread between utility stock yields and

[8] Staff/1900, Muldoon-Enright-Dlouhy/9.

utility bond yields. He concludes that the yield component of utility stocks is very high right now, providing a much higher expected return relative to bond yields.[9]

Q. Do you agree with Mr. Gorman's position on this issue?

A. No, I do not. While there has historically been a positive correlation between utility bond yields and utility dividend yields, that relationship has weakened substantially in recent years. I analyzed the monthly and quarterly correlation between the Moody's Baa-rated utility bond yield and the dividend yields for the companies in my proxy group for the period from January 2000 through July 2020. Figure 1 shows that the correlation between utility bond yields and utility dividend yields was slightly greater than 0.80 from January 2000 through July 2020. However, the monthly correlation from January 2018 through July 2020 was 0.2046, and the quarterly correlation over the same period was – 0.0419. This analysis demonstrates that historically there has been a strong positive correlation between utility bond yields and utility dividend yields; however, that correlation in recent years has weakened substantially on a monthly basis and has turned negative on a quarterly basis.

Figure 1: Correlation – Baa Utility Bond Yields and Proxy Group Dividend Yields

Period	Quarterly	Monthly
January 2000 – July 2020	0.8041	0.801
January 2018 – July 2020	(0.0419)	0.2046

Q. How has the utilities sector performed in 2020 relative to the S&P 500?

A. The utilities sector has been one of the worst performing market sectors in 2020, having declined by 14.44 percent from the mid-February peak as compared to a 3.70 percent decline for the S&P 500. The only market sectors that have underperformed utilities in 2020 are industrials (down 15.94 percent), financials

[9] AWEC/600, Gorman/7.

(down 23.42 percent) and energy (down 54.02 percent). The other six market sectors are either down slightly from their peak, or are at or near record highs.

Although regulated utilities are typically seen as a safe haven by investors during periods of economic uncertainty and market volatility, contrary to the position of CUB witness Mr. Jenks,[10] that has not been the case this year. This is partly because demand for electricity decreased as non-essential businesses in many parts of the country were forced to close for a period in March through May, and have attempted to slowly re-open in June and July. While Staff contends that electricity demand is inelastic and that utilities have not been affected by COVID-19,[11] the load data does not support Staff's assertion. In July 2020, the U.S. Energy Information Administration forecast that overall electricity sales would decrease by 4.2 percent in 2020 compared to 2019. Commercial sales are projected to decline by 7.0 percent this year due to COVID-19 mitigation efforts, electricity sales to the industrial sector are expected to fall by 5.6 percent, while residential electricity sales are projected to be approximately the same as the previous year.[12] The underperformance of the utilities sector is an indication that it has become more difficult for utilities to attract capital in the current economic environment. While their dividend yields remain attractive to income-oriented investors, there is heightened risk that lower electricity demand will cause electric utilities without revenue decoupling mechanisms to be unable to earn their authorized return for several quarters until demand returns to pre-COVID-19 levels.

[10] CUB/400, Jenks/9.
[11] Staff/1900, Muldoon-Enright-Dlouhy/62-63.
[12] U.S. Energy Information Administration: Short-Term Energy Outlook, July 7, 2020.

Q. Staff contends that increased volatility in utility stocks has not led to increased returns for utility companies.[13] What is your response?

A. Staff testifies that it may be reasonable to expect that increased volatility would translate into an increase in returns through higher risk premiums. According to Staff, however, this has not been the case in the utilities sector. As support for this position, Staff observes that the return for the S&P 500 Index far exceeds the return for the S&P Utilities Index. I disagree with Staff's interpretation of the under-performance of the utilities sector relative to the broader market in 2020. The fact that utilities have not been a safe haven during this market dislocation and the fact that the correlation between utility stocks and the broader market has increased substantially provides evidence that investors are requiring a higher return to compensate them for these added risks. Utilities are underperforming the broader market because investors view the risk/reward relationship for this sector as less attractive than for many other market sectors.

Q. AWEC, Staff and CUB have provided authorized return data for regulated utilities in other jurisdictions in 2020.[14] Please comment.

A. Both AWEC witness Mr. Gorman and Staff report that the average authorized ROE for electric utilities in 2020 has been 9.47 percent, while the average authorized ROE for natural gas distribution companies in 2020 has been 9.40 percent. CUB witness Mr. Jenks argues that PacifiCorp's requested ROE of 10.20 percent is higher than other Oregon utilities and, if approved, would place the Company's authorized ROE among the highest nationwide for electric utilities since 2018.

[13] Staff/1900, Muldoon-Enright-Dlouhy/18.
[14] AWEC/603, Staff/1900, Muldoon-Enright-Dlouhy40-41, and CUB/300, Jenks/5-9.

While I agree that authorized returns in other jurisdictions are a relevant benchmark considered by investors in setting their return expectations for regulated utilities, I note that Mr. Gorman and Staff have included both vertically integrated electric utilities and transmission and distribution (T&D) only utilities in the average return for electric utilities. I do not agree with the inclusion of T&D only utilities because utilities that own regulated generation assets are considered by investors and credit rating agencies to have greater risk than companies that do not own generation. When T&D utilities are excluded, the average ROE for integrated electric utilities in 2020 is 9.64 percent and the median ROE is 9.70 percent. Further, among the T&D only utility decisions included by Mr. Gorman is one for Central Maine Power Co. at 8.25 percent. However, this decision includes a 100 basis point penalty reduction in the authorized ROE for the first year after the decision was issued. It is not appropriate to include a penalty ROE in calculating the average authorized equity return for electric utilities.

Q. Have you further analyzed the authorized ROE data for 2020?

A. Yes, I have. In order to better understand the authorized returns for integrated electric utilities, I have further segmented the decisions based on the Regulatory Research Associates (RRA) ranking for the individual jurisdictions. Based on this analysis, I found that six out of seven decisions issued by state jurisdictions that are considered more credit supportive by RRA (i.e., Average/1 and Above Average/3) have been from 9.70 percent to 10.02 percent in 2020, while the three decisions issued by jurisdictions that are less credit supportive (i.e., Average/3 and Below Average/2) have been either 9.40 percent or 9.45 percent in 2020. I also found that the average

ROE for integrated electric utilities in litigated cases has been 9.61 percent as compared to 9.70 percent for settled cases in 2020, and that seven of the 12 decisions have included an authorized ROE of 9.70 percent or higher.[15]

Q. What is your conclusion regarding the authorized return data for electric utilities in 2020?

A. My primary conclusion is that authorized ROEs for integrated electric utilities in 2020 have been within a range from approximately 9.60 percent (average return in litigated cases) to approximately 10.00 percent (high return for all cases). In this period of significant economic uncertainty and market volatility, it is extremely important that PacifiCorp have an authorized ROE in Oregon that allows the Company continued access to capital markets on reasonable terms and conditions.

Q. What is Mr. Jenks' position regarding how the COVID-19 pandemic should affect the authorized ROE for PacifiCorp in this proceeding?

A. Mr. Jenks contends that "it is irresponsible to propose raising shareholder returns during the pandemic,"[16] and that "the pandemic has the potential to cause wider economic distress and could drive down earnings for investments in general."[17] He ultimately recommends that the authorized ROE for PacifiCorp be no higher than 9.40 percent.[18]

Q. What is your response?

A. As discussed in the surrebuttal testimony of Company witness Ms. Etta Lockey, PacifiCorp is sensitive to the needs of customers. At the same time, the Company has

[15] S&P Global, Regulatory Research Associated accessed August 10, 2020.
[16] CUB/400, Jenks/5.
[17] Ibid, at 9.
[18] Ibid, at 10.

not filed a rate case since 2013 and must continue to make investments to fulfill its obligation to provide safe and reliable service to customers. This has not changed due to the COVID-19 pandemic. PacifiCorp must also have the opportunity to earn a just and reasonable return that is comparable to other investments with similar risk. The Company has taken steps to mitigate the rate impact on customers, including a reduction in the requested ROE from 10.20 percent to 9.80 percent, which is the currently authorized return for PacifiCorp in Oregon.

III. UPDATED ROE ANALYSIS

Q. Have you updated your ROE analyses?

A. Yes. As shown in Exhibits PAC/3501 through PAC/3507, I have updated my ROE analyses using market data as of July 31, 2020. All of the methodologies in my updated analysis have been developed in a manner that is consistent with the approach taken in my direct and reply testimonies. As in my reply testimony, I excluded CenterPoint Energy from my updated analyses because the company no longer meets my proxy group screening criteria after its recent dividend cut. In my surrebuttal testimony, I also have excluded FirstEnergy from my updated analyses because there was only one earnings per share growth rate projection for this company at the time that I updated my analyses. I have continued to exclude results below 7.0 percent because such returns do not provide a sufficient risk premium above the long-term debt cost to compensate equity investors for the risks associated with ownership. Figure 2 summarizes the results of my updated analyses.

As shown in Figure 2, and Exhibit PAC/3502, the Constant Growth DCF model results range from 8.54 percent to 9.89 percent. The Multi-Stage DCF results shown in Exhibit PAC/3503 and Exhibit PAC/3504 are between 9.32 percent and 9.78 percent.[19] Dividend yields remain below the historical average dividend yields for the proxy group, suggesting that the results of the DCF model may still understate the investor-required return on equity. The CAPM results shown in Exhibit PAC/3505 range from 11.52 percent to 12.58 percent and the Empirical CAPM (ECAPM) results are 12.09 percent to 12.80 percent.[20] Increases in the CAPM and ECAPM model results are primarily due to significantly higher Beta coefficients reported by both Bloomberg and Value Line, as the correlation between utility returns and returns for the broader market has increased substantially. The higher Betas more than offset the decline in government bond yields. Exhibit PAC/3506 demonstrates that the results from the Risk Premium analysis range from 9.26 percent to 9.96 percent. Finally, the mean and median results of the Expected Earnings approach are 10.70 percent and 10.73 percent respectively, shown in Exhibit PAC/3507.

[19] Based on mean results of the 30-day average stock price scenario.
[20] Based on near-term projected Treasury bond yields, using average results for both Value Line and Bloomberg betas.

Figure 2: Updated Analytical Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.54%	9.00%	9.89%
90-Day Average	8.54%	8.98%	9.86%
180-Day Average	8.43%	8.76%	9.54%
Constant Growth Average	8.50%	8.91%	9.76%
Multi-Stage DCF			
First-Stage Growth	Mean Low	Mean	Mean High
30-Day Average	9.32%	9.55%	9.78%
90-Day Average	9.31%	9.53%	9.76%
180-Day Average	8.99%	9.20%	9.41%
Multi-Stage Average	9.21%	9.42%	9.65%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Calculated Return on the S&P 500 Companies			
Value Line Beta	12.26%	12.31%	12.46%
Bloomberg Beta	11.52%	11.60%	11.83%
S&P Implied Return on the S&P 500			
Value Line Beta	12.37%	12.42%	12.58%
Bloomberg Beta	11.63%	11.70%	11.93%
ECAPM			
Calculated Return on the S&P 500 Companies			
Value Line Beta	12.65%	12.68%	12.80%
Bloomberg Beta	12.09%	12.15%	12.32%
S&P Implied Return on the S&P 500			
Value Line Beta	12.76%	12.80%	12.92%
Bloomberg Beta	12.21%	12.27%	12.44%
Treasury Yield Plus Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Analysis	9.26%	9.44%	9.96%
Risk Premium Mean Result	9.55%		
Expected Earnings Analysis			
	Mean		Median
Expected Earnings Result	10.70%		10.73%

IV. SUMMARY AND RECOMMENDATION

Q. Please summarize your conclusions and recommendation.

A. I conclude that the range of reasonable ROE results for the proxy group companies remains between 9.75 percent and 10.25 percent. This range is conservative given the results of my updated analyses. Although my updated ROE analysis continues to support an authorized ROE of 10.20 percent for PacifiCorp in Oregon, the Company has decided to lower its requested ROE by 40 basis points to 9.80 percent.

As explained in my reply testimony, other federal and state regulatory commissions have reviewed the results of ROE estimation models and concluded that current market conditions (*i.e.*, the low interest rate environment) have affected the inputs used in ROE estimation models. As a result, other regulators have determined that it is appropriate and necessary to consider the results of multiple ROE estimation models. I agree with these regulatory commissions that the inputs to the DCF model have been influenced by market conditions, and that it is appropriate to consider the results of multiple analytical approaches.

Consistent with the recent conclusions of other regulators, the Company's requested ROE takes into consideration both the results of the DCF models and risk premium methodologies, specifically the forward-looking CAPM analysis and the Risk Premium model, as well as the Expected Earnings analyses. In addition, my recommendation considers other factors in determining the appropriate ROE, including company-specific risk factors, and the capital attraction standard. Further, the Company's proposed capital structure of 53.52 percent common equity and

46.48 percent long-term debt are reasonable relative to the operating utility companies held by the proxy group companies.

Q. What factors support PacifiCorp's requested ROE in this proceeding?

A. Based on my updated analyses, I conclude that the Company's requested ROE of 9.80 percent is reasonable, if not conservative, for PacifiCorp in Oregon. A return at this level is:

1. Supported by the analyses contained in my direct testimony and updated in my reply and surrebuttal testimonies;
2. Consistent with current and prospective capital market conditions;
3. Supported by the methodologies considered by other regulatory jurisdictions; and
4. Consistent with the range of ROEs awards for integrated electric utilities in other state jurisdictions.

Furthermore, a 9.80 percent ROE balances the need to maintain access to capital on reasonable terms, considering the increased risk associated with current market conditions, with concerns for customers during these difficult economic times.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/3501
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated Summary of Results

August 2020

SUMMARY OF ROE ANALYSES RESULTS[1]

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.54%	9.00%	9.89%
90-Day Average	8.54%	8.98%	9.86%
180-Day Average	8.43%	8.76%	9.54%
Constant Growth Average	8.50%	8.91%	9.76%
Multi-Stage DCF			
First-Stage Growth	Mean Low	Mean	Mean High
30-Day Average	9.32%	9.55%	9.78%
90-Day Average	9.31%	9.53%	9.76%
180-Day Average	8.99%	9.20%	9.41%
Multi-Stage Average	9.21%	9.42%	9.65%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Calculated Return on the S&P 500 Companies			
Value Line Beta	12.26%	12.31%	12.46%
Bloomberg Beta	11.52%	11.60%	11.83%
S&P Implied Return on the S&P 500			
Value Line Beta	12.37%	12.42%	12.58%
Bloomberg Beta	11.63%	11.70%	11.93%
ECAPM			
Calculated Return on the S&P 500 Companies			
Value Line Beta	12.65%	12.68%	12.80%
Bloomberg Beta	12.09%	12.15%	12.32%
S&P Implied Return on the S&P 500			
Value Line Beta	12.76%	12.80%	12.92%
Bloomberg Beta	12.21%	12.27%	12.44%
Treasury Yield Plus Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Analysis	9.26%	9.44%	9.96%
Risk Premium Mean Result	9.55%		
Expected Earnings Analysis			
	Mean		Median
Expected Earnings Result	10.70%		10.73%

Notes:

[1] The analytical results included in the table reflect the results of the Constant Growth, Multi-Stage and Projected DCF analyses excluding the results for individual companies that did not meet the minimum threshold of 7 percent.

Docket No. UE 374
Exhibit PAC/3502
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated Constant Growth DCF Model

August 2020

30-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth
ALLETE, Inc.	ALE	$2.47	$57.12	4.32%	4.46%	5.50%
Alliant Energy Corporation	LNT	$1.52	$49.95	3.04%	3.13%	6.50%
Ameren Corporation	AEE	$1.98	$75.02	2.64%	2.72%	6.00%
American Electric Power Company, Inc.	AEP	$2.80	$83.65	3.35%	3.44%	5.00%
Avista Corporation	AVA	$1.62	$36.34	4.46%	4.55%	1.00%
CMS Energy Corporation	CMS	$1.63	$60.46	2.70%	2.79%	7.50%
Dominion Resources, Inc.	D	$3.76	$79.01	4.76%	4.86%	7.00%
DTE Energy Company	DTE	$4.05	$109.66	3.69%	3.80%	5.00%
Duke Energy Corporation	DUK	$3.78	$81.80	4.62%	4.72%	5.00%
Entergy Corporation	ETR	$3.72	$98.13	3.79%	3.88%	3.00%
Evergy, Inc.	EVRG	$2.02	$61.76	3.27%	3.34%	3.00%
IDACORP, Inc.	IDA	$2.68	$89.76	2.99%	3.03%	3.50%
NextEra Energy, Inc.	NEE	$5.60	$259.84	2.16%	2.25%	10.00%
NorthWestern Corporation	NWE	$2.40	$54.28	4.42%	4.49%	1.50%
OGE Energy Corporation	OGE	$1.55	$31.44	4.93%	5.01%	3.00%
Otter Tail Corporation	OTTR	$1.48	$38.56	3.84%	3.96%	3.50%
Pinnacle West Capital Corporation	PNW	$3.13	$77.80	4.02%	4.11%	4.00%
PNM Resources, Inc.	PNM	$1.23	$39.58	3.11%	3.20%	6.00%
Portland General Electric Company	POR	$1.54	$42.62	3.61%	3.70%	4.00%
PPL Corporation	PPL	$1.66	$25.74	6.45%	6.54%	2.50%
Southern Company	SO	$2.56	$53.57	4.78%	4.87%	3.00%
Xcel Energy Inc.	XEL	$1.72	$65.24	2.64%	2.72%	6.00%
MEAN				3.80%	3.89%	4.61%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line Investment Survey
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth
ALLETE, Inc.	ALE	$2.47	$57.32	4.31%	4.44%	5.50%
Alliant Energy Corporation	LNT	$1.52	$49.15	3.09%	3.18%	6.50%
Ameren Corporation	AEE	$1.98	$73.61	2.69%	2.77%	6.00%
American Electric Power Company, Inc.	AEP	$2.80	$82.40	3.40%	3.49%	5.00%
Avista Corporation	AVA	$1.62	$38.99	4.15%	4.24%	1.00%
CMS Energy Corporation	CMS	$1.63	$58.78	2.77%	2.87%	7.50%
Dominion Resources, Inc.	D	$3.76	$79.25	4.74%	4.85%	7.00%
DTE Energy Company	DTE	$4.05	$105.29	3.85%	3.95%	5.00%
Duke Energy Corporation	DUK	$3.78	$83.69	4.52%	4.62%	5.00%
Entergy Corporation	ETR	$3.72	$97.64	3.81%	3.90%	3.00%
Evergy, Inc.	EVRG	$2.02	$59.91	3.37%	3.44%	3.00%
IDACORP, Inc.	IDA	$2.68	$90.33	2.97%	3.01%	3.50%
NextEra Energy, Inc.	NEE	$5.60	$245.67	2.28%	2.38%	10.00%
NorthWestern Corporation	NWE	$2.40	$57.13	4.20%	4.26%	1.50%
OGE Energy Corporation	OGE	$1.55	$31.15	4.98%	5.05%	3.00%
Otter Tail Corporation	OTTR	$1.48	$41.32	3.58%	3.69%	3.50%
Pinnacle West Capital Corporation	PNW	$3.13	$76.62	4.08%	4.17%	4.00%
PNM Resources, Inc.	PNM	$1.23	$39.89	3.08%	3.17%	6.00%
Portland General Electric Company	POR	$1.54	$45.18	3.41%	3.49%	4.00%
PPL Corporation	PPL	$1.66	$25.87	6.42%	6.50%	2.50%
Southern Company	SO	$2.56	$55.15	4.64%	4.73%	3.00%
Xcel Energy Inc.	XEL	$1.72	$63.50	2.71%	2.79%	6.00%
MEAN				3.78%	3.86%	4.61%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of July 31, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line Investment Survey
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth
ALLETE, Inc.	ALE	$2.47	$67.72	3.65%	3.76%	5.50%
Alliant Energy Corporation	LNT	$1.52	$51.90	2.93%	3.01%	6.50%
Ameren Corporation	AEE	$1.98	$75.89	2.61%	2.69%	6.00%
American Electric Power Company, Inc.	AEP	$2.80	$88.42	3.17%	3.25%	5.00%
Avista Corporation	AVA	$1.62	$43.64	3.71%	3.79%	1.00%
CMS Energy Corporation	CMS	$1.63	$61.13	2.67%	2.76%	7.50%
Dominion Resources, Inc.	D	$3.76	$80.75	4.66%	4.76%	7.00%
DTE Energy Company	DTE	$4.05	$114.11	3.55%	3.65%	5.00%
Duke Energy Corporation	DUK	$3.78	$87.60	4.32%	4.41%	5.00%
Entergy Corporation	ETR	$3.72	$108.59	3.43%	3.51%	3.00%
Evergy, Inc.	EVRG	$2.02	$62.71	3.22%	3.29%	3.00%
IDACORP, Inc.	IDA	$2.68	$97.50	2.75%	2.79%	3.50%
NextEra Energy, Inc.	NEE	$5.60	$246.24	2.27%	2.37%	10.00%
NorthWestern Corporation	NWE	$2.40	$64.53	3.72%	3.77%	1.50%
OGE Energy Corporation	OGE	$1.55	$36.55	4.24%	4.31%	3.00%
Otter Tail Corporation	OTTR	$1.48	$45.81	3.23%	3.33%	3.50%
Pinnacle West Capital Corporation	PNW	$3.13	$83.44	3.75%	3.83%	4.00%
PNM Resources, Inc.	PNM	$1.23	$44.64	2.76%	2.84%	6.00%
Portland General Electric Company	POR	$1.54	$50.74	3.03%	3.10%	4.00%
PPL Corporation	PPL	$1.66	$29.69	5.59%	5.67%	2.50%
Southern Company	SO	$2.56	$59.32	4.32%	4.40%	3.00%
Xcel Energy Inc.	XEL	$1.72	$63.95	2.69%	2.77%	6.00%
MEAN				3.47%	3.55%	4.61%

Notes

[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of July 31, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line Investment Survey
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

-- PACIFICORP PROXY GROUP

				All Proxy Group			With Exclusions	
[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
7.00%	NA%	6.25%	9.94%	10.71%	11.48%	9.94%	10.71%	11.48%
5.30%	5.50%	5.77%	8.42%	8.90%	9.64%	8.42%	8.90%	9.64%
5.85%	6.80%	6.22%	8.57%	8.94%	9.53%	8.57%	8.94%	9.53%
5.82%	5.70%	5.51%	8.43%	8.95%	9.26%	8.43%	8.95%	9.26%
6.00%	5.20%	4.07%	5.48%	8.62%	10.59%		8.62%	10.59%
7.08%	7.00%	7.19%	9.79%	9.99%	10.30%	9.79%	9.99%	10.30%
2.76%	3.00%	4.25%	7.58%	9.11%	11.93%	7.58%	9.11%	11.93%
6.03%	5.70%	5.58%	8.79%	9.37%	9.83%	8.79%	9.37%	9.83%
3.81%	4.30%	4.37%	8.52%	9.09%	9.74%	8.52%	9.09%	9.74%
5.95%	5.70%	4.88%	6.85%	8.77%	9.85%		8.77%	9.85%
4.10%	5.00%	4.03%	6.32%	7.37%	8.35%		7.37%	8.35%
2.60%	2.60%	2.90%	5.62%	5.93%	6.54%			
8.17%	8.00%	8.72%	10.24%	10.97%	12.26%	10.24%	10.97%	12.26%
3.71%	3.40%	2.87%	5.95%	7.36%	8.21%		7.36%	8.21%
2.40%	3.70%	3.03%	7.39%	8.04%	8.72%	7.39%	8.04%	8.72%
9.00%	NA%	6.25%	7.41%	10.21%	13.01%	7.41%	10.21%	13.01%
4.36%	4.70%	4.35%	8.10%	8.46%	8.82%	8.10%	8.46%	8.82%
5.60%	6.20%	5.93%	8.79%	9.13%	9.40%	8.79%	9.13%	9.40%
4.45%	5.30%	4.58%	7.69%	8.28%	9.01%	7.69%	8.28%	9.01%
2.90%	NA%	2.70%	9.03%	9.24%	9.44%	9.03%	9.24%	9.44%
4.53%	4.00%	3.84%	7.85%	8.71%	9.42%	7.85%	8.71%	9.42%
6.10%	6.10%	6.07%	8.72%	8.78%	8.82%	8.72%	8.78%	8.82%
5.16%	5.15%	4.97%	7.98%	8.86%	9.73%	8.54%	9.00%	9.89%

-- PACIFICORP PROXY GROUP

			All Proxy Group			With Exclusions		
[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
7.00%	NA%	6.25%	9.93%	10.69%	11.46%	9.93%	10.69%	11.46%
5.30%	5.50%	5.77%	8.47%	8.95%	9.69%	8.47%	8.95%	9.69%
5.85%	6.80%	6.22%	8.62%	8.99%	9.58%	8.62%	8.99%	9.58%
5.82%	5.70%	5.51%	8.48%	9.00%	9.32%	8.48%	9.00%	9.32%
6.00%	5.20%	4.07%	5.18%	8.31%	10.28%		8.31%	10.28%
7.08%	7.00%	7.19%	9.87%	10.07%	10.38%	9.87%	10.07%	10.38%
2.76%	3.00%	4.25%	7.57%	9.10%	11.91%	7.57%	9.10%	11.91%
6.03%	5.70%	5.58%	8.94%	9.53%	9.99%	8.94%	9.53%	9.99%
3.81%	4.30%	4.37%	8.41%	8.99%	9.63%	8.41%	8.99%	9.63%
5.95%	5.70%	4.88%	6.87%	8.79%	9.87%		8.79%	9.87%
4.10%	5.00%	4.03%	6.42%	7.47%	8.46%		7.47%	8.46%
2.60%	2.60%	2.90%	5.61%	5.91%	6.52%			
8.17%	8.00%	8.72%	10.37%	11.10%	12.39%	10.37%	11.10%	12.39%
3.71%	3.40%	2.87%	5.73%	7.13%	7.99%		7.13%	7.99%
2.40%	3.70%	3.03%	7.44%	8.09%	8.77%	7.44%	8.09%	8.77%
9.00%	NA%	6.25%	7.14%	9.94%	12.74%	7.14%	9.94%	12.74%
4.36%	4.70%	4.35%	8.17%	8.53%	8.88%	8.17%	8.53%	8.88%
5.60%	6.20%	5.93%	8.77%	9.11%	9.38%	8.77%	9.11%	9.38%
4.45%	5.30%	4.58%	7.48%	8.07%	8.80%	7.48%	8.07%	8.80%
2.90%	NA%	2.70%	9.00%	9.20%	9.41%	9.00%	9.20%	9.41%
4.53%	4.00%	3.84%	7.71%	8.57%	9.28%	7.71%	8.57%	9.28%
6.10%	6.10%	6.07%	8.79%	8.86%	8.89%	8.79%	8.86%	8.89%
5.16%	5.15%	4.97%	7.95%	8.84%	9.71%	8.54%	8.98%	9.86%

-- PACIFICORP PROXY GROUP

				All Proxy Group			With Exclusions	
[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
7.00%	NA%	6.25%	9.25%	10.01%	10.77%	9.25%	10.01%	10.77%
5.30%	5.50%	5.77%	8.31%	8.78%	9.52%	8.31%	8.78%	9.52%
5.85%	6.80%	6.22%	8.54%	8.91%	9.50%	8.54%	8.91%	9.50%
5.82%	5.70%	5.51%	8.25%	8.76%	9.08%	8.25%	8.76%	9.08%
6.00%	5.20%	4.07%	4.73%	7.85%	9.82%		7.85%	9.82%
7.08%	7.00%	7.19%	9.76%	9.96%	10.27%	9.76%	9.96%	10.27%
2.76%	3.00%	4.25%	7.48%	9.01%	11.82%	7.48%	9.01%	11.82%
6.03%	5.70%	5.58%	8.64%	9.22%	9.69%	8.64%	9.22%	9.69%
3.81%	4.30%	4.37%	8.21%	8.78%	9.42%	8.21%	8.78%	9.42%
5.95%	5.70%	4.88%	6.48%	8.39%	9.48%		8.39%	9.48%
4.10%	5.00%	4.03%	6.27%	7.32%	8.30%		7.32%	8.30%
2.60%	2.60%	2.90%	5.38%	5.69%	6.30%			
8.17%	8.00%	8.72%	10.37%	11.10%	12.39%	10.37%	11.10%	12.39%
3.71%	3.40%	2.87%	5.25%	6.64%	7.50%			7.50%
2.40%	3.70%	3.03%	6.69%	7.34%	8.02%		7.34%	8.02%
9.00%	NA%	6.25%	6.79%	9.58%	12.38%		9.58%	12.38%
4.36%	4.70%	4.35%	7.83%	8.19%	8.54%	7.83%	8.19%	8.54%
5.60%	6.20%	5.93%	8.43%	8.77%	9.04%	8.43%	8.77%	9.04%
4.45%	5.30%	4.58%	7.10%	7.69%	8.42%	7.10%	7.69%	8.42%
2.90%	NA%	2.70%	8.16%	8.37%	8.57%	8.16%	8.37%	8.57%
4.53%	4.00%	3.84%	7.38%	8.24%	8.94%	7.38%	8.24%	8.94%
6.10%	6.10%	6.07%	8.77%	8.84%	8.87%	8.77%	8.84%	8.87%
5.16%	5.15%	4.97%	7.64%	8.52%	9.39%	8.43%	8.76%	9.54%

Docket No. UE 374
Exhibit PAC/3503
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated Multi-State DCF Model

August 2020

30-DAY MULTI-STAGE DCF -- AVER

Inputs		[1]	[2]	[3]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth
ALLETE, Inc.	ALE	$57.12	$2.47	6.25%
Alliant Energy Corporation	LNT	$49.95	$1.52	5.77%
Ameren Corporation	AEE	$75.02	$1.98	6.22%
American Electric Power Company, Inc.	AEP	$83.65	$2.80	5.51%
Avista Corporation	AVA	$36.34	$1.62	4.07%
CMS Energy Corporation	CMS	$60.46	$1.63	7.19%
Dominion Resources, Inc.	D	$79.01	$3.76	4.25%
DTE Energy Company	DTE	$109.66	$4.05	5.58%
Duke Energy Corporation	DUK	$81.80	$3.78	4.37%
Entergy Corporation	ETR	$98.13	$3.72	4.88%
Evergy, Inc.	EVRG	$61.76	$2.02	4.03%
IDACORP, Inc.	IDA	$89.76	$2.68	2.90%
NextEra Energy, Inc.	NEE	$259.84	$5.60	8.72%
NorthWestern Corporation	NWE	$54.28	$2.40	2.87%
OGE Energy Corporation	OGE	$31.44	$1.55	3.03%
Otter Tail Corporation	OTTR	$38.56	$1.48	6.25%
Pinnacle West Capital Corporation	PNW	$77.80	$3.13	4.35%
PNM Resources, Inc.	PNM	$39.58	$1.23	5.93%
Portland General Electric Company	POR	$42.62	$1.54	4.58%
PPL Corporation	PPL	$25.74	$1.66	2.70%
Southern Company	SO	$53.57	$2.56	3.84%
Xcel Energy Inc.	XEL	$65.24	$1.72	6.07%
MEAN				

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of July 31, 2020
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/3504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- AVER

Inputs		[1]	[2]	[3]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth
ALLETE, Inc.	ALE	$57.32	$2.47	6.25%
Alliant Energy Corporation	LNT	$49.15	$1.52	5.77%
Ameren Corporation	AEE	$73.61	$1.98	6.22%
American Electric Power Company, Inc.	AEP	$82.40	$2.80	5.51%
Avista Corporation	AVA	$38.99	$1.62	4.07%
CMS Energy Corporation	CMS	$58.78	$1.63	7.19%
Dominion Resources, Inc.	D	$79.25	$3.76	4.25%
DTE Energy Company	DTE	$105.29	$4.05	5.58%
Duke Energy Corporation	DUK	$83.69	$3.78	4.37%
Entergy Corporation	ETR	$97.64	$3.72	4.88%
Evergy, Inc.	EVRG	$59.91	$2.02	4.03%
IDACORP, Inc.	IDA	$90.33	$2.68	2.90%
NextEra Energy, Inc.	NEE	$245.67	$5.60	8.72%
NorthWestern Corporation	NWE	$57.13	$2.40	2.87%
OGE Energy Corporation	OGE	$31.15	$1.55	3.03%
Otter Tail Corporation	OTTR	$41.32	$1.48	6.25%
Pinnacle West Capital Corporation	PNW	$76.62	$3.13	4.35%
PNM Resources, Inc.	PNM	$39.89	$1.23	5.93%
Portland General Electric Company	POR	$45.18	$1.54	4.58%
PPL Corporation	PPL	$25.87	$1.66	2.70%
Southern Company	SO	$55.15	$2.56	3.84%
Xcel Energy Inc.	XEL	$63.50	$1.72	6.07%
MEAN				

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of July 31, 2020
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/3504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- AVER

Inputs		[1]	[2]	[3]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth
ALLETE, Inc.	ALE	$67.72	$2.47	6.25%
Alliant Energy Corporation	LNT	$51.90	$1.52	5.77%
Ameren Corporation	AEE	$75.89	$1.98	6.22%
American Electric Power Company, Inc.	AEP	$88.42	$2.80	5.51%
Avista Corporation	AVA	$43.64	$1.62	4.07%
CMS Energy Corporation	CMS	$61.13	$1.63	7.19%
Dominion Resources, Inc.	D	$80.75	$3.76	4.25%
DTE Energy Company	DTE	$114.11	$4.05	5.58%
Duke Energy Corporation	DUK	$87.60	$3.78	4.37%
Entergy Corporation	ETR	$108.59	$3.72	4.88%
Evergy, Inc.	EVRG	$62.71	$2.02	4.03%
IDACORP, Inc.	IDA	$97.50	$2.68	2.90%
NextEra Energy, Inc.	NEE	$246.24	$5.60	8.72%
NorthWestern Corporation	NWE	$64.53	$2.40	2.87%
OGE Energy Corporation	OGE	$36.55	$1.55	3.03%
Otter Tail Corporation	OTTR	$45.81	$1.48	6.25%
Pinnacle West Capital Corporation	PNW	$83.44	$3.13	4.35%
PNM Resources, Inc.	PNM	$44.64	$1.23	5.93%
Portland General Electric Company	POR	$50.74	$1.54	4.58%
PPL Corporation	PPL	$29.69	$1.66	2.70%
Southern Company	SO	$59.32	$2.56	3.84%
Xcel Energy Inc.	XEL	$63.95	$1.72	6.07%
MEAN				

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of July 31, 2020
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/3504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MINIM

Inputs		[1]	[2]	[3]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth
ALLETE, Inc.	ALE	$57.12	$2.47	5.50%
Alliant Energy Corporation	LNT	$49.95	$1.52	5.30%
Ameren Corporation	AEE	$75.02	$1.98	5.85%
American Electric Power Company, Inc.	AEP	$83.65	$2.80	5.00%
Avista Corporation	AVA	$36.34	$1.62	1.00%
CMS Energy Corporation	CMS	$60.46	$1.63	7.00%
Dominion Resources, Inc.	D	$79.01	$3.76	2.76%
DTE Energy Company	DTE	$109.66	$4.05	5.00%
Duke Energy Corporation	DUK	$81.80	$3.78	3.81%
Entergy Corporation	ETR	$98.13	$3.72	3.00%
Evergy, Inc.	EVRG	$61.76	$2.02	3.00%
IDACORP, Inc.	IDA	$89.76	$2.68	2.60%
NextEra Energy, Inc.	NEE	$259.84	$5.60	8.00%
NorthWestern Corporation	NWE	$54.28	$2.40	1.50%
OGE Energy Corporation	OGE	$31.44	$1.55	2.40%
Otter Tail Corporation	OTTR	$38.56	$1.48	3.50%
Pinnacle West Capital Corporation	PNW	$77.80	$3.13	4.00%
PNM Resources, Inc.	PNM	$39.58	$1.23	5.60%
Portland General Electric Company	POR	$42.62	$1.54	4.00%
PPL Corporation	PPL	$25.74	$1.66	2.50%
Southern Company	SO	$53.57	$2.56	3.00%
Xcel Energy Inc.	XEL	$65.24	$1.72	6.00%
MEAN				

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of July 31, 2020
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/3504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MINIM

Inputs		[1]	[2]	[3]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth
ALLETE, Inc.	ALE	$57.32	$2.47	5.50%
Alliant Energy Corporation	LNT	$49.15	$1.52	5.30%
Ameren Corporation	AEE	$73.61	$1.98	5.85%
American Electric Power Company, Inc.	AEP	$82.40	$2.80	5.00%
Avista Corporation	AVA	$38.99	$1.62	1.00%
CMS Energy Corporation	CMS	$58.78	$1.63	7.00%
Dominion Resources, Inc.	D	$79.25	$3.76	2.76%
DTE Energy Company	DTE	$105.29	$4.05	5.00%
Duke Energy Corporation	DUK	$83.69	$3.78	3.81%
Entergy Corporation	ETR	$97.64	$3.72	3.00%
Evergy, Inc.	EVRG	$59.91	$2.02	3.00%
IDACORP, Inc.	IDA	$90.33	$2.68	2.60%
NextEra Energy, Inc.	NEE	$245.67	$5.60	8.00%
NorthWestern Corporation	NWE	$57.13	$2.40	1.50%
OGE Energy Corporation	OGE	$31.15	$1.55	2.40%
Otter Tail Corporation	OTTR	$41.32	$1.48	3.50%
Pinnacle West Capital Corporation	PNW	$76.62	$3.13	4.00%
PNM Resources, Inc.	PNM	$39.89	$1.23	5.60%
Portland General Electric Company	POR	$45.18	$1.54	4.00%
PPL Corporation	PPL	$25.87	$1.66	2.50%
Southern Company	SO	$55.15	$2.56	3.00%
Xcel Energy Inc.	XEL	$63.50	$1.72	6.00%
MEAN				

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of July 31, 2020
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/3504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MINI

Inputs		[1]	[2]	[3]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth
ALLETE, Inc.	ALE	$67.72	$2.47	5.50%
Alliant Energy Corporation	LNT	$51.90	$1.52	5.30%
Ameren Corporation	AEE	$75.89	$1.98	5.85%
American Electric Power Company, Inc.	AEP	$88.42	$2.80	5.00%
Avista Corporation	AVA	$43.64	$1.62	1.00%
CMS Energy Corporation	CMS	$61.13	$1.63	7.00%
Dominion Resources, Inc.	D	$80.75	$3.76	2.76%
DTE Energy Company	DTE	$114.11	$4.05	5.00%
Duke Energy Corporation	DUK	$87.60	$3.78	3.81%
Entergy Corporation	ETR	$108.59	$3.72	3.00%
Evergy, Inc.	EVRG	$62.71	$2.02	3.00%
IDACORP, Inc.	IDA	$97.50	$2.68	2.60%
NextEra Energy, Inc.	NEE	$246.24	$5.60	8.00%
NorthWestern Corporation	NWE	$64.53	$2.40	1.50%
OGE Energy Corporation	OGE	$36.55	$1.55	2.40%
Otter Tail Corporation	OTTR	$45.81	$1.48	3.50%
Pinnacle West Capital Corporation	PNW	$83.44	$3.13	4.00%
PNM Resources, Inc.	PNM	$44.64	$1.23	5.60%
Portland General Electric Company	POR	$50.74	$1.54	4.00%
PPL Corporation	PPL	$29.69	$1.66	2.50%
Southern Company	SO	$59.32	$2.56	3.00%
Xcel Energy Inc.	XEL	$63.95	$1.72	6.00%
MEAN				

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of July 31, 2020
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/3504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MAXIM

Inputs		[1]	[2]	[3]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth
ALLETE, Inc.	ALE	$57.12	$2.47	7.00%
Alliant Energy Corporation	LNT	$49.95	$1.52	6.50%
Ameren Corporation	AEE	$75.02	$1.98	6.80%
American Electric Power Company, Inc.	AEP	$83.65	$2.80	5.82%
Avista Corporation	AVA	$36.34	$1.62	6.00%
CMS Energy Corporation	CMS	$60.46	$1.63	7.50%
Dominion Resources, Inc.	D	$79.01	$3.76	7.00%
DTE Energy Company	DTE	$109.66	$4.05	6.03%
Duke Energy Corporation	DUK	$81.80	$3.78	5.00%
Entergy Corporation	ETR	$98.13	$3.72	5.95%
Evergy, Inc.	EVRG	$61.76	$2.02	5.00%
IDACORP, Inc.	IDA	$89.76	$2.68	3.50%
NextEra Energy, Inc.	NEE	$259.84	$5.60	10.00%
NorthWestern Corporation	NWE	$54.28	$2.40	3.71%
OGE Energy Corporation	OGE	$31.44	$1.55	3.70%
Otter Tail Corporation	OTTR	$38.56	$1.48	9.00%
Pinnacle West Capital Corporation	PNW	$77.80	$3.13	4.70%
PNM Resources, Inc.	PNM	$39.58	$1.23	6.20%
Portland General Electric Company	POR	$42.62	$1.54	5.30%
PPL Corporation	PPL	$25.74	$1.66	2.90%
Southern Company	SO	$53.57	$2.56	4.53%
Xcel Energy Inc.	XEL	$65.24	$1.72	6.10%
MEAN				

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of July 31, 2020
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/3504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MAXIM

Inputs		[1]	[2]	[3]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth
ALLETE, Inc.	ALE	$57.32	$2.47	7.00%
Alliant Energy Corporation	LNT	$49.15	$1.52	6.50%
Ameren Corporation	AEE	$73.61	$1.98	6.80%
American Electric Power Company, Inc.	AEP	$82.40	$2.80	5.82%
Avista Corporation	AVA	$38.99	$1.62	6.00%
CMS Energy Corporation	CMS	$58.78	$1.63	7.50%
Dominion Resources, Inc.	D	$79.25	$3.76	7.00%
DTE Energy Company	DTE	$105.29	$4.05	6.03%
Duke Energy Corporation	DUK	$83.69	$3.78	5.00%
Entergy Corporation	ETR	$97.64	$3.72	5.95%
Evergy, Inc.	EVRG	$59.91	$2.02	5.00%
IDACORP, Inc.	IDA	$90.33	$2.68	3.50%
NextEra Energy, Inc.	NEE	$245.67	$5.60	10.00%
NorthWestern Corporation	NWE	$57.13	$2.40	3.71%
OGE Energy Corporation	OGE	$31.15	$1.55	3.70%
Otter Tail Corporation	OTTR	$41.32	$1.48	9.00%
Pinnacle West Capital Corporation	PNW	$76.62	$3.13	4.70%
PNM Resources, Inc.	PNM	$39.89	$1.23	6.20%
Portland General Electric Company	POR	$45.18	$1.54	5.30%
PPL Corporation	PPL	$25.87	$1.66	2.90%
Southern Company	SO	$55.15	$2.56	4.53%
Xcel Energy Inc.	XEL	$63.50	$1.72	6.10%
MEAN				

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of July 31, 2020
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/3504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MAXI

Inputs		[1]	[2]	[3]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth
ALLETE, Inc.	ALE	$67.72	$2.47	7.00%
Alliant Energy Corporation	LNT	$51.90	$1.52	6.50%
Ameren Corporation	AEE	$75.89	$1.98	6.80%
American Electric Power Company, Inc.	AEP	$88.42	$2.80	5.82%
Avista Corporation	AVA	$43.64	$1.62	6.00%
CMS Energy Corporation	CMS	$61.13	$1.63	7.50%
Dominion Resources, Inc.	D	$80.75	$3.76	7.00%
DTE Energy Company	DTE	$114.11	$4.05	6.03%
Duke Energy Corporation	DUK	$87.60	$3.78	5.00%
Entergy Corporation	ETR	$108.59	$3.72	5.95%
Evergy, Inc.	EVRG	$62.71	$2.02	5.00%
IDACORP, Inc.	IDA	$97.50	$2.68	3.50%
NextEra Energy, Inc.	NEE	$246.24	$5.60	10.00%
NorthWestern Corporation	NWE	$64.53	$2.40	3.71%
OGE Energy Corporation	OGE	$36.55	$1.55	3.70%
Otter Tail Corporation	OTTR	$45.81	$1.48	9.00%
Pinnacle West Capital Corporation	PNW	$83.44	$3.13	4.70%
PNM Resources, Inc.	PNM	$44.64	$1.23	6.20%
Portland General Electric Company	POR	$50.74	$1.54	5.30%
PPL Corporation	PPL	$29.69	$1.66	2.90%
Southern Company	SO	$59.32	$2.56	4.53%
Xcel Energy Inc.	XEL	$63.95	$1.72	6.10%
MEAN				

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of July 31, 2020
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/3504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

AGE FIRST STAGE GROWTH RATE

[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Second Stage Growth				
Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
6.13%	6.02%	5.90%	5.79%	5.67%	5.56%	10.56%
5.73%	5.70%	5.66%	5.63%	5.59%	5.56%	8.94%
6.11%	6.00%	5.89%	5.78%	5.67%	5.56%	8.57%
5.52%	5.52%	5.53%	5.54%	5.55%	5.56%	9.23%
4.32%	4.56%	4.81%	5.06%	5.31%	5.56%	10.05%
6.92%	6.65%	6.38%	6.10%	5.83%	5.56%	8.84%
4.47%	4.69%	4.91%	5.12%	5.34%	5.56%	10.42%
5.57%	5.57%	5.57%	5.56%	5.56%	5.56%	9.64%
4.57%	4.77%	4.96%	5.16%	5.36%	5.56%	10.31%
5.00%	5.11%	5.22%	5.33%	5.45%	5.56%	9.56%
4.29%	4.54%	4.80%	5.05%	5.30%	5.56%	8.81%
3.34%	3.79%	4.23%	4.67%	5.12%	5.56%	8.29%
8.20%	7.67%	7.14%	6.61%	6.09%	5.56%	8.44%
3.32%	3.77%	4.21%	4.66%	5.11%	5.56%	9.68%
3.45%	3.88%	4.30%	4.72%	5.14%	5.56%	10.22%
6.13%	6.02%	5.90%	5.79%	5.67%	5.56%	9.98%
4.55%	4.76%	4.96%	5.16%	5.36%	5.56%	9.67%
5.87%	5.81%	5.75%	5.68%	5.62%	5.56%	9.05%
4.75%	4.91%	5.07%	5.23%	5.40%	5.56%	9.30%
3.18%	3.65%	4.13%	4.61%	5.08%	5.56%	11.62%
4.13%	4.42%	4.70%	4.99%	5.27%	5.56%	10.32%
5.98%	5.90%	5.81%	5.73%	5.64%	5.56%	8.54%
						9.55%

AGE FIRST STAGE GROWTH RATE

[4]	[5]	[6]	[7]	[8]	[9]	[10]
Second Stage Growth						
Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
6.13%	6.02%	5.90%	5.79%	5.67%	5.56%	10.54%
5.73%	5.70%	5.66%	5.63%	5.59%	5.56%	9.00%
6.11%	6.00%	5.89%	5.78%	5.67%	5.56%	8.63%
5.52%	5.52%	5.53%	5.54%	5.55%	5.56%	9.29%
4.32%	4.56%	4.81%	5.06%	5.31%	5.56%	9.73%
6.92%	6.65%	6.38%	6.10%	5.83%	5.56%	8.94%
4.47%	4.69%	4.91%	5.12%	5.34%	5.56%	10.41%
5.57%	5.57%	5.57%	5.56%	5.56%	5.56%	9.81%
4.57%	4.77%	4.96%	5.16%	5.36%	5.56%	10.20%
5.00%	5.11%	5.22%	5.33%	5.45%	5.56%	9.58%
4.29%	4.54%	4.80%	5.05%	5.30%	5.56%	8.91%
3.34%	3.79%	4.23%	4.67%	5.12%	5.56%	8.27%
8.20%	7.67%	7.14%	6.61%	6.09%	5.56%	8.61%
3.32%	3.77%	4.21%	4.66%	5.11%	5.56%	9.46%
3.45%	3.88%	4.30%	4.72%	5.14%	5.56%	10.27%
6.13%	6.02%	5.90%	5.79%	5.67%	5.56%	9.68%
4.55%	4.76%	4.96%	5.16%	5.36%	5.56%	9.74%
5.87%	5.81%	5.75%	5.68%	5.62%	5.56%	9.03%
4.75%	4.91%	5.07%	5.23%	5.40%	5.56%	9.08%
3.18%	3.65%	4.13%	4.61%	5.08%	5.56%	11.59%
4.13%	4.42%	4.70%	4.99%	5.27%	5.56%	10.18%
5.98%	5.90%	5.81%	5.73%	5.64%	5.56%	8.62%
						9.53%

RAGE FIRST STAGE GROWTH RATE

[4]	[5]	[6]	[7]	[8]	[9]	[10]
Second Stage Growth						
Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
6.13%	6.02%	5.90%	5.79%	5.67%	5.56%	9.76%
5.73%	5.70%	5.66%	5.63%	5.59%	5.56%	8.81%
6.11%	6.00%	5.89%	5.78%	5.67%	5.56%	8.53%
5.52%	5.52%	5.53%	5.54%	5.55%	5.56%	9.03%
4.32%	4.56%	4.81%	5.06%	5.31%	5.56%	9.27%
6.92%	6.65%	6.38%	6.10%	5.83%	5.56%	8.80%
4.47%	4.69%	4.91%	5.12%	5.34%	5.56%	10.31%
5.57%	5.57%	5.57%	5.56%	5.56%	5.56%	9.47%
4.57%	4.77%	4.96%	5.16%	5.36%	5.56%	9.99%
5.00%	5.11%	5.22%	5.33%	5.45%	5.56%	9.17%
4.29%	4.54%	4.80%	5.05%	5.30%	5.56%	8.76%
3.34%	3.79%	4.23%	4.67%	5.12%	5.56%	8.06%
8.20%	7.67%	7.14%	6.61%	6.09%	5.56%	8.61%
3.32%	3.77%	4.21%	4.66%	5.11%	5.56%	9.00%
3.45%	3.88%	4.30%	4.72%	5.14%	5.56%	9.54%
6.13%	6.02%	5.90%	5.79%	5.67%	5.56%	9.27%
4.55%	4.76%	4.96%	5.16%	5.36%	5.56%	9.39%
5.87%	5.81%	5.75%	5.68%	5.62%	5.56%	8.65%
4.75%	4.91%	5.07%	5.23%	5.40%	5.56%	8.68%
3.18%	3.65%	4.13%	4.61%	5.08%	5.56%	10.77%
4.13%	4.42%	4.70%	4.99%	5.27%	5.56%	9.84%
5.98%	5.90%	5.81%	5.73%	5.64%	5.56%	8.60%
						9.20%

IUM FIRST STAGE GROWTH RATE

[4]	[5]	[6]	[7]	[8]	[9]	[10]
Second Stage Growth						
Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
5.51%	5.52%	5.53%	5.54%	5.55%	5.56%	10.33%
5.34%	5.39%	5.43%	5.47%	5.52%	5.56%	8.84%
5.80%	5.75%	5.70%	5.66%	5.61%	5.56%	8.50%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	9.11%
1.76%	2.52%	3.28%	4.04%	4.80%	5.56%	9.22%
6.76%	6.52%	6.28%	6.04%	5.80%	5.56%	8.80%
3.23%	3.69%	4.16%	4.63%	5.09%	5.56%	9.97%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	9.49%
4.10%	4.39%	4.68%	4.98%	5.27%	5.56%	10.14%
3.43%	3.85%	4.28%	4.71%	5.13%	5.56%	9.10%
3.43%	3.85%	4.28%	4.71%	5.13%	5.56%	8.59%
3.09%	3.59%	4.08%	4.57%	5.07%	5.56%	8.23%
7.59%	7.19%	6.78%	6.37%	5.97%	5.56%	8.31%
2.18%	2.85%	3.53%	4.21%	4.88%	5.56%	9.32%
2.93%	3.45%	3.98%	4.51%	5.03%	5.56%	10.04%
3.84%	4.19%	4.53%	4.87%	5.22%	5.56%	9.26%
4.26%	4.52%	4.78%	5.04%	5.30%	5.56%	9.58%
5.59%	5.59%	5.58%	5.57%	5.57%	5.56%	8.98%
4.26%	4.52%	4.78%	5.04%	5.30%	5.56%	9.16%
3.01%	3.52%	4.03%	4.54%	5.05%	5.56%	11.54%
3.43%	3.85%	4.28%	4.71%	5.13%	5.56%	10.06%
5.93%	5.85%	5.78%	5.71%	5.63%	5.56%	8.52%
						9.32%

IUM FIRST STAGE GROWTH RATE

[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Second Stage Growth				
Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
5.51%	5.52%	5.53%	5.54%	5.55%	5.56%	10.31%
5.34%	5.39%	5.43%	5.47%	5.52%	5.56%	8.90%
5.80%	5.75%	5.70%	5.66%	5.61%	5.56%	8.56%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	9.16%
1.76%	2.52%	3.28%	4.04%	4.80%	5.56%	8.96%
6.76%	6.52%	6.28%	6.04%	5.80%	5.56%	8.89%
3.23%	3.69%	4.16%	4.63%	5.09%	5.56%	9.96%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	9.65%
4.10%	4.39%	4.68%	4.98%	5.27%	5.56%	10.04%
3.43%	3.85%	4.28%	4.71%	5.13%	5.56%	9.11%
3.43%	3.85%	4.28%	4.71%	5.13%	5.56%	8.69%
3.09%	3.59%	4.08%	4.57%	5.07%	5.56%	8.22%
7.59%	7.19%	6.78%	6.37%	5.97%	5.56%	8.47%
2.18%	2.85%	3.53%	4.21%	4.88%	5.56%	9.12%
2.93%	3.45%	3.98%	4.51%	5.03%	5.56%	10.08%
3.84%	4.19%	4.53%	4.87%	5.22%	5.56%	9.01%
4.26%	4.52%	4.78%	5.04%	5.30%	5.56%	9.64%
5.59%	5.59%	5.58%	5.57%	5.57%	5.56%	8.95%
4.26%	4.52%	4.78%	5.04%	5.30%	5.56%	8.94%
3.01%	3.52%	4.03%	4.54%	5.05%	5.56%	11.51%
3.43%	3.85%	4.28%	4.71%	5.13%	5.56%	9.93%
5.93%	5.85%	5.78%	5.71%	5.63%	5.56%	8.61%
						9.31%

MUM FIRST STAGE GROWTH RATE

[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Second Stage Growth				
Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
5.51%	5.52%	5.53%	5.54%	5.55%	5.56%	9.56%
5.34%	5.39%	5.43%	5.47%	5.52%	5.56%	8.71%
5.80%	5.75%	5.70%	5.66%	5.61%	5.56%	8.46%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	8.91%
1.76%	2.52%	3.28%	4.04%	4.80%	5.56%	8.57%
6.76%	6.52%	6.28%	6.04%	5.80%	5.56%	8.76%
3.23%	3.69%	4.16%	4.63%	5.09%	5.56%	9.88%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	9.33%
4.10%	4.39%	4.68%	4.98%	5.27%	5.56%	9.83%
3.43%	3.85%	4.28%	4.71%	5.13%	5.56%	8.74%
3.43%	3.85%	4.28%	4.71%	5.13%	5.56%	8.54%
3.09%	3.59%	4.08%	4.57%	5.07%	5.56%	8.01%
7.59%	7.19%	6.78%	6.37%	5.97%	5.56%	8.47%
2.18%	2.85%	3.53%	4.21%	4.88%	5.56%	8.69%
2.93%	3.45%	3.98%	4.51%	5.03%	5.56%	9.38%
3.84%	4.19%	4.53%	4.87%	5.22%	5.56%	8.65%
4.26%	4.52%	4.78%	5.04%	5.30%	5.56%	9.30%
5.59%	5.59%	5.58%	5.57%	5.57%	5.56%	8.58%
4.26%	4.52%	4.78%	5.04%	5.30%	5.56%	8.56%
3.01%	3.52%	4.03%	4.54%	5.05%	5.56%	10.70%
3.43%	3.85%	4.28%	4.71%	5.13%	5.56%	9.61%
5.93%	5.85%	5.78%	5.71%	5.63%	5.56%	8.59%
						8.99%

MUM FIRST STAGE GROWTH RATE

[4]	[5]	[6]	[7]	[8]	[9]	[10]
Second Stage Growth						
Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
6.76%	6.52%	6.28%	6.04%	5.80%	5.56%	10.79%
6.34%	6.19%	6.03%	5.87%	5.72%	5.56%	9.11%
6.59%	6.39%	6.18%	5.97%	5.77%	5.56%	8.69%
5.78%	5.73%	5.69%	5.65%	5.60%	5.56%	9.30%
5.93%	5.85%	5.78%	5.71%	5.63%	5.56%	10.63%
7.18%	6.85%	6.53%	6.21%	5.88%	5.56%	8.91%
6.76%	6.52%	6.28%	6.04%	5.80%	5.56%	11.32%
5.95%	5.87%	5.79%	5.72%	5.64%	5.56%	9.76%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	10.51%
5.88%	5.82%	5.75%	5.69%	5.62%	5.56%	9.85%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	9.02%
3.84%	4.19%	4.53%	4.87%	5.22%	5.56%	8.41%
9.26%	8.52%	7.78%	7.04%	6.30%	5.56%	8.69%
4.02%	4.33%	4.63%	4.94%	5.25%	5.56%	9.91%
4.01%	4.32%	4.63%	4.94%	5.25%	5.56%	10.43%
8.43%	7.85%	7.28%	6.71%	6.13%	5.56%	10.80%
4.84%	4.99%	5.13%	5.27%	5.42%	5.56%	9.77%
6.09%	5.99%	5.88%	5.77%	5.67%	5.56%	9.12%
5.34%	5.39%	5.43%	5.47%	5.52%	5.56%	9.47%
3.34%	3.79%	4.23%	4.67%	5.12%	5.56%	11.70%
4.70%	4.87%	5.04%	5.22%	5.39%	5.56%	10.53%
6.01%	5.92%	5.83%	5.74%	5.65%	5.56%	8.54%
						9.78%

MUM FIRST STAGE GROWTH RATE

[4]	[5]	[6]	[7]	[8]	[9]	[10]
Second Stage Growth						
Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
6.76%	6.52%	6.28%	6.04%	5.80%	5.56%	10.77%
6.34%	6.19%	6.03%	5.87%	5.72%	5.56%	9.17%
6.59%	6.39%	6.18%	5.97%	5.77%	5.56%	8.75%
5.78%	5.73%	5.69%	5.65%	5.60%	5.56%	9.36%
5.93%	5.85%	5.78%	5.71%	5.63%	5.56%	10.28%
7.18%	6.85%	6.53%	6.21%	5.88%	5.56%	9.00%
6.76%	6.52%	6.28%	6.04%	5.80%	5.56%	11.31%
5.95%	5.87%	5.79%	5.72%	5.64%	5.56%	9.93%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	10.39%
5.88%	5.82%	5.75%	5.69%	5.62%	5.56%	9.87%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	9.14%
3.84%	4.19%	4.53%	4.87%	5.22%	5.56%	8.39%
9.26%	8.52%	7.78%	7.04%	6.30%	5.56%	8.87%
4.02%	4.33%	4.63%	4.94%	5.25%	5.56%	9.69%
4.01%	4.32%	4.63%	4.94%	5.25%	5.56%	10.48%
8.43%	7.85%	7.28%	6.71%	6.13%	5.56%	10.45%
4.84%	4.99%	5.13%	5.27%	5.42%	5.56%	9.83%
6.09%	5.99%	5.88%	5.77%	5.67%	5.56%	9.09%
5.34%	5.39%	5.43%	5.47%	5.52%	5.56%	9.25%
3.34%	3.79%	4.23%	4.67%	5.12%	5.56%	11.66%
4.70%	4.87%	5.04%	5.22%	5.39%	5.56%	10.38%
6.01%	5.92%	5.83%	5.74%	5.65%	5.56%	8.63%
						9.76%

MUM FIRST STAGE GROWTH RATE

[4]	[5]	[6]	[7]	[8]	[9]	[10]
Second Stage Growth						
Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
6.76%	6.52%	6.28%	6.04%	5.80%	5.56%	9.96%
6.34%	6.19%	6.03%	5.87%	5.72%	5.56%	8.97%
6.59%	6.39%	6.18%	5.97%	5.77%	5.56%	8.65%
5.78%	5.73%	5.69%	5.65%	5.60%	5.56%	9.10%
5.93%	5.85%	5.78%	5.71%	5.63%	5.56%	9.77%
7.18%	6.85%	6.53%	6.21%	5.88%	5.56%	8.87%
6.76%	6.52%	6.28%	6.04%	5.80%	5.56%	11.20%
5.95%	5.87%	5.79%	5.72%	5.64%	5.56%	9.59%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	10.17%
5.88%	5.82%	5.75%	5.69%	5.62%	5.56%	9.43%
5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	8.97%
3.84%	4.19%	4.53%	4.87%	5.22%	5.56%	8.17%
9.26%	8.52%	7.78%	7.04%	6.30%	5.56%	8.86%
4.02%	4.33%	4.63%	4.94%	5.25%	5.56%	9.19%
4.01%	4.32%	4.63%	4.94%	5.25%	5.56%	9.72%
8.43%	7.85%	7.28%	6.71%	6.13%	5.56%	9.97%
4.84%	4.99%	5.13%	5.27%	5.42%	5.56%	9.47%
6.09%	5.99%	5.88%	5.77%	5.67%	5.56%	8.70%
5.34%	5.39%	5.43%	5.47%	5.52%	5.56%	8.83%
3.34%	3.79%	4.23%	4.67%	5.12%	5.56%	10.84%
4.70%	4.87%	5.04%	5.22%	5.39%	5.56%	10.03%
6.01%	5.92%	5.83%	5.74%	5.65%	5.56%	8.61%
						9.41%

Docket No. UE 374
Exhibit PAC/3504
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated GDP Growth

August 2020

CALCULATION OF LONG-TERM GDP GROWTH RATE

Step 1	
Real GDP ($ Billions) [1]	
1929	$ 1,109.4
2019	$ 19,091.7
Compound Annual Growth Rate	**3.21%**
Step 2	
Consumer Price Index (YoY % Change) [2]	
2027-2031	2.20%
Average	2.20%
Consumer Price Index (All-Urban) [3]	
2031	3.39
2050	5.25
Compound Annual Growth Rate	2.32%
GDP Chain-type Price Index (2009=1.000) [3]	
2031	1.49
2050	2.29
Compound Annual Growth Rate	2.30%
Average Inflation Forecast	**2.27%**
Long-Term GDP Growth Rate	**5.56%**

Notes:
[1] Bureau of Economic Analysis, July 30, 2020
[2] Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[3] Energy Information Administration, Annual Energy Outlook 2020 at Table 20, January 29, 2

Docket No. UE 374
Exhibit PAC/3505
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated Capital Asset Pricing Model

August 2020

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

$K = Rf + \beta (Rm - Rf)$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE
ALLETE, Inc.	ALE	1.34%	0.85	13.81%	12.47%	11.94%	12.41%
Alliant Energy Corporation	LNT	1.34%	0.80	13.81%	12.47%	11.32%	11.94%
Ameren Corporation	AEE	1.34%	0.80	13.81%	12.47%	11.32%	11.94%
American Electric Power Company, Inc.	AEP	1.34%	0.75	13.81%	12.47%	10.70%	11.48%
Avista Corporation	AVA	1.34%	0.95	13.81%	12.47%	13.19%	13.35%
CMS Energy Corporation	CMS	1.34%	0.80	13.81%	12.47%	11.32%	11.94%
Dominion Resources, Inc.	D	1.34%	0.80	13.81%	12.47%	11.32%	11.94%
DTE Energy Company	DTE	1.34%	0.90	13.81%	12.47%	12.57%	12.88%
Duke Energy Corporation	DUK	1.34%	0.85	13.81%	12.47%	11.94%	12.41%
Entergy Corporation	ETR	1.34%	0.95	13.81%	12.47%	13.19%	13.35%
Evergy, Inc.	EVRG	1.34%	1.05	13.81%	12.47%	14.44%	14.28%
IDACORP, Inc.	IDA	1.34%	0.80	13.81%	12.47%	11.32%	11.94%
NextEra Energy, Inc.	NEE	1.34%	0.85	13.81%	12.47%	11.94%	12.41%
NorthWestern Corporation	NWE	1.34%	0.90	13.81%	12.47%	12.57%	12.88%
OGE Energy Corporation	OGE	1.34%	1.05	13.81%	12.47%	14.44%	14.28%
Otter Tail Corporation	OTTR	1.34%	0.85	13.81%	12.47%	11.94%	12.41%
Pinnacle West Capital Corporation	PNW	1.34%	0.85	13.81%	12.47%	11.94%	12.41%
PNM Resources, Inc.	PNM	1.34%	0.90	13.81%	12.47%	12.57%	12.88%
Portland General Electric Company	POR	1.34%	0.85	13.81%	12.47%	11.94%	12.41%
PPL Corporation	PPL	1.34%	1.05	13.81%	12.47%	14.44%	14.28%
Southern Company	SO	1.34%	0.90	13.81%	12.47%	12.57%	12.88%
Xcel Energy Inc.	XEL	1.34%	0.75	13.81%	12.47%	10.70%	11.48%
Mean						12.26%	12.65%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line
[3] Source: Exhibit PAC/3505, page 7 (Analysts Long-term growth estimates)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VL BETA

$K = Rf + \beta (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q4 2020 - Q4 2021)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE
ALLETE, Inc.	ALE	1.76%	0.85	13.81%	12.05%	12.01%	12.46%
Alliant Energy Corporation	LNT	1.76%	0.80	13.81%	12.05%	11.40%	12.01%
Ameren Corporation	AEE	1.76%	0.80	13.81%	12.05%	11.40%	12.01%
American Electric Power Company, Inc.	AEP	1.76%	0.75	13.81%	12.05%	10.80%	11.55%
Avista Corporation	AVA	1.76%	0.95	13.81%	12.05%	13.21%	13.36%
CMS Energy Corporation	CMS	1.76%	0.80	13.81%	12.05%	11.40%	12.01%
Dominion Resources, Inc.	D	1.76%	0.80	13.81%	12.05%	11.40%	12.01%
DTE Energy Company	DTE	1.76%	0.90	13.81%	12.05%	12.61%	12.91%
Duke Energy Corporation	DUK	1.76%	0.85	13.81%	12.05%	12.01%	12.46%
Entergy Corporation	ETR	1.76%	0.95	13.81%	12.05%	13.21%	13.36%
Evergy, Inc.	EVRG	1.76%	1.05	13.81%	12.05%	14.42%	14.27%
IDACORP, Inc.	IDA	1.76%	0.80	13.81%	12.05%	11.40%	12.01%
NextEra Energy, Inc.	NEE	1.76%	0.85	13.81%	12.05%	12.01%	12.46%
NorthWestern Corporation	NWE	1.76%	0.90	13.81%	12.05%	12.61%	12.91%
OGE Energy Corporation	OGE	1.76%	1.05	13.81%	12.05%	14.42%	14.27%

Otter Tail Corporation	OTTR	1.76%	0.85	13.81%	12.05%	12.01%	12.46%
Pinnacle West Capital Corporation	PNW	1.76%	0.85	13.81%	12.05%	12.01%	12.46%
PNM Resources, Inc.	PNM	1.76%	0.90	13.81%	12.05%	12.61%	12.91%
Portland General Electric Company	POR	1.76%	0.85	13.81%	12.05%	12.01%	12.46%
PPL Corporation	PPL	1.76%	1.05	13.81%	12.05%	14.42%	14.27%
Southern Company	SO	1.76%	0.90	13.81%	12.05%	12.61%	12.91%
Xcel Energy Inc.	XEL	1.76%	0.75	13.81%	12.05%	10.80%	11.55%
Mean						12.31%	12.68%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 7, July 1, 2020, at 2
[2] Source: Value Line
[3] Source: Exhibit PAC/3505, page 7 (Analysts Long-term growth estimates)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA

K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2022 - 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	3.00%	0.85	13.81%	10.81%	12.19%	12.60%
Alliant Energy Corporation	LNT	3.00%	0.80	13.81%	10.81%	11.65%	12.19%
Ameren Corporation	AEE	3.00%	0.80	13.81%	10.81%	11.65%	12.19%
American Electric Power Company, Inc.	AEP	3.00%	0.75	13.81%	10.81%	11.11%	11.79%
Avista Corporation	AVA	3.00%	0.95	13.81%	10.81%	13.27%	13.41%
CMS Energy Corporation	CMS	3.00%	0.80	13.81%	10.81%	11.65%	12.19%
Dominion Resources, Inc.	D	3.00%	0.80	13.81%	10.81%	11.65%	12.19%
DTE Energy Company	DTE	3.00%	0.90	13.81%	10.81%	12.73%	13.00%
Duke Energy Corporation	DUK	3.00%	0.85	13.81%	10.81%	12.19%	12.60%
Entergy Corporation	ETR	3.00%	0.95	13.81%	10.81%	13.27%	13.41%
Evergy, Inc.	EVRG	3.00%	1.05	13.81%	10.81%	14.36%	14.22%
IDACORP, Inc.	IDA	3.00%	0.80	13.81%	10.81%	11.65%	12.19%
NextEra Energy, Inc.	NEE	3.00%	0.85	13.81%	10.81%	12.19%	12.60%
NorthWestern Corporation	NWE	3.00%	0.90	13.81%	10.81%	12.73%	13.00%
OGE Energy Corporation	OGE	3.00%	1.05	13.81%	10.81%	14.36%	14.22%
Otter Tail Corporation	OTTR	3.00%	0.85	13.81%	10.81%	12.19%	12.60%
Pinnacle West Capital Corporation	PNW	3.00%	0.85	13.81%	10.81%	12.19%	12.60%
PNM Resources, Inc.	PNM	3.00%	0.90	13.81%	10.81%	12.73%	13.00%
Portland General Electric Company	POR	3.00%	0.85	13.81%	10.81%	12.19%	12.60%
PPL Corporation	PPL	3.00%	1.05	13.81%	10.81%	14.36%	14.22%
Southern Company	SO	3.00%	0.90	13.81%	10.81%	12.73%	13.00%
Xcel Energy Inc.	XEL	3.00%	0.75	13.81%	10.81%	11.11%	11.79%
Mean						12.46%	12.80%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[2] Source: Value Line
[3] Source: Exhibit PAC/3505, page 7 (Analysts Long-term growth estimates)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA

K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	1.34%	0.83	13.81%	12.47%	11.72%	12.24%
Alliant Energy Corporation	LNT	1.34%	0.81	13.81%	12.47%	11.45%	12.04%
Ameren Corporation	AEE	1.34%	0.76	13.81%	12.47%	10.79%	11.54%
American Electric Power Company, Inc.	AEP	1.34%	0.77	13.81%	12.47%	10.92%	11.64%
Avista Corporation	AVA	1.34%	0.79	13.81%	12.47%	11.24%	11.88%
CMS Energy Corporation	CMS	1.34%	0.77	13.81%	12.47%	10.91%	11.63%
Dominion Resources, Inc.	D	1.34%	0.69	13.81%	12.47%	10.01%	10.96%
DTE Energy Company	DTE	1.34%	0.85	13.81%	12.47%	11.92%	12.39%
Duke Energy Corporation	DUK	1.34%	0.73	13.81%	12.47%	10.43%	11.28%
Entergy Corporation	ETR	1.34%	0.84	13.81%	12.47%	11.78%	12.29%
Evergy, Inc.	EVRG	1.34%	0.81	13.81%	12.47%	11.45%	12.04%
IDACORP, Inc.	IDA	1.34%	0.85	13.81%	12.47%	11.91%	12.39%
NextEra Energy, Inc.	NEE	1.34%	0.76	13.81%	12.47%	10.83%	11.58%
NorthWestern Corporation	NWE	1.34%	0.91	13.81%	12.47%	12.66%	12.95%

OGE Energy Corporation	OGE	1.34%	0.93	13.81%	12.47%	13.00%	13.20%
Otter Tail Corporation	OTTR	1.34%	0.87	13.81%	12.47%	12.20%	12.61%
Pinnacle West Capital Corporation	PNW	1.34%	0.84	13.81%	12.47%	11.77%	12.28%
PNM Resources, Inc.	PNM	1.34%	0.94	13.81%	12.47%	13.06%	13.25%
Portland General Electric Company	POR	1.34%	0.82	13.81%	12.47%	11.57%	12.13%
PPL Corporation	PPL	1.34%	0.92	13.81%	12.47%	12.83%	13.07%
Southern Company	SO	1.34%	0.74	13.81%	12.47%	10.53%	11.35%
Xcel Energy Inc.	XEL	1.34%	0.73	13.81%	12.47%	10.49%	11.32%
Mean						11.52%	12.09%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3505, page 7 (Analysts Long-term growth estimates)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2022 - 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	1.76%	0.83	13.81%	12.05%	11.79%	12.29%
Alliant Energy Corporation	LNT	1.76%	0.81	13.81%	12.05%	11.53%	12.10%
Ameren Corporation	AEE	1.76%	0.76	13.81%	12.05%	10.89%	11.62%
American Electric Power Company, Inc.	AEP	1.76%	0.77	13.81%	12.05%	11.02%	11.72%
Avista Corporation	AVA	1.76%	0.79	13.81%	12.05%	11.33%	11.95%
CMS Energy Corporation	CMS	1.76%	0.77	13.81%	12.05%	11.00%	11.71%
Dominion Resources, Inc.	D	1.76%	0.69	13.81%	12.05%	10.14%	11.06%
DTE Energy Company	DTE	1.76%	0.85	13.81%	12.05%	11.98%	12.44%
Duke Energy Corporation	DUK	1.76%	0.73	13.81%	12.05%	10.55%	11.36%
Entergy Corporation	ETR	1.76%	0.84	13.81%	12.05%	11.85%	12.34%
Evergy, Inc.	EVRG	1.76%	0.81	13.81%	12.05%	11.52%	12.10%
IDACORP, Inc.	IDA	1.76%	0.85	13.81%	12.05%	11.98%	12.44%
NextEra Energy, Inc.	NEE	1.76%	0.76	13.81%	12.05%	10.93%	11.65%
NorthWestern Corporation	NWE	1.76%	0.91	13.81%	12.05%	12.70%	12.98%
OGE Energy Corporation	OGE	1.76%	0.93	13.81%	12.05%	13.03%	13.22%
Otter Tail Corporation	OTTR	1.76%	0.87	13.81%	12.05%	12.26%	12.65%
Pinnacle West Capital Corporation	PNW	1.76%	0.84	13.81%	12.05%	11.84%	12.33%
PNM Resources, Inc.	PNM	1.76%	0.94	13.81%	12.05%	13.09%	13.27%
Portland General Electric Company	POR	1.76%	0.82	13.81%	12.05%	11.64%	12.19%
PPL Corporation	PPL	1.76%	0.92	13.81%	12.05%	12.86%	13.10%
Southern Company	SO	1.76%	0.74	13.81%	12.05%	10.64%	11.43%
Xcel Energy Inc.	XEL	1.76%	0.73	13.81%	12.05%	10.60%	11.41%
Mean						11.60%	12.15%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 7, July 1, 2020, at 2
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3505, page 7 (Analysts Long-term growth estimates)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2022 - 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	3.00%	0.83	13.81%	10.81%	11.99%	12.45%
Alliant Energy Corporation	LNT	3.00%	0.81	13.81%	10.81%	11.76%	12.28%
Ameren Corporation	AEE	3.00%	0.76	13.81%	10.81%	11.19%	11.84%
American Electric Power Company, Inc.	AEP	3.00%	0.77	13.81%	10.81%	11.30%	11.93%
Avista Corporation	AVA	3.00%	0.79	13.81%	10.81%	11.58%	12.14%
CMS Energy Corporation	CMS	3.00%	0.77	13.81%	10.81%	11.29%	11.92%
Dominion Resources, Inc.	D	3.00%	0.69	13.81%	10.81%	10.52%	11.34%
DTE Energy Company	DTE	3.00%	0.85	13.81%	10.81%	12.17%	12.58%
Duke Energy Corporation	DUK	3.00%	0.73	13.81%	10.81%	10.88%	11.62%
Entergy Corporation	ETR	3.00%	0.84	13.81%	10.81%	12.05%	12.49%
Evergy, Inc.	EVRG	3.00%	0.81	13.81%	10.81%	11.76%	12.27%
IDACORP, Inc.	IDA	3.00%	0.85	13.81%	10.81%	12.17%	12.58%
NextEra Energy, Inc.	NEE	3.00%	0.76	13.81%	10.81%	11.23%	11.88%
NorthWestern Corporation	NWE	3.00%	0.91	13.81%	10.81%	12.81%	13.06%
OGE Energy Corporation	OGE	3.00%	0.93	13.81%	10.81%	13.11%	13.28%
Otter Tail Corporation	OTTR	3.00%	0.87	13.81%	10.81%	12.42%	12.77%

Pinnacle West Capital Corporation	PNW	3.00%	0.84	13.81%	10.81%	12.04%	12.48%
PNM Resources, Inc.	PNM	3.00%	0.94	13.81%	10.81%	13.16%	13.32%
Portland General Electric Company	POR	3.00%	0.82	13.81%	10.81%	11.87%	12.35%
PPL Corporation	PPL	3.00%	0.92	13.81%	10.81%	12.96%	13.17%
Southern Company	SO	3.00%	0.74	13.81%	10.81%	10.96%	11.68%
Xcel Energy Inc.	XEL	3.00%	0.73	13.81%	10.81%	10.93%	11.65%
Mean						11.83%	12.32%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3505, page 7 (Analysts Long-term growth estimates)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

$$K = Rf + \beta\ (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	1.34%	0.85	13.95%	12.60%	12.06%	12.53%
Alliant Energy Corporation	LNT	1.34%	0.80	13.95%	12.60%	11.43%	12.06%
Ameren Corporation	AEE	1.34%	0.80	13.95%	12.60%	11.43%	12.06%
American Electric Power Company, Inc.	AEP	1.34%	0.75	13.95%	12.60%	10.80%	11.58%
Avista Corporation	AVA	1.34%	0.95	13.95%	12.60%	13.32%	13.47%
CMS Energy Corporation	CMS	1.34%	0.80	13.95%	12.60%	11.43%	12.06%
Dominion Resources, Inc.	D	1.34%	0.80	13.95%	12.60%	11.43%	12.06%
DTE Energy Company	DTE	1.34%	0.90	13.95%	12.60%	12.69%	13.00%
Duke Energy Corporation	DUK	1.34%	0.85	13.95%	12.60%	12.06%	12.53%
Entergy Corporation	ETR	1.34%	0.95	13.95%	12.60%	13.32%	13.47%
Evergy, Inc.	EVRG	1.34%	1.05	13.95%	12.60%	14.58%	14.42%
IDACORP, Inc.	IDA	1.34%	0.80	13.95%	12.60%	11.43%	12.06%
NextEra Energy, Inc.	NEE	1.34%	0.85	13.95%	12.60%	12.06%	12.53%
NorthWestern Corporation	NWE	1.34%	0.90	13.95%	12.60%	12.69%	13.00%
OGE Energy Corporation	OGE	1.34%	1.05	13.95%	12.60%	14.58%	14.42%
Otter Tail Corporation	OTTR	1.34%	0.85	13.95%	12.60%	12.06%	12.53%
Pinnacle West Capital Corporation	PNW	1.34%	0.85	13.95%	12.60%	12.06%	12.53%
PNM Resources, Inc.	PNM	1.34%	0.90	13.95%	12.60%	12.69%	13.00%
Portland General Electric Company	POR	1.34%	0.85	13.95%	12.60%	12.06%	12.53%
PPL Corporation	PPL	1.34%	1.05	13.95%	12.60%	14.58%	14.42%
Southern Company	SO	1.34%	0.90	13.95%	12.60%	12.69%	13.00%
Xcel Energy Inc.	XEL	1.34%	0.75	13.95%	12.60%	10.80%	11.58%
Mean						12.37%	12.76%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line
[3] Source: Exhibit PAC/3505 page 7 (S&P Earnings and Estimates Report)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VL BETA

$$K = Rf + \beta\ (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2020 - Q4 2021)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	1.76%	0.85	13.95%	12.19%	12.12%	12.58%
Alliant Energy Corporation	LNT	1.76%	0.80	13.95%	12.19%	11.51%	12.12%
Ameren Corporation	AEE	1.76%	0.80	13.95%	12.19%	11.51%	12.12%
American Electric Power Company, Inc.	AEP	1.76%	0.75	13.95%	12.19%	10.90%	11.66%
Avista Corporation	AVA	1.76%	0.95	13.95%	12.19%	13.34%	13.49%
CMS Energy Corporation	CMS	1.76%	0.80	13.95%	12.19%	11.51%	12.12%
Dominion Resources, Inc.	D	1.76%	0.80	13.95%	12.19%	11.51%	12.12%
DTE Energy Company	DTE	1.76%	0.90	13.95%	12.19%	12.73%	13.03%
Duke Energy Corporation	DUK	1.76%	0.85	13.95%	12.19%	12.12%	12.58%
Entergy Corporation	ETR	1.76%	0.95	13.95%	12.19%	13.34%	13.49%
Evergy, Inc.	EVRG	1.76%	1.05	13.95%	12.19%	14.56%	14.40%
IDACORP, Inc.	IDA	1.76%	0.80	13.95%	12.19%	11.51%	12.12%
NextEra Energy, Inc.	NEE	1.76%	0.85	13.95%	12.19%	12.12%	12.58%
NorthWestern Corporation	NWE	1.76%	0.90	13.95%	12.19%	12.73%	13.03%
OGE Energy Corporation	OGE	1.76%	1.05	13.95%	12.19%	14.56%	14.40%

Otter Tail Corporation	OTTR	1.76%	0.85	13.95%	12.19%	12.12%	12.58%
Pinnacle West Capital Corporation	PNW	1.76%	0.85	13.95%	12.19%	12.12%	12.58%
PNM Resources, Inc.	PNM	1.76%	0.90	13.95%	12.19%	12.73%	13.03%
Portland General Electric Company	POR	1.76%	0.85	13.95%	12.19%	12.12%	12.58%
PPL Corporation	PPL	1.76%	1.05	13.95%	12.19%	14.56%	14.40%
Southern Company	SO	1.76%	0.90	13.95%	12.19%	12.73%	13.03%
Xcel Energy Inc.	XEL	1.76%	0.75	13.95%	12.19%	10.90%	11.66%
Mean						12.42%	12.80%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 2
[2] Source: Value Line
[3] Source: Exhibit PAC/3505, page 7 (S&P Earnings and Estimates Report)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA

$$K = Rf + \beta\ (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2022 - 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	3.00%	0.85	13.95%	10.95%	12.30%	12.71%
Alliant Energy Corporation	LNT	3.00%	0.80	13.95%	10.95%	11.76%	12.30%
Ameren Corporation	AEE	3.00%	0.80	13.95%	10.95%	11.76%	12.30%
American Electric Power Company, Inc.	AEP	3.00%	0.75	13.95%	10.95%	11.21%	11.89%
Avista Corporation	AVA	3.00%	0.95	13.95%	10.95%	13.40%	13.54%
CMS Energy Corporation	CMS	3.00%	0.80	13.95%	10.95%	11.76%	12.30%
Dominion Resources, Inc.	D	3.00%	0.80	13.95%	10.95%	11.76%	12.30%
DTE Energy Company	DTE	3.00%	0.90	13.95%	10.95%	12.85%	13.13%
Duke Energy Corporation	DUK	3.00%	0.85	13.95%	10.95%	12.30%	12.71%
Entergy Corporation	ETR	3.00%	0.95	13.95%	10.95%	13.40%	13.54%
Evergy, Inc.	EVRG	3.00%	1.05	13.95%	10.95%	14.49%	14.36%
IDACORP, Inc.	IDA	3.00%	0.80	13.95%	10.95%	11.76%	12.30%
NextEra Energy, Inc.	NEE	3.00%	0.85	13.95%	10.95%	12.30%	12.71%
NorthWestern Corporation	NWE	3.00%	0.90	13.95%	10.95%	12.85%	13.13%
OGE Energy Corporation	OGE	3.00%	1.05	13.95%	10.95%	14.49%	14.36%
Otter Tail Corporation	OTTR	3.00%	0.85	13.95%	10.95%	12.30%	12.71%
Pinnacle West Capital Corporation	PNW	3.00%	0.85	13.95%	10.95%	12.30%	12.71%
PNM Resources, Inc.	PNM	3.00%	0.90	13.95%	10.95%	12.85%	13.13%
Portland General Electric Company	POR	3.00%	0.85	13.95%	10.95%	12.30%	12.71%
PPL Corporation	PPL	3.00%	1.05	13.95%	10.95%	14.49%	14.36%
Southern Company	SO	3.00%	0.90	13.95%	10.95%	12.85%	13.13%
Xcel Energy Inc.	XEL	3.00%	0.75	13.95%	10.95%	11.21%	11.89%
Mean						12.58%	12.92%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[2] Source: Value Line
[3] Source: Exhibit PAC/3505, page 7 (S&P Earnings and Estimates Report)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	1.34%	0.83	13.95%	12.60%	11.83%	12.36%
Alliant Energy Corporation	LNT	1.34%	0.81	13.95%	12.60%	11.56%	12.15%
Ameren Corporation	AEE	1.34%	0.76	13.95%	12.60%	10.88%	11.65%
American Electric Power Company, Inc.	AEP	1.34%	0.77	13.95%	12.60%	11.02%	11.75%
Avista Corporation	AVA	1.34%	0.79	13.95%	12.60%	11.34%	11.99%
CMS Energy Corporation	CMS	1.34%	0.77	13.95%	12.60%	11.01%	11.74%
Dominion Resources, Inc.	D	1.34%	0.69	13.95%	12.60%	10.10%	11.06%
DTE Energy Company	DTE	1.34%	0.85	13.95%	12.60%	12.03%	12.51%
Duke Energy Corporation	DUK	1.34%	0.73	13.95%	12.60%	10.53%	11.38%
Entergy Corporation	ETR	1.34%	0.84	13.95%	12.60%	11.89%	12.40%
Evergy, Inc.	EVRG	1.34%	0.81	13.95%	12.60%	11.55%	12.15%
IDACORP, Inc.	IDA	1.34%	0.85	13.95%	12.60%	12.02%	12.51%
NextEra Energy, Inc.	NEE	1.34%	0.76	13.95%	12.60%	10.93%	11.69%
NorthWestern Corporation	NWE	1.34%	0.91	13.95%	12.60%	12.78%	13.07%

OGE Energy Corporation	OGE	1.34%	0.93	13.95%	12.60%	13.12%	13.33%
Otter Tail Corporation	OTTR	1.34%	0.87	13.95%	12.60%	12.32%	12.72%
Pinnacle West Capital Corporation	PNW	1.34%	0.84	13.95%	12.60%	11.88%	12.40%
PNM Resources, Inc.	PNM	1.34%	0.94	13.95%	12.60%	13.18%	13.38%
Portland General Electric Company	POR	1.34%	0.82	13.95%	12.60%	11.68%	12.24%
PPL Corporation	PPL	1.34%	0.92	13.95%	12.60%	12.95%	13.20%
Southern Company	SO	1.34%	0.74	13.95%	12.60%	10.62%	11.45%
Xcel Energy Inc.	XEL	1.34%	0.73	13.95%	12.60%	10.59%	11.43%
Mean						11.63%	12.21%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3505, page 7 (S&P Earnings and Estimates Report)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q4 2020 - Q4 2021)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE
ALLETE, Inc.	ALE	1.76%	0.83	13.95%	12.19%	11.90%	12.41%
Alliant Energy Corporation	LNT	1.76%	0.81	13.95%	12.19%	11.63%	12.21%
Ameren Corporation	AEE	1.76%	0.76	13.95%	12.19%	10.99%	11.73%
American Electric Power Company, Inc.	AEP	1.76%	0.77	13.95%	12.19%	11.12%	11.82%
Avista Corporation	AVA	1.76%	0.79	13.95%	12.19%	11.43%	12.06%
CMS Energy Corporation	CMS	1.76%	0.77	13.95%	12.19%	11.10%	11.81%
Dominion Resources, Inc.	D	1.76%	0.69	13.95%	12.19%	10.23%	11.16%
DTE Energy Company	DTE	1.76%	0.85	13.95%	12.19%	12.10%	12.56%
Duke Energy Corporation	DUK	1.76%	0.73	13.95%	12.19%	10.64%	11.47%
Entergy Corporation	ETR	1.76%	0.84	13.95%	12.19%	11.96%	12.46%
Evergy, Inc.	EVRG	1.76%	0.81	13.95%	12.19%	11.63%	12.21%
IDACORP, Inc.	IDA	1.76%	0.85	13.95%	12.19%	12.09%	12.55%
NextEra Energy, Inc.	NEE	1.76%	0.76	13.95%	12.19%	11.03%	11.76%
NorthWestern Corporation	NWE	1.76%	0.91	13.95%	12.19%	12.82%	13.10%
OGE Energy Corporation	OGE	1.76%	0.93	13.95%	12.19%	13.15%	13.35%
Otter Tail Corporation	OTTR	1.76%	0.87	13.95%	12.19%	12.37%	12.76%
Pinnacle West Capital Corporation	PNW	1.76%	0.84	13.95%	12.19%	11.95%	12.45%
PNM Resources, Inc.	PNM	1.76%	0.94	13.95%	12.19%	13.21%	13.39%
Portland General Electric Company	POR	1.76%	0.82	13.95%	12.19%	11.75%	12.30%
PPL Corporation	PPL	1.76%	0.92	13.95%	12.19%	12.98%	13.22%
Southern Company	SO	1.76%	0.74	13.95%	12.19%	10.73%	11.54%
Xcel Energy Inc.	XEL	1.76%	0.73	13.95%	12.19%	10.70%	11.51%
Mean						11.70%	12.27%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 2
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3505, page 7 (S&P Earnings and Estimates Report)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2022 - 2026)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE
ALLETE, Inc.	ALE	3.00%	0.83	13.95%	10.95%	12.10%	12.56%
Alliant Energy Corporation	LNT	3.00%	0.81	13.95%	10.95%	11.87%	12.39%
Ameren Corporation	AEE	3.00%	0.76	13.95%	10.95%	11.29%	11.95%
American Electric Power Company, Inc.	AEP	3.00%	0.77	13.95%	10.95%	11.40%	12.04%
Avista Corporation	AVA	3.00%	0.79	13.95%	10.95%	11.69%	12.25%
CMS Energy Corporation	CMS	3.00%	0.77	13.95%	10.95%	11.39%	12.03%
Dominion Resources, Inc.	D	3.00%	0.69	13.95%	10.95%	10.61%	11.44%
DTE Energy Company	DTE	3.00%	0.85	13.95%	10.95%	12.28%	12.70%
Duke Energy Corporation	DUK	3.00%	0.73	13.95%	10.95%	10.98%	11.72%
Entergy Corporation	ETR	3.00%	0.84	13.95%	10.95%	12.16%	12.61%
Evergy, Inc.	EVRG	3.00%	0.81	13.95%	10.95%	11.87%	12.39%
IDACORP, Inc.	IDA	3.00%	0.85	13.95%	10.95%	12.28%	12.69%
NextEra Energy, Inc.	NEE	3.00%	0.76	13.95%	10.95%	11.33%	11.98%
NorthWestern Corporation	NWE	3.00%	0.91	13.95%	10.95%	12.93%	13.19%
OGE Energy Corporation	OGE	3.00%	0.93	13.95%	10.95%	13.23%	13.41%

Otter Tail Corporation	OTTR	3.00%	0.87	13.95%	10.95%	12.53%	12.88%
Pinnacle West Capital Corporation	PNW	3.00%	0.84	13.95%	10.95%	12.15%	12.60%
PNM Resources, Inc.	PNM	3.00%	0.94	13.95%	10.95%	13.28%	13.45%
Portland General Electric Company	POR	3.00%	0.82	13.95%	10.95%	11.97%	12.47%
PPL Corporation	PPL	3.00%	0.92	13.95%	10.95%	13.08%	13.29%
Southern Company	SO	3.00%	0.74	13.95%	10.95%	11.06%	11.78%
Xcel Energy Inc.	XEL	3.00%	0.73	13.95%	10.95%	11.03%	11.76%
Mean						11.93%	12.44%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/3505, page 7 (S&P Earnings and Estimates Report)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

MARKET RISK PREMIUM DERIVED FROM S&P EARNINGS AND ESTIMATE REPORT

[7] S&P's estimate of the S&P 500 Dividend Yield	1.72%
[8] S&P's estimate of the S&P 500 Growth Rate	12.12%
[9] S&P 500 Estimated Required Market Return	13.95%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[10] Estimated Weighted Average Dividend Yield	1.70%
[11] Estimated Weighted Average Long-Term Growth Rate	12.01%
[12] S&P 500 Estimated Required Market Return	13.81%

STANDARD AND POOR'S 500 INDEX

		[13]	[14]	[15]	[16]	[17]
Name	Ticker	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	0.07%	6.72%	0.01%	5.50%	0.00%
American Express Co	AXP	0.27%	1.84%	0.00%	8.53%	0.02%
Verizon Communications Inc	VZ	0.85%	4.28%	0.04%	3.07%	0.03%
Broadcom Inc	AVGO	0.46%	4.10%	0.02%	9.37%	0.04%
Boeing Co/The	BA	0.00%	n/a	n/a	n/a	n/a
Caterpillar Inc	CAT	0.26%	3.10%	0.01%	7.83%	0.02%
JPMorgan Chase & Co	JPM	1.05%	3.73%	0.04%	5.40%	0.06%
Chevron Corp	CVX	0.56%	6.15%	0.03%	38.90%	0.22%
Coca-Cola Co/The	KO	0.73%	3.47%	0.03%	2.19%	0.02%
AbbVie Inc	ABBV	0.60%	4.97%	0.03%	4.85%	0.03%
Walt Disney Co/The	DIS	0.76%	n/a	n/a	4.08%	0.03%
FleetCor Technologies Inc	FLT	0.08%	n/a	n/a	13.20%	0.01%
Extra Space Storage Inc	EXR	0.05%	3.48%	0.00%	1.36%	0.00%
Exxon Mobil Corp	XOM	0.64%	8.27%	0.05%	16.97%	0.11%
Phillips 66	PSX	0.10%	5.80%	0.01%	10.19%	0.01%
General Electric Co	GE	0.19%	0.66%	0.00%	5.67%	0.01%
HP Inc	HPQ	0.09%	4.01%	0.00%	4.77%	0.00%
Home Depot Inc/The	HD	1.02%	2.26%	0.02%	7.65%	0.08%
International Business Machines Corp	IBM	0.39%	5.30%	0.02%	2.62%	0.01%
Concho Resources Inc	CXO	0.04%	1.52%	0.00%	8.80%	0.00%
Johnson & Johnson	JNJ	1.37%	2.77%	0.04%	5.42%	0.07%
McDonald's Corp	MCD	0.52%	2.57%	0.01%	7.22%	0.04%
Merck & Co Inc	MRK	0.72%	3.04%	0.02%	8.45%	0.06%
3M Co	MMM	0.31%	3.91%	0.01%	7.05%	0.02%
American Water Works Co Inc	AWK	0.10%	1.49%	0.00%	8.19%	0.01%
Bank of America Corp	BAC	0.77%	2.89%	0.02%	12.70%	0.10%
Baker Hughes Co	BKR	0.04%	4.65%	0.00%	21.91%	0.01%
Pfizer Inc	PFE	0.76%	3.95%	0.03%	4.85%	0.04%
Procter & Gamble Co/The	PG	1.16%	2.41%	0.03%	7.17%	0.08%
AT&T Inc	T	0.75%	7.03%	0.05%	4.13%	0.03%
Noble Energy Inc	NBL	0.02%	0.80%	0.00%	14.32%	0.00%
Travelers Cos Inc/The	TRV	0.10%	2.97%	0.00%	9.64%	0.01%
Raytheon Technologies Corp	RTX	0.31%	3.35%	0.01%	-4.81%	-0.01%
Analog Devices Inc	ADI	0.15%	2.16%	0.00%	12.18%	0.02%
Walmart Inc	WMT	1.31%	1.67%	0.02%	3.95%	0.05%
Cisco Systems Inc	CSCO	0.71%	3.06%	0.02%	5.50%	0.04%
Intel Corp	INTC	0.73%	2.77%	0.02%	6.62%	0.05%
General Motors Co	GM	0.13%	n/a	n/a	12.76%	0.02%
Microsoft Corp	MSFT	5.55%	0.99%	0.06%	13.63%	0.76%
Dollar General Corp	DG	0.17%	0.76%	0.00%	11.63%	0.02%
Cigna Corp	CI	0.23%	0.02%	0.00%	11.09%	0.03%
Kinder Morgan Inc	KMI	0.11%	7.45%	0.01%	6.35%	0.01%
Citigroup Inc	C	0.37%	4.08%	0.02%	3.17%	0.01%
American International Group Inc	AIG	0.10%	3.98%	0.00%	13.57%	0.01%
Honeywell International Inc	HON	0.37%	2.41%	0.01%	6.98%	0.03%
Altria Group Inc	MO	0.27%	8.36%	0.02%	5.05%	0.01%
HCA Healthcare Inc	HCA	0.15%	n/a	n/a	10.01%	0.02%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Under Armour Inc	UAA	0.01%	n/a	n/a	26.60%	0.00%
International Paper Co	IP	0.05%	5.89%	0.00%	5.15%	0.00%
Hewlett Packard Enterprise Co	HPE	0.05%	4.86%	0.00%	2.40%	0.00%
Abbott Laboratories	ABT	0.64%	1.43%	0.01%	8.31%	0.05%
Aflac Inc	AFL	0.09%	3.15%	0.00%	1.55%	0.00%
Air Products and Chemicals Inc	APD	0.23%	1.87%	0.00%	11.19%	0.03%
Royal Caribbean Cruises Ltd	RCL	0.04%	n/a	n/a	-58.33%	-0.02%
American Electric Power Co Inc	AEP	0.15%	3.22%	0.00%	6.34%	0.01%
Hess Corp	HES	0.05%	2.03%	0.00%	103.20%	0.06%
Archer-Daniels-Midland Co	ADM	0.09%	3.36%	0.00%	7.20%	0.01%
Automatic Data Processing Inc	ADP	0.20%	2.74%	0.01%	12.30%	0.03%
Verisk Analytics Inc	VRSK	0.11%	0.57%	0.00%	9.18%	0.01%
AutoZone Inc	AZO	0.10%	n/a	n/a	7.70%	0.01%
Avery Dennison Corp	AVY	0.03%	2.05%	0.00%	4.55%	0.00%
MSCI Inc	MSCI	0.11%	0.83%	0.00%	11.75%	0.01%
Ball Corp	BLL	0.09%	0.81%	0.00%	6.07%	0.01%
Carrier Global Corp	CARR	0.08%	1.17%	0.00%	5.10%	0.00%
Bank of New York Mellon Corp/The	BK	0.11%	3.46%	0.00%	4.83%	0.01%
Otis Worldwide Corp	OTIS	0.10%	1.27%	0.00%	4.80%	0.00%
Baxter International Inc	BAX	0.16%	1.13%	0.00%	10.38%	0.02%
Becton Dickinson and Co	BDX	0.29%	1.12%	0.00%	8.14%	0.02%
Berkshire Hathaway Inc	BRK/B	0.97%	n/a	n/a	-3.10%	-0.03%
Best Buy Co Inc	BBY	0.09%	2.21%	0.00%	5.76%	0.01%
H&R Block Inc	HRB	0.01%	7.17%	0.00%	10.00%	0.00%
Boston Scientific Corp	BSX	0.20%	n/a	n/a	3.32%	0.01%
Bristol-Myers Squibb Co	BMY	0.47%	3.07%	0.01%	9.92%	0.05%
Fortune Brands Home & Security Inc	FBHS	0.04%	1.26%	0.00%	9.01%	0.00%
Brown-Forman Corp	BF/B	0.08%	1.01%	0.00%	4.23%	0.00%
Cabot Oil & Gas Corp	COG	0.03%	2.14%	0.00%	9.05%	0.00%
Campbell Soup Co	CPB	0.05%	2.82%	0.00%	8.89%	0.00%
Kansas City Southern	KSU	0.06%	0.93%	0.00%	10.10%	0.01%
Hilton Worldwide Holdings Inc	HLT	0.07%	n/a	n/a	0.37%	0.00%
Carnival Corp	CCL	0.03%	n/a	n/a	-14.19%	0.00%
Qorvo Inc	QRVO	0.05%	n/a	n/a	12.78%	0.01%
CenturyLink Inc	CTL	0.04%	10.36%	0.00%	-1.24%	0.00%
UDR Inc	UDR	0.04%	3.98%	0.00%	4.99%	0.00%
Clorox Co/The	CLX	0.11%	1.88%	0.00%	5.24%	0.01%
Paycom Software Inc	PAYC	0.06%	n/a	n/a	19.70%	0.01%
CMS Energy Corp	CMS	0.07%	2.54%	0.00%	6.87%	0.00%
Newell Brands Inc	NWL	0.02%	5.61%	0.00%	-6.27%	0.00%
Colgate-Palmolive Co	CL	0.24%	2.28%	0.01%	4.85%	0.01%
Comerica Inc	CMA	0.02%	7.06%	0.00%	14.75%	0.00%
IPG Photonics Corp	IPGP	0.03%	n/a	n/a	23.11%	0.01%
Conagra Brands Inc	CAG	0.07%	2.27%	0.00%	7.90%	0.01%
Consolidated Edison Inc	ED	0.09%	3.98%	0.00%	3.35%	0.00%
SL Green Realty Corp	SLG	0.01%	7.61%	0.00%	6.15%	0.00%
Corning Inc	GLW	0.08%	2.84%	0.00%	5.97%	0.01%
Cummins Inc	CMI	0.10%	2.71%	0.00%	3.92%	0.00%
Danaher Corp	DHR	0.52%	0.35%	0.00%	10.96%	0.06%
Target Corp	TGT	0.23%	2.16%	0.00%	7.83%	0.02%
Deere & Co	DE	0.20%	1.72%	0.00%	0.41%	0.00%
Dominion Energy Inc	D	0.24%	4.64%	0.01%	3.54%	0.01%
Dover Corp	DOV	0.05%	1.90%	0.00%	10.47%	0.01%
Alliant Energy Corp	LNT	0.05%	2.82%	0.00%	5.46%	0.00%
Duke Energy Corp	DUK	0.22%	4.56%	0.01%	4.02%	0.01%
Regency Centers Corp	REG	0.02%	5.80%	0.00%	4.27%	0.00%
Eaton Corp PLC	ETN	0.13%	3.14%	0.00%	9.28%	0.01%
Ecolab Inc	ECL	0.19%	1.00%	0.00%	10.90%	0.02%
PerkinElmer Inc	PKI	0.05%	0.24%	0.00%	10.58%	0.01%
Emerson Electric Co	EMR	0.13%	3.23%	0.00%	6.51%	0.01%
EOG Resources Inc	EOG	0.10%	3.20%	0.00%	8.45%	0.01%
Aon PLC	AON	0.17%	0.86%	0.00%	11.05%	0.02%
Entergy Corp	ETR	0.08%	3.54%	0.00%	5.06%	0.00%
Equifax Inc	EFX	0.07%	0.96%	0.00%	9.73%	0.01%
IQVIA Holdings Inc	IQV	0.11%	n/a	n/a	11.75%	0.01%
Gartner Inc	IT	0.04%	n/a	n/a	10.00%	0.00%
FedEx Corp	FDX	0.16%	1.54%	0.00%	12.88%	0.02%
FMC Corp	FMC	0.05%	1.66%	0.00%	9.63%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Ford Motor Co	F	0.09%	n/a	n/a	12.74%	0.01%
NextEra Energy Inc	NEE	0.49%	2.00%	0.01%	8.63%	0.04%
Franklin Resources Inc	BEN	0.04%	5.13%	0.00%	-2.69%	0.00%
Freeport-McMoRan Inc	FCX	0.07%	n/a	n/a	136.19%	0.09%
Gap Inc/The	GPS	0.02%	7.26%	0.00%	4.47%	0.00%
DexCom Inc	DXCM	0.15%	n/a	n/a	32.12%	0.05%
General Dynamics Corp	GD	0.15%	3.00%	0.00%	4.40%	0.01%
General Mills Inc	GIS	0.14%	3.10%	0.00%	4.30%	0.01%
Genuine Parts Co	GPC	0.05%	3.51%	0.00%	2.16%	0.00%
Atmos Energy Corp	ATO	0.05%	2.17%	0.00%	7.34%	0.00%
WW Grainger Inc	GWW	0.07%	1.79%	0.00%	9.65%	0.01%
Halliburton Co	HAL	0.05%	1.26%	0.00%	12.95%	0.01%
L3Harris Technologies Inc	LHX	0.13%	2.02%	0.00%	16.64%	0.02%
Healthpeak Properties Inc	PEAK	0.05%	5.42%	0.00%	3.51%	0.00%
Fortive Corp	FTV	0.08%	0.40%	0.00%	8.82%	0.01%
Hershey Co/The	HSY	0.08%	2.21%	0.00%	7.50%	0.01%
Synchrony Financial	SYF	0.05%	3.98%	0.00%	-2.50%	0.00%
Hormel Foods Corp	HRL	0.10%	1.83%	0.00%	0.76%	0.00%
Arthur J Gallagher & Co	AJG	0.07%	1.67%	0.00%	9.73%	0.01%
Mondelez International Inc	MDLZ	0.28%	2.27%	0.01%	9.73%	0.03%
CenterPoint Energy Inc	CNP	0.03%	3.16%	0.00%	-1.59%	0.00%
Humana Inc	HUM	0.19%	0.64%	0.00%	11.56%	0.02%
Willis Towers Watson PLC	WLTW	0.10%	1.30%	0.00%	10.00%	0.01%
Illinois Tool Works Inc	ITW	0.21%	2.31%	0.00%	6.44%	0.01%
CDW Corp/DE	CDW	0.06%	1.31%	0.00%	13.10%	0.01%
Trane Technologies PLC	TT	0.10%	1.90%	0.00%	4.63%	0.00%
Interpublic Group of Cos Inc/The	IPG	0.03%	5.65%	0.00%	0.14%	0.00%
International Flavors & Fragrances Inc	IFF	0.05%	2.38%	0.00%	4.95%	0.00%
Jacobs Engineering Group Inc	J	0.04%	0.89%	0.00%	7.25%	0.00%
Hanesbrands Inc	HBI	0.02%	4.25%	0.00%	2.31%	0.00%
Kellogg Co	K	0.08%	3.31%	0.00%	2.76%	0.00%
Broadridge Financial Solutions Inc	BR	0.06%	1.61%	0.00%	6.50%	0.00%
Perrigo Co PLC	PRGO	0.03%	1.70%	0.00%	2.00%	0.00%
Kimberly-Clark Corp	KMB	0.19%	2.82%	0.01%	4.95%	0.01%
Kimco Realty Corp	KIM	0.02%	n/a	n/a	4.10%	0.00%
Kohl's Corp	KSS	0.01%	n/a	n/a	1.25%	0.00%
Oracle Corp	ORCL	0.61%	1.73%	0.01%	9.23%	0.06%
Kroger Co/The	KR	0.10%	2.07%	0.00%	5.58%	0.01%
Leggett & Platt Inc	LEG	0.00%	3.99%	0.00%	n/a	n/a
Lennar Corp	LEN	0.07%	0.69%	0.00%	9.74%	0.01%
Eli Lilly and Co	LLY	0.51%	1.97%	0.01%	16.25%	0.08%
L Brands Inc	LB	0.02%	n/a	n/a	11.50%	0.00%
Charter Communications Inc	CHTR	0.42%	n/a	n/a	44.10%	0.19%
Lincoln National Corp	LNC	0.03%	4.29%	0.00%	9.00%	0.00%
Loews Corp	L	0.00%	0.69%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.40%	1.48%	0.01%	17.28%	0.07%
Host Hotels & Resorts Inc	HST	0.03%	n/a	n/a	-2.30%	0.00%
Xerox Holdings Corp	XRX	0.01%	6.01%	0.00%	1.00%	0.00%
IDEX Corp	IEX	0.04%	1.21%	0.00%	11.38%	0.01%
Marsh & McLennan Cos Inc	MMC	0.21%	1.60%	0.00%	10.07%	0.02%
Masco Corp	MAS	0.05%	0.94%	0.00%	11.94%	0.01%
S&P Global Inc	SPGI	0.30%	0.77%	0.00%	8.90%	0.03%
Medtronic PLC	MDT	0.46%	2.40%	0.01%	7.60%	0.04%
CVS Health Corp	CVS	0.29%	3.18%	0.01%	7.40%	0.02%
DuPont de Nemours Inc	DD	0.14%	2.24%	0.00%	2.56%	0.00%
Micron Technology Inc	MU	0.20%	n/a	n/a	5.83%	0.01%
Motorola Solutions Inc	MSI	0.09%	1.83%	0.00%	8.50%	0.01%
Cboe Global Markets Inc	CBOE	0.03%	1.64%	0.00%	6.40%	0.00%
Mylan NV	MYL	0.03%	n/a	n/a	0.66%	0.00%
Laboratory Corp of America Holdings	LH	0.07%	n/a	n/a	6.30%	0.00%
Newmont Corp	NEM	0.20%	1.45%	0.00%	26.30%	0.05%
NIKE Inc	NKE	0.43%	1.00%	0.00%	21.98%	0.10%
NiSource Inc	NI	0.03%	3.44%	0.00%	4.66%	0.00%
Norfolk Southern Corp	NSC	0.18%	1.96%	0.00%	6.04%	0.01%
Principal Financial Group Inc	PFG	0.04%	5.28%	0.00%	6.55%	0.00%
Eversource Energy	ES	0.11%	2.52%	0.00%	6.82%	0.01%
Northrop Grumman Corp	NOC	0.19%	1.78%	0.00%	19.56%	0.04%
Wells Fargo & Co	WFC	0.36%	1.65%	0.01%	9.61%	0.03%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Nucor Corp	NUE	0.05%	3.84%	0.00%	4.85%	0.00%
PVH Corp	PVH	0.01%	n/a	n/a	2.07%	0.00%
Occidental Petroleum Corp	OXY	0.05%	0.25%	0.00%	12.20%	0.01%
Omnicom Group Inc	OMC	0.04%	4.84%	0.00%	1.25%	0.00%
ONEOK Inc	OKE	0.04%	13.40%	0.01%	5.40%	0.00%
Raymond James Financial Inc	RJF	0.03%	2.13%	0.00%	3.50%	0.00%
Parker-Hannifin Corp	PH	0.08%	1.97%	0.00%	9.49%	0.01%
Rollins Inc	ROL	0.00%	0.61%	0.00%	n/a	n/a
PPL Corp	PPL	0.07%	6.23%	0.00%	0.63%	0.00%
ConocoPhillips	COP	0.00%	4.49%	0.00%	n/a	n/a
PulteGroup Inc	PHM	0.04%	1.10%	0.00%	10.19%	0.00%
Pinnacle West Capital Corp	PNW	0.03%	3.77%	0.00%	4.78%	0.00%
PNC Financial Services Group Inc/The	PNC	0.16%	4.31%	0.01%	-4.26%	-0.01%
PPG Industries Inc	PPG	0.09%	2.01%	0.00%	7.82%	0.01%
Progressive Corp/The	PGR	0.19%	0.44%	0.00%	5.36%	0.01%
Public Service Enterprise Group Inc	PEG	0.10%	3.50%	0.00%	4.29%	0.00%
Robert Half International Inc	RHI	0.02%	2.67%	0.00%	6.57%	0.00%
Edison International	EIX	0.08%	4.58%	0.00%	4.26%	0.00%
Schlumberger Ltd	SLB	0.09%	2.76%	0.00%	36.00%	0.03%
Charles Schwab Corp/The	SCHW	0.15%	2.17%	0.00%	1.20%	0.00%
Sherwin-Williams Co/The	SHW	0.21%	0.83%	0.00%	9.32%	0.02%
West Pharmaceutical Services Inc	WST	0.07%	0.24%	0.00%	14.94%	0.01%
J M Smucker Co/The	SJM	0.04%	3.29%	0.00%	0.24%	0.00%
Snap-on Inc	SNA	0.03%	2.96%	0.00%	4.06%	0.00%
AMETEK Inc	AME	0.08%	0.77%	0.00%	9.16%	0.01%
Southern Co/The	SO	0.21%	4.69%	0.01%	4.30%	0.01%
Truist Financial Corp	TFC	0.18%	4.81%	0.01%	2.17%	0.00%
Southwest Airlines Co	LUV	0.07%	n/a	n/a	-3.44%	0.00%
W R Berkley Corp	WRB	0.04%	0.78%	0.00%	10.70%	0.00%
Stanley Black & Decker Inc	SWK	0.09%	1.83%	0.00%	6.44%	0.01%
Public Storage	PSA	0.12%	4.00%	0.00%	3.55%	0.00%
Arista Networks Inc	ANET	0.07%	n/a	n/a	8.38%	0.01%
Sysco Corp	SYY	0.10%	3.41%	0.00%	3.90%	0.00%
Corteva Inc	CTVA	0.08%	1.82%	0.00%	8.39%	0.01%
Texas Instruments Inc	TXN	0.42%	2.82%	0.01%	10.00%	0.04%
Textron Inc	TXT	0.03%	0.23%	0.00%	2.83%	0.00%
Thermo Fisher Scientific Inc	TMO	0.59%	0.21%	0.00%	8.30%	0.05%
Tiffany & Co	TIF	0.05%	1.85%	0.00%	6.80%	0.00%
TJX Cos Inc/The	TJX	0.22%	n/a	n/a	8.60%	0.02%
Globe Life Inc	GL	0.03%	0.94%	0.00%	5.06%	0.00%
Johnson Controls International plc	JCI	0.10%	2.70%	0.00%	9.10%	0.01%
Ulta Beauty Inc	ULTA	0.04%	n/a	n/a	6.20%	0.00%
Union Pacific Corp	UNP	0.42%	2.24%	0.01%	7.57%	0.03%
Keysight Technologies Inc	KEYS	0.07%	n/a	n/a	7.83%	0.01%
UnitedHealth Group Inc	UNH	1.03%	1.65%	0.02%	12.55%	0.13%
Unum Group	UNM	0.01%	6.62%	0.00%	9.00%	0.00%
Marathon Oil Corp	MRO	0.02%	n/a	n/a	-11.50%	0.00%
Varian Medical Systems Inc	VAR	0.05%	n/a	n/a	8.40%	0.00%
Bio-Rad Laboratories Inc	BIO	0.05%	n/a	n/a	4.00%	0.00%
Ventas Inc	VTR	0.05%	4.69%	0.00%	-0.29%	0.00%
VF Corp	VFC	0.08%	3.18%	0.00%	8.83%	0.01%
Vornado Realty Trust	VNO	0.02%	6.14%	0.00%	-4.59%	0.00%
Vulcan Materials Co	VMC	0.06%	1.16%	0.00%	14.20%	0.01%
Weyerhaeuser Co	WY	0.07%	n/a	n/a	54.40%	0.04%
Whirlpool Corp	WHR	0.04%	2.94%	0.00%	-0.42%	0.00%
Williams Cos Inc/The	WMB	0.08%	8.37%	0.01%	7.78%	0.01%
WEC Energy Group Inc	WEC	0.11%	2.66%	0.00%	6.39%	0.01%
Adobe Inc	ADBE	0.76%	n/a	n/a	16.35%	0.12%
AES Corp/The	AES	0.04%	3.76%	0.00%	6.99%	0.00%
Amgen Inc	AMGN	0.51%	2.62%	0.01%	7.67%	0.04%
Apple Inc	AAPL	6.50%	0.77%	0.05%	11.60%	0.75%
Autodesk Inc	ADSK	0.19%	n/a	n/a	31.35%	0.06%
Cintas Corp	CTAS	0.11%	0.84%	0.00%	10.52%	0.01%
Comcast Corp	CMCSA	0.70%	2.15%	0.01%	9.26%	0.06%
Molson Coors Beverage Co	TAP	0.03%	n/a	n/a	2.28%	0.00%
KLA Corp	KLAC	0.11%	1.70%	0.00%	10.54%	0.01%
Marriott International Inc/MD	MAR	0.10%	n/a	n/a	1.45%	0.00%
McCormick & Co Inc/MD	MKC	0.09%	1.27%	0.00%	10.13%	0.01%

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Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
PACCAR Inc	PCAR	0.11%	1.50%	0.00%	4.47%	0.00%
Costco Wholesale Corp	COST	0.51%	0.86%	0.00%	6.87%	0.04%
First Republic Bank/CA	FRC	0.07%	0.71%	0.00%	10.43%	0.01%
Stryker Corp	SYK	0.26%	1.19%	0.00%	8.36%	0.02%
Tyson Foods Inc	TSN	0.06%	2.73%	0.00%	2.42%	0.00%
Lamb Weston Holdings Inc	LW	0.03%	1.53%	0.00%	9.13%	0.00%
Applied Materials Inc	AMAT	0.21%	1.37%	0.00%	14.04%	0.03%
American Airlines Group Inc	AAL	0.02%	n/a	n/a	-16.94%	0.00%
Cardinal Health Inc	CAH	0.06%	3.56%	0.00%	5.11%	0.00%
Cerner Corp	CERN	0.08%	1.04%	0.00%	11.76%	0.01%
Cincinnati Financial Corp	CINF	0.00%	3.08%	0.00%	n/a	n/a
ViacomCBS Inc	VIAC	0.05%	3.68%	0.00%	1.60%	0.00%
DR Horton Inc	DHI	0.09%	1.06%	0.00%	14.42%	0.01%
Flowserve Corp	FLS	0.01%	2.87%	0.00%	5.47%	0.00%
Electronic Arts Inc	EA	0.15%	n/a	n/a	7.38%	0.01%
Expeditors International of Washington Inc	EXPD	0.05%	1.23%	0.00%	6.50%	0.00%
Fastenal Co	FAST	0.10%	2.13%	0.00%	14.50%	0.01%
M&T Bank Corp	MTB	0.05%	4.15%	0.00%	-1.80%	0.00%
Xcel Energy Inc	XEL	0.13%	2.49%	0.00%	6.04%	0.01%
Fiserv Inc	FISV	0.24%	n/a	n/a	13.86%	0.03%
Fifth Third Bancorp	FITB	0.05%	5.44%	0.00%	8.97%	0.00%
Gilead Sciences Inc	GILD	0.31%	3.91%	0.01%	0.59%	0.00%
Hasbro Inc	HAS	0.04%	3.74%	0.00%	13.95%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.03%	6.47%	0.00%	-2.94%	0.00%
Welltower Inc	WELL	0.08%	4.56%	0.00%	-0.62%	0.00%
Biogen Inc	BIIB	0.16%	n/a	n/a	1.55%	0.00%
Northern Trust Corp	NTRS	0.06%	3.57%	0.00%	2.11%	0.00%
Packaging Corp of America	PKG	0.03%	3.29%	0.00%	5.60%	0.00%
Paychex Inc	PAYX	0.09%	3.45%	0.00%	6.55%	0.01%
People's United Financial Inc	PBCT	0.02%	6.67%	0.00%	2.00%	0.00%
QUALCOMM Inc	QCOM	0.43%	2.46%	0.01%	18.45%	0.08%
Roper Technologies Inc	ROP	0.16%	0.47%	0.00%	12.23%	0.02%
Ross Stores Inc	ROST	0.11%	n/a	n/a	8.75%	0.01%
IDEXX Laboratories Inc	IDXX	0.12%	n/a	n/a	13.21%	0.02%
Starbucks Corp	SBUX	0.32%	2.14%	0.01%	13.01%	0.04%
KeyCorp	KEY	0.04%	6.16%	0.00%	16.40%	0.01%
Fox Corp	FOXA	0.03%	1.79%	0.00%	-0.71%	0.00%
Fox Corp	FOX	0.02%	1.79%	0.00%	-0.71%	0.00%
State Street Corp	STT	0.08%	3.26%	0.00%	6.18%	0.00%
Norwegian Cruise Line Holdings Ltd	NCLH	0.01%	n/a	n/a	-20.75%	0.00%
US Bancorp	USB	0.20%	4.56%	0.01%	5.20%	0.01%
A O Smith Corp	AOS	0.02%	1.99%	0.00%	8.00%	0.00%
NortonLifeLock Inc	NLOK	0.05%	2.33%	0.00%	7.50%	0.00%
T Rowe Price Group Inc	TROW	0.11%	2.61%	0.00%	6.25%	0.01%
Waste Management Inc	WM	0.17%	1.99%	0.00%	5.59%	0.01%
Constellation Brands Inc	STZ	0.11%	1.68%	0.00%	8.96%	0.01%
Xilinx Inc	XLNX	0.09%	1.42%	0.00%	8.53%	0.01%
DENTSPLY SIRONA Inc	XRAY	0.03%	0.90%	0.00%	-0.71%	0.00%
Zions Bancorp NA	ZION	0.02%	4.19%	0.00%	3.26%	0.00%
Alaska Air Group Inc	ALK	0.00%	n/a	n/a	n/a	n/a
Invesco Ltd	IVZ	0.02%	6.18%	0.00%	-9.48%	0.00%
Linde PLC	LIN	0.46%	1.57%	0.01%	9.50%	0.04%
Intuit Inc	INTU	0.29%	0.69%	0.00%	13.20%	0.04%
Morgan Stanley	MS	0.28%	2.86%	0.01%	1.97%	0.01%
Microchip Technology Inc	MCHP	0.09%	1.45%	0.00%	11.57%	0.01%
Chubb Ltd	CB	0.21%	2.45%	0.01%	9.37%	0.02%
Hologic Inc	HOLX	0.06%	n/a	n/a	13.91%	0.01%
Citizens Financial Group Inc	CFG	0.04%	6.29%	0.00%	8.07%	0.00%
O'Reilly Automotive Inc	ORLY	0.13%	n/a	n/a	9.81%	0.01%
Allstate Corp/The	ALL	0.11%	2.29%	0.00%	7.33%	0.01%
FLIR Systems Inc	FLIR	0.00%	1.63%	0.00%	n/a	n/a
Equity Residential	EQR	0.07%	4.49%	0.00%	4.00%	0.00%
BorgWarner Inc	BWA	0.03%	1.86%	0.00%	8.96%	0.00%
Incyte Corp	INCY	0.08%	n/a	n/a	31.37%	0.02%
Simon Property Group Inc	SPG	0.07%	8.34%	0.01%	0.60%	0.00%
Eastman Chemical Co	EMN	0.04%	3.54%	0.00%	1.58%	0.00%
Twitter Inc	TWTR	0.10%	n/a	n/a	9.50%	0.01%
AvalonBay Communities Inc	AVB	0.08%	4.15%	0.00%	2.58%	0.00%

STANDARD AND POOR'S 500 INDEX

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Prudential Financial Inc	PRU	0.09%	6.94%	0.01%	7.00%	0.01%
United Parcel Service Inc	UPS	0.36%	2.83%	0.01%	8.86%	0.03%
Apartment Investment and Management Co	AIV	0.02%	4.22%	0.00%	1.59%	0.00%
Walgreens Boots Alliance Inc	WBA	0.13%	4.59%	0.01%	0.04%	0.00%
STERIS PLC	STE	0.05%	0.93%	0.00%	8.20%	0.00%
McKesson Corp	MCK	0.09%	1.12%	0.00%	8.62%	0.01%
Lockheed Martin Corp	LMT	0.38%	2.53%	0.01%	7.32%	0.03%
AmerisourceBergen Corp	ABC	0.07%	1.68%	0.00%	4.13%	0.00%
Capital One Financial Corp	COF	0.10%	0.63%	0.00%	1.65%	0.00%
Waters Corp	WAT	0.05%	n/a	n/a	3.13%	0.00%
Dollar Tree Inc	DLTR	0.08%	n/a	n/a	8.86%	0.01%
Darden Restaurants Inc	DRI	0.04%	n/a	n/a	12.76%	0.00%
Domino's Pizza Inc	DPZ	0.05%	0.81%	0.00%	13.89%	0.01%
NVR Inc	NVR	0.05%	n/a	n/a	7.92%	0.00%
NetApp Inc	NTAP	0.04%	4.33%	0.00%	9.73%	0.00%
Citrix Systems Inc	CTXS	0.06%	0.98%	0.00%	9.63%	0.01%
DXC Technology Co	DXC	0.02%	n/a	n/a	-17.84%	0.00%
Old Dominion Freight Line Inc	ODFL	0.08%	0.33%	0.00%	9.24%	0.01%
DaVita Inc	DVA	0.04%	n/a	n/a	9.96%	0.00%
Hartford Financial Services Group Inc/The	HIG	0.05%	3.07%	0.00%	9.50%	0.01%
Iron Mountain Inc	IRM	0.03%	8.78%	0.00%	0.06%	0.00%
Estee Lauder Cos Inc/The	EL	0.16%	n/a	n/a	20.37%	0.03%
Cadence Design Systems Inc	CDNS	0.11%	n/a	n/a	10.89%	0.01%
Tyler Technologies Inc	TYL	0.05%	n/a	n/a	12.17%	0.01%
Universal Health Services Inc	UHS	0.03%	n/a	n/a	8.00%	0.00%
E*TRADE Financial Corp	ETFC	0.04%	1.10%	0.00%	-9.84%	0.00%
Skyworks Solutions Inc	SWKS	0.09%	1.37%	0.00%	13.58%	0.01%
National Oilwell Varco Inc	NOV	0.02%	n/a	n/a	19.15%	0.00%
Quest Diagnostics Inc	DGX	0.06%	1.76%	0.00%	9.44%	0.01%
Activision Blizzard Inc	ATVI	0.23%	0.50%	0.00%	11.38%	0.03%
Rockwell Automation Inc	ROK	0.09%	1.87%	0.00%	7.44%	0.01%
Kraft Heinz Co/The	KHC	0.15%	4.65%	0.01%	4.30%	0.01%
American Tower Corp	AMT	0.41%	1.68%	0.01%	15.32%	0.06%
HollyFrontier Corp	HFC	0.02%	5.09%	0.00%	-2.42%	0.00%
Regeneron Pharmaceuticals Inc	REGN	0.23%	n/a	n/a	14.45%	0.03%
Amazon.com Inc	AMZN	5.67%	n/a	n/a	32.26%	1.83%
Jack Henry & Associates Inc	JKHY	0.05%	0.96%	0.00%	12.10%	0.01%
Ralph Lauren Corp	RL	0.01%	n/a	n/a	4.53%	0.00%
Boston Properties Inc	BXP	0.05%	4.40%	0.00%	3.97%	0.00%
Amphenol Corp	APH	0.11%	0.95%	0.00%	8.08%	0.01%
Howmet Aerospace Inc	HWM	0.02%	n/a	n/a	50.90%	0.01%
Pioneer Natural Resources Co	PXD	0.06%	2.27%	0.00%	15.50%	0.01%
Valero Energy Corp	VLO	0.08%	6.97%	0.01%	4.70%	0.00%
Synopsys Inc	SNPS	0.11%	n/a	n/a	14.23%	0.02%
Western Union Co/The	WU	0.04%	3.71%	0.00%	5.30%	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	2.18%	0.00%	8.63%	0.00%
Accenture PLC	ACN	0.51%	1.42%	0.01%	10.33%	0.05%
TransDigm Group Inc	TDG	0.08%	n/a	n/a	6.18%	0.01%
Yum! Brands Inc	YUM	0.10%	2.06%	0.00%	11.46%	0.01%
Prologis Inc	PLD	0.28%	2.20%	0.01%	7.27%	0.02%
FirstEnergy Corp	FE	0.06%	5.38%	0.00%	4.20%	0.00%
VeriSign Inc	VRSN	0.09%	n/a	n/a	10.30%	0.01%
Quanta Services Inc	PWR	0.00%	0.50%	0.00%	n/a	n/a
Henry Schein Inc	HSIC	0.04%	n/a	n/a	-0.82%	0.00%
Ameren Corp	AEE	0.07%	2.47%	0.00%	7.03%	0.00%
ANSYS Inc	ANSS	0.10%	n/a	n/a	11.30%	0.01%
NVIDIA Corp	NVDA	0.93%	0.15%	0.00%	18.78%	0.18%
Sealed Air Corp	SEE	0.02%	1.79%	0.00%	2.37%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.13%	1.29%	0.00%	10.40%	0.01%
SVB Financial Group	SIVB	0.04%	n/a	n/a	10.00%	0.00%
Intuitive Surgical Inc	ISRG	0.29%	n/a	n/a	8.93%	0.03%
Take-Two Interactive Software Inc	TTWO	0.07%	n/a	n/a	6.13%	0.00%
Republic Services Inc	RSG	0.10%	1.95%	0.00%	6.63%	0.01%
eBay Inc	EBAY	0.14%	1.16%	0.00%	13.97%	0.02%
Goldman Sachs Group Inc/The	GS	0.24%	2.53%	0.01%	3.50%	0.01%
SBA Communications Corp	SBAC	0.12%	0.60%	0.00%	29.90%	0.04%
Sempra Energy	SRE	0.13%	3.36%	0.00%	7.37%	0.01%
Moody's Corp	MCO	0.19%	0.80%	0.00%	9.80%	0.02%

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Booking Holdings Inc	BKNG	0.24%	n/a	n/a	13.20%	0.03%
F5 Networks Inc	FFIV	0.03%	n/a	n/a	11.50%	0.00%
Akamai Technologies Inc	AKAM	0.07%	n/a	n/a	11.87%	0.01%
MarketAxess Holdings Inc	MKTX	0.00%	0.46%	0.00%	n/a	n/a
Devon Energy Corp	DVN	0.01%	4.19%	0.00%	-9.16%	0.00%
Alphabet Inc	GOOGL	1.60%	n/a	n/a	15.83%	0.25%
Teleflex Inc	TFX	0.06%	0.36%	0.00%	13.00%	0.01%
Netflix Inc	NFLX	0.77%	n/a	n/a	32.13%	0.25%
Allegion plc	ALLE	0.03%	1.29%	0.00%	5.59%	0.00%
Agilent Technologies Inc	A	0.11%	0.75%	0.00%	10.30%	0.01%
Anthem Inc	ANTM	0.25%	1.39%	0.00%	12.67%	0.03%
CME Group Inc	CME	0.21%	2.05%	0.00%	8.07%	0.02%
Juniper Networks Inc	JNPR	0.03%	3.15%	0.00%	7.83%	0.00%
BlackRock Inc	BLK	0.31%	2.53%	0.01%	7.13%	0.02%
DTE Energy Co	DTE	0.08%	3.50%	0.00%	6.00%	0.00%
Nasdaq Inc	NDAQ	0.08%	1.49%	0.00%	9.29%	0.01%
Celanese Corp	CE	0.04%	2.55%	0.00%	4.01%	0.00%
Philip Morris International Inc	PM	0.43%	6.09%	0.03%	6.38%	0.03%
salesforce.com Inc	CRM	0.63%	n/a	n/a	19.08%	0.12%
Ingersoll Rand Inc	IR	0.05%	n/a	n/a	10.20%	0.00%
Huntington Ingalls Industries Inc	HII	0.03%	2.37%	0.00%	40.00%	0.01%
MetLife Inc	MET	0.12%	4.86%	0.01%	4.42%	0.01%
Under Armour Inc	UA	0.01%	n/a	n/a	12.07%	0.00%
Tapestry Inc	TPR	0.01%	n/a	n/a	8.05%	0.00%
CSX Corp	CSX	0.20%	1.46%	0.00%	8.28%	0.02%
Edwards Lifesciences Corp	EW	0.17%	n/a	n/a	13.75%	0.02%
Ameriprise Financial Inc	AMP	0.07%	2.71%	0.00%	3.90%	0.00%
Zebra Technologies Corp	ZBRA	0.05%	n/a	n/a	10.30%	0.01%
TechnipFMC PLC	FTI	0.01%	1.62%	0.00%	9.50%	0.00%
Zimmer Biomet Holdings Inc	ZBH	0.10%	0.71%	0.00%	2.44%	0.00%
CBRE Group Inc	CBRE	0.05%	n/a	n/a	8.45%	0.00%
Mastercard Inc	MA	1.09%	0.52%	0.01%	18.78%	0.21%
CarMax Inc	KMX	0.06%	n/a	n/a	9.93%	0.01%
Intercontinental Exchange Inc	ICE	0.19%	1.24%	0.00%	9.23%	0.02%
Fidelity National Information Services Inc	FIS	0.32%	0.96%	0.00%	19.58%	0.06%
Chipotle Mexican Grill Inc	CMG	0.12%	n/a	n/a	20.46%	0.02%
Wynn Resorts Ltd	WYNN	0.03%	n/a	n/a	20.00%	0.01%
Live Nation Entertainment Inc	LYV	0.00%	n/a	n/a	n/a	n/a
Assurant Inc	AIZ	0.00%	2.34%	0.00%	n/a	n/a
NRG Energy Inc	NRG	0.03%	3.55%	0.00%	-13.64%	0.00%
Regions Financial Corp	RF	0.04%	5.71%	0.00%	1.86%	0.00%
Monster Beverage Corp	MNST	0.15%	n/a	n/a	9.95%	0.01%
Mosaic Co/The	MOS	0.02%	1.48%	0.00%	38.35%	0.01%
Expedia Group Inc	EXPE	0.04%	n/a	n/a	10.00%	0.00%
Evergy Inc	EVRG	0.05%	3.12%	0.00%	6.33%	0.00%
Discovery Inc	DISCA	0.01%	n/a	n/a	-4.45%	0.00%
CF Industries Holdings Inc	CF	0.02%	3.83%	0.00%	11.05%	0.00%
Leidos Holdings Inc	LDOS	0.05%	1.43%	0.00%	10.36%	0.01%
Alphabet Inc	GOOG	1.77%	n/a	n/a	15.83%	0.28%
Cooper Cos Inc/The	COO	0.05%	0.02%	0.00%	8.45%	0.00%
TE Connectivity Ltd	TEL	0.11%	2.16%	0.00%	8.78%	0.01%
Discover Financial Services	DFS	0.05%	3.56%	0.00%	15.23%	0.01%
Visa Inc	V	1.15%	0.63%	0.01%	13.89%	0.16%
Mid-America Apartment Communities Inc	MAA	0.00%	3.36%	0.00%	n/a	n/a
Xylem Inc/NY	XYL	0.05%	1.43%	0.00%	20.17%	0.01%
Marathon Petroleum Corp	MPC	0.09%	6.07%	0.01%	11.55%	0.01%
Tractor Supply Co	TSCO	0.06%	0.98%	0.00%	12.38%	0.01%
Advanced Micro Devices Inc	AMD	0.33%	n/a	n/a	23.93%	0.08%
ResMed Inc	RMD	0.10%	0.77%	0.00%	13.80%	0.01%
Mettler-Toledo International Inc	MTD	0.08%	n/a	n/a	7.41%	0.01%
Copart Inc	CPRT	0.00%	n/a	n/a	n/a	n/a
Albemarle Corp	ALB	0.03%	1.87%	0.00%	10.02%	0.00%
Fortinet Inc	FTNT	0.08%	n/a	n/a	15.10%	0.01%
Apache Corp	APA	0.02%	0.65%	0.00%	-29.29%	-0.01%
Essex Property Trust Inc	ESS	0.05%	3.76%	0.00%	3.61%	0.00%
Realty Income Corp	O	0.07%	4.67%	0.00%	4.45%	0.00%
Seagate Technology PLC	STX	0.04%	5.75%	0.00%	5.18%	0.00%
Westrock Co	WRK	0.02%	2.98%	0.00%	-0.10%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
IHS Markit Ltd	INFO	0.11%	0.84%	0.00%	12.18%	0.01%
Westinghouse Air Brake Technologies Corp	WAB	0.04%	0.77%	0.00%	8.97%	0.00%
Western Digital Corp	WDC	0.05%	n/a	n/a	0.30%	0.00%
PepsiCo Inc	PEP	0.68%	2.97%	0.02%	4.81%	0.03%
Diamondback Energy Inc	FANG	0.02%	3.76%	0.00%	17.64%	0.00%
Maxim Integrated Products Inc	MXIM	0.06%	n/a	n/a	11.65%	0.01%
ServiceNow Inc	NOW	0.30%	n/a	n/a	34.13%	0.10%
Church & Dwight Co Inc	CHD	0.09%	1.00%	0.00%	7.89%	0.01%
Duke Realty Corp	DRE	0.05%	2.34%	0.00%	-0.65%	0.00%
Federal Realty Investment Trust	FRT	0.02%	5.50%	0.00%	3.16%	0.00%
MGM Resorts International	MGM	0.03%	0.06%	0.00%	18.70%	0.01%
JB Hunt Transport Services Inc	JBHT	0.05%	0.83%	0.00%	13.30%	0.01%
Lam Research Corp	LRCX	0.20%	1.22%	0.00%	13.41%	0.03%
Mohawk Industries Inc	MHK	0.02%	n/a	n/a	9.00%	0.00%
Pentair PLC	PNR	0.03%	1.77%	0.00%	8.60%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.25%	n/a	n/a	24.81%	0.06%
Amcor PLC	AMCR	0.06%	4.47%	0.00%	7.25%	0.00%
Facebook Inc	FB	2.18%	n/a	n/a	23.69%	0.52%
T-Mobile US Inc	TMUS	0.48%	n/a	n/a	5.00%	0.02%
United Rentals Inc	URI	0.04%	n/a	n/a	-3.65%	0.00%
ABIOMED Inc	ABMD	0.00%	n/a	n/a	n/a	n/a
Alexandria Real Estate Equities Inc	ARE	0.08%	2.39%	0.00%	4.99%	0.00%
Delta Air Lines Inc	DAL	0.06%	n/a	n/a	-7.67%	0.00%
United Airlines Holdings Inc	UAL	0.03%	n/a	n/a	-0.70%	0.00%
News Corp	NWS	0.01%	1.57%	0.00%	13.20%	0.00%
Centene Corp	CNC	0.14%	n/a	n/a	13.23%	0.02%
Martin Marietta Materials Inc	MLM	0.05%	1.06%	0.00%	10.11%	0.00%
PayPal Holdings Inc	PYPL	0.82%	n/a	n/a	21.76%	0.18%
Coty Inc	COTY	0.01%	n/a	n/a	3.45%	0.00%
DISH Network Corp	DISH	0.03%	n/a	n/a	1.62%	0.00%
Dow Inc	DOW	0.11%	6.82%	0.01%	1.60%	0.00%
Alexion Pharmaceuticals Inc	ALXN	0.08%	n/a	n/a	12.37%	0.01%
Everest Re Group Ltd	RE	0.03%	2.83%	0.00%	10.11%	0.00%
Teledyne Technologies Inc	TDY	0.04%	n/a	n/a	10.10%	0.00%
News Corp	NWSA	0.02%	1.57%	0.00%	13.20%	0.00%
Exelon Corp	EXC	0.13%	3.96%	0.01%	1.39%	0.00%
Global Payments Inc	GPN	0.19%	0.44%	0.00%	17.45%	0.03%
Crown Castle International Corp	CCI	0.25%	2.88%	0.01%	17.63%	0.04%
Aptiv PLC	APTV	0.08%	n/a	n/a	10.69%	0.01%
Advance Auto Parts Inc	AAP	0.04%	0.67%	0.00%	11.75%	0.00%
Align Technology Inc	ALGN	0.08%	n/a	n/a	13.93%	0.01%
Illumina Inc	ILMN	0.20%	n/a	n/a	18.06%	0.04%
LKQ Corp	LKQ	0.03%	n/a	n/a	7.90%	0.00%
Nielsen Holdings PLC	NLSN	0.02%	1.66%	0.00%	12.00%	0.00%
Garmin Ltd	GRMN	0.07%	2.47%	0.00%	6.93%	0.00%
Zoetis Inc	ZTS	0.26%	0.53%	0.00%	7.23%	0.02%
Equinix Inc	EQIX	0.25%	1.35%	0.00%	18.75%	0.05%
Digital Realty Trust Inc	DLR	0.15%	2.79%	0.00%	14.80%	0.02%
Las Vegas Sands Corp	LVS	0.12%	n/a	n/a	8.40%	0.01%
Discovery Inc	DISCK	0.02%	n/a	n/a	-4.45%	0.00%

Notes:
[7] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, July 31, 2020.
[8] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, July 31, 2020.
[9] Equals ([7] x (1 + (0.5 x [8]))) + [8]
[10] Equals sum of Col. [15]
[11] Equals sum of Col. [17]
[12] Equals ([10] x (1 + (0.5 x [11])) + [11]
[13] Equals weight in S&P 500 based on market capitalization
[14] Source: Bloomberg Professional, as of July 31, 2020.
[15] Equals [13] x [14]
[16] Source: Bloomberg Professional, as of July 31, 2020.
[17] Equals [13] x [16]

Docket No. UE 374
Exhibit PAC/3506
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated Risk Premium Approach

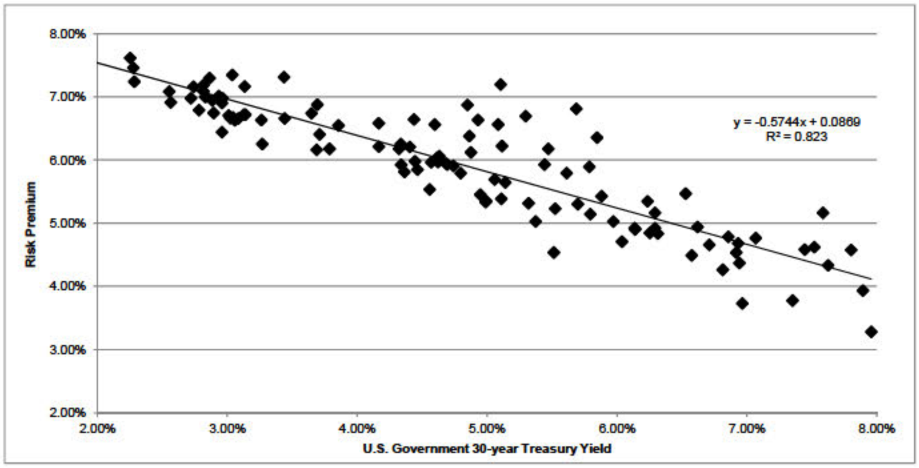
August 2020

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.52%	5.23%
2001.4	11.99%	5.30%	6.70%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.65%	5.08%	6.57%
2002.4	11.57%	4.93%	6.64%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	11.24%	4.86%	6.38%
2005.1	10.63%	4.69%	5.93%
2005.2	10.31%	4.47%	5.85%
2005.3	11.08%	4.44%	6.65%
2005.4	10.63%	4.68%	5.95%
2006.1	10.70%	4.63%	6.06%
2006.2	10.79%	5.14%	5.65%
2006.3	10.35%	4.99%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.80%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.97%
2008.3	10.43%	4.44%	5.98%
2008.4	10.39%	3.65%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.26%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.36%	5.82%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.21%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.69%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.93%	7.02%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.17%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.26%	6.64%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.04%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.71%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.24%
2019.4	9.87%	2.25%	7.62%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.20%
2020.3	9.40%	1.31%	8.09%
AVERAGE	10.69%	4.71%	5.98%
MEDIAN	10.63%	4.69%	6.12%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.907214046
R Square	0.823037326
Adjusted R Square	0.821471285
Standard Error	0.004278855
Observations	115

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.009622137	0.009622137	525.5527382	2.63777E-44
Residual	113	0.002068872	1.83086E-05		
Total	114	0.011691009			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.086872336	0.001246797	69.6763894	1.10921E-94	0.084402205	0.08934247	0.084402205	0.089342466
X Variable 1	-0.574361708	0.025054015	-22.924937	2.63777E-44	-0.62399823	-0.5247252	-0.62399823	-0.524725186

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	1.34%	7.92%	9.26%
Blue Chip Consensus Forecast (Q4 2020 - Q4 2021) [5]	1.76%	7.68%	9.44%
Blue Chip Consensus Forecast (2021-2025) [6]	3.00%	6.96%	9.96%
AVERAGE			9.55%

Notes:
[1] Source: Regulatory Research Associates, cases up until July 31, 2020
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] – Column [2]
[4] Source: Bloomberg Professional
[5] Source: Blue Chip Financial Forecasts, Vol. 39, No. 7, July 1, 2020, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, June 1, 2020, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.086872 + (-0.574362 x Column [7])
[9] Equals Column [7] + Column [8]

Docket No. UE 374
Exhibit PAC/3507
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated Expected Earnings Analysis

August 2020

EXPECTED EARNINGS ANALYSIS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Value Line ROE Projection Years 4-6	Value Line Total Capital ($mill) MRY	Value Line Common Equity Ratio MRY	Total Equity MRY	Value Line Total Capital ($mill) Projection Years 4-6	Value Line Common Equity Ratio Projection Years 4-6	Total Equity ($mill) Projection Years 4-6	Compound Annual Growth Rate	Adjustment Factor	Adjusted Return on Common Equity
ALLETE, Inc.	ALE	8.00%	3,633	61.40%	2,231	4,750	59.00%	2,803	4.67%	1.023	8.18%
Alliant Energy Corporation	LNT	10.50%	10,226	48.50%	4,960	12,000	48.00%	5,760	3.04%	1.015	10.66%
Ameren Corporation	AEE	10.00%	17,116	47.10%	8,062	23,900	50.00%	11,950	8.19%	1.039	10.39%
American Electric Power Company, Inc.	AEP	10.50%	44,759	43.90%	19,649	56,700	47.00%	26,649	6.28%	1.030	10.82%
Avista Corporation	AVA	7.50%	3,835	50.60%	1,940	4,750	49.00%	2,328	3.71%	1.018	7.64%
CMS Energy Corporation	CMS	13.50%	17,082	29.40%	5,022	24,200	31.50%	7,623	8.70%	1.042	14.06%
Dominion Resources, Inc.	D	14.00%	65,818	45.00%	29,618	75,900	46.00%	34,914	3.34%	1.016	14.23%
DTE Energy Company	DTE	10.50%	27,607	42.30%	11,678	38,400	41.50%	15,936	6.42%	1.031	10.83%
Duke Energy Corporation	DUK	8.50%	101,807	44.10%	44,897	123,600	45.00%	55,620	4.38%	1.021	8.68%
Entergy Corporation	ETR	11.00%	27,557	37.10%	10,224	32,500	41.00%	13,325	5.44%	1.026	11.29%
Evergy, Inc.	EVRG	8.00%	17,337	49.40%	8,564	20,300	46.50%	9,440	1.96%	1.010	8.08%
IDACORP, Inc.	IDA	9.50%	4,201	58.70%	2,466	5,450	53.50%	2,916	3.41%	1.017	9.66%
NextEra Energy, Inc.	NEE	12.50%	74,548	49.60%	36,976	98,400	50.50%	49,692	6.09%	1.030	12.87%
NorthWestern Corporation	NWE	8.50%	4,290	47.50%	2,038	4,825	50.00%	2,413	3.43%	1.017	8.64%
OGE Energy Corporation	OGE	12.50%	7,335	56.40%	4,137	8,150	51.50%	4,197	0.29%	1.001	12.52%
Otter Tail Corporation	OTTR	11.00%	1,471	53.10%	781	1,850	53.00%	981	4.65%	1.023	11.25%
Pinnacle West Capital Corporation	PNW	10.00%	10,263	52.90%	5,429	14,525	46.50%	6,754	4.46%	1.022	10.22%
PNM Resources, Inc.	PNM	9.50%	4,208	39.90%	1,679	5,475	49.00%	2,683	9.83%	1.047	9.94%
Portland General Electric Company	POR	9.00%	5,323	48.70%	2,592	6,400	47.50%	3,040	3.24%	1.016	9.14%
PPL Corporation	PPL	12.50%	33,712	38.50%	12,979	39,200	42.50%	16,660	5.12%	1.025	12.81%
Southern Company	SO	12.50%	69,594	39.50%	27,490	84,300	39.50%	33,299	3.91%	1.019	12.74%
Xcel Energy Inc.	XEL	10.50%	30,646	43.20%	13,239	41,700	42.50%	17,723	6.01%	1.029	10.81%
Mean											10.70%
Median											10.73%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals [2] x [3]
[5] Source: Value Line
[6] Source: Value Line
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

Docket No. UE 374
Exhibit PAC/3508
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Staff Constant Growth DCF Update

August 2020

REVISED CONSTANT GROWTH DCF -- STAFF PROXY GROUP

Company		[1] Value Line Annual Dividend (2021)	[2] Stock Price at 4/1/2020	[3] Stock Price at 5/1/2020	[4] Stock Price at 6/1/2020	[5] Average Stock Price	[6] Expected Dividend Yield	[7] Value Line Dividend Growth	[8] ROE	[9] ROE, Excluding Results Below 8%
Alliant Energy Corporation	LNT	$1.64	$48.55	$49.36	$47.84	$48.58	3.38%	6.90%	10.28%	10.28%
Ameren Corporation	AEE	$2.11	$72.75	$74.73	$70.36	$72.61	2.91%	4.81%	7.71%	
Consolidated Edison, Inc.	ED	$3.16	$78.80	$75.06	$71.93	$75.26	4.20%	3.42%	7.62%	
Eversource Energy	ES	$2.40	$80.70	$83.70	$83.27	$82.56	2.91%	5.90%	8.81%	8.81%
OGE Energy Corporation	OGE	$1.68	$31.52	$31.32	$30.36	$31.07	5.41%	6.17%	11.58%	11.58%
Portland General Electric Company	POR	$1.72	$46.79	$47.11	$41.81	$45.24	3.80%	6.48%	10.28%	10.28%
Pinnacle West Capital Corporation	PNW	$3.41	$76.99	$77.90	$73.29	$76.06	4.48%	5.96%	10.45%	10.45%
WEC Energy Group	WEC	$2.70	$90.55	$91.73	$87.65	$89.98	3.00%	6.31%	9.31%	9.31%
MEAN							3.76%	5.74%	9.50%	10.12%

Notes
[1] Source: Staff/1906 Muldoon- Enright-Dlouhy/1
[2] Source: Staff/1903 Muldoon- Enright-Dlouhy/5
[3] Source: Staff/1903 Muldoon- Enright-Dlouhy/5
[4] Source: Staff/1903 Muldoon- Enright-Dlouhy/5
[5] Equals Average ([2], [3], [4])
[6] Equals [1] / [6]
[7] Source: Value Line Investment Survey
[8] Equals [6] + [7]
[9] Equals [8], if [8] is greater than 8.00%

Docket No. UE 374
Exhibit PAC/3509
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Staff Hamada Adjustment (Re-creation) Staff Multi-Stage DCF (Revised)

August 2020

HAMADA ADJUSTMENT - STAFF'S PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
		Value Line Cap Structure Percentages (2020)								
Company	Ticker	LT Debt	Common Equity	Preferred Stock	Value Line Beta	Value Line 2020 Tax Rate	2020 Unlevered Beta	2020 Relevered Beta - Equity at 53.52%	Equity Risk Premium	Hamada 2020 Adjustment - Equity at 53.52%
Alliant Energy Corporation	LNT	52.00	48.00	0.00	0.80	11.0%	0.41	0.82	4.50%	0.11%
Ameren Corporation	AEE	54.00	45.50	0.50	0.80	12.5%	0.39	0.78	4.50%	-0.07%
Consolidated Edison, Inc.	ED	49.50	50.50	0.00	0.75	17.0%	0.41	0.81	4.50%	0.26%
Eversource Energy	ES	52.00	47.00	1.00	0.90	20.0%	0.47	0.91	4.50%	0.04%
OGE Energy Corporation	OGE	48.50	51.50	0.00	1.05	13.0%	0.58	1.16	4.50%	0.47%
Portland General Electric Company	POR	52.50	47.50	0.00	0.55	11.0%	0.28	0.56	4.50%	0.05%
Pinnacle West Capital Corporation	PNW	53.00	47.00	0.00	0.45	14.0%	0.23	0.45	4.50%	0.02%
WEC Energy Group	WEC	50.50	49.50	0.00	0.80	16.5%	0.43	0.85	4.50%	0.21%
Mean			48.3%							0.14%

Notes
[1] Source: Staff/1903 Muldoon- Enright-Dlouhy/5
[2] Source: Staff/1903 Muldoon- Enright-Dlouhy/5
[3] Equals 100% - [1] - [2]
[4] Source: Staff/1903 Muldoon- Enright-Dlouhy/5
[5] Source: Staff/1903 Muldoon- Enright-Dlouhy/5
[6] Equals [4] / (1 + (1 - [5]) x (([1] + [3]) / [2]))
[7] Equals [6] x (1 + (1 - [5]) x (53.52% / (1 - 53.52%)))
[8] Source: Duff and Phelps - 2019 Valuation Handbook
[9] Equals [8] x ([7] - [4])

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates		
CBO	3.70%	1
Composite	3.94%	2
BEA Nominal Historical	4.38%	3
PAC Growth Rate (Per Staff)	5.05%	4
Bulkley Growth Rate (as of 6/30/20)	5.56%	5

GDP GROWTH RATE INPUT	2

Average B.O.Y. & E.O.Y. Cash Flows

Company	Average IRR	IRR, Excluding Results Below 8%	Terminal Value as % of NPV_{DIV}
Alliant Energy Corporation	8.1%	8.1%	36.6%
Ameren Corporation	7.6%		46.0%
Consolidated Edison, Inc.	8.2%	8.2%	32.3%
Eversource Energy	7.7%		44.7%
OGE Energy Corporation	9.8%	9.8%	21.0%
Portland General Electric Company	8.4%	8.4%	32.6%
Pinnacle West Capital Corporation	9.1%	9.1%	28.5%
WEC Energy Group	7.7%		42.9%
MEAN	8.31%	8.72%	35.59%

E.O.Y. Cash Flows

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company		2017	2018	2019	2017-2019	2023-2025	Growth Rate (2017-19 - 2023-25)	GDP Growth Rate
Alliant Energy Corporation	Annualized DPS	1.26	1.34	1.42	1.34	2.00	6.9%	3.94%
	Annualized EPS	1.99	2.19	2.33	2.17	3.00	5.5%	3.94%
Ameren Corporation	Annualized DPS	1.78	1.85	1.92	1.85	2.45	4.8%	3.94%
	Annualized EPS	2.78	3.32	3.35	3.15	4.50	6.1%	3.94%
Consolidated Edison, Inc.	Annualized DPS	2.76	2.86	2.96	2.86	3.50	3.4%	3.94%
	Annualized EPS	4.10	4.55	4.07	4.24	5.00	2.8%	3.94%
Eversource Energy	Annualized DPS	1.90	2.02	2.14	2.02	2.85	5.9%	3.94%
	Annualized EPS	3.11	3.25	3.45	3.27	4.75	6.4%	3.94%
OGE Energy Corporation	Annualized DPS	1.24	1.36	1.48	1.36	1.95	6.2%	3.94%
	Annualized EPS	1.92	2.11	2.25	2.09	2.50	3.0%	3.94%
Portland General Electric Company	Annualized DPS	1.32	1.41	1.50	1.41	2.05	6.5%	3.94%
	Annualized EPS	2.29	2.37	2.39	2.35	3.00	4.2%	3.94%
Pinnacle West Capital Corporation	Annualized DPS	2.66	2.82	3.00	2.83	4.00	6.0%	3.94%
	Annualized EPS	4.43	4.54	4.78	4.58	6.00	4.6%	3.94%
WEC Energy Group	Annualized DPS	2.08	2.21	2.36	2.22	3.20	6.3%	3.94%
	Annualized EPS	3.14	3.47	3.58	3.40	4.75	5.7%	3.94%
MEAN								

B.O.Y. Cash Flows

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company		2017	2018	2019	2017-2019	2023-2025	Growth Rate (2017-19 - 2023-25)	GDP Growth Rate
Alliant Energy Corporation	Annualized DPS	1.26	1.34	1.42	1.34	2.00	6.9%	3.94%
	Annualized EPS	1.99	2.19	2.33	2.17	3.00	5.5%	3.94%
Ameren Corporation	Annualized DPS	1.78	1.85	1.92	1.85	2.45	4.8%	3.94%
	Annualized EPS	2.78	3.32	3.35	3.15	4.50	6.1%	3.94%
Consolidated Edison, Inc.	Annualized DPS	2.76	2.86	2.96	2.86	3.50	3.4%	3.94%
	Annualized EPS	4.10	4.55	4.07	4.24	5.00	2.8%	3.94%
Eversource Energy	Annualized DPS	1.90	2.02	2.14	2.02	2.85	5.9%	3.94%
	Annualized EPS	3.11	3.25	3.45	3.27	4.75	6.4%	3.94%
OGE Energy Corporation	Annualized DPS	1.24	1.36	1.48	1.36	1.95	6.2%	3.94%
	Annualized EPS	1.92	2.11	2.25	2.09	2.50	3.0%	3.94%
Portland General Electric Company	Annualized DPS	1.32	1.41	1.50	1.41	2.05	6.5%	3.94%
	Annualized EPS	2.29	2.37	2.39	2.35	3.00	4.2%	3.94%
Pinnacle West Capital Corporation	Annualized DPS	2.66	2.82	3.00	2.83	4.00	6.0%	3.94%
	Annualized EPS	4.43	4.54	4.78	4.58	6.00	4.6%	3.94%
WEC Energy Group	Annualized DPS	2.08	2.21	2.36	2.22	3.20	6.3%	3.94%
	Annualized EPS	3.14	3.47	3.58	3.40	4.75	5.7%	3.94%

[1]	[2]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]
			Terminal Value as			2020	2021	2022	2023	2024
Company		IRR	% of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage				
Alliant Energy Corporation	Annualized DPS	8.0%	37.5%	0.00	(48.58)	1.52	1.64	1.75	1.87	2.00
	Annualized EPS					2.45	2.55	2.69	2.84	3.00
Ameren Corporation	Annualized DPS	7.5%	46.8%	(0.00)	(72.61)	2.01	2.11	2.22	2.33	2.45
	Annualized EPS					3.45	3.65	3.91	4.20	4.50
Consolidated Edison, Inc.	Annualized DPS	8.1%	33.0%	0.00	(75.26)	3.06	3.16	3.27	3.38	3.50
	Annualized EPS					4.25	4.55	4.70	4.85	5.00
Eversource Energy	Annualized DPS	7.6%	45.6%	0.00	(82.56)	2.27	2.40	2.54	2.69	2.85
	Annualized EPS					3.65	3.85	4.13	4.43	4.75
OGE Energy Corporation	Annualized DPS	9.7%	21.8%	0.00	(31.07)	1.60	1.68	1.77	1.86	1.95
	Annualized EPS					2.15	2.25	2.33	2.41	2.50
Portland General Electric Company	Annualized DPS	8.3%	33.5%	0.00	(45.24)	1.62	1.72	1.82	1.93	2.05
	Annualized EPS					2.50	2.65	2.76	2.88	3.00
Pinnacle West Capital Corporation	Annualized DPS	9.0%	29.4%	0.00	(76.06)	3.22	3.41	3.60	3.79	4.00
	Annualized EPS					4.75	5.15	5.42	5.70	6.00
WEC Energy Group	Annualized DPS	7.6%	43.7%	0.00	(89.98)	2.53	2.70	2.86	3.02	3.20
	Annualized EPS					3.75	3.95	4.20	4.47	4.75
MEAN		8.22%	36.40%	0.00						

[1]	[2]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]
			Terminal Value as			2020	2021	2022	2023	2024
Company		IRR	% of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage				
Alliant Energy Corporation	Annualized DPS	8.2%	35.7%	0.00	(48.58)	1.64	1.75	1.87	2.00	2.13
	Annualized EPS					2.45	2.55	2.69	2.84	3.00
Ameren Corporation	Annualized DPS	7.6%	45.2%	0.00	(72.61)	2.11	2.22	2.33	2.45	2.57
	Annualized EPS					3.45	3.65	3.91	4.20	4.50
Consolidated Edison, Inc.	Annualized DPS	8.3%	31.6%	0.00	(75.26)	3.16	3.27	3.38	3.50	3.62
	Annualized EPS					4.25	4.55	4.70	4.85	5.00
Eversource Energy	Annualized DPS	7.7%	43.9%	0.00	(82.56)	2.40	2.54	2.69	2.85	3.01
	Annualized EPS					3.65	3.85	4.13	4.43	4.75
OGE Energy Corporation	Annualized DPS	9.9%	20.3%	0.00	(31.07)	1.68	1.77	1.86	1.95	2.04
	Annualized EPS					2.15	2.25	2.33	2.41	2.50
Portland General Electric Company	Annualized DPS	8.5%	31.8%	0.00	(45.24)	1.72	1.82	1.93	2.05	2.17
	Annualized EPS					2.50	2.65	2.76	2.88	3.00
Pinnacle West Capital Corporation	Annualized DPS	9.2%	27.7%	0.00	(76.06)	3.41	3.60	3.79	4.00	4.21
	Annualized EPS					4.75	5.15	5.42	5.70	6.00
WEC Energy Group	Annualized DPS	7.7%	42.0%	0.00	(89.98)	2.70	2.86	3.02	3.20	3.38
	Annualized EPS					3.75	3.95	4.20	4.47	4.75
		8.40%	34.78%	0.00						

E.O.Y. Cash Flows

[1]	[2]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
		2025	2026	2027	2028	2029	2030	2031	2032	2033
Company		Transition Stage								
Alliant Energy Corporation	Annualized DPS	2.13	2.33	2.50	2.64	2.75	2.85	2.97	3.08	3.20
	Annualized EPS	3.16	3.42	3.65	3.85	4.00	4.15	4.32	4.49	4.67
Ameren Corporation	Annualized DPS	2.57	2.77	2.94	3.10	3.22	3.34	3.48	3.61	3.76
	Annualized EPS	4.80	5.22	5.59	5.90	6.13	6.37	6.62	6.88	7.15
Consolidated Edison, Inc.	Annualized DPS	3.62	3.86	4.08	4.27	4.44	4.62	4.80	4.99	5.18
	Annualized EPS	5.15	5.47	5.76	6.03	6.27	6.52	6.77	7.04	7.32
Eversource Energy	Annualized DPS	3.01	3.26	3.49	3.68	3.83	3.98	4.13	4.30	4.47
	Annualized EPS	5.07	5.52	5.92	6.25	6.50	6.75	7.02	7.30	7.58
OGE Energy Corporation	Annualized DPS	2.04	2.22	2.38	2.51	2.61	2.71	2.82	2.93	3.05
	Annualized EPS	2.59	2.75	2.90	3.04	3.16	3.28	3.41	3.54	3.68
Portland General Electric Company	Annualized DPS	2.17	2.36	2.53	2.67	2.78	2.89	3.00	3.12	3.24
	Annualized EPS	3.12	3.35	3.55	3.73	3.87	4.03	4.18	4.35	4.52
Pinnacle West Capital Corporation	Annualized DPS	4.21	4.57	4.89	5.15	5.36	5.57	5.79	6.01	6.25
	Annualized EPS	6.30	6.77	7.20	7.56	7.86	8.17	8.49	8.83	9.18
WEC Energy Group	Annualized DPS	3.38	3.67	3.94	4.16	4.32	4.49	4.67	4.85	5.04
	Annualized EPS	5.03	5.46	5.83	6.15	6.39	6.64	6.90	7.17	7.46
MEAN										

B.O.Y. Cash Flows

[1]	[2]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
		2025	2026	2027	2028	2029	2030	2031	2032	2033
Company		Transition Stage								
Alliant Energy Corporation	Annualized DPS	2.33	2.50	2.64	2.75	2.85	2.97	3.08	3.20	3.33
	Annualized EPS	3.16	3.42	3.65	3.85	4.00	4.15	4.32	4.49	4.67
Ameren Corporation	Annualized DPS	2.77	2.94	3.10	3.22	3.34	3.48	3.61	3.76	3.90
	Annualized EPS	4.80	5.22	5.59	5.90	6.13	6.37	6.62	6.88	7.15
Consolidated Edison, Inc.	Annualized DPS	3.86	4.08	4.27	4.44	4.62	4.80	4.99	5.18	5.39
	Annualized EPS	5.15	5.47	5.76	6.03	6.27	6.52	6.77	7.04	7.32
Eversource Energy	Annualized DPS	3.26	3.49	3.68	3.83	3.98	4.13	4.30	4.47	4.64
	Annualized EPS	5.07	5.52	5.92	6.25	6.50	6.75	7.02	7.30	7.58
OGE Energy Corporation	Annualized DPS	2.22	2.38	2.51	2.61	2.71	2.82	2.93	3.05	3.17
	Annualized EPS	2.59	2.75	2.90	3.04	3.16	3.28	3.41	3.54	3.68
Portland General Electric Company	Annualized DPS	2.36	2.53	2.67	2.78	2.89	3.00	3.12	3.24	3.37
	Annualized EPS	3.12	3.35	3.55	3.73	3.87	4.03	4.18	4.35	4.52
Pinnacle West Capital Corporation	Annualized DPS	4.57	4.89	5.15	5.36	5.57	5.79	6.01	6.25	6.50
	Annualized EPS	6.30	6.77	7.20	7.56	7.86	8.17	8.49	8.83	9.18
WEC Energy Group	Annualized DPS	3.67	3.94	4.16	4.32	4.49	4.67	4.85	5.04	5.24
	Annualized EPS	5.03	5.46	5.83	6.15	6.39	6.64	6.90	7.17	7.46

[1]	[2]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]
		2034	2035	2036	2037	2038	2039	2040	2041
Company							Final Stage		
Alliant Energy Corporation	Annualized DPS	3.33	3.46	3.60	3.74	3.89	4.04	4.20	4.36
	Annualized EPS	4.85	5.04	5.24	5.44	5.66	5.88	6.11	6.36
Ameren Corporation	Annualized DPS	3.90	4.06	4.22	4.38	4.56	4.74	4.92	5.12
	Annualized EPS	7.44	7.73	8.03	8.35	8.68	9.02	9.38	9.75
Consolidated Edison, Inc.	Annualized DPS	5.39	5.60	5.82	6.05	6.29	6.54	6.79	7.06
	Annualized EPS	7.61	7.91	8.22	8.54	8.88	9.23	9.59	9.97
Eversource Energy	Annualized DPS	4.64	4.83	5.02	5.21	5.42	5.63	5.85	6.09
	Annualized EPS	7.88	8.19	8.52	8.85	9.20	9.56	9.94	10.33
OGE Energy Corporation	Annualized DPS	3.17	3.29	3.42	3.56	3.70	3.84	3.99	4.15
	Annualized EPS	3.83	3.98	4.14	4.30	4.47	4.64	4.83	5.02
Portland General Electric Company	Annualized DPS	3.37	3.50	3.64	3.78	3.93	4.09	4.25	4.42
	Annualized EPS	4.70	4.88	5.08	5.28	5.48	5.70	5.92	6.16
Pinnacle West Capital Corporation	Annualized DPS	6.50	6.75	7.02	7.30	7.58	7.88	8.19	8.52
	Annualized EPS	9.54	9.91	10.30	10.71	11.13	11.57	12.03	12.50
WEC Energy Group	Annualized DPS	5.24	5.45	5.66	5.88	6.12	6.36	6.61	6.87
	Annualized EPS	7.75	8.06	8.37	8.70	9.05	9.40	9.77	10.16
MEAN									

[1]	[2]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]
		2034	2035	2036	2037	2038	2039	2040	2041
Company							Final Stage		
Alliant Energy Corporation	Annualized DPS	3.46	3.60	3.74	3.89	4.04	4.20	4.36	4.54
	Annualized EPS	4.85	5.04	5.24	5.44	5.66	5.88	6.11	6.36
Ameren Corporation	Annualized DPS	4.06	4.22	4.38	4.56	4.74	4.92	5.12	5.32
	Annualized EPS	7.44	7.73	8.03	8.35	8.68	9.02	9.38	9.75
Consolidated Edison, Inc.	Annualized DPS	5.60	5.82	6.05	6.29	6.54	6.79	7.06	7.34
	Annualized EPS	7.61	7.91	8.22	8.54	8.88	9.23	9.59	9.97
Eversource Energy	Annualized DPS	4.83	5.02	5.21	5.42	5.63	5.85	6.09	6.32
	Annualized EPS	7.88	8.19	8.52	8.85	9.20	9.56	9.94	10.33
OGE Energy Corporation	Annualized DPS	3.29	3.42	3.56	3.70	3.84	3.99	4.15	4.31
	Annualized EPS	3.83	3.98	4.14	4.30	4.47	4.64	4.83	5.02
Portland General Electric Company	Annualized DPS	3.50	3.64	3.78	3.93	4.09	4.25	4.42	4.59
	Annualized EPS	4.70	4.88	5.08	5.28	5.48	5.70	5.92	6.16
Pinnacle West Capital Corporation	Annualized DPS	6.75	7.02	7.30	7.58	7.88	8.19	8.52	8.85
	Annualized EPS	9.54	9.91	10.30	10.71	11.13	11.57	12.03	12.50
WEC Energy Group	Annualized DPS	5.45	5.66	5.88	6.12	6.36	6.61	6.87	7.14
	Annualized EPS	7.75	8.06	8.37	8.70	9.05	9.40	9.77	10.16

E.O.Y. Cash Flows

[1]	[2]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]
Company		2042	2043	2044	2045	2046	2047	2048	2046 Terminal Value
Alliant Energy Corporation	Annualized DPS	4.54	4.72	4.90	5.09	5.30	5.50	5.72	184.39
	Annualized EPS	6.61	6.87	7.14	7.42	7.71	8.01	8.33	
Ameren Corporation	Annualized DPS	5.32	5.53	5.74	5.97	6.21	6.45	6.70	297.39
	Annualized EPS	10.13	10.53	10.94	11.37	11.82	12.29	12.77	
Consolidated Edison, Inc.	Annualized DPS	7.34	7.63	7.93	8.24	8.57	8.90	9.25	259.58
	Annualized EPS	10.36	10.77	11.19	11.63	12.09	12.57	13.07	
Eversource Energy	Annualized DPS	6.32	6.57	6.83	7.10	7.38	7.67	7.98	339.17
	Annualized EPS	10.74	11.16	11.60	12.06	12.53	13.03	13.54	
OGE Energy Corporation	Annualized DPS	4.31	4.48	4.66	4.84	5.04	5.23	5.44	108.31
	Annualized EPS	5.22	5.42	5.63	5.86	6.09	6.33	6.58	
Portland General Electric Company	Annualized DPS	4.59	4.77	4.96	5.16	5.36	5.57	5.79	163.78
	Annualized EPS	6.40	6.65	6.91	7.19	7.47	7.76	8.07	
Pinnacle West Capital Corporation	Annualized DPS	8.85	9.20	9.56	9.94	10.33	10.74	11.16	295.05
	Annualized EPS	12.99	13.51	14.04	14.59	15.17	15.76	16.38	
WEC Energy Group	Annualized DPS	7.14	7.42	7.71	8.02	8.33	8.66	9.00	354.44
	Annualized EPS	10.56	10.97	11.41	11.86	12.32	12.81	13.31	
MEAN									

B.O.Y. Cash Flows

[1]	[2]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]
Company		2042	2043	2044	2045	2046	2047	2048	2046 Terminal Value
Alliant Energy Corporation	Annualized DPS	4.72	4.90	5.09	5.30	5.50	5.72	5.95	184.62
	Annualized EPS	6.61	6.87	7.14	7.42	7.71	8.01	8.33	
Ameren Corporation	Annualized DPS	5.53	5.74	5.97	6.21	6.45	6.70	6.97	297.67
	Annualized EPS	10.13	10.53	10.94	11.37	11.82	12.29	12.77	
Consolidated Edison, Inc.	Annualized DPS	7.63	7.93	8.24	8.57	8.90	9.25	9.62	259.96
	Annualized EPS	10.36	10.77	11.19	11.63	12.09	12.57	13.07	
Eversource Energy	Annualized DPS	6.57	6.83	7.10	7.38	7.67	7.98	8.29	339.50
	Annualized EPS	10.74	11.16	11.60	12.06	12.53	13.03	13.54	
OGE Energy Corporation	Annualized DPS	4.48	4.66	4.84	5.04	5.23	5.44	5.65	108.53
	Annualized EPS	5.22	5.42	5.63	5.86	6.09	6.33	6.58	
Portland General Electric Company	Annualized DPS	4.77	4.96	5.16	5.36	5.57	5.79	6.02	164.02
	Annualized EPS	6.40	6.65	6.91	7.19	7.47	7.76	8.07	
Pinnacle West Capital Corporation	Annualized DPS	9.20	9.56	9.94	10.33	10.74	11.16	11.60	295.50
	Annualized EPS	12.99	13.51	14.04	14.59	15.17	15.76	16.38	
WEC Energy Group	Annualized DPS	7.42	7.71	8.02	8.33	8.66	9.00	9.36	354.81
	Annualized EPS	10.56	10.97	11.41	11.86	12.32	12.81	13.31	

[1]	[2]	[44]	[45]	[46]
		2049	2049	2050
Company			Sale	
Alliant Energy Corporation	Annualized DPS	5.95	178.44	
	Annualized EPS	8.66		9.00
Ameren Corporation	Annualized DPS	6.97	290.42	
	Annualized EPS	13.28		13.80
Consolidated Edison, Inc.	Annualized DPS	9.62	249.96	
	Annualized EPS	13.58		14.11
Eversource Energy	Annualized DPS	8.29	330.89	
	Annualized EPS	14.07		14.63
OGE Energy Corporation	Annualized DPS	5.65	102.65	
	Annualized EPS	6.83		7.10
Portland General Electric Company	Annualized DPS	6.02	157.76	
	Annualized EPS	8.39		8.72
Pinnacle West Capital Corporation	Annualized DPS	11.60	283.44	
	Annualized EPS	17.03		17.70
WEC Energy Group	Annualized DPS	9.36	345.08	
	Annualized EPS	13.84		14.38
MEAN				

[1]	[2]	[44]	[45]	[46]
		2049	2049	2050
Company			Sale	
Alliant Energy Corporation	Annualized DPS	6.18	178.44	
	Annualized EPS	8.66		9.00
Ameren Corporation	Annualized DPS	7.24	290.42	
	Annualized EPS	13.28		13.80
Consolidated Edison, Inc.	Annualized DPS	10.00	249.96	
	Annualized EPS	13.58		14.11
Eversource Energy	Annualized DPS	8.62	330.89	
	Annualized EPS	14.07		14.63
OGE Energy Corporation	Annualized DPS	5.88	102.65	
	Annualized EPS	6.83		7.10
Portland General Electric Company	Annualized DPS	6.25	157.76	
	Annualized EPS	8.39		8.72
Pinnacle West Capital Corporation	Annualized DPS	12.06	283.44	
	Annualized EPS	17.03		17.70
WEC Energy Group	Annualized DPS	9.72	345.08	
	Annualized EPS	13.84		14.38

Docket No. UE 374
Exhibit PAC/3510
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Staff Multi-Stage ROE Summary (Revised)

August 2020

Staff ROE Summary - Revised

Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale (Includes 8% Outlier Screen)										
Y	CBO	3.70%	Composite	3.94%	Historical	4.38%	PAC (Per Staff)	5.05%	PAC (as of 6/3/20)	5.56%
Staff Peer Screen	8.69%		8.72%		8.75%		9.16%		9.55%	

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted) (Includes 8% Outlier Screen)										
Y	CBO	3.70%	Composite	3.94%	Historical	4.38%	PAC (Per Staff)	5.05%	PAC (as of 6/3/20)	5.56%
Staff Peer Screen	8.83%		8.85%		8.89%		9.30%		9.69%	

Best Fit Range of Reasonable ROEs	8.85%	to	9.69%	ROE	
Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				**12.5**	**bps**
	8.98%	to	9.82%	ROE	
Staff Point ROE Recommendation:	Midpoint	9.4%	ROE	Testimony	

Docket No. UE 374
Exhibit PAC/3600
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Michael G. Wilding

August 2020

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ATTACHED EXHIBITS

Exhibit PAC/3601—Staff Data Request 80

Exhibit PAC/3602—Updated Annual Power Cost Adjustment Guidelines

Q. Are you the same Michael G. Wilding who previously submitted direct and reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to various issues and adjustments raised in the rebuttal testimony of Public Utility Commission of Oregon (Commission) Staff witness Mr. Scott Gibbens, Alliance of Western Electric Consumers (AWEC) witness Dr. Lance Kaufman, and Oregon Citizen's Utility Board (CUB) witness Mr. Bob Jenks.

Q. Please summarize your surrebuttal testimony.

A. My testimony explains that PacifiCorp is proposing the annual power cost adjustment (APCA) to have a fair opportunity to recover its prudently incurred actual net power costs (NPC). Under the current transition adjustment mechanism (TAM) and power cost adjustment mechanism (PCAM) structure, PacifiCorp is systematically under-recovering its NPC, in part due to the accumulated costs of responding to changes in renewable generation in real-time. The most efficient solution to this problem is PacifiCorp's proposed APCA. The APCA promotes innovation and supports generation resource portfolio changes, regulatory policies necessary to the successful transformation of Oregon energy supply as envisioned by Senate Bill 1547 and related laws. By providing the right incentives and retaining Commission oversight to ensure costs remain prudent, the APCA will produce just and reasonable rates for customers.

My testimony responds to arguments from parties that the existing TAM/PCAM structure provides incentives for better operation, NPC under recovery can be solved by better modeling or forecasting, or that the APCA is inconsistent with past orders. These arguments are flawed and distract from the basic points that it is just and reasonable for customers to pay the actual NPC prudently incurred to serve load, and that a true-up mechanism without deadbands, sharing bands, or an earnings test is the simplest and most efficient way to provide for the recovery of prudently incurred NPC. The proof of this is that mechanisms similar to the APCA are used by the majority of other jurisdictions in the country.

My testimony addresses two other issues: (1) I explain why it is impractical to accelerate the current workpaper timing requirements under the TAM/APCA guidelines; and (2) I rebut CUB's proposal to include wheeling revenues in a NPC forecast mechanism, explaining why this would be inappropriate based on clarifications regarding the nature and regulation of wheeling revenues.

II. REGULATORY POLICY SUPPORTING THE APCA

Q. Please explain why PacifiCorp is proposing that, through the APCA, customers pay the actual NPC prudently incurred to serve load.

A. PacifiCorp is seeking a fair opportunity to recover its prudently incurred NPC. In my reply testimony, I provided the quantification of PacifiCorp's historical under-recovery of prudently incurred NPC.[1] The quantification showed NPC being under-forecast, when adjusted for load, and thus under-recovered in 11 of 12 years. In nine

[1] PAC/2000, Wilding/55.

of the 12 years, the under-collection was greater than $15 million, in 10 of the 12 years the under-collection was greater than $12 million, and the sole over-collection occurred in 2016. Notably, while Staff[2] and CUB[3] claim that the current structure of the PCAM is necessary to incentivize the Company to prudently manage NPC, these recovery short-falls are unrelated to imprudent management. Indeed, had PacifiCorp simply forecast its NPC at or above its actual NPC, all of these under-recovered costs would have been allowed into rates.

In reviewing this systematic NPC under-recovery, PacifiCorp and its independent expert, Mr. Frank C. Graves, determined that the systematic differences between forecast and actual NPC are being caused by the variances in system balancing transactions. As discussed by Mr. Graves in his opening, reply, and surrebuttal testimony, the variance of different components of NPC are sometimes above or below the NPC forecast, but the variances related to system balancing transactions always result in an under-collection, demonstrating that this is a systematic problem and prudently incurred costs are being left out of rates.

One reason for this systematic under-recovery is the inability to capture the costs associated with the uncertainty and intermittency of renewable generation in the NPC forecast in the TAM. To rebut this, some parties have pointed to the annual variation of wind and hydro or annual capacity factors. This argument misunderstands the issue that the APCA is trying to solve. To be clear, these system

[2] Staff/2400, Gibbens/7-8.
[3] CUB/400, Jenks/25-27.

balancing costs are not caused by annual variations but by the intermittent nature[4] of the renewable generation (specifically wind and solar).[5]

Q. Can you provide an example that illustrates this point?

A. Yes. Consider the following hypothetical scenario using a wind plant with a capacity of 200 megawatts (MW). When balancing the system to serve load, PacifiCorp's Energy Supply Management (ESM) department will use the most recent information that will include a short-term forecast of the wind. When balancing the system for the next day, ESM will see the system is expecting 100 MW of wind in a certain hour and that expected wind will become part of the schedule. In real-time, that wind generation might be something different than 100 MW and ESM will need to respond to that change. Whether it is redispatching a resource with a fuel cost or making a market purchase or sale, this change has a cost. It is this cost that is not captured in the TAM forecast because the model includes a single balancing step and does not capture the uncertainty of the intermittent generation. In other words, it is not the annual variations of wind generations that are causing the systematic under-recovery, but rather the accumulated costs of responding to changes in renewable generation in real-time.

Q. Based on your experience, does a complete true-up for under- and over-recovery of NPC solve these issues?

A. Yes. A complete true-up for under- and over-recovery ensures that the Company has a fair opportunity to recover its prudently incurred NPC, and that customers get the full benefit of any over-recovery of NPC. This solution provides the most simple,

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[4] Intermittent refers to changes in the expected generation at the intra-day, hourly, and sub-hourly levels.
[5] As described further in the testimony of Mr. Graves, hydro resources have significant annual variations, but are not as intermittent on the hourly level like wind and solar.

effective and efficient approach to solving this issue; it also encourages the Company to continue to innovate and invest in resources that meet Oregon's energy policy goals.

Q. Staff, CUB, and AWEC have all opposed any changes to the current PCAM and continue to support a PCAM that essentially prohibits the recovery of any variances between the TAM and prudently incurred actual NPC. How do you respond?

A. Staff, CUB, and AWEC do not dispute that PacifiCorp is under-recovering its NPC but insist that this under-recovery is a non-issue. Generally speaking, the response to the under-recovery of prudently incurred NPC fits into one of three categories: 1) the under-recovery can be or has been fixed by modeling improvements; 2) the under-recovery can be fixed through more efficient operations; or 3) the Company is earning close to its return on equity (ROE), which provides a cushion for shareholders to absorb these costs. I will address each of these in further detail below.

Q. Can PacifiCorp's NPC under-recovery be fixed by modeling improvements?

A. No. As Mr. Graves and I have discussed, no amount of modeling improvements can solve an issue that is a function of forecasting. Additionally, given the amount of opposition the Company has faced when modeling changes have been introduced in the TAM, I have significant doubts about the practicality of attempting to solve this issue through increasingly complex modeling adjustments. Parties continue to point to the day-ahead/real-time (DA/RT) adjustment as a potential fix and I have already testified to the persistent opposition the Company has faced around the DA/RT adjustment since it was first introduced. The DA/RT adjustment has provided great value in filling the gap between the forecast and actual NPC but the fact is that a systematic under-recovery still exists.

Staff also points to certain costs that have been over-forecast in the past, including energy imbalance market (EIM) benefits and qualifying facility (QF) costs. These types of one-line comparisons do not tell the whole story. EIM benefits are based on the earned margins from transacting in the EIM and the Company has filed extensive testimony on the relationship between market prices and EIM benefits.[6] I will not rehash that testimony here other than to say when EIM benefits are looked at in isolation to the rest of the story, the impact of higher or lower market prices on NPC, is missed. The same is true when looking at total QF costs without evaluating the energy. However, both of these issues are fixed under the Company's proposal; customers will receive the actual EIM benefits and will pay only actual QF costs.

Q. Can the NPC under-recovery be fixed through more efficient operations?

A. No. Throughout the rebuttal testimony, certain statements are made that perhaps the Company could simply operate more efficiently to fix its NPC under-recovery. These statements are completely unfounded and based purely on speculation. The Company has enhanced its operations to the benefit of customers in the following ways:

- With the California Independent System Operator, PacifiCorp formed and continues to participate in the EIM with current benefits to customers at over \$250 million;[7]
- Leads the industry in its modified operation of the Company's coal fleet to reduce minimum operation levels and increase ramp rates to better incorporate

[6] *See In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, PAC/200, Mitchell/3-12 (Feb. 14, 2020).
[7] *See Id.* at 2-3.

renewable resources and low cost power alternatives through the EIM and the bilateral market;[8]

- Finds opportunities for low cost energy by monetizing the renewable energy certificates through blue sky programs (Schedule 272); and[9]

- Maximizes the optimization of the transmission system by moving power from East to West or West to East to take advantage of lower cost market alternatives or maximize wholesale sales opportunities.[10]

Additionally, the Company continues to look for innovative ways to lower NPC including continuing discussions around the potential extension of the day-ahead market.

Q. Is the Company's under-recovery a part of normal business risk, such that shareholders should absorb these costs?

A. No. This argument continues to ignore the fact that the current PCAM mechanism denies PacifiCorp recovery of prudently incurred NPC. Mr. Graves has addressed this argument further in his reply and surrebuttal testimony.

Q. If the APCA eliminates the deadbands and sharing band that currently exist, will the Company lose the incentive to control its NPC?

A. No. The deadbands and sharing bands have the illusion of causing the Company to have "skin in the game" and incentivize the Company to meet or "beat" the TAM forecast. Yet, all of the operational efficiencies that the Company achieves are consistently incorporated into the TAM, and the corresponding costs of those efficiencies (like the intermittent generation from renewables) are consistently ignored.

[8] *See In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, PAC/900, Mitchell/32-35 (June 9, 2020).
[9] I*n the Matter of PacifiCorp, dba Pacific Power, Changes to Schedule 272 Renewable Energy Rider Optional Bulk Purchase Option*, Docket No. UE 318, Order No. 17-051 (Feb. 13, 2017).
[10] *See In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, PAC/900, Mitchell/22-23 (June 9, 2020).

For the TAM to be an effective incentive, the TAM forecast would need to be the bench mark. This is simply not the case. For example, if the TAM forecast had a market purchase forecast at $25/megawatt-hour (MWh) and the prevailing market price was $30/MWh, ESM cannot shop around until they find a price to either meet or beat the TAM. ESM does not operate with the TAM forecast as a target (which would be extremely imprudent considering how quickly the TAM would become stale if used for anything other than setting NPC for ratemaking). ESM is constantly updating its forward prices, renewable forecast, and load forecast to manage NPC and come to the best outcome for customers.

Q. Do the deadbands and sharing bands in the PCAM have any unintended consequences?

A. Yes. I believe the deadbands and sharing bands create an incentive for an inaccurate forecast. This is demonstrated by the relitigation of the DA/RT adjustment over several years. Any under-forecast is beneficial to customers and harmful to the Company and any over-forecast is harmful to customers and beneficial to the Company. The APCA removes the perverse incentives for an inaccurate forecast and inappropriate outcomes.

Q. The Company's APCA would result in customers paying actual prudently incurred NPC; is that just and reasonable?

A. Yes. NPC have been under-recovered because there was a variance in the NPC forecast and the current structure of the PCAM favors under-recovery, regardless of the prudence of the costs. The APCA results in customers paying the actual prudently incurred costs to serve their load, no more and no less, holding both the Company and customers harmless.

Q. Staff contends that the setting of power costs prospectively alters the nature of the regulatory structure and makes comparisons to other states inappropriate.[11] Do you agree?

A. No, it has been my experience that most states set some sort of power cost baseline, and just like test periods in revenue requirement, these costs are set on a historical, current, or forecast basis. Oregon is not unique in setting these costs on a forecast basis. PacifiCorp's Energy Cost Adjustment Clause in California also sets these costs annually on a forecast basis. Regardless of whether there is a historical or prospective forecast, costs are trued-up to actual costs, which ensures that only those prudently incurred costs are recovered. Of the seven states cited by Staff in their testimony,[12] five have recovery mechanisms that allow for a full true-up, and one allows for a 90/10 sharing band only.[13]

III. PACIFICORP'S RESPONSE TO PARTIES

Q. Have parties raised other concerns about the structure of PacifiCorp's proposed APCA?

A. Yes, Staff, CUB, and AWEC have continued to raise specific concerns about PacifiCorp's proposed APCA. While a number of these concerns are addressed by Mr. Graves, I will address the following issues:

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[11] *See* Staff/2400, Gibbens/13.
[12] *See* Staff/2400, Gibbens/13, (In Washington, PacifiCorp uses a forecast test period for NPC, and has the ability to periodically reset forward-looking NPC through a power cost only rate case).
[13] *See* PAC/602 for a comprehensive review of NPC mechanisms across the country.

- Staff's and CUB's contention that the PCAM incentivizes operational efficiencies;
- Parties' contention that the under-recovery issue is fundamentally a modeling and forecasting problem;
- Certain specific concerns from Staff related to modeling QFs and wind capacity factors.

A. PacifiCorp's Operations and the PCAM Incentives

Q. Both Staff[14] and CUB[15] contend that the current PCAM structure creates incentives for PacifiCorp to more prudently manage its power costs. Do you agree?

A. No, PacifiCorp cannot operate its system to benefit the structure of one power cost mechanism in one state over another type of mechanism in another state. PacifiCorp must balance its system as a whole, and the only way to serve the needs of all states is to always strive to provide the lowest cost service, and aggressively control and mange power costs. As I describe earlier in this testimony, PacifiCorp has taken significant actions over the years to create operational efficiencies and lower costs for customers.

Q. Have Parties provided any specific examples or evidence of how PacifiCorp could further optimize operations?

A. No, Parties' testimony that PacifiCorp is incentivized by the structure of the current PCAM is simply pure speculation.

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[14] Staff/2400, Gibbens/7-8.
[15] CUB/400, Jenks/25-27.

Q. CUB contends that PacifiCorp's energy traders are specifically tasked to manage net power costs.[16] Is this an accurate description of PacifiCorp's traders?

A. Partially, however, CUB attempts to use the job description for one of PacifiCorp's energy traders to state that PacifiCorp is "in control" of its NPC.[17] PacifiCorp energy traders do not have *absolute* control over NPC. Instead, the nature of the trader position is to respond to changes in load and variable resource output to the benefit of customers. PacifiCorp's management of NPC primarily consists of reacting to changes in the system on a day-ahead and real-time basis. As the Company moves through time, traders attempt to create a position for the year, quarter, month, day, and hour in a manner that manages risk (term trading and regulatory approved risk policy) and serves load in the most cost effective way.

Q. Does PacifiCorp have as much control over its NPC as Staff and CUB seem to believe?

A. No, controlling NPC implies that ESM has an ability to take advantage of the market. For instance, when prices are high because loads are high, yet hydro run-off is low or wind output is low, the Company has limited ability to sell. Similarly, when prices are low, loads are low, wind is high and hydro run-off is high, the Company has excess generation and is unable to sell at a decent price. The traders the Company employs attempt to minimize NPC through economically trading or scheduling owned resources to most economically serve load given current conditions. CUB is implying that PacifiCorp can effectively beat the market with its traders and not be

[16] CUB/400, Jenks/21-22.
[17] CUB/400, Jenks/20-21.

subject to the market. PacifiCorp, as a load serving entity, is in lock-step with the forces that drive the market, e.g. a price taker, especially in the real-time balancing phase.

B. PacifiCorp's Modeling and Forecasting

Q. Staff[18] and AWEC[19] contend that PacifiCorp's modeling is the source of PacifiCorp's under-recovery. How do you respond?

A. As Mr. Graves and I have stated in both our direct and reply testimonies, there are certain system balancing costs that are not being captured in the forecast causing a systematic under-recovery. Perhaps PacifiCorp could further refine the modeling but as Mr. Graves addressed, any modeling refinements will be complex and controversial.[20] The simplest or most effective solution is a true-up to actual, prudently incurred NPC. Additionally, as I stated earlier, with the existence of the significant deadbands, sharing bands, and earnings test, parties know that any under-recovery of PacifiCorp's NPC will nearly always be shouldered by the Company. As a result, parties are incentivized to, and consistently do, propose unilateral adjustments to the NPC modeling to drive down PacifiCorp's forecast NPC.

Q. Staff states that "[t]he Company argues that it is not feasible to improve the forecasting model." Is this an accurate characterization of your testimony?

A. No, PacifiCorp simply stated that based on previous analysis the forecast errors are the result of changes between the forecast inputs and actual results.[21] This uncertainty creates costs that are not captured in a model that is fully optimized.

[18] Staff/2400, Gibbens/8-9.
[19] AWEC/500, Kaufman/28.
[20] PAC/3700, Graves/23.
[21] PAC/2000, Wilding/56.

Q. Staff depicts PacifiCorp's conversion to the AURORA model as a solution to the consistent under-forecasting of NPC. Please respond.

A. First, the Company is moving to AURORA because it can produce the necessary granularity and prices needed for allocating NPC in the future once allocation factors for generation resources are fixed and there are state-specific resource portfolios. The version of AURORA the Company is implementing is a commitment and dispatch optimization model, similar to the Generation and Regulation Initiative Decision Tool (GRID) model. Though it is true that AURORA has a few more features than GRID does, it cannot, on its own (without the user defining the input) capture the inherent uncertainty that exists in NPC. The use of these features would present more complexity and produce a de-optimized solution. I would expect these adjustments to be contentious in any regulatory proceeding.

Q. Staff contends that Idaho Power Company (Idaho Power) uses a version of AURORA without perfect foresight.[22] Do you know what the basis of that statement is?

A. According to Staff,[23] this statement is based off Staff's testimony from Idaho Power's Annual Power Cost Update which describes Idaho Power's implementation of AURORA as lacking perfect foresight.

Q. How do you respond to Staff's comparison?

A. Comparing the modeling of Idaho Power and PacifiCorp is an apples-to-oranges comparison. Based on my discussions with Idaho Power, they are using a version of AURORA that is a traditional logic model that uses a heuristic approach. PacifiCorp,

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[22] Staff/2400, Gibbens/9.
[23] *See* PAC/3601.

on the other hand, is implementing a different version of AURORA that is an optimization model. Just as Idaho Power's and PacifiCorp's systems are very different, so are each company's modeling needs and therefore, the comparisons between PacifiCorp's and Idaho Power's NPC modeling and use of AURORA are not appropriate.

C. Wind Capacity Factors

Q. Staff claims that adoption of PacifiCorp's APCA would undermine the protections adopted in the 2020 TAM stipulation regarding PacifiCorp's Energy Vision 2020 projects.[24] Do you agree?

A. No. PacifiCorp considered the 2020 TAM stipulation when proposing the APCA. In the stipulation parties agreed to drop their recommendation for a production tax credit (PTC) floor and PacifiCorp agreed to use certain "wind capacity factors for its owned wind facilities in its TAM forecasts".[25] The stipulation continues "[t]he Stipulating Parties expressly agree not to propose any changes to wind capacity factors until 2024, in the 2025 TAM or other annual NPC filing which uses a 2025 test year."[26] The Company's proposal for PTCs not to be subject to the APCA true-up before calendar year 2025 is consistent with the spirit of that settlement which reflected the agreement among the parties to drop the PTC floor. In other words, under the Company's proposal customers will receive the PTC benefits forecast in the TAM just as they would have under the 2020 TAM stipulation.

[24] Staff/2400, Gibbens/16 (Staff mistakenly refers to the 2019 TAM in their testimony. While filed in 2019, it is actually the 2020 TAM).
[25] *In the Matter of PacifiCorp d/b/a Pacific Power 2020 Transition Adjustment Mechanism*, Docket No. UE 356, Order No. 19-351 at Appendix A, ¶18 (Oct. 30, 2019).
[26] *Id.*

Q. Did the Commission find that the 2020 TAM stipulation satisfied the standard set in the 2017 Integrated Resource Plan (IRP)?

A. Yes. The Commission stated the following in Order No. 19-351:

> We find the amount of PTCs to be calculated pursuant to the stipulation meets the standard we set in in the 2017 IRP order, with a level of benefits consistent with projections. We recognize the significant NPC savings from the repowered wind and anticipated new wind projects. In this proceeding we see a doubling of PTCs, which act as a credit to NPC and directly reduce customer rates. In addition, there is a gradual reduction to NPC as additional zero-fuel cost energy comes online.[27]

Q. Do you agree with Staff's characterization of the 2020 TAM stipulation and the 2017 IRP order that the Company is required to adjust actual NPC to reflect owned wind generation at certain capacity factors?

A. No. This is a startling interpretation of the Commission's 2020 TAM and 2017 IRP orders. As emphasized in earlier testimony from myself[28] and Mr. Graves,[29] the systematic under-recovery of NPC is not caused by the variance between the actual and forecast annual wind capacity factors. Additionally, the NPC benefit of company-owned wind generation is from the zero-fuel cost energy provided to the system. The dollar amount of that benefit is relative to the actual NPC and is determined by multiple variables that make up actual NPC, including market prices, resource availability, weather, and load.

[27] Order No. 19-351 at 6.
[28] PAC/2000, Wilding/69.
[29] PAC/3000, Graves/28-30.

D. Qualify Facility adjustment

Q. Staff contends that renewable Qualifying Facilities (QFs) have no direct impact on "the Company's power cost under-recovery issue."[30] Do you agree with this assessment?

A. No, I do not agree with Staff's contention. Renewable QFs are intermittent generation and contribute to the costs of uncertainty not captured in the TAM. These QFs share the same variable characteristics as owned renewable resources and have similar impacts to the TAM forecast. The Company is obligated to take renewable QFs' generation which reduces the flexibility the Company has when operating the system on an hourly basis. Similar to owned-renewable generation, the Company incurs system balancing costs due to the intermittent nature of renewable QFs or the sudden changes from the expected generation during, intra-day, hourly or sub-hourly balancing phases.

Q. Staff states that a "QF adjustment mechanism" has been implemented for all electric utilities. Does PacifiCorp have a "QF adjustment mechanism"?

A. It is unclear to me what exactly Staff is referring to. PacifiCorp has implemented a contract delay rate for QFs in the TAM. However, PacifiCorp does not have a specific adjustment or mechanism that attempts to rectify the over- or under-estimation of output from QF facilities.

[30] Staff/2400, Gibbens/17.

E. Staff's Alternatives to the APCA

Q. Staff identifies certain "alternative steps" available to the Commission in lieu of adopting PacifiCorp's proposed APCA.[31] How do you respond?

A. The proposed APCA is the simplest, most effective, and efficient way to address the issue that has been identified and would result in rates that are just and reasonable. Staff suggests certain incremental changes to the PCAM including changes to the deadbands and earnings test. If the Commission opts to retain the deadbands, they should be symmetrical, and a deadband set between $5 million and $10 million would have resulted in an adjustment (not including the earnings test) in five of the last seven years, the same result as Staff's approach.[32] If the Commission opts to retain the earnings test it should be set at the authorized ROE, meaning that recovery (or refund) in the PCAM would be limited to any amount that brings the Company to its authorized ROE. This approach would have resulted in an adjustment in four of the last seven years, or the same result as Staff's 25 basis point earnings test.[33]

IV. APCA GUIDELINES

Q. AWEC previously raised certain concerns about the edits in the APCA guidelines. Has AWEC's recommendation been revised?

A. Yes. In AWEC's rebuttal testimony, the only change that AWEC now continues to recommend is to provide all workpapers concurrently with the filing of the TAM.[34]

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[31] Staff/2400, Gibbens/30-34.
[32] Staff/2400, Gibbens/31.
[33] Staff/2400, Gibbens/32.
[34] AWEC/500, Kaufman/42-43.

Q. AWEC proposes that PacifiCorp should be required to file all workpapers for the NPC forecast concurrently with the initial filing.[35] How do you respond?

A. Providing all the workpapers for the NPC forecast concurrently with the initial filing will be overly burdensome and difficult to manage under the tight timeline. Under the current TAM Guidelines, the Company provides all workpapers in three different submissions; concurrent with the filing date, five days after filing, and 15 days after filing. Below, I will explain which workpapers have been provided in each submission, and why the current filing schedule is reasonable. I also explain that the existing schedule is appropriate because it provides parties sufficient information to review at the time of filing and does not overwhelm the Company. Using the 2021 TAM as an example, the Company provided the following workpapers in the first workpaper submission concurrent with the filing:

1. Direct Testimony Support (in Excel format), is a file which provides the detailed calculations supporting all numbers, tables and figures used in the direct testimony. In the 2021 TAM, this file has thirteen tabs and requires close review and analysis after all numbers are prepared in the direct testimony.
2. Step-log NPC studies and GRID scenarios associated with these studies. The step-log NPC studies depend on the baseline NPC study and can only be created after the baseline NPC study is finished. In the 2021 TAM, the Company provided six NPC studies and the associated GRID scenarios in support of the step-log (that was requested by parties in previous TAMs).

[35] AWEC/100, Mullins/41.

3. One-off NPC studies and GRID scenarios associated with these studies. The one-off NPC studies are sensitivity analyses the Company uses to evaluate the NPC impact from a change to the baseline NPC. This file also depends on the baseline NPC study and can only be created meaningfully once the baseline NPC study is completed.

In this most recent TAM, the Company has provided 12 Excel spreadsheet format workpapers and one GRID project concurrently with the filing. All the files require substantial review and evaluation before distribution to parties. Most of the files depend on the completion of the baseline NPC. Additionally, GRID projects are uploaded to each party's GRID server, which requires a substantial amount of coordination between the Company's NPC regulatory group and the Information Technology group. Uploading a GRID project to the GRID server interrupts the functionality of the GRID server. In order to create minimal interruption to parties' GRID server, the Company usually starts the uploading of GRID project on the day of the filing.

The concurrent workpaper submission involves a substantial amount of work and it will be impracticable for the Company to provide more than what is currently required per the TAM guidelines. PacifiCorp does not expect the amount of workpapers to change significantly with the switch to AURORA.

Q. What does the Company provide in the five-day and 15-day workpaper submission?

A. According to the TAM guidelines, the Company needs to provide GRID model data inputs, such as demand, outages, heat rate, energy charge and other costs, within five days of the filing. All other data inputs such as market cap, topology, forward price curve, and short-term firm transactions are submitted no later than 15 days after the filing. However, in the current and past TAMs, the Company has provided all the GRID model data inputs in five-day workpaper submission. Only four NPC sample calculations for Schedule 294, one description about thermal and hydro unit maximum capacities, minimum up or down times or unit minimum capacities changes since the last filing, and the short-term firm transactions are provided in the 15-day workpaper.

Q. Do you agree with the claim from AWEC that "allowing the Company an additional 15 days to file a substantial portion of its workpapers compresses an already expedited process…"?

A. No, this is not true. As explained above, the Company provides all the GRID model data input in the five-day workpaper submission. More importantly, the GRID project which the Company provides concurrently with the initial filing includes all the main data inputs used in the GRID model to support the current filing. The data are either in .csv format or embedded in the GRID model setting. The files the Company provides in the five-day submission are those .csv format GRID data inputs in Excel format, plus additional supporting calculations. The current workpaper submission schedule does not prohibit the parties from viewing any major data inputs used in the GRID model concurrently with the initial filing. The current workpaper submission schedule supports efficient regulatory review as well as allows the Company to meet the workpaper delivery timeline in a reasonable manner.

Q. Does PacifiCorp recommend that the Commission reject AWEC's recommendation that all workpapers be filed concurrently with the initial filing?

A. Yes.

Q. Are you providing a revised set of APCA Guidelines along with your testimony?

A. Yes, the revised guidelines (included as Exhibit PAC/3602) reflects two changes from the proposed guidelines incorporated into my direct testimony. Both of these changes were discussed in my reply testimony: the first is to correct an error associated with language around the rate design for Schedule 200;[36] the second is to reflect the Calpine Solutions, LLC's proposed change to the APCA guideline, in which the Company agrees to provide a sample calculation of Schedule 296 as applicable to customers currently served under rate Schedules 30-secondary and 48-primary.[37]

V. WHEELING REVENUES

Q. CUB contends that wheeling revenues should be included in the TAM. Do you agree that this is appropriate?

A. No, adding wheeling revenues to the TAM is not appropriate.

Q. CUB compares Wheeling Revenues to bilateral and EIM sales.[38] How do you respond?

A. Wheeling revenues are a result of the capital investment in the transmission assets, and are not based on wholesale transmission sales volumes like CUB is implying. If the Company receives too much revenue, it is required to return it to transmission customers through lower transmission rates.

[36] PAC/2000, Wilding/80.
[37] PAC/2000, Wilding/82-83.
[38] CUB/400, Jenks/28.

Q. Do you agree that there could be significant variability in wheeling revenues as a result of the greater "regionalization of markets"?

A. No, greater participation in markets, like the EIM, has led to a shift away from the need to purchase non-firm transmission to facilitate a short-term bilateral sale, which has resulted in a lower volume of wheeling transactions, and more stable wheeling revenues from firm customers.

Q. CUB further states that "[t]he transmission that is available to be sold to third parties is what is available after dispatch of PacifiCorp's system."[39] Is that an accurate statement?

A. It is not true that wheeling revenues are related to sales after system dispatch. Under PacifiCorp's Open Access Transmission Tariff (OATT), PacifiCorp provides network transmission service (to serve load located on or connected to PacifiCorp's transmission system), firm point-to-point service, and non-firm point-to-point service. Firm service is guaranteed service absent system conditions that result in curtailments to both network and firm point-to-point transmission customers. Only non-firm point-to-point service is subject to availability. Third-party firm and network customers have the same rights and access to PacifiCorp's transmission system as PacifiCorp does, and credits from non-firm point-to-point transmission sales offset the annual transmission revenue requirement charged to transmission customers.

Q. CUB has requested that PacifiCorp make the change to wheeling revenues in the TAM guidelines. How do you respond?

A. For the reasons stated above, PacifiCorp continues to oppose the inclusion of wheeling revenues in any NPC forecast.

[39] CUB/400, Jenks/28-29.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/3601
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Michael G. Wilding

Staff Data Request 80

August 2020

Issued: July 29, 2020 – Response Due By: **August 7, 2020**

TO:
DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 2000
PORTLAND, OR 97232
datarequest@pacificorp.com

FROM: Scott Gibbens
Senior Economist

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 374- PacifiCorp Data Request filed July 31, 2020

PAC Data Request No 80:

80. Please reference Exhibit Staff/2400, Gibbens/9:22-24. Please identify the source of Staff's statement that Idaho Power uses "a version of AURORA which does not have perfect foresight." Please provide any support, documentation, or evidence which Staff is relying on to make that statement.

OPUC Response No 80:

80. Staff's understanding of Idaho Power's AURORA model is based on conversations with Idaho Power in the context of Idaho Power's Annual Power Cost Update (APCU) in which Idaho Power utilizes AURORA to forecast its annual power costs (a similar filing to PacifiCorp's TAM). The most recent APCU (UE 366), included an issue where the Boardman Coal plant was modeled to shutdown in October as opposed to the end of the year. This change from a December to October shutdown resulted in a reduction to net power costs as modeled in AURORA, when the assumed impact would have been an increase to power costs. The Company explained that the decrease was the result of AURORA's lack of perfect foresight, where the model dispatched the plant during times where it was economic to run, only to have it become uneconomic to dispatch over the course of the entire minimum run-time. Please see UE 366, Staff/200, Soldavini/10-11 for further discussion of this example.

Docket No. UE 374
Exhibit PAC/3602
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Michael G. Wilding

Updated Annual Power Cost Adjustment Guidelines

August 2020

PACIFICORP
OREGON ANNUAL POWER COST ADJUSTMENT (APCA)
General Guidelines

PacifiCorp's Annual Power Cost Adjustment (APCA) is an annual filing with the objective to update the forecast net power costs (NPC) to account for changes in market conditions, with the final forecast update close to the direct access window to capture costs associated with direct access, and to correctly identify the proper amount for the transition adjustment. Additionally, the APCA includes a true-up of actual NPC from the previous year to the forecast NPC of that year.

When filed on a stand-alone basis, the APCA is intended to be narrower and more streamlined than when the APCA is filed in or processed concurrently with a general rate case. In any case, parties to the APCA proceeding should have a full opportunity to review, challenge and litigate issues raised in the case. Parties may address the issue of whether a particular APCA proceeding should have three rounds of testimony or five at the prehearing conference.

Issues related to the prudence of contracts, the appropriate modeling of contracts and known and measurable changes to inputs for existing methodologies are within the proper scope of a stand-alone APCA proceeding. Nothing in these guidelines prevents any Party, including the Company, from advocating in a future general rate case or other proceeding other than a stand-alone APCA, that the APCA should be eliminated or revised.

A. NPC

NPC includes the amounts booked to the following Federal Energy Regulatory Commission (FERC) accounts:

FERC Account	Description
Account 447	Sales for resale, excluding revenues that are not modeled in the NPC forecast
Account 501	Fuel, steam generation; excluding costs that are not modeled in the NPC forecast
Account 503	Steam from other sources
Account 547	Fuel, other generation
Account 555	Purchased power, excluding the Bonneville Power Administration (BPA) residential exchange credit pass-through if applicable

Account 565	Transmission of electricity by others.

B. Initial Filing – Forecast NPC

Each year, on May 15, the Company will make an Initial Filing to recover any variance between the forecast and actual NPC for the previous calendar year, forecast NPC for the following calendar year, and set direct access transition adjustments for the following calendar year. In any future APCA filings after UE 374, the Initial Filing will be consistent with the following provisions:

1. At least 30 days prior to the Initial Filing, the Company will provide a pre-filing notice of substantial changes to the methodologies used to forecast NPC. The Company will include in its APCA filing a justification for each substantial change in forecast methodology, calculation of cost elements, or other major data input changes. For each change, where practical, the Company will also provide workpapers that contain a side-by-side comparison of NPC forecast model results with and without the proposed change.

2. The Company will include in the NPC forecast the variable costs and dispatch benefits of new resources that are not eligible for inclusion in the Renewable Adjustment Clause in its NPC in stand-alone APCA proceedings, irrespective of whether the fixed capital costs of the new resource are already included in rates, if: (a) the Company acquired the resource prior to May 15th of the year of the stand-alone APCA filing, or (b) the Company built the resource and it was used and useful prior to May 15th of the year of the stand-alone APCA filing.

3. The prudence of the decision to build or acquire the resource may be determined in the stand-alone APCA proceeding prior to including the variable costs and dispatch benefits in rates. The Company will provide notice to the parties if a new resource subject to this section will be included in the APCA filing by April 15th of the year of the stand-alone APCA filing.

4. The Initial Filing will include updates to all of the NPC components identified in Section A. These costs will be based on the Company's most recent official forward price curve, forecast load and allocation factors. In a stand-alone APCA filing, the Company will also update other revenues that are tracked in FERC Account 456 - Other Electric Revenue. When an APCA is filed in or processed concurrently with a general rate case, this element may be included in the APCA or the general rate case. Additionally, the APCA forecast will include production tax credits (PTC).

5. In the Initial Filing the Company will identify and provide adequate support for all known contracts it expects to be updated or added in the Rebuttal and Final updates. The Company may update or add a contract not identified in the Initial Filing if the Company demonstrates that it has followed the notification procedures in Section

A4 of these guidelines and: (1) the new contract or contract update is based upon new information of which the Company reasonably became aware after the NPC study for the Initial Filing was completed; or (2) the omission resulted from a mistake that occurred despite the Company's reasonable diligence in meeting its obligations under this Section. The Company will also identify any contracts modeled in the test period under which the Company has made a liquidated damages claim.

6. In the Initial Filing, the Company will reflect forecast changes in Other Revenue for items that have a direct relation to NPC, for which a revenue baseline has been established in rates in Docket UE 375 or subsequent rate case.

7. In any APCA proceeding, the Company has a continuing obligation to provide notice of any correction or omission promptly after the discovery of the error or new information. In addition, the Company will file a summary of all identified corrections or omissions to the components included in the Initial Filing 15 business days before Staff and Intervenor Direct Testimony is due.

8. The Company will provide access to the NPC model to Parties when it makes its Initial Filing, provided that the Party has entered into a confidentiality agreement with the Company or is subject to a protective order applicable to the relevant APCA or general rate proceeding. The Parties preserve their right to challenge the confidential designation of any documents or data.

9. The Company will provide workpapers and other supporting documents as specified in Attachment A.

10. The Parties agree to ask the Commission to make the protective order for the next APCA an ongoing protective order which will continue to be effective in future APCA proceedings.

11. The Company's Initial Filing will include direct testimony covering any unusual expenses incurred over the course of the previous calendar year and identify and discuss any large deviations of actual NPC from forecasted NPC. The Company will also provide with its workpapers a differential worksheet the produces actual minus base power costs for each separate cost category in the recovery of the previous year's NPC on a gross costs and per megawatt-hour (MWh) unit basis.

12. These Guidelines do not limit the ability of other Parties to propose updates consistent with these Guidelines after the Company's Initial Filing.

C. Rebuttal Update Filing – Forecast NPC

At the time the Company makes its Rebuttal Update Filing, it will include an update to forecast NPC consistent with the following provisions:

1. The Company will update the following NPC components, subject to the Guidelines:

    a. Most recent official forward price curve.

    b. New power, fuel and transportation/transmission contracts, both physical and financial, and updates to existing contracts. These contracts include:

        i. wholesale electric sales and purchase contracts that are for long term firm sales and purchases, short term firm sales and purchases, or exchanges and storage with and without energy or capacity prices;

        ii. coal and natural gas sales, purchases and transportation contracts;

        iii. wheeling contracts; and

        iv. coal contracts for mines directly or indirectly owned by the Company.

    These transactions may have fixed prices or prices linked to market indexes. They may require physical deliveries or be settled financially *(e.g.,* swaps). Contracts must be independent and verifiable.

2. In its Rebuttal Update filing, the Company may make corrections to or address omissions in the components included in the Initial Filing. The Company may make corrections or address omissions in the components included in the Rebuttal Update filing within five business days of the date of filing of the Rebuttal Update. The Company agrees to provide notice of any impending correction promptly after the discovery of the error and agrees to correct all errors and omissions within five business days of the initial Rebuttal Update filing.

3. Parties reserve all of their procedural rights, including the right to submit data requests and seek postponement of the hearing, related to the correction of the Rebuttal Update filing.

4. The Company will provide workpapers and the other supporting documents as specified in Attachment A.

D. Final Updates – Forecast NPC

The Company will file Final Updates to forecast NPC and calculate transition adjustments as follows, subject to the Guidelines:

1. At least five business days prior to the direct access window, the Company will:

    a. File an update to forecast NPC, incorporating the following:

i. Commission-ordered adjustments;

ii. Forward Price Curve from within nine days of the filing date;

iii. New contracts, or updates to existing contracts. These contracts include: (a) wholesale electric sales and purchase contracts that are for long term firm sales and purchases, short term firm sales and purchases, or exchanges and storage with and without energy or capacity prices; and (b) natural gas sales and purchase contracts. These transactions may have fixed prices or prices linked to market indexes. They may require physical deliveries or be settled financially (e.g., swaps);

b. Post indicative transition adjustments for Schedules 294 and 295;

c. Provide indicative supply service NPC rates (to be Schedule 201); and

d. Provide an attestation that will confirm that all contracts executed prior to the contract lockdown date have been included in the indicative filing and will identify any exceptions and the reason why such contracts were excluded. The attestation will also include a statement confirming that, for the executed power purchase agreements with new qualifying facilities (QFs) included in the TAM, PacifiCorp has a commercially reasonable good faith belief that these QFs will reach commercial operation during the rate effective period based on the information known to the Company as of the contract lockdown date. This attestation does not require the Company to opine on the commercial viability of any QF.

2. On November 15, in accordance with OAR 860-038-0275(1),the Company will:

a. File an update to NPC incorporating the forward price curve from within seven days of the filing date.

b. Post final transition adjustments for Schedules 294 and 295.

i. Transition Adjustments in Schedules 294 and 295 will be calculated based on the Final Update and consistent with the modification to the calculation described in Section 15 of the Stipulation adopted by the Commission in Order 08-543 in Docket UE-199 and modified so that any remaining monthly thermal generation that is backed down for assumed direct access load will be priced at the simple monthly average of the California-Oregon Border (COB) price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by GRID. The monthly COB and Mid-Columbia prices will be applied to the heavy load hours or light load hours separately. The existing balancing account mechanisms will remain in effect.

~~ii. Schedule 200 Supply Service rate design will be non-bypassable to direct access customers and will not be subtracted in the calculation of the Transition Adjustment. In addition, the Schedule 201 rate design as proposed by the Company will be allowed to go into effect and will be bypassable to direct access customers. The rate design for proposed Schedule 200 applicable to delivery service Schedules 30, 47, and 48 will be changed from its present energy only cents per kilowatt-hour (kWh) rate design to a two-part rate design which includes a demand charge equal to $1.00 per billing kilowatt (as defined in the respective tariffs) plus a cents per kWh energy charge.~~

c. Provide supply service NPC rates (to be Schedule 201)

3. The Company will provide workpapers and other supporting documents for both the indicative and final filings as specified in Attachment A.

4. If a Party objects to any aspect of the Final Update, the Party reserves all of its procedural rights to seek review of the controverted issue.

5. The Parties agree to meet and review whether to recommend to the Commission an extension in length for the election window for PacifiCorp's multi-year direct access option beginning in November 2009.

E. Actual NPC True-Up

The ACPA true-up is calculated on a monthly basis. Actual APCA costs are compared to base APCA cost on a per-unit basis. APCA costs are established in the APCA forecast and include NPC, Other Revenues, and PTCs. Any differences in the system per-unit cost are multiplied by the actual megawatt hours of Oregon retail sales in that month to determine Oregon's share of any differential. The calculation uses the following formula:

$$(APCAC_a \div Load_a) - (APCAC_b \div Load_b) = \text{System APCA Unit Cost Differential}$$

$$\text{System APCA Unit Cost Differential} \times Load_o + (SR_a - SR_b) = \text{APCA Differential}$$

Where:

$APCAC_a$	= Total Company Adjusted Actual NPC (Excluding Situs Resources) plus other costs/benefits reflected in Oregon APCA Forecast
$Load_a$	= Actual System Retail Load
$APCAC_b$	= Total Company Base NPC (Excluding Situs Resources) adjusted for Direct Access plus other costs/benefits reflected in Oregon Forecast
$Load_b$	= Base System Retail Load

$Load_o$ = Actual Oregon Retail Load
SR_a = Actual Situs Resource Value
SR_b = Forecasted Situs Resource Value

F. Rate Design

1. In the Company's current general rate case, proposed NPC are unbundled from other generation costs. All NPC will be collected through a new Schedule 201, Annual Power Cost Adjustment, which will be applied as a rider to Schedule 200. Schedule 200 will continue to collect other generation costs.

2. In any future APCA filed in or processed concurrently with a general rate case after UE 207, the APCA rate design test year will be the general rate case rate design test year. In a stand-alone APCA, the APCA rate design test year will be the forecast test year during which the Schedule 201 rates will be effective.

3. In any future APCA filed in or processed concurrently with a general rate case after UE 374, proposed Schedule 201 revenues by rate schedule will be determined by spreading the total forecast NPC for the test year to the rate schedules in the same manner as the revenues for Schedule 200 are spread to the rate schedules: based on the functionalized revenue requirement as determined by the Commission based upon a Cost of Service study, or by the method proscribed by the Commission in the most recent general rate case or Commission proceeding regarding rate spread and rate design.

   In any future stand-alone APCA, Proposed Schedule 201 revenues by rate schedule will be determined by spreading the total forecast NPC for the test year to the rate schedules based upon each schedule's proportion of "Present Schedule 201 revenues." "Present Schedule 201 revenues" for the test year shall reflect the projected test year sales forecasts. Proposed Schedule 201 rate design shall reflect the method prescribed by the Commission in the most recent general rate case or other Commission proceeding regarding rate spread and rate design.

G. APCA Filings Made in or Processed Concurrently with a General Rate Case

1. If the Company files a general rate case prior to May 15 in a given year, then the Company may file the APCA before May 15. If the Company chooses not to file a APCA prior to May 15, then it must file on May 15. If the APCA is filed on a stand-alone basis, it will be filed no later than May 15. In order to accommodate the direct access window that begins November 15, the APCA may be bifurcated from the full rate case in order to allow for a Commission decision by November 1. Bifurcation of the APCA does not alter any provision below.

2. When an APCA is filed in or processed concurrently with a general rate case, the Company or any Party may propose changes to how the Company's Rate Mitigation Adjustment or other rate spread tools should operate in a stand-alone APCA filing made before the APCA is again filed in or processed concurrently with a general rate case.

3. When an APCA is filed in or processed concurrently with a general rate case, the APCA will be subject to rebuttal and final updates identifies above and the agreements on workpapers and other supporting documents specific in Attachment A.

H. Other Provisions

1. These guidelines do not limit the ability of the Company or other Parties to propose changes to these guidelines, including changes to the cost elements that will comprise NPC in stand-alone APCA proceedings or in future general rate cases.

Attachment A
APCA Workpapers and Supporting Documents

Workpapers are defined in OAR 860-001-0480(5) as “documents that show the source, calculations, and details supporting the testimony and other exhibits submitted.” In an APCA proceeding, the term “workpapers” means the documents used to develop the final inputs to GRID and the final modeling in GRID. The data relied upon to support the cost details in the filing may include contracts, emails, white papers, studies, PacifiCorp computer programs, Excel spreadsheets, Word documents or pdf, and text files.

If the Commission adopts new minimum filing requirements, rules or guidelines for net power cost filings, these will replace the requirements set forth in this document. Additionally, if the APCA is eliminated, the APCA Design Guidelines to which this document is attached are materially changed, or the Parties otherwise agree, the requirements set forth in this document will cease to be operative. In cases where systems change or are replaced in the future, PacifiCorp will continue to provide substantially the same information as provided in data request responses in PacifiCorp’s 2009 TAM (UE 199), the relevant citations to which are listed below, as long as these filing requirements remain operative.

The Parties agree to continue the current practice of providing all discovery response answers, workpapers, including any other documents produced pursuant to this agreement via email (for non-confidential documents) and overnight mail. The GRID model and its inputs, however, will be produced on the day of the filing electronically to the Parties in accordance with the terms of the stipulation in docket UE 199.

Parties will expeditiously work to rectify any workpaper deficiencies without requiring other Parties to submit follow-up data requests.

In cases where the Company has relied upon documents or workpapers it considers to be “highly confidential” it will notify the Parties of such, and, if the amount of data considered highly confidential is limited, it will redact the highly confidential data or otherwise modify the non-confidential workpapers to prevent disclosure of highly confidential material. If the Company has withheld any information on the grounds that the information is “highly confidential,” the Company will request a “highly confidential” protective order or other special handling measures within five days of providing the non-highly confidential material.

A. Initial Filing by Company

For the Initial Filing, PacifiCorp will provide workpapers and supporting documents as described below. All information will be provided electronically and, in the case of Excel spreadsheets, with all cells and formulas intact.

1. Concurrent with the filing:

    a) Workpapers that show the source, calculations and details supporting the testimony and other exhibits. The workpapers will include, at a minimum, copies of the net power cost report in Excel and the net power cost model database. Access to the power cost model will also be provided.

b) Identification of the Four Year Period used to determine outage rates and other input items in the net power cost model.
c) Compilations of actual net power costs produced by PacifiCorp that were referenced in the testimony or exhibits, to the extent that actual power cost results are discussed or cited in the Company's direct testimony or exhibits. *See, e.g.,* ICNU 1.5-1 in UE 199.
d) A list and explanation of all modeling or logic changes or enhancements to the net power cost model that have been implemented since the most recent Oregon APCA or general rate case. This will include a statement of the direction and amount of change in net power costs resulting from each such change and documentation describing each change as well as net power cost model runs and workpapers quantifying the impacts of these changes.

2. Within five business days after the Initial Filing, the Company will deliver to the Parties:

   a) Workpapers showing the computation of the outage rates (planned and unplanned) used in the power cost model. Include all backup data showing each outage (planned or unplanned, etc.) and duration (planned or unplanned) considered in the four-year period, including NERC cause code, type of event, duration, energy lost, etc. *See, e.g.,* ICNU 1.6-1 and 1.6-2 in UE 199.
   b) The heat rate curves for each resource and the spreadsheets showing the derivation of the heat rate curves. *See, e.g.,* ICNU 1.22 in UE 199.
   c) Workpapers and documentation supporting the inputs contained in the "Other Cost" file as of UE 199, used in the power cost model, including all electronic spreadsheets used to compute any of the line items in the file. This includes test year: wheeling expenses modeled in GRID. *See, e.g.,* ICNU 1.28 in UE 199.
   d) Workpapers and documentation supporting the "Energy Cost" file used in the power cost model, including all electronic spreadsheets used to compute any of the line items in the file. *See, e.g.,* ICNU 1.29 in UE 199.
   e) Workpapers and documentation supporting the "Demand" file used in the power cost model including all electronic spreadsheets used to compute any of the line items in the file. *See, e.g.,* ICNU 1.31 in UE199.

3. As soon as practical after filing, delivered on an as-ready basis, but no later than 15 days after the Initial Filing, the Company will deliver to the Parties:

   a) All documents, workpapers or other information relied upon by the Company in determining the market caps used in the power cost model for the Pro-Forma Period. See, e.g., ICNU 1.2 in UE 199.

b) The current topology maps in the power cost model along with an explanation for all the differences that have been made to the topology since the last APCA or general rate case and an explanation of why the changes were made. Include supporting documentation, such as contracts resulting in changes to the transfer capabilities used in GRID. *See, e.g.,* ICNU 1.3 and 1.68 in UE 199.

c) The date and a copy of the forward price curve, showing monthly heavy load hour and light load hour forward prices, used in creating the Test Year power cost model studies.

d) Documents showing all short-term firm transactions (including short-term firm indexed transactions and swaps) modeled in the test year power cost study, *see, e.g.,* ICNU 1.11, and as long as the Commission retains an adjustment for wholesale trading margin, the backup for the calculation of the trading margin, *see, e.g.* 1.13 and ICNU Supplemental 18.24 in UE 199. In addition, each contract will have a designation as to its purpose (i.e., trading, arbitrage or balancing.)

e) For all power, fuel and transmission related contracts modeled in GRID that were not included in the most recent Oregon APCA or general rate case:
   1. A copy of the contract (in pdf or electronic format, if available).
   2. Any workpapers or other documents used to develop the power cost model input assumptions related to the contract.

f) Regulatory Fuel Budget filing used for the test year and any other workpapers used in developing the power cost model fuel cost inputs.

g) Workpapers and documentation supporting the "Demand Cost" file used in the power cost model, including all electronic spreadsheets used to compute any of the line items in the file. *See, e.g.,* ICNU 1.30 in UE 199.

h) Identification of each instance in which the Company changed any maximum capacities, minimum up or down times or unit minimum capacities for thermal or hydro generators modeled in the power cost model since the last Oregon APCA or general rate case, if applicable.

i) Workpapers explaining the development of each line of load adjustments presented on the Company's power cost model output reports. *See, e.g.,* ICNU 1.53 in UE 199. These include but are not limited to:
   1. DSM (irrigation)
   2. MagCorp Curtailment
   3. Monsanto Curtailment
   4. Station Service

j) Workpapers used to develop inputs for qualifying facility contracts modeled in GRID. *See, e.g.,* ICNU 1.33b in UE 199.

k) A 40-year hydro data set suitable for input into the GRID model applicable to the test year so long as the Company has been required by regulators in proceedings in other states to produce this material, and the Company proposes to change its hydro modeling from the single (Median hydro) scenario filed in the initial filing in UE 207.

l) Data necessary to calculate forced outages using hourly forced outage shaping as adopted by the Commission in Order 15-394.

m) Sample calculations of the transition adjustments for Schedule 30 Secondary and Schedule 48 Primary in Schedule 294, with all supporting documentation.

n) Workpapers for any screens applied to prevent uneconomic commitment and dispatch of resources in the GRID model.

o) Supporting transaction level detail for compilations of actual power costs produced by PacifiCorp that were referenced in the testimony or exhibits, to the extent that actual power costs results are discussed or cited in the Company's direct testimony or exhibits. *See, e.g.* ICNU 1.5-2 in UE 199.

p) Workpapers and all supporting documents underlying the start-up fuel and start-up operations and maintenance costs included in GRID.

4. Within 30 days of the initial filing, the Company will deliver to the Parties:

~~m)~~a) A sample calculation of Schedule 296 as applicable to customers currently served under rate schedules 30 and 48 (Primary).

B. Response Filing (or Surrebuttal Filing, if applicable) by Staff and Intervenors

Parties filing testimony in response to the Company's Initial Filing (or Rebuttal Filing, if applicable), will provide workpapers and supporting documents as described below.

1. Concurrent with the filing:

a) Workpapers that show the source, calculations and details supporting the testimony and other exhibits. The workpapers will show on an adjustment-by-adjustment basis, the power cost model input file or files used, the back-up to the input files, and the power cost model study reports or documents showing the impact of the adjustment on net power costs as compared to the comparison scenario. The associated power cost model input files will be provided as well.

C. Rebuttal Update Filing (and Sursurrebuttal Filing, if applicable) and Final Updates by Company

For the Rebuttal Update Filing and Final Updates, PacifiCorp will provide workpapers and supporting documents as described below.

1. Concurrent with the filing:

a) Workpapers that show the source, calculations and details supporting the testimony and other exhibits. The workpapers will include the net power costs report on an adjustment-by-adjustment basis. The workpapers will include, at a minimum, electronic copies of the net power cost report and the net power cost model.

b) For any update, adjustment or correction to the power cost model, the Company will include a description of the change and a calculation of the adjustment amount.

2. As soon as practical after filing, but no later than three days after the filing:

   a) To the extent that any of the items in Section A above change, new versions of the supporting documentation and workpapers will be provided.

   Access to the updated runs in power cost model via the designated internet access or power cost model input files containing all inputs and output reports associated with the update filings.

D. Other Items

1. The Company will provide information on new contracts or updates to contracts that are executed after the Rebuttal Filing and will be included in the Final Updates as soon as practical after execution. The Company will track the contracts and produce them in groups as their total number or value become material.

2. The Company will provide broker quotes compared to the Company's forward price curve used in the final net power cost update as soon as practical.

REDACTED
Docket No. UE 374
Exhibit PAC/3700
Witness: Frank C. Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Frank C. Graves

August 2020

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ATTACHED EXHIBITS

Q. Are you the same Frank C. Graves that provided direct and reply testimony on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) in this proceeding?

A. Yes. I provided direct and reply testimony in support of the Company's Annual Power Cost Adjustment (APCA) proposal, presenting empirical evidence for why it is needed and for how the proposal fits with generally accepted regulatory principles and practices.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. I will address criticisms of the APCA proposal that have been offered by the Public Utility Commission of Oregon (Commission) Staff (Staff) witness Mr. Scott Gibbens, Oregon Citizens' Utility Board (CUB) witness Mr. Bob Jenks, and Alliance of Western Energy Consumers (AWEC) witness Dr. Lance D. Kaufman. None of them accepts the need for the APCA relative to the Transition Adjustment Mechanism (TAM) and Power Cost Adjustment Mechanism (PCAM) process as it currently stands.

Q. Please summarize your testimony in support of the APCA.

A. PacifiCorp's experience of persistent cost net power cost (NPC) under-recovery since adoption of the PCAM in 2013 demonstrates the shortcomings of this mechanism as applied to PacifiCorp, which operates a complex system on a multi-state basis. The deficiencies in the PCAM are likely to increase in the face of new NPC forecasting challenges presented by electric market transformation and generation portfolio changes required by Oregon energy policy. To incent PacifiCorp to continue to actively engage and seek customer benefits in these emerging paradigms, the Commission should ensure that PacifiCorp is able to recover its prudent NPC through the APCA. Based on my experience, the APCA is a standard and fair approach to NPC recovery, supported by appropriate regulatory policies. In my surrebuttal testimony, I explain these points and rebut the other parties' arguments to the contrary.

Q. Please give an overview of Staff's and intervenors' views with which you disagree and will respond.

A. I find there are three general themes opposing APCA in the rebuttal testimonies of Staff and the intervenors. I summarize them below and will use these numbers to match sections in my surrebuttal testimony that correspond to these points.

1. Section II: Qualitative views that the current PCAM system is getting it right and no changes are needed. Purportedly:
    - The PCAM satisfies the five Commission criteria (which are themselves appropriate), and is functioning as expected/desired.
    - The PCAM defines unusual events (in terms of return on equity (ROE) impacts, not the character of the event); none have occurred. This is consistent with "normal business risk" as incurred by unregulated firms (such as ski businesses facing warm weather or other possible bad outcomes) without any potential true-up mechanisms; likewise NPC forecasting and variance problems are just ordinary business risk for utilities.[1]
    - The PCAM is "revenue neutral" in terms of not having caused either net increases

[1] CUB/400, Jenks/11-13, 19-20; Staff/2400, Gibbens/34.

or decreases in customer rates via its adjustments (which have not actually occurred because of variances being within the several tolerance bounds).[2]

- The PCAM creates desirable incentives that would vanish under APCA.[3]
- Even if the APCA had merit, this is not the right time or circumstances for shifting risk to customers. The COVID pandemic and equitable considerations for customers indicate that PacifiCorp should stick with the PCAM and just settle for somewhat low returns that are "close enough".[4]

2. Section III: Alleged empirical errors by PacifiCorp in interpreting its operating history to show whether there is an NPC shortfall:

- Too short a history of alleged shortfalls to conclude they are systematic.[5]
- Gross load vs. net load variance in explaining NPC under-recovery.[6]
- Declining NPC forecasting errors in the past, and lack of statistical significance for a time trend that would demonstrate the problem is getting worse.[7]
- Over-forecasting of economy sales, because PacifiCorp's Generation and Regulation Initiative Decision Tools (GRID) is able to optimize better than PacifiCorp's actual operations.[8]
- Increasing renewable resources in the PacifiCorp portfolio do not warrant changes to PCAM.[9]
- Hydro resources are more variable than renewables (yet Avista Corporation

[2] Staff/2400, Gibbens/6-7; CUB/400, Jenks/23-24.
[3] Staff/2400, Gibbens/7, 35; CUB/400, Jenks/13, 21, 25-27.
[4] CUB/400, Jenks/2-4, 17-18, 27, 58; Staff/2400, Gibbens/23-24.
[5] Staff/2400, Gibbens/10.
[6] Staff/2400, Gibbens/29, 39.
[7] Staff/2400, Gibbens/29-30; AWEC/500, Kaufman/25.
[8] Staff/2400, Gibbens/8, 21.
[9] Staff/2400, Gibbens/14-18.

(Avista) and Portland General Electric Company (PGE) with proportionately more hydro do not seem to have as much of the NPC problem as PacifiCorp).[10]

3. Section IV: There is no need for the APCA because other fixes are available or imminent

- Positive gross load errors undo some of the NPC losses by increased revenues from volumetrically priced sales.[11]
- AURORA will soon (or may) improve forecasting.[12]
- Day-Ahead/Real-Time (DA/RT) adjustment has helped, and could be used more aggressively.[13]
- Some changes in the asymmetries of the deadbands, sharing limits, etc. could be introduced to preserve incentives.[14]

Q. Can you provide a synopsis of your reactions to these points?

A. Yes. Some of these observations are partly correct but incomplete in terms of explaining or eliminating the systemic NPC under-recovery problem. Some are simply rhetorical and circular, redefining success on the terms of the policies that are under scrutiny rather than asking if those policies and criteria are fair or beneficial terms in the first place. The Company is not disputing whether the mechanics of the rules have been faithfully applied but whether that is a desirable regulatory approach.

Nearly all of these mischaracterize the APCA as a risk-shifting mechanism rather than as primarily a simple (and industry-standard) means of patching a cost-

[10] AWEC/500, Kaufman/27.
[11] Staff/2400, Gibbens/39-40.
[12] Staff/2400, Gibbens/9, 39; AWEC/500, Kaufman/28-29.
[13] Staff/2400, Gibbens/9-11, 38.
[14] Staff/2400, Gibbens/30-34, 41.

recovery shortfall that is a systemic byproduct of the increasingly complex production and market system that PacifiCorp is shifting towards. This shift is being done in order to achieve greater average, long-term cost savings and lower emissions. It ultimately should reduce the NPC, but it comes with a side-effect of some uncontrollable, unforecastable transaction costs. Those are being prudently incurred, but not reliably recovered.

Finally, all of them share certain oversights or misperceptions:

- All mischaracterize what kinds of incentives are being created by the current PCAM. They implicitly assume that some degree of risk-bearing for NPC is *per se* desirable and motivational for the Company, without considering whether the possible shortfalls are controllable. These shortfalls are not controllable—so the incentives created do not find efficiencies. Rather, the incentives are to avoid the problem (penalties from an uncontrollable risk) by pursuing less dynamic, likely less economical, but safer resource plans (such as less renewables) and operational activities (such as reduced reliance on market transactions). The Company has not gone down this path, but that is the true incentive they are being presented.
- All misunderstand the acute and important differences between normal business risk for an unregulated private firm that can choose when and where to enter or exit a market, can set its own prices (subject to market feedback) and can keep arbitrarily large profits if it is successful versus a public utility with an obligation to serve and no opportunity to set value-based prices.

II. RESPONSE TO QUALITATIVE VIEWS THAT THE CURRENT PCAM SYSTEM IS GETTING IT RIGHT AND NO CHANGES ARE NEEDED

Q. The first category of issues you dispute with the parties are various ideas about regulatory concepts that they believe justify the PCAM as-is, and would be violated by the APCA. Please explain.

A. These issues generally relate back to the five principles that were articulated at the time of the initial design of the PCAM, having to do with the cost-recovery risk sharing for unusual conditions only, subject to revenue neutrality within a range of overall returns, while providing incentives and being in ratepayer interests. As I explained in my rebuttal testimony, these are reasonable conceptual goals and values in some regulatory contexts, but they are not well specified or well suited for the purposes of the TAM and PCAM (despite that being their origin). In particular, they fail in regard to defining normal business risk, revenue neutrality, and incentives. Here, several witnesses have defended the PCAM on the grounds that it is working like it said it would rather than reconsider whether it actually applies well to NPC.

Q. Please be more specific about the problems in how normal business risk is defined under the five principles and interpreted by Staff and intervenors.

A. There are two distinct problems. First, Mr. Gibbens and Mr. Jenks have both stressed that the PCAM should only apply to "unusual conditions" (which indeed is in the language of those principles), but they then define that strictly in terms of circumstances that would produce an ROE deviation larger than the earnings test (+/- 100 basis points) after the asymmetric sharing rules. This standard of course has nothing to do with conditions being unusual, just with being large, defined in a somewhat arbitrary way. Since this approach uses the financial terms of the PCAM itself, it prevents consideration of whether there are certain types of events or operating difficulties that merit cost recovery allowance because they are important, prudently met, uncontrollable, and costly, regardless of strangeness or their financial impact. I explained in my reply testimony why NPC balancing costs have all those features—which in other regulatory contexts are sufficient grounds for full allowed recovery.

Indeed, by this definition of unusual events, none have occurred in the past five years for the Company, as its cost recovery variances have never exceeded the filters and ranges that the PCAM imposes. This would of course be true if the Company had been arbitrarily and systematically prevented from recovering 50 basis points (about $15 million per year in Oregon) of any cost (or any other amount within the deadbands), regardless of causes or merits. The fact that the gap is within the PCAM's notional bounds does not prove it is properly foregone.

Q. What is the second issue related to understanding and defining "unusual events"?

A. The second problem is a common confusion over what constitutes the other side of the coin, i.e., defining what is "normal" business risk for a utility (apart from the inaccurate financial definition just described). Confusion arises from a mistaken analogy between competitive, unregulated firms and public utilities. Mr. Jenks cites the problem a ski shop owner faces from warm weather conditions, for which it (purportedly) has no financial recourse, as evidence of how/why firms should and normally do just absorb the variance from good vs. bad market conditions. By analogy, utilities should also absorb the risk of under-forecasting their operating costs or of having more costly balancing transactions than were expected. That is the "normal" way of bearing risk, and is notionally what ROE is for.

Mr. Jenks is correct that weather variance is a normal business risk for a ski shop operator, but this is not comparable to an electric utility in several respects. In general, unregulated and regulated companies incur and bear risk in very different ways. The key difference is that an unregulated company has the luxury or freedom of being able to choose when and where it takes risks, and for how long, by virtue of what market segments it pursues, with what products, for how long. Further, it can control (to some extent, depending on competition) its revenue risk by changing prices. For instance, Mr. Jenks overstates the impotence of the ski shop owner, as s/he could, if conditions are bad enough, shut down for the season and cut future losses. No public utility can do this (as the moratoria throughout the country on terminating service from customers in COVID-stricken areas demonstrate clearly).

Unlike the competitive ski shop owner, a utility has an obligation to invest in order to provide nearly universal service, with no opportunity to cherry-pick which market sectors are most attractive and which to leave behind. It also cannot exit, and it cannot change or increase prices if it happens to be providing more value than is typical or was expected, or discount if it wants to attract some new customers. Because of those strict obligations and inflexibilities, plus the natural monopoly in the scale of their assets, we apply cost-of-service pricing with the premise that all prudently incurred costs of doing business can at least be expected to be recovered. That may not be realized all the time, but there has to be a fair chance for that to happen or else cost-based rates are not compensatory.

Here, PacifiCorp is suffering that impairment because the difficulty in forecasting NPC balancing costs set against the asymmetry of the PCAM recovery filters crushes a fair shot at full cost recovery. For the same reason of allowing an expectation of full cost recovery, it is not appropriate to justify eating into the ROE for cost shortfalls, as long as the bite is not "too large". What is normal business risk for a utility is to have an unbiased opportunity to recover all its prudent costs while also expecting to be able to earn its full allowed return on capital.

Q. How is "revenue neutrality" misunderstood or misapplied in the PCAM context?

A Staff and intervenors argue that the PCAM is achieving revenue neutrality because the over versus under adjustments it has allowed so far have balanced out. They define this as success rather than whether the PCAM is fairly allowing variances in actual costs to be recovered over time. Indeed, the intervenors are correctly describing results, because all of the adjustments to date in either direction have been zero—but this is a bizarre notion of neutrality that has no connection to the normal usage of the term.

Ordinarily, revenue neutrality refers to a constraint put on new pricing practices (such as shifting to time-of-use rates, or shifting cost allocations from volumetric to demand charges) when there is no underlying change in costs, in order to make sure that the same amount of revenue (the revenue requirement) is being collected before and after the change. It is not a mechanism for saying there should be no rate increases when there are prudent costs that are not being recognized for recovery.

Q. What about incentives? Those are emphasized as a key goal of the PCAM and are strongly defended by Mr. Gibbens and Mr. Jenks as healthy effects of the current arrangement.

A. There are several blanket assertions (none supported by any analysis of operating choices that the Company could use to manage the NPC shortfall or NPC variances generally) to the effect that the PCAM is essential because of its incentives to manage costs. Unfortunately, these are entirely based on implicit, unfounded assumptions that incurring risk always helps induce more care and efficiency. However, as I pointed out in my reply testimony, this is only true if there are material opportunities to foresee and mitigate the problem at risk. If not, *i.e*., if it is largely uncontrollable, then bearing the risk is simply a financial friction with no behavioral benefit. To the contrary, it is likely to induce risk avoidance as the only rational response. Here, that could take the form of the Company preferring to not participate as extensively in the Western Electricity Coordinating Council competitive market operations, or to not use as much renewable generation that is intermittent and not controllable. Those choices would be bad for customers, but they are the actual incentives created by the PCAM.

Q. Regarding ratepayer interests (the fifth PCAM design principle), Messrs. Gibbens and Jenks have averred that even if the APCA had merit, this is not the right time or circumstances for shifting risk to customers, because the COVID pandemic and equitable considerations for customers indicate that PacifiCorp should just settle for somewhat low returns that are "close enough".

A. In my view, this is the most understandable and important of the concerns raised by the intervenors, but it too has some misplaced assumptions and solutions. There is no doubt that utilities can and should contribute to mitigating the terrible hardships arising from the pandemic. Indeed, they are doing so all over the country with deferred billing and shutoff moratoriums, and more may be required. But that need should not confound appropriate cost recognition. Despite the pandemic, the utility must provide service and must have a fair opportunity to eventually recover those prudent costs. That recovery can be delayed or socialized in new ways because of the pandemic, but it should not be disallowed outright, and the PCAM's inappropriate design should not be defended because it happens to give a nice outcome for customers under these extreme and unusual risk conditions.

Further, characterizing the APCA as risk-shifting to customers confuses the mechanism with the purpose. The key goal for the APCA is to restore accurate cost recovery for customers and shareholders. It happens that the easiest way to achieve this is by simply making it into a flow-through mechanism with no filters, albeit subject to *ex-post* prudence reviews. It would be possible to do so with other filters, if they were more symmetric and there were additional approximate NPC corrections (like the DA/RT adjustments) built into the TAM forecast. But those would be complicated to apply, while a full pass-through is simple and in keeping with the vast majority of fuel and purchased power recovery mechanisms in use around the rest of the country.

III. RESPONSE TO ALLEGED EMPIRICAL ERRORS BY PACIFICORP IN INTERPRETING ITS OPERATING HISTORY TO SHOW THERE IS AN NPC SHORTFALL

Q. Please summarize the arguments raised by Staff and intervenors regarding PacifiCorp's interpretation of its operating history on the persistence and drivers of NPC under-recovery.

A. Staff and intervenors criticized PacifiCorp's interpretation on several grounds: i) there is too short a history of NPC shortfalls to conclude they are systematic;[15] ii) gross load deviation appears to have a statistically stronger influence on NPC under-recovery than net load deviation;[16] iii) NPC forecasting errors declined in the past, and there is a lack of statistical significance for a time trend variable, indicating that the NPC under-recovery problem is not getting worse;[17] iv) PacifiCorp's NPC forecast suffers from over-forecasting of economy sales, because GRID is able to optimize better than PacifiCorp's actual operations;[18] v) increasing renewable resources in the PacifiCorp portfolio do not warrant changes to PCAM;[19] and vi) hydro resources are more variable than renewables, yet Avista and PGE do not seem to have as much of the NPC problem as PacifiCorp.[20] I will address each of these in the subsections below.

[15] Staff/2400, Gibbens/10.
[16] Staff/2400, Gibbens/29, 39.
[17] Staff/2400, Gibbens/29-30; AWEC/500, Kaufman/25.
[18] Staff/2400, Gibbens/8, 21.
[19] Staff/2400, Gibbens/14-18.
[20] AWEC/500, Kaufman/27.

A. Too Short a History

Q. How do you respond to Staff's claim that the increasing trend in NPC under-recovery is based on a limited number of data points that represent just three years of data (and the unverified data from 2019) and that the problem may not continue after switching to the AURORA model?

A. PacifiCorp's NPC under-recovery has been increasing since 2016. If Staff considers three to four years of historical evidence as not sufficient, Staff's proposal to wait to see if the under-recovery problem can be fixed with AURORA means that PacifiCorp will be at risk of further NPC under-recoveries until at least three to four years after starting to implement AURORA. Staff simply speculates by stating "an entire new model may be able to provide further benefits" without any evidence that the new model would overcome the intrinsic input data problem associated with trying to forecast hourly NPC year-ahead. In addition, the recurring shortfalls since 2016 are not just gaps we do not understand, *i.e*. they are not just "noise". Rather, they arise, at least in part, from a systemic difficulty in forecasting certain kinds of short run market activity that is beyond the lens of the TAM. These costs may vary from year to year, but they are not likely to go away.

Q. But wouldn't the ability to introduce forecast error in the AURORA model address some of the imbalance cost under-forecasting problems in the GRID model?

A. No. I do not expect that using AURORA in the year-ahead NPC forecasts will resolve this problem. I discuss the reasons why this is not a modeling technique problem so much as an information problem in section III of this testimony.

AURORA is not being adopted to do better NPC forecasting, but instead to be better able to represent the new granularity that will be required when nodal pricing and jurisdiction-specific supply portfolios are used for state-level NPC allocations. Mr. Wilding also includes a more in-depth discussion of the AURORA model in his testimony.

B. <u>Historical drivers of NPC under-recovery and trend over time</u>

Q. Staff presents results of regression analyses used in reaching their conclusions of the relative importance of gross load deviations versus net load deviations in explaining PacifiCorp's historical pattern of NPC variance. Do you agree with Staff's methods and conclusions from those regression analyses?

A. No, I do not. Mr. Gibbens asserts that his regressions show that "gross load variance, not net load variance is another driving factor for under-recovery."[21] He uses this to argue that "… the main issue is not wind, hydro, long term purchase and sales; these have small, insignificant impacts on recovery of power costs."[22] These are among the major drivers of net load deviations that I believe are the more substantial and difficult cause of the NPC shortfalls. He also concludes that there is "no statistical evidence to support the Company's assertion that NPC under-recovery is indeed increasing over time."[23] However, Mr. Gibbens' regression models suffer from some statistical problems that make his conclusions about statistical significance of individual variables unreliable.

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[21] Staff/2400, Gibbens/40.
[22] Staff/2400, Gibbens/40.
[23] Staff/2400, Gibbens/30.

Q. Please explain.

A. First, in all four of Mr. Gibbens' regression models, the variance of the regression residuals (difference between the dependent variable's observed values and the model's predicted values), is not constant across observations. This may sound like nitpicking, but it actually is quite important. The differing variance, or "heteroscedasticity" as it is called by statisticians, undermines the ability of a regression model to predict the dependent variable (NPC deviations) consistently across all of its values. For instance, the statistical model may be able to predict the dependent variable's low values accurately, but fail to predict its high values well, or vice versa (depending on how the variance changes across the range). The problem is that a regression model assigns equal weight to all observations. Therefore, when there are differing variances, the observations with greater variance in reality contain less information. For Ordinary Least Squares regressions to obtain reliable estimates at accurate confidence levels, the regression residuals must be relatively constant.

In Mr. Gibbens' regression models, it is quite apparent that the regression errors vary depending on what part of the time frame under review is examined. In order to demonstrate this problem, I performed the Breusch-Pagan[24] test, and the results (shown in Exhibit PAC/3701) indicate that all four of Mr. Gibbens' regression models suffer from the heteroscedasticity problem at 95 percent confidence level, rendering his conclusions about the significance (or insignificance) of the explanatory variables invalid.

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[24] The Breusch-Pagan test is used to test whether the dispersion of errors from the regression model is dependent on the values of explanatory variables.

Q. Are there any additional statistical design or data problems with his analysis?

A. Yes. There are several problems having to do with whether the data are independent observations or are co-dependent on each other in significant ways. Also, I have tested his specification (the equation for the relationships he chose to test) and find that another use of that data provides a better understanding of what is going on. More specifically:

- Mr. Gibbens' regression analyses suffer from having a correlation in regression error terms with their lagged values, i.e., auto-correlation. That is, the results in one period depend on what happened in the prior period, such that a forecasting error in one period may tend to be repeated with the same (or a predictable) direction of error in the next period. Similar to heteroscedasticity, the presence of auto-correlation results in invalid estimates of statistical significance test results for individual regression coefficients. As shown in Exhibit PAC/3701, applying the Durbin-Watson[25] test for autocorrelation in Mr. Gibbens' regression models indicate the presence of autocorrelation at 95 percent confidence level in two of his regressions and at 90 percent confidence level in all of his regressions.
- A regression model that Mr. Gibbens used suffers from what is called a multicollinearity problem, which arises when some explanatory variables are highly correlated with each other. This causes them to compete for explanatory power in the fit, and as a result their coefficients to explain the dependent variable are not reliable. This occurs when two or more variables depend on the same

[25] The Durbin-Watson test evaluates whether the errors from the regression model are correlated with their lagged values. The test statistic in Mr. Gibbens' four regression models varies in a range between 1.56 and 1.69, indicating some level of autocorrelation. A test statistic of 2 would indicate no autocorrelation.

thing (which may have been omitted from the specification) or if one is derived from another. In this case, Mr. Gibbens' regression model uses both gross load deviation and net load deviation as explanatory variables, which are obviously closely correlated (Net Load deviation starts with Gross Load and subtracts out the uncontrollable supply elements). Not surprisingly, as shown in Exhibit PAC/3701, they have a very high correlation (0.85 correlation coefficient, where 1.0 would be perfect correlation). Therefore, Mr. Gibbens' regression analysis is not a valid evidence of his conclusion in Exhibit Staff/2403 that "net load percent … is realistically only driven by gross load variance."[26] Given the high degree of correlation, the reverse could be true.

- He uses his equation with a strong coefficient for gross load deviations to conclude that hydro and wind deviations are not significant or important. But as shown in Exhibit PAC/3701, there is a negative correlation between load/hydro deviations and load/wind deviations, which suggests the load deviation variable captures some of the impacts of hydro and wind. To test this, I ran a regression without the gross load deviation, which shows that wind deviation is statistically significant at a 90 percent confidence level and hydro and long-term purchase deviations at a 99 percent confidence level in explaining the NPC under-recovery.
- During the period 2014-2019, relationships between NPC variance and independent variables (and the statistical significance of the coefficient estimates) varied over time, suggesting regime shifts in those relationships (meaning compiling six years of data into a single model does not adequately capture what

[26] Staff/2403; Gibbens/1.

is going on). As shown in Exhibit PAC/3701, if it is analyzed in sub-periods, different results arise. For example, gross load variation is no longer statistically significant for the two-year period 2016-2017 while wind/hydro/purchase deviation variables become significant during the same period. Therefore, Mr. Gibbens' conclusion that gross load variance is the only statistically significant factor in explaining the NPC deviations is an over-generalization from a specification that has too much data with interdependencies in it.

Q. Are there other problems with Staff's regression analysis?

A. Yes. It is not typical to try to understand or predict power market results with a statistical model, for two reasons. First, the explanatory data are intensely interdependent as discussed above, largely because they arise in the market from a process of co-optimizing the plants' utilization as a function of fuel costs and locational demands. Second, there are many possible explanatory variables for power costs, more than would be feasible to analyze and include in a regression. Third, it is not likely that the underlying probability distributions for the variables are stable over time, because of episodic shifting market conditions. I am not aware of any utility that goes into an integrated resource plan or budgeting process with a statistical model for the entirety of its expected costs. Instead, because of the complex interactions, system models (like GRID or AURORA) that imitate market operations are used to understand the conditions that could cause costs to rise or fall in the future.

Here, even ignoring some of the specification problems identified above, we see a fairly low coefficient of determination[27] in Gibbens' first regression model (46 percent). This means that the variables in his equation explain that proportion of the total variance. Conversely, it means that more than half of the variation in the NPC shortfall costs is not being explained by his variables, possibly because he did not include some other important explanatory variables to explain the NPC deviations.

Q. What are the other possible explanatory variables that Mr. Gibbens omitted in his models?

A. As I explained in my direct testimony, deviations from forecasts in purchase and sale prices are a major driver of NPC under-recovery because of the nonlinear shape of the market supply curve (dispatch ladder, or roughly equivalent, spot market prices) that gets steeper at higher load (and also when there is low hydro/wind). There are no price deviation variables in Mr. Gibbens' regressions that could capture this cost sensitivity. Adding the monthly values for sales and purchase price variances (actual minus forecast) to Mr. Gibbens' first regression equation substantially changes the model results. In particular, the new purchase price variance variable has a statistically significant effect in explaining the NPC deviations, while the sales price variance variable is not significant. This difference in influence is not surprising, and in some ways it affirms my description of why balancing transactions tend to raise NPC and cause a shortfall relative to forecast. The purchase price deviations from forecast are much larger than the sales price deviations, which comports with the facts

[27] This is also known as R-squared, which is a measure of how close the data are to the predicted values of dependent variable. The first model's adjusted R-squared, which takes into account the number of explanatory variables, is lower at 42 percent.

that the supply curve in the market tends to be nonlinear and upward sloping, such that unplanned purchases tend to cost more than unplanned sales. This is what I explained in my direct and rebuttal testimonies. In addition, adding these new variables makes the wind deviation variable and the long-term sales deviation variable statistically significant, while it reduces the size and significance of the gross load deviation variable. The explanatory power of the regression also is much improved, as shown by the coefficient of determination increasing to more than 74 percent as well (improving the fit), compared to 46 percent in Mr. Gibbens' original specification.

In addition to his model possibly being under-specified, as just explained, it may also treat the data as too homogeneous, i.e., too similar across all the observations and time scales. It can be tricky to analyze causality in costs that change very dynamically over short periods of time (e.g. intra-hourly for NPC variances) with data that is aggregated up to a higher level. Data is often much smoother over long periods than it is in short periods, and if variability matters, the longer period data may miss the effect. Here, the monthly data in Mr. Gibbens' regression analyses likely masks some of the explanatory power of wind deviations, since the hourly variance of wind is much higher than the monthly variance. For example, in 2017, actual hourly wind generation deviated from forecast by 63 percent, while the monthly wind generation deviated from forecast by 15 percent.[28] The deviation from annual average is even smaller, as was shown graphically in Confidential Figure 7 of

[28] Hourly deviation percentage is the sum of the absolute value of the hourly deviations divided by the total annual forecast. Likewise, the monthly deviation percentage is the sum of the absolute value of the monthly deviations divided by the total annual forecast.

my direct testimony in this proceeding. In addition, the increasing penetration of wind in PacifiCorp's portfolio and in the region in the future would likely increase the impact of wind variability on PacifiCorp's balancing sale/purchase transaction prices.

Q. What are your conclusions after reviewing the regression analyses presented by Mr. Gibbens and your sensitivity analyses?

A. First, while I agree with Mr. Gibbens that gross load deviation is inherently a driver of the NPC under-recovery, his analyses do not support his conclusions that net load deviation is not a significant driver of historical NPC under-recovery or that the other factors displaced by gross load in his regressions are not in fact significant. Of course unexpected increases in load are going to cause unexpected increases in NPC, but so are all the types of changes in net load that I have described with structural explanations for why they matter. Second, the statistical problems in his analyses cast doubt on his conclusions about the lack of significance for the impact of time trend. Third, Mr. Gibbens' regression models omit a clearly relevant source of NPC deviations, namely the impact of price deviations from forecasts in purchase and sale transactions. Fully specified regression models that include price deviation variables support my findings and weaken his. Fourth, and finally, Mr. Gibbens' reliance on monthly data in his regression models understates the importance of much wider hourly deviations in wind generation. In general this shows the difficulties of using statistical models for power system costs.

C. Impact of increasing renewables on NPC under-recovery

Q. Dr. Kaufman tries to dismiss the impact of increasing renewables on NPC shortfalls by noting that the increased penetration of renewables has not resulted in larger NPC deviations since 2008 even though PacifiCorp added 4,789 megawatts (MW) of new renewable resources since then. How do you respond?

A. Dr. Kaufman reaches this conclusion by comparing the data from Table 7 on page 65 of Mr. Wilding's reply testimony in the six years between 2008 and 2013 (when deviations between forecasted and actual NPC averaged about $27 million per year) to the same measure in the six-year period between 2014 and 2019 (where those deviations averaged about $19 million per year). He further notes that "… one can see that PacifiCorp's forecasts over the 2014-2019 period improved even without incorporating the effects of the DA/RT adjustment—the average deviation was $24,329,420, still $3 million less on average than the deviations the Company experienced between 2008 and 2013."[29]

His description of the numbers is correct, but Dr. Kaufman ignores that PacifiCorp's NPC under-recovery since 2008 has been driven by multiple factors in addition to increased penetration of renewables in PacifiCorp's portfolio. These include changing extent and pattern of deviations in gross load, hydro generation, and balancing purchase and sale transaction costs. These can vary in ways that cause the overall forecasting error to decline, even if the renewables are making it worse—as they inherently will because of their intermittency and unpredictability. In addition, of the total 4,789 MW of new renewables cited by Dr. Kaufman, about half of it

[29] AWEC/500, Kaufman/25.

(2,358 MW) was not online prior to 2020. Therefore, the impact of the new renewables coming online starting in 2020 on NPC under-recovery has yet to be seen in the historical data.

D. <u>Hydro resources more variable than renewables?</u>

Q. Dr. Kaufman provides a comparison of annual (year-to-year) variation in wind versus hydro generation to argue that "the variability of renewable resources is not a basis to deviate from a PCAM structure that was created specifically to address similar variability in hydro". How do you respond?

A. Dr. Kaufman is trying to support his belief that renewables are not a problem, but his finding is meaningless because annual variance is not the issue. Wind is much more predictable on an annual basis than on a shorter term, to such an extent that its annual variance is almost meaningless as a predictor of NPC shortfalls, even though it is a big factor in the short run. Using annual renewable data to evaluate its contribution to fuel cost risk would be a bit like saying annual average road congestion does not vary a lot, so traffic jams have nothing to do with how much variance there is in the time it takes to get to work.

Hydro is much more variable on an annual basis than wind, because it depends much more on seasonal and long time-period factors like snowfall and episodic droughts. But at the very short term time frame, hydro generation becomes almost completely controllable for load-following or price-sensitive dispatch. This is what makes it such a premium system resource. In contrast, hourly generation from wind plants is barely controllable at all, and hence is of little use in responding to changes in load or market conditions. The figures below clearly demonstrate these dynamics. Confidential Figure 1 depicts the 2017 hydro variance (actual generation minus forecast) normalized by actual hydro generation averaged across the 8760 hours of that same year. The normalized hydro variance ranges from [redacted] to [redacted], an order of magnitude smaller than the normalized wind variance (which can sometimes be [redacted] of the average levels) as shown in Confidential Figure 2. The average hourly deviations of PacifiCorp wind generation from the year-ahead forecast (in absolute value of deviations) was [redacted] percent compared to [redacted] percent for PacifiCorp hydro generation. Importantly, some of this hydro variation from forecast was due to controlled, deliberate adjustments to use the hydro at better times than had been forecasted, whereas the wind variances are just random, hence far more consequential to NPC shortfalls. That is, the observed hydro variance is mostly beneficial, managed variance, while the wind variance is random and unhelpful. In the same year, annual generation deviated from forecast by only [redacted] percent for wind and [redacted] percent for hydro. Similarly, intra-day hourly volatility of actual wind generation in 2017 (measured as the standard deviation normalized by average hourly generation in 2017) was [redacted] on average compared to [redacted] for hydro. As seen in Confidential Figure 3, the normalized hourly standard deviations of actual wind generation on a daily basis were much higher than the deviations in hydro.

Confidential Figure 1: Normalized Hydro Generation Variance in 2017

[redacted]

Confidential Figure 2: Normalized Wind Generation Variance in 2017

[redacted]

Confidential Figure 3: Normalized Intra-daily Standard Deviations for Actual Wind and Hydro Generation in 2017

[redacted]

IV. RESPONSE TO CLAIMS THAT THERE IS NO NEED FOR THE APCA BECAUSE OTHER FIXES ARE AVAILABLE OR IMMINENT

Q. Beyond disputing the motivations or empirical evidence for the NPC shortfall problem, several parties argue that there is simply no need for the APCA, for such reasons as offsetting revenues when the variance is due to higher than expected gross load, the opportunity to improve the problem with the new system model AURORA, better possible use of the DA/RT adjustment, and possibly, more symmetric sharing terms being applied (to preserve incentives). What is your reaction?

A. I will address each in turn. In general, it may be possible to improve the risk sharing rules, but it is a mistake to believe this problem is a methodological one that can be fixed with more careful analysis.

Q. Please discuss whether gross load errors undo some of the NPC losses by increased revenues from volumetrically priced sales.

A. Mr. Gibbens makes this point in order to argue that the NPC cannot be evaluated as a problem to fix on its own, but rather must be treated holistically in relation to other aspects of cost recovery and profitability. He argues that sometimes profitability may be improved by the same things that make NPC under-recoveries occur (e.g. if increased sales volume from higher than expected gross loads cause realized NPC to be above the TAM forecast). As noted above, he also believes his statistical analysis of NPC monthly variances show that this is a common occurrence, if not the dominant one causing NPC shortfalls. As explained above, there are several statistical flaws with his analysis, but even ignoring those, there are two problems with his inference about offsetting profitability.

Q. Please elaborate. Would this not mitigate the NPC problem?

A. Under some conditions it could help, but Mr. Gibbens was not careful (or was not able) to unpack the details. If the unexpected gross load variance were to come from residential customers, who mostly pay for their service under volumetric rates, this would cause an increase in revenues outside of the adverse NPC effect. Note that this offset is only positive for extra, unplanned gross load. If realized loads are smaller than expected, NPC may fall but there is a large loss of volumetric revenue. The revenue volume gains and losses are symmetric if the load forecast was a good one, but the NPC gains and losses may not be for the reasons I explained in my direct testimony. Further, he has no analysis of whether this increase would typically be larger than the incremental NPC losses per MWh or whether the favorable load variances would tend to occur from residential customers. If the excess load came from commercial and industrial customers, who pay much closer to avoidable costs for the volumetric portion of their bills, there would be no revenue or profit offset.

Q. Do you agree that switching to AURORA is likely to make these cost forecasting problems go away, or at least be reduced?

A. I do not share that expectation. All power system models have some of the same limitations once they reach a certain level of detail in their data representation and decision differentiation. That is, assuming they are not making (deliberately) a coarse approximation to some aspect of the power system (for the sake of expediting other aspects of the planning analysis, such as leaving out nodal detail so that long-term capacity expansion can be optimized), then they run up against the shared problem that much of the planning environment is simply not known or knowable at the time resource plans or budgets must be made. In particular, it is not known at the time frames of weeks, days, or hours within the coming year, yet it is at these shorter time dimensions where a huge amount of market activity occurs. This is partly because short-term weather is not predictable far in advance, and partly because the problem involves interacting with many other market participants whose own expectations, plans and operational methods are not public and perhaps not even decided. Numerous technical problems can also arise, such as unplanned outages. Unfortunately, there are likely to be incremental costs from those unforeseen, uncontrollable variations from plan, rather than incremental benefits. That is not always going to be the case, but more often it will be.

As also explained in Mr. Wilding's surrebuttal testimony, the benefit of going to AURORA is not to reduce NPC estimation error, but to capture nodal details and allow more specific geographical and sub-system accounting for NPC. In general, moving towards nodal pricing and state-specific resource allocations is more likely to heighten the NPC forecasting difficulties than to reduce them. There could be average cost savings, but likely not improved NPC variance management.

Q. What about AURORA's capability to incorporate forecasting error and uncertainty into its modeling? Isn't that related to the NPC shortfall problem?

A. Yes it is related, but a model of uncertainty still requires assumptions about the pattern of uncertainty that will be faced. It could be very controversial, and at the least, difficult, to reach agreement on what ranges of uncertainty should be considered and how those conditions should be weighted. I understand that the current requirements are that the TAM must be based on normalized, median (50th percentile) expectations for the major inputs. If that protocol is preserved, the extra features of AURORA will not be used. Even if they are, those features probably are mostly useful for improving the unit commitment of the resources that provide ramping and regulation, rather than modeling what the actual costs of unanticipated variances will be. Those savings should show up in the TAM, but not in the PCAM variances.

Q. Will AURORA avoid the "over forecasting" of economic sales that Mr. Gibbens complains seems to cause some of the NPC variances?

A. No, not significantly. That result is not a product of bad modeling by GRID but of unrealistic, idealistic trading flexibility occurring in the model plus requiring the model to allow a very large amount of purchase and sales transactions that are in excess of what practical experience indicates is likely. Any system model like GRID or AURORA is robotically in search of cost reductions, including making thousands of very tiny trades at non-standard volumes (e.g. not restricted to 25 MW blocks that are fairly standard in market trading). They have no transaction or search costs, no risk aversion, no negotiations, and no dynamic market flow or production constraints that can limit feasible transactions. AURORA may pick up some of the latter (via a more detailed representation of grid congestion), but it will not cure all the other over-zealous trading features.

Q. Could better use of the DA/RT adjustment help reduce this problem?

A. Possibly, but it will take a lot of regulatory debate to agree on how to set more realistic adjustment terms. The problem is that the market conditions that drive the problem are not stable or directly observable over time, so a creative insight would be required each year. It would be simpler to just adopt the true-ups of the APCA.

Q. Would it help to have more symmetric risk sharing?

A. Somewhat, but again this is no panacea. First, it would remain a fallacy to think this is important because it would preserve valuable incentives. The incentives it would preserve are not beneficial. Beyond that, there is a compound problem in the current situations whereby the NPC tends to get under-estimated, then under-corrected thanks to the asymmetric risk sharing. More symmetric risk-sharing only fixes half of this problem. That said, it would be better than the current PCAM.

Q. Does that complete your surrebuttal testimony?

A. Yes.

REDACTED
Docket No. UE 374
Exhibit PAC/3701
Witness: Frank C. Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Frank C. Graves

Review of Staff's Regression Analyses

August 2020

THIS ATTACHMENT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 374
Exhibit PAC/3800
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Redacted Surrebuttal Testimony of Rick T. Link

August 2020

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Q. Are you the same Rick T. Link who previously provided direct and reply testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. I respond to adjustments related to PacifiCorp's decision to install selective catalytic reduction (SCR) emission-reduction systems at Jim Bridger Units 3 and 4 presented by Oregon Public Utility Commission (Commission) Staff witness Ms. Sabrinna Soldavini, Oregon Citizens' Utility Board (CUB) witness Mr. Bob Jenks, Alliance of Western Energy Consumers (AWEC) witness Dr. Lance Kaufman, and Sierra Club witness Dr. Jeremy Fisher.

I respond to adjustments proposed by Dr. Kaufman relating to emission-control investments at the Hunter plant.

I also briefly respond to the recommendation made by Sierra Club witness Dr. Ezra D. Hausman to accelerate the 2020 Inter-Jurisdictional Allocation Protocol's (2020 Protocol) "Exit Dates" for all the Company's coal units to 2025.

Q. Please summarize your surrebuttal testimony.

A. My testimony addresses claims that the Company acted imprudently when it installed SCRs at Jim Bridger Units 3 and 4. My surrebuttal testimony demonstrates that:

- Based on all the information in the Company's possession on December 1, 2013, natural gas prices remained above the breakeven point and therefore installation of SCRs remained the lowest cost compliance option.

- The Company analyzed a reasonable number of alternative compliance scenarios, including natural gas conversion and early retirement. Every scenario analyzed favored the SCRs. The record in this case appropriately responds to the Commission's direction in the 2013 Integrated Resource Plan (IRP) by providing a more robust and detailed evidentiary record describing the analysis and decision-making process the Company undertook before moving forward with the SCRs on December 1, 2013.
- Applying Oregon's 2025 depreciable life for Units 3 and 4 did not change the outcome of the Company's economic analysis—SCRs remained favorable by a significant margin.
- Retiring Units 3 and 4 in lieu of the SCRs would not have allowed the Company to avoid necessary transmission system investment in western Wyoming.

My testimony also shows that the Company's investment in emission-control equipment at the Hunter plant was prudent when analyzed using a 2029 depreciable life.

Finally, my testimony demonstrates that the Company's 2019 IRP does not show that the Company's coal fleet is uneconomic or in a precarious economic situation. Therefore, Sierra Club's recommendation to revisit the dates for Exit Orders agreed to in the 2020 Protocol and retire all the Company's coal units by 2025 is unreasonable and unsupported.

II. JIM BRIDGER SCR INVESTMENTS

Q. Please provide an overview of each party's recommendation relating to the SCR investments at Units 3 and 4 of the Jim Bridger plant.

A. Staff recommends that the Commission either apply a 10 percent management disallowance of $5.6 million or disallow a return on the full undepreciated cost of the investments.[1] Staff also recommends an adjustment to the net book value based on an adjusted depreciation expense, which is addressed by Company witness Ms. Shelley E. McCoy. CUB, AWEC, and Sierra Club recommend a full disallowance.[2] CUB also offers an alternative recommendation to either limit recovery to the portion of the project used during the Oregon 2025 depreciable life, subject to recovery through the Transition Adjustment Mechanism[3] or align depreciation with the Oregon 2025 depreciable life, plus a 10 percent penalty.[4]

The Company disagrees with these recommendations. The decision to invest in the Jim Bridger SCRs was analyzed extensively and the results showed consistently that the SCRs were the least-cost, least-risk compliance option available to the Company. The Company's analysis and decision making were reasonable and prudent. Indeed, based on what the Company knew in 2013 when it committed to the SCR installation, any other decision would have been unsupported by objective economic analysis and would have been inherently higher risk to customers.

If the Commission concludes that the Company's analysis was insufficient, however, a one-time disallowance of no more than 10 percent of current rate base

[1] Staff/2300, Soldavini/4.
[2] CUB/400, Jenks/59; AWEC/500, Kaufman/1; Sierra Club/100, Fisher/4-6.
[3] CUB/400, Jenks/53.
[4] CUB/400, Jenks/56-57.

should be the cap. This is consistent with Staff's initial recommendation in this docket and the Commission's disallowance in Order No. 12-493 in docket UE 246, which was based on the finding that PacifiCorp "failed to reasonably examine alternative courses of action and perform adequate analysis to support its investments."[5] As the Commission observed in Order No. 12-493, "With regard to a total disallowance, even CUB acknowledges the difficulty of excluding from rate base investments that enable the affected plants to continue to operate and provide service to customers."[6] This reasoning is especially applicable here given that the SCRs have enabled environmentally compliant service from Jim Bridger 3 since 2015 and Jim Bridger 4 since 2016—without customers bearing any of the costs of these investments to date.

A. <u>Natural Gas Price Forecasts</u>

Q. Please summarize how the Company reassessed natural gas prices before issuing the full notice to proceed (FNTP) for the SCRs on December 1, 2013.

A. The Company used the System Optimizer (SO) model to determine a natural gas price breakeven point that could be used to rapidly reassess the SCR investments in light of changes in forward gas prices that were occurring throughout 2013. That breakeven analysis showed that, as long as the nominal levelized price at Opal over the 2016-through-2030 timeframe remained above \$4.86/million British thermal units (MMBtu), the SCRs were the lowest cost compliance option for Jim Bridger Units 3 and 4. The nominal levelized price at Opal over the 2016-through-2030 timeframe

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[5] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket UE 246, Order No. 12-493 at 31 (Dec. 20, 2012).
[6] Order No. 12-493 at 31.

from the September 2013 official forward price curve (OFPC) was $5.35/MMBtu. Based on the September 2013 OFPC, the SCR investment was $130 million lower cost than the next best alternative, which was natural gas conversion of Units 3 and 4.

The September 2013 OFPC was the last OFPC created by the Company before December 1, 2013, in accordance with the Company's long-standing policy. However, after September 2013 the Company continued to monitor natural gas prices even though it did not construct a one-off ad hoc OFPC specifically to review the SCR decision.

Q. What information did the Company receive after September 2013 relating to natural gas prices?

A. The Company received two of the three third-party expert forecasts that it used at the time to develop the OFPC. First, on October 22, 2013, the Company received a long-term forecast from [redacted] that had a nominal levelized price of $5.55/MMBtu over the 2016-through-2030 timeframe. This forecast was well above the breakeven point and 20 cents *higher* than the September 2013 OFPC. Using the [redacted] long-term forecast natural gas price, the SCR alternative would have been roughly $182 million lower cost than natural gas conversion.[7]

Second, the Company received a long-term forecast from [redacted] on November 20, 2013. Although the [redacted] forecast was below the breakeven point, that particular forecast was consistently an outlier relative to the other two expert forecasts. Moreover, the [redacted] forecast had decreased by less than one percent since

[7] For every one cent change in the nominal levelized natural gas price, the present-value revenue requirement differential (PVRR(d)) changes by roughly $2.6 million.

its prior forecast, which did not indicate on a directional basis that prices were plummeting.[8]

Third, the Company was monitoring actual market forward prices. Although those prices were decreasing, when considered together with the long-term forecasts provided by the third-party experts, the Company determined that natural gas prices had not declined sufficiently to justify abandoning the SCR investment and pursuing natural gas conversion. This assessment was confirmed when the Company issued the December 2013 OFPC on December 31, 2013, which was still above the breakeven point.

Q. Sierra Club argues that there was nothing preventing the Company from developing an out-of-cycle OFPC before December 1, 2013.[9] How do you respond?

A. While it is true that the Company could have created an ad hoc OFPC before December 1, 2013, it would have been based on incomplete information. In addition, with the information the Company had at that time, an ad hoc OFPC would not have shown that natural gas prices had fallen below the breakeven point. Indeed, based on the [redacted] long-term forecast, it is possible that an ad hoc OFPC created especially to review the SCR investment would have shown an *increase* relative to the September 2013 OFPC because the long-term component would have likely been derived from [redacted].

[8] The [redacted] forecast received in November 2013 had a levelized price of $4.35/MMBtu, which was three cents lower [redacted] prior forecast of $4.38/MMBtu.
[9] Sierra Club/400, Fisher/4.

Q. Why would an ad hoc OFPC created before December 1, 2013, have been based on incomplete information?

A. As previously explained, at that time, the Company developed its OFPC after reviewing price projections from three third-party expert forecasts. The Company did not receive the [redacted] forecast until December 11, 2013. That [redacted] forecast was also above the breakeven point and *higher* than the September 2013 OFPC. Using the [redacted] forecast, the PVRR(d) would have been roughly $145.6 million in favor of the SCRs.[10]

Q. Sierra Club argues that the OFPC is heavily influenced by the market forwards used to develop the first six years of the curve and there was no reason that the Company could not have accessed market forwards before December 1, 2013.[11] How do you respond?

A. It is true that market forwards are an important component of the OFPC. But I disagree with Sierra Club's conclusion that if the Company had created an ad hoc OFPC before December 1, 2013, it would have caused a reasonable utility to change course. What we know is that even using the December 2013 OFPC, the PVRR(d) remained favorable to the SCRs. We also know that, before December 1, 2013, the long-term forecast that the Company likely would have used to develop an ad hoc OFPC was higher than the September 2013 OFPC, higher than the December 2013 OFPC, and higher than the breakeven point. If natural gas prices were falling rapidly as Sierra Club claims, then market forwards in November 2013 were presumably

[10] The [redacted] forecast had a nominal levelized natural gas price of $5.41/MMBtu, which was six cents higher than the 2013 OFPC.
[11] Sierra Club/400, Fisher/4-8.

higher than at the end of December. This evidence suggests that an ad hoc November 2013 OFPC would have been higher than the actual December 2013 OFPC and would therefore have confirmed that the SCRs remained the lowest cost compliance option.

Q. Sierra Club also argues that the Company was "disingenuous" when it made the factual statement that two of the three third-party expert forecasts received after the September 2013 OFPC were above the breakeven point because what actually matters is that the forecasts had decreased relative to the same forecasts earlier in 2013.[12] How do you respond?

A. First, I disagree that it is "disingenuous" to point out that two of the three expert forecasts were above the breakeven point. That is a fact Sierra Club does not dispute, and it is ultimately the fact that matters.

Second, the decrease in each third-party expert forecast is not a fact on its own that would have caused a reasonable utility to dramatically change course. As Sierra Club notes, the decreases were modest, which hardly supports Sierra Club's conclusion that prices were falling "rapidly."[13] Sierra Club also ignores the fact that two of the three expert forecasts were higher than the September 2013 OFPC. If directionality is what actually matters, then the fact the experts were forecasting an increase relative to the most recent OFPC is meaningful. Most importantly, however, a reasonable utility would not change course at the last minute and pursue a higher cost alternative in the hopes that a trend of declining natural gas prices would

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[12] Sierra Club/400, Fisher/8.
[13] Sierra Club/400, Fisher/9; Sierra Club/100, Fisher/44.

continue in perpetuity. The Company's long-term resource decisions are not based on this kind of speculation.

Sierra Club agrees that "at some point the decision became binary,"[14] and that the binary decision to either pursue the SCRs or change course and pursue natural gas conversion was based on the *undisputed* fact that natural gas prices were above the breakeven point when the Company issued the FNTP on December 1, 2013.

Q. Even using the December 2013 OFPC, as Sierra Club does in its testimony, would the SCRs have been higher cost than natural gas conversion as of December 1, 2013?

A. No. Sierra Club points out that using the December 2013 OFPC the SCRs were still lower cost by $36.7 million.[15] At that time, the Company knew that the Engineering, Procurement, and Construction (EPC) contract costs were lower, which increased the PVRR(d) by $21 million. This shows a PVRR(d) of almost $58 million *in favor of the SCRs*. This figure provided a reasonable cushion to cover relatively minor fluctuations in coal costs, as described by Mr. Dana M. Ralston.[16] While this figure is lower than prior PVRR(d) results, it does not show that the binary decision favored natural gas conversion. A reasonable utility would not look at economic analysis favoring the SCRs and conclude that it should instead pursue the alternative just because the benefits of the SCRs had declined.

[14] Sierra Club/400, Fisher/11.
[15] Sierra Club/100, Fisher/52.
[16] In my reply testimony, I included a sentence that stated: "However Mr. Ralston shows that under the October 2013 mine plan, there were no coal cost increases at all." PAC/2300, Link/21, lines 14-15. This sentence should have stated that "However, Mr. Ralston shows that under the October 2013 mine plan, there were no material coal cost increases." As was made clear in Mr. Ralston's accompanying reply testimony, the October 2013 mine plan did result in a minor coal cost increase of approximately 2.8 percent, but this increase was well within the cushion for cost fluctuations described above.

Moreover, as discussed by Mr. James Owen, when the Company issued the FNTP on December 1, 2013, it knew that the estimated costs for natural gas conversion would have been substantially higher than those used in the SCR analysis, both because a change of course in December 2013 would have created a compressed schedule for conversion and because it had market-based evidence of conversion costs based on the proposal to convert Naughton Unit 3.[17] This means that the $58 million PVRR(d) in favor of the SCRs was conservative and the actual benefits of the SCRs relative to natural gas conversion were significantly higher. Taken together, these factors would have made it entirely unreasonable to change course and pursue a higher-cost, higher-risk compliance option.

Q. Given all the changes that had occurred before issuing the FNTP on December 1, 2013, why did you not rerun the SO model?

A. There was no need to rerun the SO model because the impact on the PVRR(d) of the changes that had occurred could be readily ascertained without the SO model. For example, the impact of changing natural gas prices was assessed using the breakeven analysis, which itself was derived from multiple SO model runs. The impact of changing EPC contract costs on the PVRR(d) was also easily determined and did not require an SO model run. An updated SO model run that included the updated inputs discussed above would not have selected a different compliance option.

An updated SO model run would have been necessary if there was a material change in system conditions that was not already thoroughly evaluated. For instance, if there was a material change in the load forecast or a material change in system

[17] *See* PAC/2500, Owen/16.

supply, an updated model run would be useful to ensure that those changes would not alter the results of the economic analysis. The Company had already thoroughly evaluated how changes in natural gas prices would affect the economic analysis. There simply were no other material changes, such as a change in the load forecast or system supply, that suggested an updated SO model run would be needed to inform the decision to proceed with installation of the SCRs on Jim Bridger Units 3 and 4.

B. <u>Alternative Scenario Analysis</u>

Q. The parties' testimony reflects some confusion concerning the Company's analysis of alternative early retirement scenarios. Can you please summarize the early retirement scenarios that the Company examined as part of its economic analysis of the SCR investments?

A. Yes. The Company's initial assessment compared the installation of the SCRs to two alternatives: natural gas conversion or retirement of Units 3 and 4 in 2015 and 2016, respectively. This analysis showed that installation of SCRs was the lowest cost alternative and that natural gas conversion was the next best, albeit higher cost alternative. Retirement of Units 3 and 4 in 2015 and 2016, respectively, was the highest cost alternative. As discussed in my direct testimony, retiring the units in 2015/2016 produced a PVRR(d) that was $588 million higher than the SCR alternative.[18]

The 2013 IRP was filed in the spring of 2013 before PacifiCorp made its decision to proceed with the SCRs. In the 2013 IRP, PacifiCorp analyzed an additional sensitivity exploring a phase-out scenario that assumed Jim Bridger Units 3

[18] PAC/700, Link/110.

and 4 could continue to operate without the SCR investments through 2020 and 2021, respectively.[19] It is my understanding that this sensitivity was generally analogous to the Boardman example, where Portland General Electric Company was able to negotiate a shut-down four years after the applicable compliance deadline.[20] At the request of Staff in the 2013 IRP docket, in December 2013, PacifiCorp produced another scenario in which the phase-out retirement dates were extended to 2022 and 2023.[21] These studies all showed that the SCR installations at Jim Bridger Units 3 and 4 were the lowest cost alternative. Indeed, the 2020/2021 retirement scenario had a PVRR(d) of $174 million in favor of the SCRs and the 2022/2023 retirement scenario had a PVRR(d) of $77 million in favor of the SCRs.

Q. Staff testifies that the Company was misleading when it stated that it had analyzed the 2022/2023 retirement scenario because the Company did not perform that analysis until Staff requested it, which occurred after the Company had committed to the SCR investment.[22] How do you respond?

A. My testimony did not state that the Company analyzed the 2022/2023 retirement scenario before December 1, 2013, and I never intended to suggest otherwise. But that analysis was performed using the same information that was available to the Company when it made the decision to move forward with the SCR investments.

[19] 2013 IRP, Confidential Volume III at Table V3.12.
[20] *See* Order No. 12-493 at 23-24.
[21] The Company provided the 2022-2023 retirement analysis to the parties in the 2013 IRP proceeding on December 13, 2013 (see PacifiCorp's response to OPUC DR 262).
[22] Staff/2300, Soldavini/8.

Q. Staff and CUB claim that the Company did not analyze a sufficient number of alternative scenarios before moving forward with the SCR investment.[23] How do you respond?

A. As discussed above, before issuing the FNTP on December 1, 2013, the Company analyzed several different compliance alternatives. Each analysis demonstrated that the SCRs were the least-cost, least-risk compliance option. Of course, the Company could have continued to analyze many more potential compliance options but, at some point, decisions must be made based on the best available information. The Company's analysis showed that the PVRR(d) favored SCRs in every alternative considered. Given the compliance timelines and the risks of delay, a reasonable utility would have moved forward with the SCR investments.

Moreover, as discussed by Mr. Owen, the Company's assessment of potential compliance alternatives was informed by what could have been realistically achieved. It makes little sense to study scenarios that would not have been approved by environmental regulators.

Q. Were there any other considerations specific to the Jim Bridger plant that informed the Company's assessment of potential early retirement scenarios?

A. Yes. Since the four Jim Bridger units were built between 1974 and 1979, the 2,100 megawatt plant has been an integral resource for PacifiCorp's customers. In 2013, the Jim Bridger plant represented approximately 20 percent of baseload capacity, on top of the plant's other important ancillary services such as voltage regulation, frequency regulation and response, energy imbalance correction, and

[23] Staff/2300, Soldavini/14; CUB/400, Jenks/32.

operating reserves. As noted in my reply testimony and discussed below, Staff's comments in the 2013 IRP docket highlighted the value provided by Jim Bridger when they recommended acknowledging the SCRs because Units 3 and 4 at Jim Bridger were not viable candidates for early retirement.[24]

Q. CUB argues that the Company refused to study coal plant retirement as a compliance alternative until after the Company had invested billions of dollars in emission control investments.[25] Is this claim relevant to the SCR investments at Jim Bridger Units 3 and 4?

A. No. CUB points to investments that predated the Jim Bridger SCR investments and that have already been addressed by the Commission in other dockets, including previous IRPs and rate cases. As discussed above, the Company did consider retiring Jim Bridger Units 3 and 4 as potential compliance alternatives to the SCR investment and further considered early retirement over different timeframes.

Q. Sierra Club and CUB argue that the Company should have also examined a potential retirement scenario where Units 3 and 4 were retired in 2023 and 2024.[26] How do you respond?

A. I disagree. As noted above, the retirement scenarios the Company analyzed consistently supported the SCRs. And again, as discussed by Mr. Owen, the Company's assessment of potential compliance alternatives was informed by what could have been realistically achieved in terms of early retirement scenarios.

[24] *See* PAC/2300, Link/37-38.
[25] CUB/400, Jenks/32-33.
[26] *See, e.g.*, Sierra Club/400, Fisher/12.

C. 2013 IRP

Q. CUB claims that the Company is relying on the analysis presented in its 2013 IRP without addressing the concerns raised by the Commission when it reviewed that IRP.[27] Do you agree?

A. No. As CUB's testimony points out, the Commission found that it may be more economical to retire Units 3 and 4 in 2022/2023 and, based on the information it had in the record, it could not "dismiss these results as unrealistic or unreasonable."[28] The more developed record in this case, however, addresses this issue.

First, as discussed by Mr. Owen, an alternative compliance scenario that assumed retirement in 2022/2023, or later, is not realistic based on what could have been negotiated with the federal and Wyoming regulators. These scenarios would have allowed the units to operate for an additional seven years or more past the compliance deadlines; in contrast, the Boardman plant early retirement extended operations for only four years.

Second, as discussed above, the 2022/2023 retirement scenario favored SCRs. And more importantly, simply because more than one option may be reasonable does not mean that selecting one of the two reasonable options is imprudent.

Third, the record in this case is more comprehensive than the record in the non-contested 2013 IRP acknowledgement docket. By their nature, contested cases, such as this rate case, include multiple rounds of testimony, a hearing where testimony is tested by cross examination, and briefing. The 2013 IRP, in contrast,

[27] CUB/400, Jenks/37.
[28] CUB/400, Jenks/36.

consisted of several rounds of comments, workshops, and a public meeting. While the 2013 IRP process was certainly robust, the record of evidence here is much more substantial.

Q. Staff claims that the Company should have included the Jim Bridger SCR investments in the 2011 IRP so that the Commission would have had sufficient time to review before the Company decided to move forward.[29] Do you agree?

A. No. As noted in my previous testimony, the 2011 IRP was filed on March 31, 2011. At that time, PacifiCorp's IRPs did not typically address specific coal plant emission control investments because it was not understood at the time that such an analysis fit within the purview of an IRP.

Q. Did the Company address potential emission control investments at Jim Bridger Units 3 and 4 in a supplemental filing in the 2011 IRP proceeding?

A. Yes. In response to stakeholder feedback, PacifiCorp produced a supplemental coal analysis in September 2011. The supplemental coal analysis updated and documented environmental compliance cost assumptions for PacifiCorp's coal fleet and broadened the scope of potential replacement resource alternatives in potential early retirement scenarios.

Q. What were the key findings from the 2011 supplemental coal analysis?

A. The 2011 supplemental coal analysis showed that continued operation of PacifiCorp's coal units, inclusive of costs for known and reasonably foreseeable environmental compliance obligations, was lower cost than early retirement.

[29] Staff/2300, Soldavini/17.

Q. Did PacifiCorp perform other coal analyses during the 2011 IRP cycle?

A. Yes. PacifiCorp worked with stakeholders to evaluate whether potential flexibility in emerging environmental regulations could be leveraged to avoid near-term compliance costs by committing to retire specific coal units before the end of their useful lives. PacifiCorp developed a spreadsheet-based, coal-screening model to prioritize specific coal units to analyze further. To support this effort, PacifiCorp held technical workshops with stakeholders to describe and discuss input assumptions, methodology, and results. High-priority coal units identified for further analysis were then further evaluated in an updated coal-replacement study that was included in PacifiCorp's 2011 IRP update. The high-priority coal units included Naughton Unit 3, Jim Bridger Units 3 and 4, Hunter Unit 1, Craig Units 1 and 2, and Hayden Units 1 and 2.

The updated coal-replacement study considered a broader spectrum of natural gas price and carbon dioxide price scenarios and broadened the scope of potential replacement resources to include wind resources, brownfield natural-gas conversion alternatives, and demand-side management alternatives. The updated analysis also accounted for potential flexibility in environmental compliance obligations and eliminated all incremental environmental compliance costs in the years preceding early retirement or conversion to natural gas.

Q. What were the key findings from the updated coal-replacement study that was included in PacifiCorp's 2011 IRP update?

A. The study showed that installation of equipment required to achieve environmental compliance was lower cost than early retirement or conversion to natural gas for Jim

Bridger Units 3 and 4. Thus, while the specific SCR investment decision was not presented to the Commission in the initial 2011 IRP filing (because it was too soon), the Company presented supplemental analysis examining alternatives to SCR investments at Jim Bridger Units 3 and 4, showing that the SCRs were the lowest cost alternative.

Q. Would there have been any other concerns over seeking Commission acknowledgment of the SCR investments at Units 3 and 4 in the 2011 IRP?

A. Yes. That IRP was developed years before the relevant decision-making point. Therefore, any analysis included in the 2011 IRP would have been necessarily preliminary. Many of the critical inputs, such as natural gas and coal price forecasts, and expected costs of SCR installation and natural gas conversion, would have been uncertain. While the Company could have presented its preliminary economic analysis in the 2011 IRP, we would have necessarily refreshed and updated that analysis in the same timeframe that occurred.

D. <u>Oregon Depreciable Life</u>

Q. Please describe the Company's SCR analysis that accounted for the 2025 depreciable life used for ratemaking in Oregon.

A. In 2013, the Company analyzed the SCR investment assuming a 2025 depreciable life and found that the PVRR(d) remained favorable to the SCRs. The Company's analysis did not assume that the Jim Bridger plant retired in 2025. Instead, consistent with the Company's 2013 IRP, the Jim Bridger plant was assumed to continue operating; it was just fully depreciated for purposes of Oregon rates.

Q. CUB faults the Company for not analyzing whether it was reasonable to assume that the Jim Bridger plant would continue operating beyond 2025.[30] AWEC presents a similar argument.[31] How do you respond?

A. In 2013, there was no basis to assume that the Jim Bridger plant would be uneconomic and retired in 2025. The Company's resource planning considered all the factors CUB identified—potential carbon regulation, emission control investments, future coal costs—and concluded that the economic life of Jim Bridger for purposes of resource planning was reasonably set at 2037.

Q. In the 2013 IRP docket, did Staff expressly recognize the importance of the Jim Bridger plant to the Company's system?

A. Yes. As part of its recommendation to acknowledge the SCR investments, Staff's comments acknowledged the "importance of the Bridger facility to PacifiCorp's system in that it provides a number of ancillary services to PacifiCorp's system, including voltage regulation, frequency regulation and response, energy imbalance correction and operating reserves to PacifiCorp's balancing authorities."[32] Staff concluded that "additional alternative analysis for Bridger would not have likely changed the outcome for Bridger because there are other coal plants in PacifiCorp's fleet that are better candidates for shutdown or gas conversion."[33]

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[30] CUB/400, Jenks/47-48.
[31] AWEC/500, Kaufman/6-7.
[32] *In the Matter of PacifiCorp's 2013 Integrated Resource Plan,* Docket No. LC 57, Staff's Public Meeting Memorandum at 18 (Mar. 4, 2014).
[33] *Id.*

Q. Is CUB's and AWEC's recommendation essentially a proposal for another retirement scenario in 2025 in lieu of the SCR investment?

A. Yes. As Mr. Owen explains, it is not realistic to assume PacifiCorp could have achieved compliance by retiring the Jim Bridger plant in 2025—10 years into the future.

Q. CUB also recommends that the Company recover the SCR costs only through 2025 as a way of calculating a proposed disallowance.[34] How do you respond to this recommendation?

A. CUB's proposed disallowance does not follow from the facts. According to CUB, Oregon customers would be paying for the removal of pollution that will be generated after the plant is fully depreciated because the Jim Bridger plant will be fully depreciated by 2025, while the SCR investment assumed a 20-year life.[35] Such a scenario, however, would not have harmed customers if they received the benefits of continued generation at the fully depreciated Jim Bridger plant, as the Company had planned for in 2013. CUB analogizes this scenario to customers paying for coal that is mined after 2025 and suggests there is an inequity if customers pay for coal that does not serve them. In that situation, however, it would be reasonable for customers to continue to pay the costs of coal for the Jim Bridger plant as long as the plant continues to serve customers, even if that occurs after the plant is fully depreciated. The same is true here.

[34] CUB/400, Jenks/50-51.
[35] CUB/400, Jenks/51.

Moreover, CUB's adjustment presumes that the SCR investment would have been uneconomic using a 2025 depreciable life for Jim Bridger Units 3 and 4. The Company's analysis shows this assumption is incorrect.

E. <u>Transmission Investments</u>

Q. For the first time in this docket, Sierra Club now claims that if Jim Bridger Units 3 and 4 were retired in lieu of the SCR investments, the Company could have avoided large transmission investments.[36] Does this argument have merit?

A. No. Sierra Club presumes that if Jim Bridger Units 3 and 4 were retired, there would be sufficient freed-up transmission in Wyoming that the Company would not need to build certain segments of its Energy Gateway West Transmission Expansion Project (Gateway West). As discussed below and in the testimony of Company witness Mr. Richard A. Vail, the investment in Gateway West is not dependent on continued operation of Jim Bridger Units 3 and 4 such that Gateway West, or a component thereof, could be avoided if these units were retired early.

Q. As background, what assumptions for the Energy Gateway Transmission Expansion Project were included in the Company's analysis?

A. The base case and scenario analyses performed by the Company assume that all segments of the Energy Gateway project will be implemented, including Gateway West, which connects Windstar to Populus and Populus to Hemmingway.

Q. Are any of the Energy Gateway transmission segments driven by the decision to install SCR equipment on Jim Bridger Units 3 and 4?

A. No. The decision to install SCR equipment at the Jim Bridger plant is independent of

[36] Sierra Club/400, Fisher/23.

the decision-making process for Energy Gateway transmission investments. Gateway West will provide reliability benefits, increase access to low-cost generation resources, and allow for a more efficient use of system resources, as evidenced by the accelerated construction of Gateway West Segment D.2 and the interconnection of new wind resources facilitated by the line. Indeed, in the 2013 IRP, the Company's analysis showed that Gateway West could provide potential system-wide net benefits of $231 million.[37]

Sierra Club's argument is flawed because it incorrectly assumes a causal relationship between Gateway West (or, more specifically, the segment from Bridger to Populous) and continued operation of Units 3 and 4. Based on this incorrect assumption, Sierra Club incorrectly assumes that all of the cost savings associated with removing the Bridger to Populus transmission project from the analysis should be assigned to a potential decision to retire Jim Bridger Units 3 and 4, without accounting for the loss of benefits that this transmission line would provide to customers. In short, Sierra Club's position fails to recognize the long-term benefits associated with this potential transmission investment and the independent relationship between Gateway West and Jim Bridger Units 3 and 4.

Q. Sierra Club claims that the Company admitted in 2013 that, if Jim Bridger Units 3 and 4 were retired, it could reduce the need for the Bridger to Populous segment of Gateway West.[38] Do you agree?

A. No. Sierra Club quotes a Company data request response from the Wyoming SCR

[37] 2013 IRP at 67.
[38] Sierra Club/400, Fisher/28.

proceeding where the Company explained: "Retirement of Bridger Units 3 and 4 would not avoid the need for Gateway West[.]" This is hardly an admission that retiring Jim Bridger Units 3 and 4 would allow the Company to avoid Gateway West when the response says the opposite.

Q. Has Sierra Club provided any evidence that portions of Gateway West could actually have been avoided if Jim Bridger Units 3 and 4 were retired?

A. No. Sierra Club simply assumes this is true and then misrepresents a Company data request to purportedly confirm Sierra Club's assumptions. As discussed by Mr. Vail, however, there is no basis for assuming that retiring Jim Bridger Units 3 and 4 would have obviated the need for Gateway West, or segments thereof, and therefore the Company's modeling was not flawed for failing to account for such an unrealistic scenario.

Q. Sierra Club's supplemental rebuttal testimony reiterates its argument that the Company's sensitivity study that removed incremental transmission investment from both the with- and without-SCR scenarios did not address Sierra Club's claims.[39] How do you respond?

A. Sierra Club's supplemental testimony generally repeats the same argument made in its rebuttal testimony. Both arguments rest on the incorrect assumption that by not installing SCRs the Company could have avoided certain transmission investments. As explained by Mr. Vail, however, even if Jim Bridger Units 3 and 4 were retired, there would have been no basis for the Company to avoid constructing segments of

[39] Sierra Club/600, Fisher/3.

Gateway West. Because Sierra Club's argument rests on an incorrect assumption, it does not support any adjustments to the Company's PVRR(d) analysis.

Q. Sierra Club claims the Company did not show that retiring Jim Bridger Units 3 and 4 would have avoided transmission investment when Sierra Club raised this issue in Utah and Wyoming.[40] How did the Wyoming Commission address Sierra Club's argument?

A. The Wyoming Commission found Sierra Club's argument unpersuasive. In particular, the Wyoming Commission noted that Dr. Fisher "glosse[d] over the fact that the other parties have not ignored transmission," including PacifiCorp.[41] The Wyoming Commission "put more weight on the testimony of witnesses who have actually done calculations, and [did] not find Fisher persuasive."[42]

Q. How did the Utah Commission address Sierra Club's argument?

A. Similar to Wyoming, the Utah Commission also found Dr. Fisher unpersuasive:

> . . . Sierra Club argue[s] the Company does not properly account for the costs of certain Energy Gateway transmission investment which, they claim, would be avoided if Bridger Units 3 and 4 were retired. We find the Company's sensitivity case which retires Bridger Units 3 and 4 and cancels certain Energy Gateway transmission investment, and consequential wind resource investment, shows this alternative would be higher cost than the Project. We are not persuaded by WRA or Sierra Club this sensitivity analysis is flawed because it removes more of the Energy Gateway project than they consider appropriate for the scenario. Based on the Company's testimony, *we are neither persuaded the Company may cancel select portions of transmission segments as suggested by WRA*

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[40] Sierra Club/400, Fisher/31.

[41] *In the Matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4 Located Near Point of Rocks, Wyoming*, Wyoming PSC Docket No. 20000-418-EA-12 (Record No. 13314), Memorandum Opinion, Findings and Order Granting Application for a Certificate of Public Convenience and Necessity at ¶ 51 (May 29, 2013) (emphasis added).

[42] *Id*.

> *and Sierra Club; nor are we convinced if it did, the savings would outweigh the higher cost of the required replacement power*. We conclude the evidence in this case does not support a conclusion that cost savings from avoiding segments of Energy Gateway transmission outweigh the benefits of the Project.[43]

Q. Sierra Club's supplemental testimony claims that the Company misrepresented the Utah Commission's order because, according to Dr. Fisher, the Company "knows that the Utah Commission did not understand [the] sensitivity."[44] How do you respond?

A. I disagree that my prior testimony misrepresented the Utah Commission's finding. As the excerpt above explains, the Utah Commission appeared to understand Dr. Fisher's adjustment and rejected it. Dr. Fisher omits the fact that the Company's testimony in the Utah SCR proceeding included both the sensitivity that I described in my previous testimony and explained that the decision to install the SCRs was unrelated to the need for Gateway West transmission segments, and therefore the Company could not avoid investing in transmission resources if it had retired Jim Bridger Units 3 and 4. The Utah Commission specifically found that, "Based on the Company's testimony, we are [not] persuaded the Company may cancel select portions of transmission segments as suggested by WRA and Sierra Club[.]" This suggests to me that the Utah Commission understood Sierra Club's argument and found the Company's testimony persuasive.

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[43] *In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4,* Utah PSC Docket No. 12-035-092, Redacted Report and Order at 30 (May 10, 2013) (hereinafter Utah SCR Order)(emphasis added).
[44] Sierra Club/600, Fisher/8.

III. HUNTER UNIT 1 BAGHOUSE AND LOW NO_X BURNERS

Q. AWEC repeats its claim that if the Hunter plant were retired in 2029, then the emission control investments would have been uneconomic.[45] Did AWEC provide any additional evidence to support this argument?

A. No. The Company provided testimony refuting AWEC's analysis and showing why a 2029 retirement date was flawed.[46] In response, AWEC simply argues that the Company misinterpreted and discredited its analysis. I disagree that the Company misinterpreted Dr. Kaufman's analysis, although my testimony did explain that it was unclear how AWEC performed its adjustment and Dr. Kaufman's testimony and workpapers appeared inconsistent. I agree with Dr. Kaufman, however, that the Company's testimony ultimately discredited his analysis.

Q. Did AWEC respond to the Company's evidence refuting Dr. Kaufman's claim that a 2029 retirement date would render the emission control investments uneconomic?

A. No. AWEC neither clarified nor defended its previous testimony.

IV. COAL PLANT EXIT DATES

Q. Sierra Club continues to argue that the 2019 IRP showed the "precarious economic position of the Company's coal fleet[.]"[47] Do you agree?

A. No. Sierra Club clarified that this statement refers to Table R.4 of Appendix R of the 2019 IRP. Based on that table, Sierra Club claims there would be customer savings from retiring most of the Company's coal units individually in 2022, including

[45] AWEC/500, Kaufman/6.
[46] PAC/2300, Link/48-49.
[47] Sierra Club/500, Hausman/11.

Hunter, Huntington, and Wyodak units.[48] Sierra Club acknowledged that the data did not show the economics of retiring more than one unit in combination and Dr. Hausman admits he is "mindful of the numerous caveats in the associated text" of the 2019 IRP explaining Table R.4.[49]

Q. Did Sierra Club explain the "numerous caveats" related to Table R.4?

A. No. Those caveats, however, are critical to understanding the limitations in the study results cited by Sierra Club and explain why the Company disagrees that those study results show that the Company's coal units are in a "precarious economic position[.]" As the 2019 IRP explained, the results in Table R.4 were based on a preliminary screening study, "the potential benefits of retiring more than one unit would not be the same as adding up the potential benefits from the unit-by-unit results," and the study results do "not account for the costs to remedy capacity shortfalls" necessary to maintain a reliable system as each coal unit was retired (costs which were addressed in the next phase of the coal analysis).[50] This means that the results cited by Sierra Club showing potential customer savings from early coal unit retirements omitted potentially significant replacement capacity costs required for reliable service that, when accounted for, would have created a very different PVRR(d) result for each unit and would influence the results of multiple unit retirement scenarios in ways that cannot not be inferred from the unit-by-unit studies. These issues were subsequently addressed in a more comprehensive analysis of coal unit retirements. While I appreciate that Dr. Hausman was apparently aware of this important caveat, it is

[48] Sierra Club/500, Hausman/11.
[49] Sierra Club/500, Hausman/11.
[50] 2019 IRP, App. R at 597.

troubling that he chose to leave that caveat unstated when making the blanket allegation that the Company's coal fleet is in a precarious economic position.

Q. Do you have any other concerns with Sierra Club's selective reliance on the 2019 IRP?

A. Yes. Sierra Club's testimony focused only on the SO model results. The more comprehensive stochastic analysis performed by the Planning and Risk (PaR) model, however, showed different results. For example, under base case assumptions, the PaR model showed that retirement in 2022 was higher cost for the Hunter, Huntington, and Wyodak units, except for Huntington Unit 2, which showed neither a customer benefit nor a customer harm.

Q. Is PacifiCorp assessing its long-term resource strategies in light of COVID-19 and the changing regulatory landscape in Oregon?

A. Yes. The Company's 2021 IRP, which is currently in development, will address in a holistic and comprehensive manner COVID-19 and recent political and regulatory changes since the 2019 IRP. As Sierra Club acknowledges,[51] the IRP is the proper forum to address the broader system-wide impact of these changes, not a general rate case where the Company has a matter of weeks to prepare responsive testimony and analysis. The 2021 IRP will therefore provide the analysis Dr. Hausman recommends if the Commission rejects his 2025 Exit Dates—*i.e.*, an updated IRP analysis based on current load and market prices, along with updated resource costs and the social cost of carbon.[52]

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[51] Sierra Club/500, Hausman/7.
[52] Sierra Club/500, Hausman/13.

Q. Do you have any other responses to Sierra Club's testimony regarding the coal plant Exit Dates?

A. No. PacifiCorp witness Ms. Etta Lockey provides the Company's response to the remainder of Sierra Club's recommendations.

V. SCHEDULE 272 INVESTIGATION

Q. Do any parties propose limiting PacifiCorp's ability to enter into future agreements like Pryor Mountain under Schedule 272?

A. Yes. Staff witness Mr. Storm proposes restricting PacifiCorp's ability to enter into future utility-owned agreements under Schedule 272, pending the outcome of a new investigation to determine whether utility-owned resources under Schedule 272 meet the guidelines for the Voluntary Renewable Energy Tariff.[53]

Q. Do you believe that the proposed investigation and restriction are necessary or appropriate at this time?

A. No. PacifiCorp does not anticipate entering into another Schedule 272 agreement involving a utility-owned facility in the foreseeable future. If the Company is presented with an opportunity to achieve substantial customer benefits involving a utility-owned facility in the future, PacifiCorp agrees that it would meet and confer with stakeholders before proceeding with the transaction. In addition, the Company understands that no party opposes the ongoing use of Schedule 272 in conjunction with power purchase agreements. Therefore, neither an investigation nor the proposed restriction on using Schedule 272 are necessary or appropriate at this time.

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[53] Staff/2000, Storm/35.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

ERRATA
REDACTED
Docket No. UE 374
Exhibit PAC/3900
Witness: Robert Van Engelenhoven

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

ERRATA
REDACTED
Surrebuttal Testimony of Robert Van Engelenhoven

August 2020

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ATTACHED EXHIBITS

Exhibit PAC/3901—PacifiCorp's Email Correspondence with Kiewit Representatives

Confidential Exhibit PAC/3902—Letter from Kiewit Regarding Independent Evaluation Report Submitted to Public Utility Commission of Oregon on June 21, 2020

Q. Are you the same Robert Van Engelenhoven that submitted direct and rebuttal testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this case?

A. The purpose of my surrebuttal testimony is two-fold. First, I provide a construction status update regarding the Pryor Mountain Wind Project. Second, I respond to the Rebuttal and Cross-Answer Testimony of the Public Utility Commission of Oregon (Commission) Staff witness Mr. Steve Storm,[1] Oregon Citizens' Utility Board (CUB) witness Mr. Bob Jenks,[2] and the Alliance of Western Energy Consumers (AWEC) witness Dr. Lance D. Kaufman[3] regarding the Decommissioning Studies performed by Kiewit Engineering Group, Inc. (Kiewit). I also address the Independent Evaluator's (IE) Report on the Decommissioning Studies, which is attached to Mr. Storm's testimony.[4]

Q. Please summarize your surrebuttal testimony.

A. In my surrebuttal testimony, I provide an update regarding the cost and construction status of the Pryor Mountain Wind Project with respect to impacts of the COVID-19 pandemic. I also conclude that the Decommissioning Studies meet the requirement of an Association for the Advancement of Cost Engineering (AACE) Class 3 estimate

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[1] Staff/1700 filed on July 17, 2020.
[2] CUB/300 filed on July 17, 2020.
[3] AWEC/400 filed on July 17, 2020; Dr. Kaufman provided additional rebuttal testimony on decommissioning costs in testimony filed on July 24, 2020.
[4] Staff/1701.

and are appropriate for inclusion in rates. Ms. Etta Lockey discusses this further in her surrebuttal testimony.

II. PRYOR MOUNTAIN WIND PROJECT

Q. In reply testimony, you stated that you would provide an update regarding the impacts of COVID-19 on the construction status of the Pryor Mountain Wind Project. What is the current construction status of the Project?

A. As described in my reply testimony, as a result of the COVID-19 pandemic, the Company has received force majeure notices from most suppliers and contractors providing materials or service for the Pryor Mountain Wind Project. In general they claim disruption to the global supply chain caused by the pandemic. The Company continues to review the notices to substantiate whether the notices represent valid claims and are directly linked to the pandemic. PacifiCorp also continues to review the information provided by suppliers and contractors as the situation with the pandemic continues to evolve. Our primary focus has been to ensure the safety of the workers at the site by following the guidelines established by the Centers for Disease Control and Prevention to control the spread of the COVID-19 virus. To date we have had no confirmed cases of the COVID-19 virus within the workforce at the Pryor Mountain Wind Project.

Wind turbine components supplier, Vestas-American Wind Technology, Inc. (Vestas), has provided notice of delayed deliveries of all wind turbine components due to the force majeure event. Wind turbine component delivery has been a particularly dynamic situation. In July 2020, some of the supply and transportation issues started to stabilize and Vestas provided a schedule indicating that deliveries would be completed the week of November 23, 2020. This represented a six-week delay and pushed the construction of the project well into the high-wind, winter period. To work safely, wind turbine construction cannot take place with wind speeds over 25 miles per hour, thus limiting the time available to work due to increased daily wind speeds starting late in September. The Company negotiated a change order with Vestas to adjust the schedule to complete the wind turbine component deliveries by the week of November 2, 2020. This revised schedule has been forwarded to the balance of plant (BOP) contractor so that they can update their costs and schedule. The Company continues to negotiate the revised costs and schedule with the BOP contractor, with an objective to economically place in service as many of the wind turbines as possible in 2020.

III. DECOMMISSIONING STUDIES

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my surrebuttal testimony, I will address the testimony of Staff witness Mr. Storm, CUB witness Mr. Jenks, and AWEC witness Dr. Kaufman regarding the Decommissioning Studies prepared by Kiewit and the IE Report on them. I first address overall recommendations and claims made by Messrs. Storm and Jenks and Dr. Kaufman. I then address certain specific assertions made and conclusions reached regarding the Decommissioning Studies by the IE and the parties.

A. Overall Comments to the Decommissioning Studies by Staff, CUB, and AWEC

Q. Staff, CUB, and AWEC argue that there is no support for the Decommissioning Studies.[5] Do you agree?

A. No. The Staff, CUB, and AWEC arguments are related to the conclusion that the IE Report reaches regarding (1) the information provided by PacifiCorp to Kiewit; and (2) access to Kiewit and its subcontractors' workpapers. The Company appreciates the review performed by the IE; however, the IE's criticisms of the Decommissioning Studies are in error. First, as I explain later in my testimony, the IE Report reflects a misunderstanding about information that was supplied by PacifiCorp to Kiewit to perform the Decommissioning Studies and what costs from the Decommissioning Studies are included for recovery in depreciation rates. The errors may have resulted from the fact that the IE [redacted].[6] [redacted] In the end, because of the [redacted] and a misunderstanding of certain data, the IE reviewed the process undertaken to develop the Decommissioning Studies and not the estimated costs.

Second, the IE Report states that without access to the [redacted]

[5] Staff/1700, Storm/36:17-37:9; CUB/300, Jenks/4:3-15; AWEC/400, Kaufman/1:15-20.
[6] The IE states [redacted] Staff/1701 at 4, IE Report, Section I.

[redacted][7] With respect to the workpapers of Kiewit and its subcontrctors, the reluctance of these third parties to share workpapers that contain proprietary information, such as pricing data and modeling, is not surprising. Kiewit, a third-party engineering firm, and its specialized subcontractors are experienced in the decommissioning, demolition, and reclamation of coal-fueled gas fired plants and public disclosure of such information would place them at a competitive disadvantage relative to competitors that may be bidding for the same or similar work in the future. The refusal to provide workpapers would likely occur with any third-party specialized engineering firms and contractors engaged by the Company to perform a decommissioning study.

Further, it is my understanding that the IE's Statement of Work provides:

> As a component of the Independent Evaluator Review, Contractor is to prepare and deliver an AACE Class 3 cost estimate for each item in PacifiCorp's Study where Contractor does not concur with the methodology used or with the cost estimate (or the range of cost estimates) obtained in PacifiCorp's Study. Additionally, Contractor is to prepare and deliver an AACE Class 3 cost estimate for those items that were not included in PacifiCorp's Study which Contractor believes should have been included.[8]

Thus, if the IE rejected the entirety of the Kiewit assumptions, it was within the IE's Statement of Work to prepare an AACE Class 3 estimate. I believe that if the IE had an understanding of the PacifiCorp-provided information and the costs that were included in the base estimate, an AACE Class 3 estimate could have been performed to validate the Decommissioning Studies.

[7] Staff/1701, IE Report at 6.
[8] Docket No. UE 374, Staff Report dated May 6, 2020, Attachment C at 16.

Q. Do you agree with Mr. Storm and Dr. Kaufman that there is a transparency issue resulting from the lack of supporting workpapers for the PacifiCorp-provided information and the Kiewit supporting workpapers?[9]

A. No. There is a misunderstanding among the IE and the parties about the information provided by PacifiCorp to Kiewit to perform the Decommissioning Studies. Further, as I noted above, the unavailability of Kiewit's workpapers should not have impacted the IE from validating the estimates of decommissioning costs.

Q. Are parties bound by the results of the Decommissioning Studies prepared by Kiewit?

A. No. In their rebuttal testimony, Dr. Kaufman and Mr. Storm appear to refer to a statement in my reply testimony regarding AWEC proposing adjustments as an improper end run around the process set forth in the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol to develop updated decommissioning costs.[10] My statement was not directed toward AWEC's ability to review and make recommendations regarding the Decommissioning Studies but was directed to the timing of AWEC's proposals because they were made before the IE issued its report.

Q. Do you agree with Dr. Kaufman's assertion that the IE Report supports his conclusion that PacifiCorp has an incentive to overestimate decommissioning expense?[11]

A. No. The Decommissioning Studies represent an independent third-party estimation of the cost to decommission, decontaminate, demolish, and reclaim the sites of the

[9] Staff/1700, Storm/28:21-29:7.
[10] AWEC/500, Kaufman/39:1-24; Staff/1700, Storm/36:1-16, referring to my testimony at PacifiCorp/2400, 14:1-7.
[11] AWEC/400, Kaufman/6:4-8.

Company's coal-fired plants. As explained further in Ms. Lockey's testimony, it is in the public interest to ensure the correct estimated depreciation costs are reflected in the Company's rates.

Q. Mr. Storm testifies that the Company "has provided no support indicating it requested that Kiewit provide [its workpapers] nor any support indicating that Kiewit objected to such a request."[12] How do you respond?

A. The Company asked Kiewit two times over the course of this proceeding if Kiewit would provide its supporting workpapers for the Decommissioning Studies. First, on May 26, 2020, following the receipt of discovery requesting the workpapers, PacifiCorp sent Kiewit an email requesting that Kiewit provide supporting workpapers. Second, on July 23, 2020, in an email to Kiewit, PacifiCorp expressed Staff concerns regarding the supporting workpapers and asked if Kiewit and the subcontractors would enter into a nondisclosure agreement (NDA) with Staff to share workpapers. Kiewit declined to provide supporting workpapers or enter into an NDA with Staff. Please see Exhibit PAC/3901 for PacifiCorp's email correspondence with Kiewit representatives.

Q. Dr. Kaufman criticizes the Company for not including in its contract with Kiewit a provision requiring Kiewit to provide supporting workpapers for the Decommissioning Studies.[13] He adds that when asked in a discovery request to explain why supporting workpapers were not requested, the Company declined to respond. How do you respond?

A. I disagree with Dr. Kaufman's characterization of the Company's response to data

[12] Staff/1700, Storm//29:12-14.
[13] AWEC/500, Kaufman/36:9-14.

request AWEC 140. In that response, the Company explained that the processes, calculations, work papers and information sources used by consultants and subcontractors for these types of studies are typically proprietary, confidential, intellectual property and trade secrets. As I explained earlier, consultants and subcontractors typically consider this information to be essential to maintaining their competitive position.

Q. Is Mr. Chad A. Teply's supplemental testimony regarding the original decommissioning study and your reply testimony inconsistent regarding whether the original depreciation study included site reclamation as Mr. Storm asserts?[14]

A. No. I disagree with Mr. Storm's characterization of Mr. Teply's testimony, Exhibit PAC/1700, which I have adopted, and my reply testimony, Exhibit PAC/2700. The statements made in each testimony are consistent. In response to the question "[i]s PacifiCorp proposing changes to decommissioning costs in the Depreciation Study for the company's thermal generation resources," Mr. Teply responds in part by stating that the original decommissioning study (1) was performed in the 2014 and 2016 time frame; and (2) included plant demolition, ash pile and ash pond abatement and closure, asbestos and other hazardous materials abatement and remediation, and final site cleanup and restoration as applicable to each plant.[15]

As a point of clarification, the decommissioning cost studies performed in the 2014 to 2016 timeframe referred to by Mr. Teply were updated with a 2017 demolition study, which did not include reclamation, owner's costs or site specific

[14] Staff/1700, Storm/34:19-35:18.
[15] PAC/1700, Teply/11:13-12:5.

items. The decommissioning costs included in PAC/1702 reflect the 2017 demolition update. Further, when describing the decommissioning costs included in PAC/1702, Mr. Teply does include "final site cleanup and restoration," which means that the site would not have any structures or debris; final grading of the site would have left the site in a condition that would be noticeably different than the surrounding terrain; and the site would include drainage control and may or may not have top soil covering the site. By comparison, reclamation costs include those costs that would leave the property in its natural condition, in other words, a condition that would require close observation to determine that a facility has previously been located at the site and would have local top soil and be planted with native vegetation. Thus, the statements made in Exhibit PAC/1700 and in my reply testimony are consistent.

Q. Dr. Kaufman asserts that the Company did not respond to all of his individual proposals regarding decommissioning costs.[16] How do you respond?

A. Burden of proof will be addressed in the Company's briefs, but, while I am not an attorney, it is my understanding that a party proposing an adjustment to the Company's case has the burden of proof going forward with its proposal. Dr. Kaufman's proposals did not provide any basis or support for how he arrived at his conclusions. Having made a proposal, it is AWEC's responsibility to support its proposal.

Q. Dr. Kaufman asserts your claim that AWEC was not consistent in applying its adjustment across all coal-fired plants is unsupported.[17] How do you respond?

A. The approach to preparing the estimates for the Decommissioning Studies was to

[16] AWEC/500, Kaufman/36:15-38:13.
[17] AWEC/500, Kaufman/38:5-11.

apply a consistent design basis to the estimates for all the facilities in the Studies. Dr. Kaufman offers adjustments for certain categories without providing a basis for those recommendations, which allows AWEC to pick and choose adjustments at its discretion. This is contrary to the design of the Decommissioning Studies, which is to apply consistent assumptions across all sites to define 10-40 percent of the project scope. The adjustments Dr. Kaufman proposes are the type of the refinements that will be made as the remaining 60-90 percent of scope is determined, in other words when the Company prepares to decommission the site.

For example, Contractor estimates (Section 5.9 and 5.91 of the Decommissioning Studies) are based on work that the Company expects to engage contractors to perform. These assumptions are reasonable based on having 10-40 percent of the project scope defined. However, at the time each plant is retired (when the remaining scope of the project is better defined), the Company will refine these estimates based on the circumstances at the time. These Decommissioning Studies take an incremental step to improve the estimates reflected in the original depreciation study.

B. Estimates Developed by Kiewit in the Decommissioning Studies

Q. The IE Report states [redacted][18] Is it appropriate to combine these cost categories?

A. No. Including items in the "Other Items to be Considered" section results in a significant distortion of the cost to decommission, decontaminate, demolish, and reclaim the site of a coal-fired plant. The IE's conclusion stems from a misunderstanding about the scope of Kiewit's responsibility and the information provided by PacifiCorp to Kiewit to complete the studies. In the Decommissioning Studies, costs are broken down in two categories: (1) the base estimate to decommission, decontaminate, demolish, and reclaim the site; and (2) "Other Items to be Considered." The "Other Items to be Considered" category includes (1) items included for transparency purposes, such as materials and supply (M&S) inventory; and (2) items for which the Company did not have a good cost estimate, such as coal pile excavation and haul off.

The Kiewit Decommissioning Studies makes this distinction. In Section 5 of each Decommissioning Study,[19] Kiewit sets forth the general cost categories that the base estimate includes. In Section 5.14 of each Study, Kiewit lists the costs included

[18] Staff/1701 at 18.
[19] PAC/1900 at 20; PAC/1901 at 21.

in the "Other Items to be Considered" category that are not reflected in the base estimate and states that certain items are outside the base scope of the estimate.[20] More specifically, in Section 6.1 of each Decommissioning Study, Kiewit describes the cost estimates as follows:

[redacted]

Q. Appendix A to the IE Report indicates that category 2b, in the Decommissioning Cost Evaluation Spreadsheet, write down of M&S Inventory Sale and Disposal, [redacted] How do you respond?

A. This is a good example of why the items in the "Other Items to be Considered" category cannot be included in the base estimate. This transaction is not charged to the cost to decommission, decontaminate, demolish, and reclaim the site of a coal-fired plant. Please see the direct testimony of Ms. Shelley E. McCoy[22] and the supplemental testimony of Mr. Steven R. McDougal[23] for how "Other Items to be Considered," including M&S Inventory, are reflected in rates. The value included in

[20] PAC/1900 at 37; PAC/1901 at 33.
[21] PAC/1900 at 39; *see also* PAC/1901 at 36. (emphasis added)
[22] PAC/1300, McCoy/23:15-24:7.
[23] PAC/1800, McDougal/4:1-5:5.

the report was the actual book value of M&S Inventory at the time the Decommissioning Studies were prepared. Because the item was provided for transparency purposes, providing the list of all M&S Inventory at the time the study was performed was not practical or necessary for the completion of the Decommissioning Studies because this item does not impact the base estimate. As a result, this item does not impact the accuracy of the base estimate and [redacted].

Another example is the IE's treatment of the cost of the Bridger Coal Mine Closure. The IE [redacted] This cost is not charged to the decommissioning, decontamination, demolition, and reclamation of the coal-fired plants. The cost of the Bridger Coal Mine Closure was not included in Kiewit's scope of work, but was provided for transparency purposes. This item does not impact the accuracy of the base estimate [redacted]. See the direct testimony of Ms. McCoy and the supplemental testimony of Mr. McDougal for how the Bridger Coal Mine Closure costs are reflected in rates.

Q. Regarding M&S Inventory, Dr. Kaufman claims that the Company has admitted that it can be repurposed to other coal-fired plants.[24] How do you respond?

A. Dr. Kaufman mischaracterizes the Company's response to data request AWEC 141, where the Company stated:

> The *small portion* of materials and supplies (M&S) that are consumables *may be usable* at a generating facility that is not being decommissioned. The majority of the M&S are specific to the equipment at the generating facility that will be

[24] AWEC/500, Kaufman/37:5-6.

> decommissioned. These M&S are not usable at a generating facility that will continue operation.
>
> Generating facilities typically have all of the rolling stock needed to operate each generating facility based on the design, equipment and needs of each individual facility. Generating facilities that are not decommissioned will have little or no need or use for additional rolling stock. Transferring unneeded rolling stock to a generating facility will increase operating costs.
>
> Company-owned railcars are only used at the Jim Bridger generating facility. No other PacifiCorp generating facility has a need or use for railcars.[25]

The M&S Inventory includes items that are plant-specific to each of the coal-fired plants. As an owner and operator of coal-fired plants, it is PacifiCorp's experience that there is no market for these items because they cannot be used in other plants.[26] Thus, without a specific recommendation as to how the items in M&S Inventory can be re-purposed, AWEC's conclusion that an adjustment is required should be rejected.

Q. The IE Report also states that [redacted][27] **How do you respond?**

A. I disagree with the IE based on the purpose of the "Other Items to be Considered" cost category as I describe above.[28]

[25] AWEC/501 at 24. (emphasis added).
[26] However, at the time each plant is retired, the Company will perform its due diligence to determine if there is a market for a particular plant's inventory.
[27] Staff/1701 at 5, IE Report, Section I.
[28] The IE provides percentages of information that he claims PacifiCorp provided to Kiewit but Company was unable to reproduce these values.

Q. What information did PacifiCorp provide to Kiewit to calculate the base estimate to decommission and reclaim coal plant sites?

A. PacifiCorp provided (1) the Asset Retirement Obligation (ARO) for each plant with asbestos removal separated out, which I address later in my testimony; and (2) owner's costs. In general, PacifiCorp also provided physical attributes of each coal plant, including depth of excavation for the clean-up of the coal piles, so that Kiewit could properly estimate the base estimate for each coal fired plant.

Q. What are owner's costs and why did PacifiCorp provide these estimates to Kiewit?

A. Owner's costs include three types of costs: development labor, project management, and owner's workforce. Development labor costs includes internal labor costs for project development, project planning, the cost of identifying the scope of the project, conducting surveys of hazardous materials (other than the asbestos containing material (ACM) survey), obtaining permits, hiring an owner's engineer, issuing a request for proposal and evaluating the proposals, negotiating the demolition, and any other work required up to signing the demolition contract.

Project management costs include internal labor costs for the project manager, site manager and inspectors; permit fees; utility turn offs; and any other work required during project execution. Owner's workforce costs include internal labor costs to prepare to turn the coal-fired plant over to the demolition contractor, which includes, but is not limited to, the labor associated with removal of bottom and fly ash from boiler including economizer, silos, ductwork, baghouse, etc., insofar as possible, and transportation to the landfill; flushing and removing waste from scrubbers;

removal of residuals, wastes, and other debris from ponds and other areas; drain, as much as practical, oil and lubricants from equipment; isolating, purging and venting of natural gas lines, if any; draining of boilers and water tanks; and disconnection and isolating all sources of energy.

Owner's costs also include the owner's engineering fees for the development (preparation of specifications and assisting in evaluating proposals) and execution (technical support during demolition and reclamation) of project.

PacifiCorp estimated these labor costs, and provided them to Kiewit because the Company is in the best position to estimate these costs as owner of the coal-fired plants and having had experience with the demolition of the Carbon generating facility. Please see the direct testimony of Ms. McCoy and the supplemental testimony of Mr. McDougal for how the "Other Items to be Considered" are reflected in rates.

Q. In your review of the IE Report did you identify instances where the IE incorrectly identified the source of information as being PacifiCorp?

A. Yes. The following list of costs in the IE Report have been identified as being provided by PacifiCorp when in actuality the cost estimate was developed by Kiewit:

- Line 2a: Owner's Engineer
- Line 3d: Underground Pipe ACM removal and disposal (non-ARO): Drawings, specifications and documentation from the original installation of underground piping were provided to Kiewit. Kiewit developed the cost estimate for removal of the underground pipe. I note that in its review, Kiewit identified an asbestos removal issue.
- Huntington Line 6a: Off-site Pumphouse at the River Diversion Intake Structure;
- Huntington Line 6e: Electric Lake Removal;

- Dave Johnston Line 6a: Dam Removal;
- Hayden Line 6e: Rail Removal; and
- Colstrip Units 3 and 4 Line 6f: Raw water pipeline.[29]

Q. In Section V of the IE report, Assessment of Assumptions Used in the Studies, the IE asserts that [redacted].[30] How do you respond?

A. As noted in the IE Report, a characteristic of AACE Class 3 estimate is that the maturity level of project definition deliverables should be between 10 and 40 percent of the total project definition.[31] The time and funding to characterize the items in the manner identified in the report were not available. However, more importantly, characterizing all of the items described in the report would have gone beyond the 40 percent of the total project definition specified as the primary characteristic of a Class 3 cost estimate. The work completed is still within the limits of an AACE Class 3 estimate.

For example, [redacted] To drill all sites for the Studies would have taken additional lengthy amount of time to complete and would have exceeded the level of scope definition for an AACE Class 3

---

[29] This has also been confirmd by Kiewit. See PAC/3902. PacifiCorp provided Kiewit the IE Report. In a letter to PacifiCorp, Kiewit provided its comments to the IE Report, which I have attached to my testimony.
[30] See, for example, Staff/1701 at 14-17.
[31] Staff/1701 at 12.

estimate. Therefore, the Company made an assumption based on previous experience.

Q. Regarding the assumption that 10 feet of soils below the coal piles be removed, what previous experience was this assumption based on?

A. Excavating to 10 feet below the coal piles is an appropriate assumption based on the Company's experience decommissioning and demolishing the Carbon generating facility. Given that the design of the Decommissioning Studies is to apply consistent assumptions across all sites to achieve a 10-40 percent project scope, this is an appropriate assumption. Attempts to reduce the assumption as suggested by Dr. Kaufman[32] and Mr. Storm[33] is not appropriate. This type of refinement will be made when the Company prepares to decommission the site.

Q. The IE Report states that [redacted][34] How do you respond?

A. Of the eight plants studied, the PacifiCorp [redacted]; thus, these estimates were reflected in the base estimates developed by Kiewit.[35]

[32] AWEC/500, Kaufman/36:21-37:4.
[33] Staff/1700, Storm/33:5-10.
[34] Staff/1701 at 14.
[35] *See* PAC/3902.

PacifiCorp also adjusted its ARO accounts to reflected the estimate used in the studies.

Q. The IE Report states that [redacted][36] **How do you respond?**

A. I disagree with the IE's conclusion regarding non-asbestos AROs. AROs describe a legal obligation associated with the retirement of a tangible, long-lived asset where PacifiCorp is responsible for the removal of that asset at some future date. While I am not an accountant, it is my understanding that AROs are governed by the Accounting Standards Codification published by the Financial Accounting Standards Board, Topic 410-20. The AROs are reviewed quarterly and as part of the annual audit, the liabilities associated with AROs are subject to external audit. The value of AROs is based on PacifiCorp's recent experience and estimates prepared by consultants and represents the present value of the existing retirement/removal obligation. Kiewit was provided a list of projects that were classified as AROs and chose not to include the list in their report. ARO obligations for coal plants are required for Coal Combustion Residuals ponds and landfills. The AROs are valid and appropriate.

Q. The IE Report states that the assumption that all structures will be removed to three feet below existing grade [redacted] **How do you respond?**

A. The removal depth for foundations is a judgment that all facility owners must make.

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[36] *Id* at 16.

Removal of foundations to three feet in depth is common in the power industry because it balances demolition costs against future use of the property. This has been confirmed by the Kiewit demolition contractor [redacted].[37]

Q. The IE Report states that the thickness of 12 inches for all asphalt roads and parking lots is [redacted] How do you respond?

A. The removal of asphalt roads and parking lots is required to reclaim the coal-fired plant site. As I stated earlier, reclamation includes those activities that would leave the property in a condition that would require close observation to determine that a facility has previously been located at the site and would have local top soil and be planted with native vegetation. Regarding the thickness of the asphalt roads and parking lots, Kiewit or their subcontractor [redacted][38] Coring the asphalt roads and parking lots would have gone beyond the 10-40 percent constraint of the AACE Class 3 estimate definition.

Q. The IE Report identifies the liabilities in Section 5.8 in each Decommissioning Study and a cost line item that [redacted].[39] How do you respond?

A. This line item should have been included in the "Other Item to be Considered" category and the reference should have been included in Section 5.14 of each Study.

[37] *See* PAC/3902.
[38] *See* PAC/3902.
[39] Staff/1701, 6.

Kiewit has confirmed that these costs are not included in the base estimates.[40]

Q. Dr. Kaufman claims that the Company is simply incorrect that his adjustment removes all costs for hazardous materials from the base estimate.[41] How do you respond?

A. In estimating the costs to remove hazardous material from a coal-fired plant site, there are two categories of costs that need to be considered: costs of known asbestos and costs of unknown asbestos. It is important to include a contingency for unknown asbestos given the age of the plants. As a result, this is an item that will be included in bids when the Company prepares to decommission a site. Thus, the specialized subcontractor engaged by Kiewit appropriately estimated two types of costs related to hazardous materials that is reflected in the Decommissioning Studies base estimates. First, Decommissioning Studies Section 5.4.2 describes [redacted][42] Second, Section 5.7.1 of the Decommissioning Studies includes [redacted][43]

[40] PAC/3902
[41] AWEC/500, Kaufman/37:7-11.
[42] PAC/1900, 34; PAC/1901, 29.
[43] PAC/1900, 37; PAC/1900, 32.

Q. Dr. Kaufman revised his adjustment related to reclamation costs from 100 percent to 50 percent because for sites that PacifiCorp does not repurpose it may be obligated to perform some remediation.[44] How do you respond?

A. Dr. Kaufman's proposal is based on a faulty premise, namely that if a site is not repurposed, it does not need to be reclaimed. Further, if materials are not removed from a coal-fired plant site, hazardous materials are introduced to the environment, the Company would run the risk of not meeting the requirements of permits, and the site becomes an attractive nuisance.

IV. CONCLUSION

Q. What is your recommendation in surrebuttal testimony?

A. It is my recommendation that the Decommissioning Studies meet the requirement of an AACE Class 3 estimate and are appropriate for inclusion in depreciation rates. The conclusions reached by the IE were based on a misunderstanding of the purpose of certain data and what entity was the source of data.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

---

[44] AWEC/500, Kaufman/37:12-38:3.

Docket No. UE 374
Exhibit PAC/3901
Witness: Robert Van Engelenhoven

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Robert Van Engelenhoven

PacifiCorp's Email Correspondence with Kiewit Representatives

August 2020

From: Bob.Slettehaugh
To: Laughter, Grant (PacifiCorp)
Cc: Max.Sherman; Chuck.Nordhausen
Subject: [INTERNET] RE: 2019 Demolition Study: Data Request - Work Papers
Date: Tuesday, May 26, 2020 10:51:02 AM
Attachments: image001.gif
image002.png

** REMEMBER SAIL WHEN READING EMAIL **

Sender	The sender of this email is Bob.Slettehaugh@kiewit.com using a friendly name of Bob.Slettehaugh . Are you expecting the message? Is this different from the message sender displayed above?
Attachments	Does this message contain attachments? Yes If yes, are you expecting them? image001.gif, image002.png
Internet Tag	Messages from the Internet should have **[INTERNET]** added to the subject.
Links	Does this message contain links? Yes Check links before clicking them or removing BLOCKED in the browser.
Cybersecurity risk assessment: Medium	

Grant,

Respectfully, we are unable to accommodate this request. Thank you for your understanding.

Regards,

BOB SLETTEHAUGH, PE
Manager, Technology Assessments
Engineering & Consulting Services

KIEWIT ENGINEERING GROUP INC.
8900 Renner Boulevard, Lenexa, KS 66219
913-928-7743
kiewit.com

From: Laughter, Grant [mailto:Grant.Laughter@pacificorp.com]
Sent: Tuesday, May 26, 2020 8:46 AM
To: Bob.Slettehaugh <Bob.Slettehaugh@kiewit.com>; Max.Sherman <Max.Sherman@Kiewit.com>; Chuck.Nordhausen <Chuck.Nordhausen@kiewit.com>
Subject: [EXTERNAL] 2019 Demolition Study: Data Request - Work Papers

Bob:

PacifiCorp received a data request for the work papers that support the 2019 demolition study Thermal Power Plant Demolition Estimates. The work papers were not included as a deliverable in the scope of work for the study. PacifiCorp does not possess or control the work papers.

PacifiCorp and the requestor have been in contact. As a result of the contact and for due diligence PacifiCorp needs to determine if Kiewit and Kiewit's subcontractors are willing to provide the work papers.

Please let me know if Kiewit is willing to provide the work papers and, if so, the cost and conditions for providing the work papers.

Thank you,

Grant Laughter, P.E.*
Principal Engineer
1407 West North Temple, Suite 230
Salt Lake City, Utah 84116

RMP_Email_Signature_WorkingSafely-2

*Licensed in Nevada and Utah

From: Bob.Slettehaugh
To: Laughter, Grant (PacifiCorp)
Cc: Chuck.Nordhausen
Subject: [INTERNET] RE: 2019 Demolition Study
Date: Tuesday, July 28, 2020 12:08:52 PM
Attachments: image001.png

**** REMEMBER SAIL WHEN READING EMAIL ****

Sender	The sender of this email is Bob.Slettehaugh@kiewit.com using a friendly name of Bob.Slettehaugh . Are you expecting the message? Is this different from the message sender displayed above?
Attachments	Does this message contain attachments? Yes If yes, are you expecting them? image001.png
Internet Tag	Messages from the Internet should have **[INTERNET]** added to the subject.
Links	Does this message contain links? Yes Check links before clicking them or removing BLOCKED in the browser.
Cybersecurity risk assessment: Medium	

Grant,
I hope you enjoyed the long weekend.

Respectfully, we are unable to accommodate this request. Thank you for your understanding.

BOB SLETTEHAUGH, PE
Manager, Technology Assessments
Engineering & Consulting Services

KIEWIT ENGINEERING GROUP INC.
8900 Renner Boulevard, Lenexa, KS 66219
(O) 913.928.7743
(M) 913.909.7634
kiewit.com

From: Laughter, Grant (PacifiCorp) [mailto:Grant.Laughter@pacificorp.com]
Sent: Thursday, July 23, 2020 3:33 PM
To: Bob.Slettehaugh <Bob.Slettehaugh@kiewit.com>
Cc: Chuck.Nordhausen <Chuck.Nordhausen@kiewit.com>
Subject: [EXTERNAL] 2019 Demolition Study

Bob:

We are continuing to work to resolve stakeholder concerns with the demolition study. The Oregon PUC is continuing to look for work papers.

Would Kiewit be willing to enter into an NDA with the Oregon PUC and share work papers with them? You probably need to coordinate this with NADC and the asbestos abatement companies.

Tomorrow is a state holiday, I will be available again on Monday.

Thank you,

Grant Laughter
(801) 220-2208

ERRATA
REDACTED
Docket No. UE 374
Exhibit PAC/3902
Witness: Robert Van Engelenhoven

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

ERRATA
REDACTED
Exhibit Accompanying Surrebuttal Testimony of Robert Van Engelenhoven

Letter from Kiewit Regarding Independent Evaluation Report Submitted to Public Utility Commission of Oregon on June 21, 2020

August 2020

THIS ATTACHMENT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 374
Exhibit PAC/4000
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Redacted Surrebuttal Testimony of James Owen

August 2020

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ATTACHED EXHIBITS

Q. Are you the same James Owen who previously submitted reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this case?

A. My surrebuttal testimony responds to the testimonies of Oregon Public Utility Commission (Commission) Staff, Sierra Club, the Alliance of Western Energy Consumers (AWEC), and the Oregon Citizens' Utility Board (CUB), challenging the prudence of the Company's investments in selective catalytic reduction systems (SCR) at Jim Bridger Units 3 and 4.

II. SUMMARY OF TESTIMONY

Q. Please summarize your surrebuttal testimony.

A. My surrebuttal testimony can be summarized as follows:

- First, I respond to claims made by Staff witness Ms. Soldavini, CUB witness Mr. Jenks, AWEC witness Mr. Kaufman, and Sierra Club witness Dr. Fisher, asserting that the Company should have negotiated early retirement dates for Jim Bridger Units 3 and 4 eight-to-thirteen years beyond their regional haze compliance deadlines. I explain that, given the challenging regulatory context, the Company could not have realistically negotiated early retirement for these units.
- Second, I respond to speculation by AWEC witness Mr. Kaufman and Sierra Club witness Dr. Fisher that other unexplored avenues for environmental compliance

might have existed, such as later natural gas conversion or reduced output agreements. These proposals are speculative and unrealistic.

- I respond to CUB's argument that PacifiCorp should have evaluated the SCRs based on Oregon's 2025 depreciable life for the Jim Bridger plant and that the installation of the low nitrogen oxide burners (LNB) and overfire air (OFA) was intended to bias the Environmental Protection Agency's (EPA) SCR analysis. PacifiCorp evaluated SCRs based on a 20-year useful life as required by EPA and understood that EPA would evaluate the emissions compliance for Jim Bridger Units 3 and 4 in light of existing emissions control technologies.
- I respond to Sierra Club's contention that the cost-effectiveness analysis performed for environmental compliance purposes is not relevant to a cost-effectiveness analysis for ratemaking purposes. The cost-effectiveness inquiry serves the same purpose in both contexts, as regulators seek to identify the most cost-effective means of ensuring environmental compliance and operation of generation facilities.
- I respond to CUB's and Sierra Club's arguments that the Wyoming Department of Environmental Quality (DEQ) decision was not binding prior to approval by the EPA. State rules, permits, and approval orders are enforceable under state law, irrespective of EPA action. PacifiCorp reasonably complied with the Wyoming DEQ's requirements and proceeded with the understanding that the EPA would approve the Wyoming DEQ's deadlines—which the EPA in fact did.
- I respond to Sierra Club's claim that the Company privately supported SCRs while publicly opposing them. While the Company's communication to the

Wyoming DEQ expressed [redacted], the Company nonetheless continued to believe that LNB and OFA should have been considered the Best Available Retrofit Technology (BART) for Jim Bridger Units 3 and 4.

- I respond to Sierra Club's critique of the understood increase in natural gas conversion costs, following competitive bidding for the Naughton Unit 3 natural gas conversion. The understood increase in costs was based on a reasoned comparison of previous natural gas conversion estimates and actual competitive bids.

Q. Please identify the related issues addressed by other PacifiCorp witnesses.

A. Mr. Rick T. Link responds to arguments addressing the Company's process for evaluation, review, and approval of the Jim Bridger SCRs, as well as Sierra Club's arguments concerning the alleged material decreases in natural gas prices. Mr. Dana M. Ralston responds to Sierra Club's and AWEC's testimonies concerning alleged material increases in coal costs in 2013, as relevant to the Jim Bridger SCR investments.

III. JIM BRIDGER SCR INVESTMENTS

A. Early Retirement Alternatives to SCRs

Q. Parties claim that PacifiCorp should have negotiated the early retirement of Jim Bridger Units 3 and 4 as an alternative to installing SCRs.[1] Please summarize these proposals.

A. Staff, CUB, AWEC, and Sierra Club criticize PacifiCorp for failing to negotiate with Wyoming DEQ and the EPA to close Jim Bridger Units 3 and 4 between 2023 and

[1] Staff/2300, Soldavini/14; AWEC/500, Kaufman/6; Sierra Club/400, Fisher/22-23.

2025[2]—or "maybe as late as 2028"[3]—as an alternative to installing SCRs on these units by 2015 and 2016, as required by the Wyoming DEQ. Parties are not clear at what stage in the environmental review process this negotiation should have occurred, but I understand the parties' comments to refer to sometime between the Wyoming DEQ's 2009 decision to require SCRs and EPA's January 2014 decision to uphold the Wyoming DEQ's Regional Haze Plan.

Q. From a reliability and power supply standpoint, during the relevant time period, were Jim Bridger Units 3 and 4 good candidates for early retirement?

A. No. As discussed by Mr. Link, between 2009 and 2013, the idea of retiring the Jim Bridger units early was not a realistic option given the central role of the Jim Bridger plant in PacifiCorp's system. During this time period, PacifiCorp was balancing system-wide considerations and multiple pollution control requirements at multiple plants, so Jim Bridger could not be considered in isolation. Instead, PacifiCorp had to balance the costs, outage timing, construction resources, installation time, system stability and state and federal policies and requirements for each plant with that plant's role within the overall system. During this same time, PacifiCorp was considering early retirement of another Wyoming unit, Dave Johnston Unit 3 as well as one in Utah.[4] This meant Jim Bridger was likely to play an increasingly important role in PacifiCorp's overall system. The combination of these considerations meant

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[2] CUB/100, Jenks/14 (proposing retiring Units 3 and 4 in 2023 and 2024, respectively); *see also* CUB/300, Jenks/45 (stating that 2025 would have been a reasonable retirement scenario if the EPA had extended the compliance deadline to 2019); AWEC/300, Kaufman/38 (proposing retiring Units 3 and 4 in 2024 and 2025, respectively); *see also* AWEC/500, Kaufman/6 (arguing that PacifiCorp should have modeled a 2025 retirement date).
[3] CUB/300, Jenks/46.
[4] *See* PAC/2509, Owen/15 (*Final Regional Haze Plan for Wyoming*, 79 Fed. Reg. 5032, (Jan 30, 2014)).

Jim Bridger, as a central and reliable piece of PacifiCorp's generation portfolio, was not a serious candidate for early retirement.

Q. Would it have been realistic for the Company to negotiate with the Wyoming DEQ for the early retirement of Jim Bridger Units 3 and 4 as an alternative to SCRs between 2009 and 2014?

A. No. It is implausible to contend that the Company could have successfully negotiated a retirement date between 2023 and 2028 for Jim Bridger Units 3 and 4 with the Wyoming DEQ. Negotiating an early retirement date for Jim Bridger would have required a modification to Wyoming's regional haze State Implementation Plan (SIP), which the State had expressly opted not to undertake at that time. Wyoming also refused to include an early retirement proposal for the smaller Dave Johnston Unit 3 in its SIP.

As I explained in my reply testimony, PacifiCorp initially proposed LNB and OFA as BART controls at Jim Bridger Units 3 and 4, not SCRs.[5] Nonetheless, the Wyoming DEQ required SCRs as part of the State's "long-term strategy" (LTS)—a decision that PacifiCorp appealed.[6] In that appeal, PacifiCorp filed a summary judgment motion seeking to remove the SCR requirements for Jim Bridger Units 3 and 4.[7] At the same time, EPA was pushing Wyoming to include an SCR requirement as BART for the Jim Bridger units, which would have required earlier installation of SCRs than the LTS.[8]

[5] PAC/2500, Owen/3.
[6] PAC/2500, Owen/4.
[7] PAC/2503 (PacifiCorp Appeal and Petition for Review of BART Permits, Feb. 26, 2010).
[8] PAC/4001 (Comments of U.S. Environmental Protection Agency to Wyoming Air Quality Division Regarding Proposed Best Available Retrofit Technology Determinations, Aug. 3, 2009).

After the denial of PacifiCorp's motion for summary judgment, PacifiCorp reached the settlement with Wyoming DEQ, which addressed emissions compliance for both the Jim Bridger and Naughton plants.[9] The Company subsequently requested that Wyoming DEQ consider altering its SIP by extending the compliance deadlines for installing SCRs on Jim Bridger Units 3 and 4.[10] However, the State again declined PacifiCorp's request to consider changing its SIP, this time for the LTS compliance requirements. Similar to its refusal to accommodate PacifiCorp's early retirement proposal for Dave Johnston Unit 3 by changing the SIP, the State identified changes to the SIP as an action it was not willing to take. In relation to changing the LTS compliance date requirements for Jim Bridger, Wyoming said that action "would entail a revision to our overall SIP with EPA. This is one step that the DEQ-AQD does not intend to undertake at this time."[11]

CUB, AWEC, and Staff seemingly contend that at this stage, PacifiCorp should have proposed a new compliance alternative to retire Jim Bridger Units 3 and 4 between eight-to-thirteen years later. However, adoption of such a proposal would have forced Wyoming to revise its SIP with EPA. More than just revising the SIP (an action Wyoming had indicated it was unwilling to take) a new retirement compliance alternative would have required the State to re-evaluate its LTS determinations, revise its cost analysis, re-initiate visibility modeling, and re-evaluate environmental impacts before it could have revised the SIP. Based on all of these facts, the Company reasonably did not believe that any proposal to modify the LTS

[9] PAC/2510, Owen/1.
[10] PAC/2500, Owen/12.
[11] PAC/830.

requirements for Jim Bridger Units 3 and 4 would have been acceptable to Wyoming DEQ.

Q. CUB argues that the Wyoming LTS requirements were subject to change if the federal requirements changed, and that the Company could have sought deferred early retirement dates from the EPA.[12] Was this a realistic alternative to SCRs?

A. No. As explained above, EPA suggested that Wyoming include SCR requirements as part of the BART determinations for the Jim Bridger Units. Wyoming ultimately compromised and included those requirements as part of the LTS rather than BART. Because the agencies had thus reached an agreement that achieved both of their objectives, the Company reasonably determined that Wyoming and EPA would not then immediately back-track from the SCR requirements in favor of any other alternative compliance scenario.

The language in the BART settlement agreement referenced by CUB states that the agreement *may be* subject to modification if federal or state requirements change that materially alter the emission control required under the agreement.[13] However, it was not reasonable for the Company to rely on federal regional haze requirements changing in a way that materially altered the settlement emission control requirements to allow a retirement alternative that cancelled SCRs. This is true for two reasons. First, EPA has stated that the regional haze rule does not provide EPA with authority to require the shutdown of a source.[14] Instead EPA relies on state-adopted requirements negotiated between the source operator and the state

[12] CUB/400, Jenks/44.
[13] PAC/2510.
[14] PAC/2509, Owen/14 (79 F.R. 5032, 5045 (2014)).

regulatory authority to require an early shutdown.[15] Without this state cooperation, EPA is not willing to act unilaterally to create early retirement commitments under the regional haze rule. Thus PacifiCorp had a sound basis not to anticipate a change in federal requirements that would force early retirement for Jim Bridger.

Second, Wyoming had already made clear that it would not undertake modifications to the SIP for the LTS determinations for Jim Bridger Units 3 and 4. Wyoming specifically told PacifiCorp in March of 2013 that Wyoming DEQ was "unaware of any change in federal or state requirements, or technology, that would materially alter the required emission controls or rates for Jim Bridger Units 3 and 4."[16] PacifiCorp therefore did not anticipate a change in state requirements. While CUB states that "EPA would likely have been supportive of an alternative compliance plan that retired the units,"[17] this is mere speculation and does not take into account Wyoming's stated position, EPA's desire to obtain the SCR requirements, or the negotiated position the two agencies had worked out. Wyoming had indicated it would not entertain a revision to the SIP, and so it follows that it would not have considered an additional alternative seeking early retirement. Therefore it was reasonable that the Company did not pursue an alternative that would require a revision to the SIP.

Q. CUB states that it was not provided with a copy of the Wyoming LTS.[18] Is this correct?

A. CUB appears to misunderstand the nature of Wyoming's LTS. An LTS, as the EPA

[15] *Id*.
[16] PAC/830.
[17] CUB/300, Jenks 45.
[18] CUB/400, Jenks/43.

has explained, is a "compilation of all control measures a state will use during the implementation period of the specific SIP[.]"[19] States are obligated to prepare an LTS under section 169A(b) of the Clean Air Act.[20] PacifiCorp does not have a document from the State of Wyoming called a "Long-Term Strategy." The Company referred to EPA's 2014 rule because it discusses EPA's review of Wyoming's LTS. The Company also referred to PacifiCorp Exhibit 2510 because that document presents Wyoming's requirements under the state's LTS, as modified by settlement.

Q. CUB points out that Portland General Electric Company's (PGE) analysis in 2009 led that company to plan for the early retirement of the Boardman plant as an emissions compliance alternative. Is the Boardman plant analogous to Jim Bridger?

A. No. A direct comparison of Boardman and Jim Bridger is not reasonable. First, the plants are located in different states, are governed by different EPA regions, impact visibility for different Class I Areas, and play distinct dispatch roles for different grid systems from two different utilities.

Regional haze compliance analysis, strategies, and requirements vary greatly unit-by-unit and plant-by-plant, and in the case of the Company, fleet-wide considerations must also be taken into account. It is speculation to assume that the strategy adopted by the State of Oregon at Boardman would be appropriate for the State of Wyoming at Jim Bridger.

PacifiCorp, after extensive negotiations with the State of Wyoming, met the established compliance requirements and pursued what it believed to be the most

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[19] PAC/2506, Owen/8 (Excerpt from June 10, 2013 Federal Register).
[20] *Id*.

cost-effective environmental compliance options that were legally and reasonably achievable for that plant. Over-reliance on later retirement dates was risky due to the quickly changing nature of pollution control equipment and options for pollution reduction. Over-reliance on more distant projections introduced additional uncertainty and risk:

> [redacted][21]

Finally, as Mr. Link describes, the Boardman early retirement agreement allowed that plant to run for four years past its regional haze compliance deadline, far shorter than the time periods parties are suggesting in this case. As Mr. Link describes, the Company analyzed a 2020/2021 retirement date in the 2013 IRP (five years after the 2015/2016 compliance deadline for Jim Bridger Units 3 and 4) before it made its decision to install the SCRs. This analysis showed that the SCRs remained the most beneficial alternative to customers.

Q. CUB points out that, in December 2013, the Company was in discussions with EPA concerning how long it could operate the Dave Johnston plant without emissions controls.[22] Does this mean the Company should have taken the same approach regarding the Jim Bridger plant?

A. No. There are multiple factors that distinguish the compliance approaches taken for

[21] Sierra Club/410 (PacifiCorp Letter to Wyoming Division of Air Quality at 4-5, Jan. 29, 2009).
[22] CUB/400, Jenks/40.

Dave Johnston Unit 3 and Jim Bridger Units 3 and 4. First, and most significantly, EPA and Wyoming agreed that SCR installation was the appropriate compliance requirement for Jim Bridger Units 3 and 4, while the agencies disagreed on whether SCR was the appropriate compliance requirement for Dave Johnston Unit 3. EPA approved the portion of Wyoming's SIP that adopted the LTS requirements for Jim Bridger Units 3 and 4, but disapproved the portion of the SIP which did not require SCR and instead required LNB and OFA as BART for Dave Johnston Unit 3. Because of this disagreement between the state and federal agencies regarding Dave Johnston Unit 3, PacifiCorp was essentially forced to negotiate alternate control options. In August 2013, PacifiCorp submitted comments[23] to EPA supporting Wyoming's SIP requiring LNB and OFA as BART but noted that EPA had requested input on control options that could be required instead of, or in conjunction with, the BART requirements. For Dave Johnston Unit 3, PacifiCorp suggested a requirement to install selective non-catalytic reduction (SNCR) as a less-costly option than SCR. Specifically, PacifiCorp stated that "SNCR is preferable to SCR for Dave Johnston Unit 3 when considering all currently available information and the current emissions performance of the unit."[24] PacifiCorp also commented on the remaining useful life of Dave Johnston Unit 3 (2027) and requested that EPA properly consider the unit's depreciable life when analyzing the costs of and SCR requirements. EPA ultimately opted not to adopt an SNCR requirement and instead incorporated "two alternative compliance paths to compliance": either to install SCR by January 2019 or cease

[23] PAC/4002.
[24] *Id*.

operation by December 31, 2027.[25] However, Wyoming continued to disagree with this approach and declined to submit a SIP revision to require the 2027 shutdown. Because EPA would not accept LNB, OFA, or SNCR requirements and PacifiCorp could not justify the installation of an SCR on the unit with the relatively short depreciable life, the 2027 retirement was PacifiCorp's most certain and cost-effective compliance option.

Second, while Dave Johnston Unit 3's depreciable life ended in 2027, Jim Bridger's extended until 2037. The Dave Johnston Unit 3 closure requirement compliance path aligned with the Unit's depreciable life. The depreciable lives of Jim Bridger Units 3 and 4 was 10 years beyond that. A 10-year difference in depreciable life clearly differentiates the Jim Bridger Units 3 and 4 from Dave Johnston Unit 3 in terms of simply assuming the Company could pursue the same compliance option.

Third, Dave Johnston Unit 3 lacks the same capacity and reliability significance as Jim Bridger Units 3 and 4, meaning that early retirement for Dave Johnston Unit 3 was more achievable and would have less impact on system reliability than an early retirement of Jim Bridger Units 3 and 4.

Finally, the early retirement of Dave Johnston Unit 3 made the same compliance strategy less likely, not more likely, for Jim Bridger Units 3 and 4. EPA evaluates SCR requirements on individual operator units, but also evaluates broader cost requirements on an operator's system when SCRs are required on multiple units. EPA has discretion to determine that SCR installation costs are unreasonable if an

[25] PAC/2509.

operator is required to install multiple SCRs within a single compliance period.[26] Therefore, the enforcement of an early retirement on Dave Johnston Unit 3 in lieu of an SCR requirement resulted in one less SCR requirement for the Company. Thus the SCR requirements on Jim Bridger Units 3 and 4 became even more reasonable when considering the total SCR costs across PacifiCorp's system.

B. Other Alternatives to SCRs

Q. Sierra Club also argues that PacifiCorp could have proposed a firm natural gas conversion at a later date as an alternative to SCRs.[27]

A. Sierra Club's suggestion that PacifiCorp could have explored negotiating a firm date for converting Jim Bridger Units 3 and 4 to natural gas, as an alternative to SCRs for environmental compliance, has several flaws. First, as already discussed in Mr. Link's testimony, the Company's analysis indicated that natural gas conversion was not economic relative to installing SCRs.[28] Second, as stated above, the Wyoming DEQ already informed PacifiCorp that it would not undertake a process to modify its SIP with EPA. As was the case with an alternative retirement scenario, a gas conversion scenario would have required the state to re-evaluate its LTS determinations, revise its cost analysis, re-initiate visibility modeling, re-evaluate environmental impacts and revise the SIP. A SIP revision modifying the LTS requirements for Jim Bridger Units 3 and 4 is something the Wyoming DEQ had told PacifiCorp it would not undertake.

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[26] PAC/2509; 79 F.R. 5032, 5045 (2014).
[27] Sierra Club/400, Fisher/23.
[28] PAC/700, Link/98, 107.

Q. AWEC also argues that PacifiCorp should have explored reduced dispatch as an alternative to SCRs.[29] How do you respond?

A. AWEC references a regional haze compliance option PacifiCorp is currently pursuing for the Jim Bridger plant. AWEC mischaracterizes this application in multiple ways. First, AWEC claims that the compliance option does not apply to Jim Bridger Units 3 and 4. This is simply not correct. As PacifiCorp explained and cited in response to AWEC's data request regarding this issue,[30] PacifiCorp's proposal includes the adoption of emission limits for compliance with regional haze requirements. These emission limits are plant-wide and include a combination of both monthly and annual limits which are enforceable in lieu of requirements to install SCRs on Jim Bridger Units 1 and 2.[31] Because the limits are enforceable plant-wide, they apply to all four Jim Bridger units.

Second, while PacifiCorp acknowledges in the application that the emission limits will effectively limit the maximum average annual capacity factor of the plant, it is an over-simplification to state that PacifiCorp proposed "reduced dispatch." The application did not propose any dispatch limit, capacity factor limit or heat input limit.

Third, AWEC appears to argue that PacifiCorp should have pursued a similar compliance strategy for Jim Bridger Units 3 and 4 in 2013. The application, which was submitted in February of 2019, is an innovation in regional haze compliance and, to my knowledge, is the first of its kind. The approach relies on tailored month-by-month air dispersion modeling to ascertain specific visibility impacts for various

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[29] AWEC/500, Kaufman/10.
[30] AWEC/501, Kaufman/14.
[31] PAC/4003, Owen/25.

haze-causing pollutants. It then tailors emission limits for each pollutant to each month that result in the least negative impacts to visibility, and demonstrated improved visibility when compared to SCR, at a fraction of the cost. The approach was not analyzed in 2013 because it was not conceived as a compliance strategy at that time by either operators or regulators. The application was approved by the Wyoming DEQ in May of 2020 and is currently under review by EPA.

C. Analysis of SCRs

Q. CUB argues that it was inappropriate to assume that the SCRs would have a 20-year useful life, given that the Oregon depreciable life extended only until 2025. Would it have been reasonable to assume a shorter depreciable life for the SCRs from an environmental perspective?

A. No. EPA mandates specific depreciable lives be used for control technologies when analyzing cost for regional haze compliance.[32] At the time the analysis was completed, the EPA required a 20-year assessment period for SCR retrofit cost effectiveness, unless the affected resource had a federal or state enforceable commitment to an earlier retirement date. EPA currently uses a 30-year assessment period for SCR.[33] The EPA does not consider depreciable life as the relevant metric for determining the useful life of emissions control equipment, given that "the depreciable life is often shorter than the economic life of [a] facility."[34]

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[32] PAC/4004.
[33] *Id*. The EPA finalized revisions to the Air Pollution Control Cost Manual (Chapters 1 and 2) in May of 2016; these revisions changed the amortization period for SCR from 20 years to 30 years. 83 Fed. Reg. 18243 FN. 24 (2018).
[34] PAC/2509, Owen/135 (EPA's Wyoming Regional Haze Decision).

Q. CUB also argues that, by "installing LN[B] and OFA before the SCR, PacifiCorp hoped to limit the Regional Haze review to just an SCR, which would not have been cost-effective on a stand-alone basis. . . . This approach made it difficult to establish the future closure date that should be modeled as an alternative to installing SCR in 2015 and 2016."[35] Please respond.

A. The Company's analysis of SCR cost effectiveness was in the Company's extensive comments in EPA's Wyoming Regional Haze Federal Implementation Plan (FIP) proceeding. PacifiCorp stated its understanding that EPA must consider existing controls installed on a unit when evaluating appropriate BART controls, which would have had the opposite effect of making the SCR more cost-effective. Ultimately, the EPA declined to follow this reasonable interpretation of the law and instead concluded that it possesses "considerable discretion" to consider existing emissions control technologies, "so long as that consideration is explained and reasonable."[36] The Company's installation of LNB/OFA did not impact analysis of future closure dates.

Q. Sierra Club argues that SCRs may have been a cost-effective form of pollution control, but not a cost-effective form of pollution control for customers.[37] Do you agree with Sierra Club's distinction?

A. No. Sierra Club has argued both sides of the cost-effectiveness issue and is now unsuccessfully trying to make sense of its contradictory positions. In this case, Sierra Club attempts to contrive a distinction between its past enthusiastic advocacy of the cost-effectiveness of pollution controls for environmental compliance and its current

[35] CUB/400, Jenks/38.
[36] PAC/2509, Owen/74.
[37] Sierra Club/400, Fisher/37.

contrary position on cost-effectiveness of pollution controls for ratemaking. There is no basis for such a distinction. PacifiCorp is required to operate its generation facilities in compliance with all applicable environmental regulations. These regulations involve identifying which options provide the most cost-effective means of meeting the requisite emissions control standards. Sierra Club suggests that the analysis is different in a ratemaking context because early retirement may be a more economical means of compliance.[38] Yet, as Sierra Club goes on to state, early retirement can be used as a cost-effective means of emissions control in an environmental compliance context as well, where appropriate.[39] While the analysis remains the same, Sierra Club's position does not. In the past, Sierra Club's position was that SCRs are cost effective and now in this proceeding, Sierra Club claims that they are not.

D. <u>Timing of SCRs</u>

Q. Sierra Club and CUB claim that the Wyoming DEQ decision was not truly binding because it was subject to approval and modification by the EPA.[40] Do you agree?

A. No. While Dr. Fisher and Mr. Jenks are correct that the Wyoming DEQ decision allowed for the possibility that the EPA might modify the Wyoming regional haze compliance requirements, this possibility did not make that Wyoming DEQ decision less binding for PacifiCorp in the interim. Indeed, as I explained in reply testimony, Sierra Club specifically urged the Wyoming DEQ to conclude that the Company's compliance deadline was "contingent on EPA's review and finalization, and that its

[38] Sierra Club/400, Fisher/37.
[39] Sierra Club/400, Fisher/37.
[40] Sierra Club/400, Fisher/33-34; CUB/400, Jenks/44.

deadlines would be no earlier than five years after EPA's final approval."[41] The Wyoming DEQ disagreed, stating that PacifiCorp "ha[d] a legal obligation . . . to complete the work on Jim Bridger Units 3 and 4 by December 31, 2015, and December 31, 2016, respectively."[42] Furthermore, Wyoming explicitly clarified, when asked, that under state regulations, PacifiCorp was required to comply with all terms and conditions of the Wyoming SIP, notwithstanding the fact that EPA had not yet taken action and that the requirement to install SCR on Jim Bridger Units 3 and 4 was independently legally enforceable.[43] It would have been imprudent for the Company to violate state law based on the assumption that its legal obligations would be modified by EPA.

Q. Sierra Club claims that the Company should "not have begun making plans" to install SCRs by 2015 and 2016 until *after* the EPA issued its January 2014 decision.[44] How do you respond?

A. If the Company had delayed making plans to comply with the Wyoming DEQ decision until after the plan was approved by the EPA, then PacifiCorp would simply have been unable to comply with both state and federal regulations. In essence, Dr. Fisher claims that PacifiCorp would have been prudent to have disregarded clearly stated and enforceable compliance deadlines in the hope that the EPA approved a more lenient timeline—which, in fact, the EPA did not.

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[41] PAC/2500, Owen/12 (quoting Sierra Club/100, Fisher/25).
[42] PAC/2516 (*In the Matter of the Application of Rocky Mountain Power for Approval of Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4 Located Near Point of Rocks, Wyoming*, WPSC Docket No. 20000-418-EA-12 (Record No. 13314), Order Denying Motion for a Stay or Continuance Pending Final EPA Action, ¶ 14 (Feb. 4, 2013) (Wyoming Stay Order)).
[43] PAC/2516.
[44] Sierra Club/400, Fisher/34.

Q. Sierra Club argues that the Company should have asked EPA to delay the deadline for installing SCRs until 2019.[45] Is it your understanding that Sierra Club believes that installing SCRs in 2019 would have been prudent?

A. No. Sierra Club appears to be conflating delaying the SCRs with not installing them at all. Specifically, Sierra Club states that the Company should have sought a five-year delay from EPA as "an opportunity" to seek "cost-effective retirement" of the units.[46] Clearly, Sierra Club does not believe that it would have been reasonable or prudent to actually install the SCRs at a later date—only to close the units as soon as possible. Sierra Club's discussion of delaying installation of the SCRs until 2019 is a red herring. Furthermore, on March 5, 2013, PacifiCorp specifically requested "that the Wyoming Air Quality Division reconsider PacifiCorp's request to change the deadlines for installation of the Jim Bridger Units 3 and 4 SCR controls from December 31, 2015, and December 31, 2016, to five years after EPA's approval of the Wyoming SIP or FIP issuance."[47] Wyoming DEQ declined to extend the dates and simply denied the request one day later.[48]

Q. Sierra Club goes on to claim that if the Company had not supported the Wyoming DEQ's deadlines of 2015 and 2016 for installation of the Jim Bridger Unit 3 and 4 SCRs, then EPA "would have delayed the need to install SCRs until 2019."[49] Do you agree?

A. No. Sierra Club's argument is simple speculation. Indeed, as CUB recognizes in its own rebuttal testimony, there was no reason to believe that the EPA would not adopt

[45] Sierra Club/400, Fisher/34.
[46] Sierra Club/400, Fisher/38.
[47] PAC/829.
[48] PAC/830.
[49] Sierra Club/400, Fisher/35.

the Wyoming DEQ's stipulated deadlines as "better-than-BART."[50]

Q. Staff suggests that Sierra Club's advocacy for early compliance dates in prior EPA proceedings indicates that there may have been more flexibility in the Company's deadlines for installing SCRs.[51] Do you agree?

A. No. Staff appears to reason that because Sierra Club previously supported the EPA maintaining Wyoming's 2015 and 2016 deadlines, later deadlines were in fact plausible. This assumption is mistaken. There is no reason to believe that, in examining the Wyoming DEQ's requirement for the 2015 and 2016 deadlines to install SCRs at Jim Bridger Units 3 and 4, the EPA would have deemed it preferable to allow a *longer* period of higher emissions for Regional Haze compliance.

E. <u>Company Support for SCRs</u>

Q. Sierra Club claims that the Company was simultaneously advocating for the SCRs in confidential communications, while publicly stating that it opposed them.[52] How do you respond?

A. Sierra Club mischaracterizes the nature of the Company's communications. The confidential communication to the Wyoming DEQ sets out [redacted]. Thus, the Company sought to avoid unnecessary environmental compliance costs, while also recognizing the need to communicate with its regulator under the assumption that the existing direction was binding.

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[50] CUB/400, Jenks/44.
[51] Staff/2300, Soldavini/21.
[52] Sierra Club/400, Fisher/32.

Q. Sierra Club claims that the Company supported SCRs at Jim Bridger Units 3 and 4 because, in 2003, [redacted][53] Do these comments suggest that the Company intended to install SCRs at Jim Bridger in 2003?

A. No. The 2003 report described by Dr. Fisher did not state that the Company planned to install SCR at these units. The report merely characterized [redacted].

F. Natural Gas Conversion Cost Increase

Q. Sierra Club argues that there was no basis to assume that the costs of natural gas conversion had increased substantially since the Company's initial 2013 estimates.[54] Did you previously explain the basis for this increase in reply testimony?

A. Yes. As I explained in reply testimony, since the Company's 2013 natural gas conversion estimates, the Company had received market evidence to suggest that actual costs would likely be much higher. Specifically, by January 2014, the Company had received competitive bids for the Naughton Unit 3 gas conversion that were, under a conservative estimate, approximately 30 percent more expensive than forecast.[55]

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[53] Sierra Club/400, Fisher/33.
[54] Sierra Club/400, Fisher/38-39.
[55] PacifiCorp/2500, Owen/16.

Q. Dr. Fisher describes this 30 percent figure as a "guesstimate," claims that you "never calculated anything," and challenges your ability to testify to the increase in natural gas conversion costs because you did not work at PacifiCorp in 2014.[56] Please respond.

A. As I explained in my reply testimony, I testify to matters "both within my direct personal knowledge and to matters where I have carefully reviewed the underlying materials and have become familiar with the relevant facts."[57]

Q. What materials and facts did you review to inform your opinion about the increase in natural gas conversion costs?

A. As I explained in the supplemental response to Sierra Club data request 8.3(c),[58] I reviewed the documents underlying both the Company's initial 2013 cost forecast for the Naughton Unit 3 natural gas conversion, as well as the subsequent competitive bids.

Q. Did you explain to Sierra Club how you calculated the anticipated cost increase, as it would have been known to the Company at the time?

A. Yes. I provided this explanation in my supplemental response to Sierra Club data request 8.3(c).[59]

Q. Please summarize how you calculated the natural gas conversion cost increase.

A. For the 2013 cost forecast, I reviewed progress review updates from early to mid-2013 and a budget calculation sheet from early 2014. The costs in those documents ranged from $29 million to $30.4 million, with the number $30.2 million appearing

[56] Sierra Club/400, Fisher/39.
[57] PAC/2500, Owen/1.
[58] Sierra Club/403.
[59] Sierra Club/403.

twice. I therefore concluded that $30.2 million was a reasonable cost estimate for the project in late 2013.

For the updated cost information that would have been known in January 2014, I reviewed the competitive market bids for the Naughton Unit 3 gas conversion, and found that two competitive bids were received by the Company in December 2013 in the amounts of $56,300,015 and $48,559,000. To further solidify the likely costs as known in January 2014, I also conferred with project managers involved in receiving the bids at the time. Based on these conversations, I understand that the higher cost bid was not considered plausible. I also learned that the lower cost bid had errantly included costs for a certain ducting bypass, which was unnecessary. I therefore subtracted the cost of this ducting bypass from the lower cost bid, and re-calculated the project implementation cost. This evaluation yielded a conservative estimate for Naughton Unit 3's updated gas conversion cost of $39,136,850.

By comparing the initial estimate of $30.2 million to the subsequent information available in January 2014, I concluded that the understood gas conversion costs for Naughton Unit 3 had increased by approximately 30 percent.[60]

Q. Sierra Club claims that the information suggesting that natural gas conversion costs had increased is irrelevant, because the Company would not have had this information when it issued its FNTP on December 1, 2013.[61] Do you agree?

A. No. My comments responded to Sierra Club's proposal that the Company should have reversed its decision *after* issuing the FNTP.[62]

[60] ($39,136,850-$30.2 million)/($30.2 million) = 0.2959 ≈30 percent.
[61] Sierra Club/400, Fisher/39-40.
[62] PAC/2500, Owen/14 ("Sierra Club argues that the Company should have reversed its decision and terminated construction of the Jim Bridger SCRs[.]").

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/4001
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of James Owen

Comments of U.S. Environmental Protection Agency to Wyoming Air Quality Division Regarding Proposed Best Available Retrofit Technology Determinations, Aug. 3, 2009

August 2020

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

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AUG 2009
RECEIVED
AIR QUALITY
DIVISION

David Finley, Administrator
Air Quality Division
Wyoming Department of
Environmental Quality
122 W. 25th St.
Cheyenne, WY 82002

Re: Proposed BART determinations for the following facilities: Basin Electric-Laramie River, PacifiCorp-Dave Johnston, Jim Bridger, Naughton, and Wyodak

Dear Mr. Finley:

We are writing in response to Wyoming's proposed Best Available Retrofit Technology (BART) determinations open for public comment until August 4, 2009. The BART determinations that we are commenting on include: Basin Electric Power Cooperative's Laramie River facility and PacifiCorp's Dave Johnston, Jim Bridger, Naughton , and Wyodak facilities. We have completed our initial review of the BART determinations and are providing our preliminary comments on the analysis below. Please note that we will only reach a final conclusion regarding the adequacy of Wyoming's BART determinations and Regional Haze SIP when we act on Wyoming's Regional Haze SIP revision through notice and comment rulemaking.

Modeling

1. A background ozone concentration of 44 parts per billion (ppb) was used for all electric generating unit (EGU) sources in the BART Calpuff modeling as the default value when actual ozone monitoring data were unavailable. This value appears to be too low based on typical annual average ozone levels measured at Wyoming ozone monitoring sites close to the facilities. For example, the Campbell County (Thunder Basin) monitor recently recorded annual average values ranging between 50 and 55 ppb, while the Sublette County, Jonah monitor, observed values of 55 to 58 ppb. The State should provide an analysis of how these higher ozone values would affect visibility and the modeling results.

2. It is not clear how the State considered large visibility benefits for nitrogen oxides (NO_x) controls in their determination, mainly in selecting low NO_x burners (LNB) and overfire air (OFA) as BART for sources instead of selective catalytic reduction (SCR). One example of this is the Laramie River analysis. Figure 9 in the analysis shows a

significantly lower impact at Wind Cave and Badlands National Park for control scenario 4 (SCR) compared to the less stringent NO_x control scenarios modeled. The SCR scenario cumulatively provides 25 fewer days of impairment at these parks and 1.5 delta-deciviews for all three units. This is a substantial improvement considering that the threshold level for considering a source subject-to-BART is 0.5 deciview. The State should provide an explanation of how visibility improvements were weighed in making the proposed BART determinations.

3. Deciview impacts are presented separately for each unit. However, it would be the cumulative impact of all units from a given power plant that would impact Class I area visibility. Tables should include total visibility impacts from all units at a facility as well as individual unit impacts. This will provide larger baseline impacts, but also larger visibility improvements. In the case of Naughton and Jim Bridger, it is possible that the impacts of all seven units will impact a Class I area at the same time. Consideration should be given to modeling all of these units together. It would also be helpful to have tables and figures that provide the improvement, in deciview, for all EGUs at a power plant.

4. Language for the draft BART determinations, such as the following from the Jim Bridger analysis, need further explanation: "The cumulative 3-year averaged visibility improvement from the baseline summed across the three Class I areas ..." (e.g., see page 49 of the Jim Bridger analysis). The State needs to provide clarification on the following: 1) Are deciview improvements calculated for each of the Class I areas added together?; 2) If so, what is the meaning of the number?; 3) Are three Class I areas sufficient to quantify the cumulative impact?; and 4) Were all Class I areas within 300 km considered?

NO_x Controls

5. Throughout the analysis, the most stringent emission control level for the control technologies has not been evaluated; resulting in inflated calculated cost effectiveness values. The BART Guidelines state that "It is not our intent to require analysis of each possible level of efficiency for a control technique as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving. You should consider recent regulatory decisions and performance data *(e.g.,* manufacturer's data, engineering estimates and the experience of other sources) when identifying an emissions performance level or levels to evaluate." (see 70 FR 39166, July 6, 2005). Second, we disagree with the controlled rates presented in the BART analysis that could be achieved with SNCR and SCR. EPA estimates that SNCR can reduce NO_x by 40% - 50% for most large boilers ("EPA Air Pollution Control Cost Manual", 2002, Sixth ed., EPA-452-02-001, Section 4.2, Chapter 1, pg 1-3). EPA also estimates that SCR can reduce NO_x by 70% - 90%+ for most large boilers (EPA 2002, Section 4.2, Chapter 2, pg 2-3). In the recent decision in the Cinergy NSR lawsuit, SCR Best Available Control Technology (BACT) was determined to be 90% control. Even assuming 80% SCR control efficiency (in order to minimize ammonia slip), one gets a

controlled rate of less than 0.05 lb/MMBtu. PPL Montana has evaluated SCR at 0.06 lb/MMBtu and across the country there are many SCRs operating in the range of 0.03 – 0.04 lb/MMBtu. We therefore recommend that tighter emission limits be evaluated for both SNCR and SCR.

6. For all the sources, except Laramie River, there is no formula provided to calculate if the 12-month rolling emission rate has exceeded the NO_x ton per year (tpy) limits in the proposed permit conditions. A condition should be created for all sources to mirror condition 12.a.iii from page 50 the Laramie River Application Analysis proposed permit conditions.

Particulate Matter Controls

7. The conclusion section on BART control for particulate matter/particulate matter less than ten microns (PM/PM_{10}) should list the associated averaging periods for the lb/MMBtu, lb/hr, and tpy limits. The proposed permit conditions should also include the associated averaging period for all PM/PM_{10} limits.

8. The PM_{10} BART analyses assume that the lowest emission rate achievable by either a fabric filter (baghouse) or an electrostatic precipitator (ESP) is 0.015 lb/MMBtu. However, EPA has proposed that the Desert Rock power plant will meet a filterable PM_{10} limit of 0.010 lb/MMBtu (see Desert Rock Energy Center Proposed Permit, AZP 04-01). In addition, the current BACT determinations in Wyoming for new coal fired power plants are more stringent than the proposed PM BACT limit of 0.015 lb/MMBtu. Current BACT determinations indicate that new baghouses can achieve emissions in the range of 0.010lb/MMBtu to 0.012 lb/MMBtu. The BART determinations should include an analysis of ESPs and baghouses at a control level in the range of 0.010 lb/MMBtu to 0.012 lb/MMBtu.

9. Condition 5 in the proposed permits for all the sources contains an inappropriate exemption. BART is intended to be met continuously and should be a limit that effectively reflects proper operation of the BART control option. In general, a performance based (lb/MMBtu) limit would be necessary to assess the operational performance of a control device. Therefore, it is necessary that the exemption from the lb/MMBtu PM/PM_{10} limit during startup be removed from the permit. Performance based BART limits should be effective during all operational periods, including startup. In the event that a control option cannot achieve the level of control proposed as BART it may be appropriate to analyze the need for a startup BART limit (i.e., for an ESP controlled source). However, sources controlled with a baghouse should not need a separate startup BART limit due to the fact that baghouse control efficiency does not depend on the baghouse coming up to operating temperature.

10. Flue gas conditioning (FGC) is presented as a control option for PM. FGC is a low-cost option because it involves the injection of sulfur trioxide (SO_3) in the flue gas to make the PM more easily collectable by an ESP. We caution the Division that FGC must be

applied after flue gas desulfurization (FGD) is installed or upgraded, to assure that there is not a collateral increase in emissions of sulfuric acid mist. In the case of Naughton, there is projected to be an interim period when sulfuric acid mist emissions will exceed the PSD significance threshold. This increase is due to the operation of the FGC prior to FGD upgrades. For the purposes of BART a control option should not be considered as a BART option if it will result in increased emissions of visibility degrading pollutants (sulfuric acid mist).

Sulfur Dioxide Controls

11. The State correctly points out that since Wyoming proposes to be one of the four Section 309 states, BART sources'sulfur dioxide (SO_2) emissions would be regulated by the 2018 milestone under the backstop trading program when considering the impacts of these sources on Class I areas on the Colorado Plateau. However, for non-Plateau Class I areas, SO_2 controls need to be evaluated under 309(g) as part of the State's long-term strategy and reasonable progress goals. The State must include provisions in their SIP for establishing reasonable progress goals and must implement any additional measures needed to demonstrate reasonable progress for the Class I areas off the Colorado Plateau. (see 40 C.F.R. 51.309(g)(2)) The regulations provide that a state may take credit for and build upon the strategies implemented under Section 309 in its reasonable progress analysis, but the State must also provide a demonstration in its SIP of how the Section 309 strategies, including the backstop trading program, are meeting its visibility goals, and an analysis of whether other SO_2 controls are needed in order to meet reasonable progress. This means that stationary sources that are not required to implement SO_2 BART controls may still have to address SO_2 controls for the purposes of reasonable progress.

Wyodak

12. Due to a recent State-issued Prevention of Significant Determination (PSD) permit, Wyodak is required to install a new fabric filter for PM control. It is therefore inappropriate for the BART analysis options considered to be less protective than the permitted enforceable controls. Controls already permitted through PSD should be viewed as a baseline for control in the BART analysis. As mentioned above, the level of control achievable by new fabric filters is in the range of 0.010 to 0.012 lb/MMBtu, which is below the proposed level of 0.015 lb/MMBtu.

13. The control efficiencies assumed for NO_x technologies underestimate the capabilities of the technologies and therefore inflate cost effectiveness (see comment #6 above). The State should re-evaluate the cost effectiveness of NO_x controls. If the true control efficiencies of these technologies is considered, controlled lb/MMBtu rates and cost effectiveness ($/ton) will be reduced further from what is currently evaluated in the BART analysis. The reanalysis should indicate that SCR is cost effective at Wyodak.

Dave Johnston

14. On page 14 of the analysis, it states, "An ESP is an effective PM control device, as the existing units are already capable of controlling PM_{10} emissions from Unit 3 to 0.030 lb/MMBtu. The technology continually improves and is commonly proposed for consideration in BACT analyses to control particulate emissions from new PC boilers." This statement is not accurate. The current technology most often chosen to satisfy PM/PM_{10} BACT within Region 8 and Wyoming for new pulverized coal (PC) boilers of this size is a fabric filter or baghouse. The control efficiency of fabric filters is not dependent on temperature, which makes them a suitable control measure during periods of startup. An ESP must come up to temperature before becoming effective and may not be used during periods of fuel oil firing.

15. The control efficiencies assumed for NO_x technologies underestimate the capabilities of the technologies, and therefore inflate cost effectiveness values (see comment #6 above). The State should reevaluate the cost effectiveness of NO_x controls. If the true control efficiencies of these technologies is considered, controlled lb/MMBtu emission rates and cost effectiveness values ($/ton) will be much lower than evaluated in the BART analysis. Thus, we question the State's decision to limit BART controls to LNB/OFA without post combustion controls In addition, the State should take the large visibility improvement attributable to SCR into consideration in making the final BART determination.

16. It is not clear how Post-Control Scenario 3 and Post-Control Scenario B differ in Table 28. Both control scenarios seem to be LNB with advanced OFA, Dry FGD, Fabric Filter, and SCR. However, the impacts shown in Table 28 depict one less day above 0.5 dv for Post-Control Scenario 3 for 2003 data at Wind Cave NP, 2 fewer days for 2001 data at Badlands NP, and one fewer day using the 3-year average at Badlands NP. The State needs to provide an explanation of how the two scenarios differ and an explanation of how the difference affects the modeled impacts.

17. The Dave Johnson determination is missing the averaging period for the tpy NO_x limits in the proposed permit conditions. As we have stated previously, the State should include the averaging periods for all limits within the permit conditions.

Jim Bridger

18. The Calpuff visibility analysis showed the highest impacts at the Mt. Zirkel Wilderness area in Colorado, with lower impacts at the Bridger Wilderness area northwest of the plant. Given that the highest impacts from the facility seem to be focused on locations south and east of the Bridger plant, receptors should be also placed at the Flattops Wilderness area in Colorado to determine the level of visibility impairment at that location.

19. Insufficient information has been presented to warrant NO_x BART limits in excess of the NO_x presumptive BART levels. As shown in Table 1, NO_x emissions at Jim Bridger

Units 2 and 3 are under 0.22 lb/MMBtu, while Unit 4's emissions are somewhat higher at 0.26 lb/MMBtu. Unit 1 emissions in 2008 were 0.39 lb/MMBtu prior to the retrofitting of new controls. EPA presumptive BART is 0.15 lb/MMBtu if you assume the coal is sub-bituminous and 0.28 lb/MMBtu if you assume the coal is bituminous. It is not clear why all the units could not achieve 0.22 lb/MMBtu with LNB/OFA since two of the units are. All of Jim Bridger's units are identically sized nominal 530 megawatt (MW) tangential fired boilers, which should be able to meet nearly identical emission profiles and limits. We would like to point out that although PacifiCorp concluded that Jim Bridger's units cannot meet presumptive NO_x BART, the State has chosen to impose long term strategies that would reduce NO_x emissions to 0.07 lb/MMBtu, which is well below the presumptive level of 0.15 lb/MMBtu. This demonstrates the ability of Jim Bridger to meet a limit lower than the proposed BART limits of 0.26 lb/MMBtu.

20. The BART analysis must include an examination of greater levels of control for NO_x. The BART determination states, "Therefore, based on the cost of compliance and visibility improvement presented by PacifiCorp in the BART applications for Jim Bridger Units 1-4 and taking into consideration the logistical challenge of managing multiple pollution control installations within the regulatory time allotted for installation of BART by the Regional Haze Rule, the Division is requiring the installation of SCR on Jim Bridger Unit 3 in 2015 and on Jim Bridger Unit 4 in 2016 for the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan. The Division is also requiring PacifiCorp to submit a permit application to install additional add-on NO_x control on Units 1 and 2 that includes an analysis of: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of existing sources that contribute to visibility impairment (i.e., the four statutory factors taken into consideration when establishing reasonable progress goals); and (5) the associated visibility impacts from the application of each proposed NO_x control. Each proposed add-on NO_x control shall achieve an emission rate, on an individual unit basis, at or below 0.07 lb/MMBtu on a 30-day rolling average. The permit application shall be submitted by January 1, 2015. Additional add-on NO_x control shall be installed and operational no later than the end of 2023 calendar year on Jim Bridger Units 1 and 2." (see page 55 of the Jim Bridger analysis). We wish to commend the State in its selection of SCR as the control technology for this source, but must point out that, as stated in comment #6 above, the BART guidelines require the consideration of the most stringent level of control of a technology under BART. If a limit of 0.07 lb/MMBtu is achievable by Jim Bridger Units 1 and 2, it needs to be included as the BART level of control, not postponed under reasonable progress.

21. Rotating Opposed Fire Air (ROFA) is considered as one of the NO_x control options, but it is not clear that this option is consistent with PacifiCorp's current permitting requirements to advanced LNB/OFA technology. Regardless, it does not appear to result in any additional control beyond what is currently being achieved on two of the units (0.22 lb/MMBtu). The other two proposed post-combustion control options, SNCR and SCR, could always be retrofitted after LNB/OFA. In the BART analysis for Jim Bridger, SNCR and SCR costs are higher for Unit 2 than for the other units, apparently because

new LNB/OFA is not assumed. The State should provide an analysis on why new combustion controls could not be applied.

22. The BART determination states that "The installation of SNCR and SCR could impact the saleability and disposal of fly ash due to higher ammonia levels, and could potentially create a visible stack plume sometimes referred to as a blue plume, if the ammonia injection rate is not well controlled." (see page 12 of the Jim Bridger analysis). The creation of a blue plume should not occur because control options must be maintained in accordance with good operating practices for minimizing emissions. If chosen as BART, any control option should be operated in a manner that maximizes control efficiency and minimizes collateral impacts. The fact that the injection rate may not be well controlled should not be a factor in eliminating SNCR, as modern plant data acquisition systems should facilitate the computation of an appropriate injection rate and location.

23. An explanation should be provided to address the difference in control of Units 1, 3, and 4 versus Unit 2. The control option "Existing LNB with separated OFA and SNCR" for Units 1, 3, and 4 is projected to reduce annual NO_x by 5,913 tpy while the reduction at Unit 2 is projected to be 1,420 tpy. We note that Jim Bridger has "four (4) identically sized nominal 530 MW tangential fired boilers…" and question why Unit 2 reductions should differ from reductions from Units 1, 3, and 4. (see page 3 of the Jim Bridger Analysis).

24. The option of SNCR was not carried forward to step 5 of the BART process, visibility analysis. The State should complete an analysis of improvements attributable to SNCR.

Laramie River

25. No additional controls for PM emissions from Laramie River were considered. We suggest that the State evaluate whether FGC would be a suitable low-cost control option on Laramie River. On PacifiCorp's units, this control option yielded significant emission reductions at a reasonable cost. If this option is considered, we caution that collateral emission increases should be avoided (please see comment #10 above).

26. Laramie River Units 1-3 are dry-bottom wall-fired boilers, currently emitting at approximately 0.27 lb/MMBtu, and burning sub-bituminous coal. They are all equipped with early generation LNB. EPA presumptive BART for such a boiler/fuel combination is 0.23 lb/MMBtu. Although three different cost tables are provided, one for each unit, they all appear to provide essentially an identical control level for the different control technologies. LNB, OFA, and a LNB/OFA combination are all evaluated as separate control options but it is not clear why the controlled rates are all the same (0.23 lb/MMBtu). One would expect differences, especially with the LNB/OFA combination, which should be lower than the other two options alone. In addition, the cost of LNB/OFA is much higher than on PacifiCorp's plants and the State should provide a reason for this difference.

27. The BART analysis must include an examination of greater levels of control for NO_x. The BART determination states, "Based on the costs and visibility improvement presented by Basin Electric in the BART applications for Laramie River Station Units 1-3, and taking into consideration the logistical challenge of managing multiple pollution control installations within the regulatory timeframe allotted for BART installations by the Regional Haze Rule, the Division is requiring the installation of additional controls under the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan. The Division is requiring Basin Electric submit a permit application to install additional add-on NO_x control that includes an analysis of: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of existing sources that contribute to visibility impairment (i.e., the four statutory factors taken into consideration when establishing reasonable progress goals 5) and the associated visibility impacts from the application of each proposed NO_x control. Each proposed add-on NO_x control shall achieve an emission rate, on an individual unit basis, at or below 0.07 lb/MMBtu on a 30-day rolling average. Additional add-on controls shall be installed and operational on one of the Laramie River Station units by December 31, 2018 and on a second Laramie River Station unit by December 31, 2023." (see page 46 of the Laramie River Analysis). As noted with Jim Bridger, the BART guidelines require the consideration of the most stringent level of control of a technology under BART. If a limit of 0.07 lb/MMBtu is achievable at Laramie River, it needs to be included as the BART level of control, not postponed under reasonable progress.

Naughton

28. The Calpuff visibility modeling of the Naughton facility indicated maximum visibility impacts would occur in the Bridger Wilderness area. Given the relatively common incidence of winds from the north at Naughton, receptors should also be included at the Flattops Wilderness Class 1 area in Colorado to determine the level of visibility impairment at that location.

29. The control efficiencies assumed for all NO_x technologies underestimate the capabilities of the technologies and therefore inflate cost effectiveness (see comment #6 above). The State should re-evaluate the cost effectiveness of NO_x controls. If the true control efficiencies of these technologies is considered, controlled lb/MMBtu rates and cost effectiveness ($/ton) will be much lower than evaluated in the BART analysis. The reanalysis should indicate that SCR is cost effective at Naughton.

30. FGC will be applied to Naughton Units 1 and 2 and decommissioned from Unit 3 upon installation of a fabric filter permitting under PSD. The application of FGC prior to FGD upgrades will result in a PSD significant increase in sulfuric acid mist. This collateral increase should be avoided to maintain continuous visibility improvements at Class I areas impacted by Naughton.

We appreciate the opportunity to comment on these proposed BART determinations. If you have any questions, please contact Laurel Dygowski at (303) 312-6144.

Sincerely,

Callie A. Videtich, Director
Air Program

Docket No. UE 374
Exhibit PAC/4002
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of James Owen

PacifiCorp's Comments to U.S. Environmental Protection Agency in EPA Docket No. EPA-R08-OAR-2012-0026, August 26, 2013

August 2020

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

August 26, 2013

Submitted via email and electronically to www.regulations.gov

Carl Daly
Director, Air Program
U.S. EPA, Region 8
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Re: Docket ID No. EPA-R08-OAR-2012-0026
Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze" (78 Fed. Reg. 34,738 (June 10, 2013)

Dear Mr. Daly:

PacifiCorp submits these comments (including attachments and exhibits) in response to the U.S. Environmental Protection Agency's re-proposed action regarding the Wyoming Regional Haze State Implementation Plan ("RH SIP"). PacifiCorp appreciates the opportunity to offer these comments.

Sincerely,

Micheal G. Dunn

Micheal G. Dunn
President and Chief Executive Officer
PacifiCorp Energy
1407 W. North Temple
Salt Lake City, Utah 84116

August 13, 2013
PacifiCorp's "Detailed Comments" regarding: "Approval, Disapproval and Promulgation of State Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze"

PacifiCorp submits these comments concerning EPA's proposed partial approval and partial disapproval of the Wyoming State Implementation Plan for Regional Haze ("Wyoming RH SIP"), as well as EPA's proposed Federal Implementation Plan ("RH FIP") for Wyoming. (*See* "Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze," 78 Fed. Reg. 34,738 (June 10, 2013) (hereinafter referred to sometimes as "RH FIP Action").) The RH FIP focuses primarily on the "Best Available Retrofit Technology" ("BART") determinations for nitrogen oxides ("NO_X"). In addition to these written comments, PacifiCorp has submitted oral comments during public hearings held in Cheyenne, Wyoming on June 24 and July 17, 2013 and in Casper Wyoming on July 26, 2013.

PacifiCorp believes that the Wyoming RH SIP complies with all applicable requirements and should be approved in total by EPA. PacifiCorp also believes that EPA's proposed disapproval of the Wyoming RH SIP, and EPA's proposed adoption of its RH FIP, are flawed because of the following main reasons, as explained more fully below.

* **BART Bootstrap.** EPA claims that Wyoming failed to properly consider two BART factors (cost and modeled visibility improvement) in connection with Wyoming's BART NO_X determinations. As its chosen remedy for these alleged failures, EPA disapproved Wyoming's entire five-factor BART NO_X determinations for five PacifiCorp BART Units, performed its own BART analysis for each unit (leaving out some factors as explained below), and issued its own BART determinations. This is little more than a classic bootstrap maneuver by EPA in order to take over the regional haze program in Wyoming (and other states) that the Clean Air Act ("CAA") intended to be administered by the states. Even if EPA found that Wyoming committed errors with part of its BART determinations, it should have identified the errors, allowed Wyoming to correct them, and instructed Wyoming to reissue its BART determinations.

* **Remaining Useful Life.** PacifiCorp is submitting to EPA new information demonstrating a shorter useful life than EPA assumed in its BART analyses for Naughton Units 1 and 2, and Dave Johnston Unit 3. Accordingly, EPA must redo its BART analyses before taking final action on its proposed RH FIP. This new information, in turn, significantly changes the cost analyses for these units, and demonstrates that EPA's proposed BART controls are not cost-effective. This new information regarding useful lives is contained in Section 6.D of these comments.

* **Potential Unit Retirement.** PacifiCorp expects that EPA's proposed action requiring SCR on Naughton Unit 1, Naughton Unit 2, and Dave Johnston Unit 3 is not justifiable for its customers. As a result, if EPA makes the SCR requirements final, that action is expected to lead to the retirement or gas conversion of PacifiCorp units by the compliance date. Retirement and fuel switching are outside of the scope of the regional haze program and EPA lacks the authority to impose BART controls that results in such. Also, PacifiCorp identifies the significant energy and economic costs relating to retirements or fuel-switching that EPA must consider before finalizing the proposed RH FIP.

* **EPA's Cost and Visibility Analyses.** In the RH FIP Action, EPA indicated that it had received "new information" which resulted in it not taking action on its prior proposal and instead proposing a new action. This new action, the RH FIP Action, proposes to require additional SCR controls as BART at many additional electric generating units. In terms of dollars per ton of NO_X removed and the modeled change in visibility ("ΔdV") of visibility improvement, however, EPA's consideration of "new information" did not significantly change the results identified in Wyoming's BART analyses. The small differences between EPA's and Wyoming's analyses do not justify EPA rejecting Wyoming's carefully balanced BART determinations and imposing its own will. Nor do the minor differences in results justify the significant changes EPA has made in the controls that it now prescribes in its proposed FIP.

* **EPA's Review of Other BART factors**. EPA's re-proposal has only considered new information related to the costs of controls and the modeled visibility impacts, and did not consider the other BART factors. For this reason alone, EPA's RH FIP Action is unlawful.

* **Alternate Controls.** The Wyoming RH SIP is supported by relevant facts and law, and should be approved by EPA in total. However, since EPA requested consideration of alternate approaches to its BART proposals, PacifiCorp discusses possible alternate approaches in Section 11 (which incorporate the remaining useful life, cost updates and other relevant issues discussed in Section 6).

INTRODUCTION

PacifiCorp supplies electricity to more than 1.8 million residential and business customers in Wyoming and five other western states. Twenty-six of its generating resources are coal-fueled units. PacifiCorp operates 19 of these units in Wyoming and Utah. Among those, 14 are BART-eligible and ten of those are located in Wyoming ("BART Units"). PacifiCorp also has an ownership interest in four coal-fueled units located in Colorado, two units in Montana, and one unit in Arizona. Five of these seven units are BART-eligible units.

EPA proposes to disapprove portions of the Wyoming RH SIP, and implement a RH FIP, for BART NO_X at PacifiCorp's Dave Johnston Unit 3 ("DJ3"), Dave Johnston Unit 4

("DJ4"), Naughton Units 1 and 2 ("NTN 1 & 2"), and Wyodak Unit 1 ("Wyodak"). EPA's RH FIP Action also rejects the Wyoming RH SIP, and imposes a RH FIP, for the NO_X Reasonable Progress Goals at Dave Johnston Units 1 and 2 ("DJ 1 & 2"). EPA ultimately proposes to "approve" Wyoming's BART NO_X determinations for Jim Bridger Units 1, 2, 3, and 4, but requests comment on what EPA characterizes as a "second proposed approach" for Jim Bridger Units 1 and 2 that would require the installation of selective catalytic reduction ("SCR") as BART NO_X within five years of EPA's final action. EPA also proposes to approve Wyoming's BART NO_X determinations for Naughton Units 3, but requests comment on the possible conversion of Naughton Unit 3 to a natural gas fired unit.

Because the Wyoming RH SIP and EPA's RH FIP Action have a unique and significant impact on PacifiCorp and its customers, PacifiCorp offers these comments.

SUMMARY AND OUTLINE OF COMMENTS

PacifiCorp believes that the Wyoming RH SIP complies with all applicable requirements and should be approved in total by EPA. EPA's proposed partial disapproval of the Wyoming RH SIP, and EPA's associated RH FIP, are contrary to the CAA and the federal regional haze program, and also are arbitrary and capricious and outside the scope of EPA's authority.

PacifiCorp submits that:

(1) EPA fails to afford the required deference to Wyoming's significant discretion under the CAA and Regional Haze Program.

(2) EPA illegally bases its proposed partial disapproval of the Wyoming RH SIP on a fabricated "reasonableness" standard not found in the CAA.

(3) EPA exceeded its authority under Section 110 of the CAA.

(4) EPA improperly proposed a rulemaking (the RH FIP) without completing the required legal analyses.

(5) EPA improperly proposed to reject Wyoming's BART determinations for NO_X, which were based on Wyoming's own thorough and well-supported five-factor BART analyses.

(6) EPA improperly proposed a FIP based on an incomplete and flawed five-factor BART analysis.

(7) EPA improperly assumed that post-combustion controls for NO_X can be BART, contrary to Appendix Y and the regional haze requirements.

(8) EPA arbitrarily proposed to require "reasonable progress" controls at DJ 1 & 2 using a different standard than EPA used for other Wyoming sources, and elsewhere.

(9) EPA failed to take into account the collective impact to PacifiCorp of EPA's proposed RH FIP Action, together with EPA's proposed and final actions in the other states where PacifiCorp owns affected facilities.

(10) EPA acted in an untimely fashion in reviewing the Wyoming RH SIP, to the extreme detriment of PacifiCorp, which already has installed, or is in the process of installing, controls mandated by the Wyoming RH SIP.

(11) At EPA's request, PacifiCorp provides information regarding control technology options that could be finalized either instead of, or in conjunction with EPA's RH FIP.

HISTORY OF THE WYOMING RH SIP

PacifiCorp summarizes the history of the Wyoming RH SIP to provide important context for understanding how EPA's RH FIP Action is improper.

On July 1, 1999, EPA first published regulations to address regional haze visibility impairment. Importantly, the regulations required states (not EPA) to address BART requirements for regional haze visibility impairment. In addition, the regulations allowed nine western states, including Wyoming, to develop regional haze plans based on the Grand Canyon Visibility Transport Commission ("GCVTC") recommendations for stationary SO_2 sources in lieu of making BART determinations. (*See* Wyoming RH SIP, pg. 89.) In accordance with the law, Wyoming developed the required plans.

In 2000, the Western Regional Air Partnership ("WRAP") submitted an Annex to the GCVTC recommendations that provided more details regarding the regional SO_2 milestones and backstop trading program recommended in the GCVTC Report. The Annex also included a demonstration that the milestones program would achieve greater reasonable progress than would be achieved by the application of BART for SO_2 in the region. The Annex was approved by EPA in 2003, but this approval was later vacated by the D.C. Circuit Court of Appeals in 2005 due to problems with the methodology that was required in the regional haze rule for demonstrating greater reasonable progress than BART. (*See id.*)

On December 29, 2003, the State of Wyoming submitted a regional haze SIP to meet the requirements of 40 C.F.R. § 51.309. The 309 SIP, and subsequent revisions addressed the first phase of regional haze requirements, with an emphasis on stationary source SO_2 emission reductions and a focus on improving visibility on the Colorado Plateau. In the 309 SIP submittal, Wyoming committed to addressing additional visibility improvements in Wyoming's seven Class I areas by means of a future additional SIP meeting the requirements of 309(g). (*See* WYOMING RH SIP at pg. 1.)

After Wyoming submitted the 309 SIP to EPA in 2003, EPA revised both 40 C.F.R. §§ 51.308 and 309 in response to numerous judicial challenges. Following a lengthy public review period, EPA published new versions of 40 CFR Part 51 and Appendix Y in the Federal Register in 2005 (collectively the "Regional Haze Rules"). As a result, Wyoming submitted revisions to the 309 SIP on November 21, 2008. (*See id.*)

A few years earlier on October 10, 2006, Wyoming's Environmental Quality Council ("EQC") approved a State-only BART regulation (Chapter 6, Permitting Requirements, Section 9, Best Available Retrofit Technology) that became effective in December 2006. This regulation required BART-subject sources to submit an application for a BART determination and a BART permit, according to a schedule determined by Wyoming. (*See* Wyoming RH SIP at pg. 90.)

PacifiCorp submitted individual BART permit applications for its Wyoming BART Units in 2006 and early 2007. PacifiCorp also submitted subsequent information and amendments to Wyoming in support of the BART permit applications. Wyoming published its BART application analyses for PacifiCorp's Wyoming BART Units in May of 2009, and solicited public comment. Public hearings were held for each affected facility during August of 2009. After reviewing and responding to public comments, Wyoming issued BART permits for PacifiCorp's Wyoming BART Units in December 2009.

On February 26, 2010, PacifiCorp appealed the BART permits for Naughton Unit 3 and the four Jim Bridger units to the Wyoming Environmental Quality Council. In particular, PacifiCorp appealed Wyoming's determination that SCR must be installed as BART for Naughton Unit 3 and as part of regional haze long term strategy ("LTS") requirements for Jim Bridger Units 1-4. After appealing the case to the EQC, the parties entered into a settlement agreement in November of 2010. EPA chose not to participate in, challenge or influence Wyoming's decision to issue the BART permits, PacifiCorp's appeal or the subsequent resolution by settlement.

On December 8, 2010, Wyoming held a public hearing in Cheyenne, Wyoming to receive comments on the 309(g) portion of the Wyoming RH SIP. In addition, Wyoming collected public comment on the 309 SIP revisions. After carefully considering all comments, and based upon the settlement agreement, Wyoming Air Quality Division ("WAQD") determined that SCR was not BART for the Jim Bridger Units. Instead, WAQD determined that SCR should be installed over time as part of Wyoming's LTS. On January 7, 2011, Wyoming submitted its 309 SIP (concerning SO_2) and the Wyoming RH SIP (which includes the BART and Reasonable Progress NO_X controls and limits addressed in these comments).[1]

[1] For a reason that is not clear from the record, EPA claims Wyoming's 309(g) SIP, which is also referred to herein as Wyoming's "RH SIP," was submitted on January 12, 2011. 77 Fed. Reg. at 33,022. However, the RH SIP is dated "January 7, 2011" on its title page. *Found at* http://deq.state.wy.us/aqd/308%20SIP/309(g)%20SIP%201-7-11%20Clean%20Final.pdf.

EPA approved the 309 SIP on December 12, 2012. 73 Fed. Reg. 73,926. PacifiCorp's comments herein focus only on the Wyoming RH SIP, primarily as it relates to BART NO_X determinations.

As required by Wyoming's state-only BART regulations, the BART permits and the Wyoming RH SIP and 309 SIP, PacifiCorp installed controls at many of its Wyoming facilities at the cost of hundreds of millions of dollars. The equipment already installed is listed in the following table. Capital costs shown are total project costs and are not limited to PacifiCorp's share of costs for jointly owned facilities.

Table 1

Unit	Wyoming SIP NO_X Technology	Wyoming SIP SO_2 Technology	Wyoming SIP PM Technology	Total Capital Cost*
Naughton 1	LNB/OFA Spring 2012	New Scrubber Spring 2012	ESP upgrade August 2010	$130 million
Naughton 2	LNB/OFA Fall 2011	New Scrubber Fall 2011	ESP upgrade August 2010	$151 million
Jim Bridger 1	LNB/OFA Spring 2010	Scrubber Upgrade Spring 2010	ESP upgrade 2007	$31 million
Jim Bridger 2	LNB/OFA Spring 2005	Scrubber Upgrade Spring 2009	ESP upgrade 2007	$28 million
Jim Bridger 3	LNB/OFA Spring 2007	Scrubber Upgrade Spring 2011	ESP upgrade 2007	$33 million
Jim Bridger 4	LNB/OFA Spring 2008	Scrubber Upgrade Spring 2008	ESP upgrade 2007	$14 million
Dave Johnston 3	LNB/OFA Spring 2010	New Scrubber Spring 2010	New Baghouse Spring 2010	$324 million
Dave Johnston 4	LNB/OFA Spring 2012	New Scrubber Spring 2012	New Baghouse Spring 2012	$115 million
Wyodak	LNB/OFA Spring 2011	Scrubber Upgrade Spring 2011	New Baghouse Spring 2011	$141 million
Total Capital				$967 million

* Total capital costs shown include allowance for funds used during construction.

In addition to these controls that are already in service, engineering is currently underway to convert Naughton Unit 3 to be fueled with natural gas. PacifiCorp is pursuing this course in lieu of installing the BART requirements (i.e. upgrading the scrubber and installing a baghouse and SCR) because BART controls are not economical for PacifiCorp customers compared to the natural gas alternative. This conversion will reduce the hourly and annual NO_X emissions from Naughton Unit 3 to amounts even lower than the required BART controls would have achieved. Naughton Unit 3 is an example of how stringent BART requirements can result in retirement and/or the refueling of a coal-fueled unit.

In addition, consistent with the Wyoming RH SIP and related requirements, engineering and permitting is underway for the installation of SCR on Jim Bridger Unit 3 in 2015 and Jim Bridger Unit 4 in 2016.

Controls installed to date in compliance with the Wyoming RH SIP and BART permits have reduced annual SO_2 emissions by 56% (72,400 tons per year to 31,500 tons per year) and NO_X emissions by 48% (70,900 tons per year to 36,800 tons per year), with the resulting visibility improvements. When all of the controls required under the Wyoming RH SIP are installed, annual SO_2 emissions will have been reduced to 27,600 tons per year (a 62% reduction) and annual NO_X emissions will have been reduced to 19,200 tons per year (a 73% reduction).

DETAILED COMMENTS

(1) EPA Fails to Afford the Required Deference to Wyoming's Significant Discretion Under Clean Air Act and the Regional Haze Program.

EPA's RH FIP Action failed to afford the required deference to the technical, policy and other discretion granted to Wyoming under the CAA and regional haze program.

Congress added § 169A to the CAA in order to address the "impairment of visibility" in Class I areas that "results from man-made air pollution." This provision of the CAA, in turn, describes separate roles for EPA, the states, and major sources such as PacifiCorp's BART Units.

EPA -- EPA's roles are to create a report, *see* CAA § 169A(a)(2)-(3), create regional haze regulations, *see* CAA § 169A(a)(4), provide guidelines for the states, *see* CAA § 169A(b)(1), and determine whether RH SIPs submitted by the states follow the regulations and guidelines, and contain the required elements. CAA § 110.

States -- The States' roles, which are central to the regional haze program, are intended to be accomplished using substantial discretion which, in turn, requires significant deference from EPA.[2] States are required to submit a RH SIP that contains "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." CAA § 169A(b)(2). States also must "determine[]" BART for "each major stationary source." CAA 169A(b)(2)(A).[3]

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[2] Where, as here, the CAA gives decision-making authority to the states, EPA must defer to Wyoming's judgments unless EPA meets it burden of showing that Wyoming acted unreasonably by failing to follow the applicable statutes, regulations and guidelines, or by failing to support with evidence its decision making. See Alaska Dept. of Envtl. Conservation v. EPA, 540 U.S. 461,494 (2004). EPA has made no such showing herein the RH FIP Action. Therefore, Wyoming's BART determinations as contained in the Wyoming RH SIP should stand and EPA should not make final the RH FIP final.

[3] A recent decision by the 10th Circuit Court of Appeals affirmed that "it is undoubtedly true that the statute gives states discretion in balancing the five BART factors…." See

BART Sources -- Finally, BART sources, such as PacifiCorp's BART Units, are required to "procure, install, and operate (BART) as expeditiously as practicable." CAA § 169A(b)(2)(A).

Thus, the CAA mandates that states have the primary role in developing RH SIPs to protect visibility in Class I areas. Likewise, the Regional Haze Rules make clear that states have the responsibility to create and implement RH SIPs. In contrast, EPA's role is to develop "guidelines" for the states to use in implementing RH SIPs and to determine whether states followed those guidelines. CAA § 169A(b)(1). In short, the CAA anticipates that states, using their discretion, develop RH SIPs using EPA guidelines. This is exactly what Wyoming did in issuing BART permits and developing the Wyoming RH SIP.

In issuing regional haze guidelines, EPA recognized the broad discretion granted to the states by the CAA. Specifically, EPA adopted guidance to address BART determinations for certain large electrical generating facilities, referred to as "Appendix Y."[4] EPA created further guidance in the Federal Register responding to comments concerning the then-proposed Appendix Y, referred to as the "Preamble." EPA recognized in the Preamble that "how states make BART determinations or how they determine which sources are subject to BART" are among the issues "where the Act and legislative history indicate that Congress evinced a special concern with insuring that states would be the decision makers." 70 Fed. Reg. 39,104, 39,137 (July 6, 2005) (emphasis added). Likewise, in analyzing the applicability of certain executive orders, EPA stated that "ultimately states will determine the sources subject to BART and the appropriate level of control for such sources" and that "states will accordingly exercise substantial intervening discretion in implementing the final rule." *Id.* at 39,155 (emphasis added).[5]

Okla. V. EPA, No. 12-9526, 2013 U.S. App. LEXIS 14634, (10th Cir. July 19, 2013). Although the court ultimately found in a divided panel that EPA was within its authority to reject the Oklahoma RH SIP and impose a RH FIP because the state of Oklahoma had not properly followed some of EPA's guidelines in making BART determinations, such is not the case here. In this case and as more fully explained herein, the state of Wyoming followed EPA's guidelines in making BART determinations in support of the Wyoming RH SIP. Having done so, EPA must give deference to the discretion the state of Wyoming used in making technical and policy regional haze decisions, including BART determinations. In that case, EPA further must approve the RH SIP and not make final the RH FIP.

[4] "Guidelines for BART Determinations under the Regional Haze Rule," 40 C.F.R. Part 51, Appendix Y.

[5] EPA also has explained that "(i]n some cases, the State may determine that a source has already installed sufficiently stringent emission controls for compliance with other programs . . . such that no additional controls would be needed for compliance with the BART requirement." 64 Fed. Reg. 35714, 35740 (July 1, 1999) (emphasis added). EPA further acknowledges that, in making BART determinations, "[s]tates are free to

The U.S. Court of Appeals for the D.C. Circuit has affirmed that EPA's role regarding regional haze programs is limited and that a state's role is paramount. Indeed, the Court found that the CAA "calls for states to play the lead role in designing and implementing regional haze programs." *American Corn Growers Ass'n v. E.P.A.,* 291 F.3d 1, 2 (D.C. Cir. 2002). The court also reversed a portion of EPA's original Regional Haze Rule because it found that EPA's method of analyzing visibility improvements distorted the statutory BART factors and was "inconsistent with the Act's provisions giving the states broad authority over BART determinations." *Id.* at 8; (*see also Utility Air Regulatory Group v. EPA*, 471 F.3d 1333, 1336 (D.C. Cir. 2006) (The second step in a BART determination "requires states to determine the particular technology that an individual source 'subject to BART' must install.")). The court in *American Corn Growers* emphasized that Congress specifically entrusted states with making BART five-factor analysis decisions: "To treat one of the five statutory factors in such a dramatically different fashion distorts the judgment Congress directed the states to make for each BART-eligible source." *American Corn Growers*, 291 F.3d at 6.

The court in *American Corn Growers* also outlined the relevant legislative history that recounts a specific agreement reached in Congress which granted this authority to the states: "The 'agreement' to which the Conference Report refers was an agreement to reject the House bill's provisions giving EPA the power to determine whether a source contributes to visibility impairment and, if so, what BART controls should be applied to that source. Pursuant to the agreement, language was inserted to make it clear that the states—not EPA —would make these BART determinations. <u>The Conference Report thus confirms that Congress intended the states to decide which sources impair visibility and what BART controls should apply to those sources. The Haze Rule attempts to deprive the states of some of this statutory authority, in contravention of the Act.</u>" *Id*. at 8 (citations omitted) (emphasis added). EPA's RH FIP Action makes the same mistake and, if finalized, will be similarly reversible.

In sum, based on the language in the CAA, the Regional Haze Rules, EPA's own guidelines, and case law, the states have significant discretion when creating RH SIPs. EPA failed to properly account for that discretion in analyzing the Wyoming RH SIP. EPA should have acknowledged that the Wyoming RH SIP followed the law and was supported by the facts. Examples of EPA ignoring Wyoming's discretion include:

- visibility improvement;
- cost effectiveness analysis;
- modeling;
- application of the five BART factors; and
- reasonable progress analyses.

<u>determine the weight and significance</u> to be assigned to each factor." 76 Fed. Reg. 64,186, 64,192 (emphasis added).

EPA's failure to recognize Wyoming's discretion in these areas is arbitrary and capricious.

(2) EPA Illegally Bases its Disapproval on an Unsupported "Reasonableness" Standard not Found in the CAA.

A. EPA's "Reasonableness" Standard is Overly Subjective and Arbitrary.

EPA cannot sidestep the CAA's mandate for state discretion by developing and applying a new "reasonableness" standard for evaluating and rejecting that discretion. EPA's RH FIP Action, however, does just that. For example, EPA incorrectly declared "the state's BART analysis and determination must be reasonable in light of the overarching purpose of the regional haze program." (*See* 78 Fed. Reg. at 34,743, emphasis added.) This overly broad and illegal "reasonableness" standard allows EPA to reject any BART determination that EPA dislikes by merely arguing that a state's BART determination is "unreasonable" and without comparing the state's determination to any firm or fixed standards. EPA's "reasonableness" standard requires statutory and regulatory limitations on EPA's authority to disapprove a reasoned RH SIP. The fallacy of EPA's improper reasonableness standard is made even more apparent in its application by EPA, which simply rejects as "unreasonable" many of Wyoming's BART-related decisions without offering sufficient justification of why that is the case.

B. EPA Uses the "Reasonableness" Standard to Substitute its Judgment for Wyoming's.

In creating and employing its reasonableness standard, EPA goes to an even greater extreme by defining "reasonable" in the most self-serving manner imaginable. In short, EPA defines "reasonable" to mean that EPA agrees with the state's exercise of discretion, and it defines "unreasonable" to mean EPA does not agree with the state. (*See e.g., 78* Fed. Reg. at 34,767, where EPA substitutes its consideration of costs and visibility improvement for Wyoming's). In this way, EPA attempts to bootstraps itself into the role of the sole decision-maker of what is BART and what is not. The CAA does not countenance such overreaching by EPA.

The egregiousness of EPA's actions becomes even more apparent when comparing EPA's conclusions regarding cost and visibility impacts for certain of PacifiCorp's BART Units against the cost and visibility impact conclusions reached by Wyoming for the same units. Table 2 below provides a comparison between Wyoming's modeled ΔdV improvements and EPA's ΔdV improvements based on the "new information" EPA claims it has developed. Recognizing EPA's conclusion that one deciview is barely perceptible to the human eye and considering the inaccuracies and limitations of the model inputs and versions of the visibility models being used, there is no significant difference between Wyoming's results and EPA's results. Additionally, without any "bright line" test regarding the amount of visibility improvement that justifies a given control device, EPA cannot show that these insignificant differences would have any impact on the BART determinations for PacifiCorp's BART Units.

Table 2

COMPARISON OF WYOMING'S AND EPA'S FIVE-FACTOR ANALYSIS RESULTS - VISIBILITY				
Visibility Analysis Comparison - Modeled ΔdV Improvement				
Unit	Technology	State Analysis	EPA Re-Proposal	Difference
Naughton Unit 1	LNB/OFA	0.79	0.84	0.05
	SCR	1.07	1.23	0.16
Naughton Unit 2	LNB/OFA	0.70	0.97	0.27
	SCR	1.10	1.42	0.32
Dave Johnston Unit 3	LNB/OFA	0.77	0.64	(0.13)
	SCR	1.16	1.00	(0.16)
Dave Johnston Unit 4	LNB/OFA	0.71	0.84	0.13
	SNCR	0.80	0.95	0.15
Wyodak	LNB/OFA	0.25	0.24	(0.01)
	SNCR	0.40	0.38	(0.02)

Table 3 below provides a comparison between Wyoming's cost estimates (dollars per ton of NO_X removed) and EPA's cost estimates developed based on "new information". Recognizing that EPA has stated that differences of up to $700 per ton[6] are insignificant, there is no significant difference between Wyoming's results and EPA's results.

Table 3

COMPARISON OF WYOMING'S AND EPA'S FIVE-FACTOR ANALYSIS RESULTS - $ PER TON REMOVED				
Cost Analysis Comparison - Dollar Per Ton NO_X Removed				
Unit	Technology	State Analysis	EPA Re-Proposal	Difference
Naughton Unit 1	LNB/OFA	$426	$444	$18
	SCR	$2,750	$2,318	-$432
Naughton Unit 2	LNB/OFA	$357	$342	-$15
	SCR	$2,848	$2,255	-$593
Dave Johnston Unit 3	LNB/OFA	$648	$599	-$49
	SCR	$3,243	$2,540	-$703
Dave Johnston Unit 4	LNB/OFA	$137	$246	$109
	SNCR	$323	$740	$417
Wyodak	LNB/OFA	$881	$1,027	$146
	SNCR	$958	$1,979	$1,021

For all of the criticism that EPA makes concerning the state's analyses, the reality is that the results of the analyses of both agencies are very similar. In some cases, EPA's

[6] 76 Fed. Reg. 38,997, 39,000

numbers (such as the cost of SNCR at Wyodak) provide less of a justification for EPA's chosen BART controls than Wyoming's numbers did in its analyses. However, EPA has used its broad and unjustified criticisms of the state's work to discredit the state's studies and usurp the discretion the state has applied to its BART determinations.

C. EPA's Subjective "Reasonableness" Standard Leads to Arbitrary and Inconsistent Results.

As shown in Table 3 above, EPA attempted to use post-hoc, immaterial changes that it calculated in costs and visibility improvements to justify usurping Wyoming's BART decision-making authority. EPA attempted this even though its actions run counter to the vast discretion it has given to other states' RH SIPs.

Oregon -- For example, despite EPA and Oregon differing in how each calculated BART costs that resulted in cost variance of over $700 per ton, EPA stated that such difference "between the two estimates would not materially affect ODEQ's evaluation." 76 Fed. Reg. 38,997, 39,000. EPA further explained that in "EPA's view, ODEQ's final selection of BART would not have changed even if the cost effectiveness had been adjusted to reflect the EPA Cost Manual."[7] *Id.* As explained above, the difference between the cost analyses under EPA's RH FIP Action and the Wyoming RH SIP similarly is immaterial. In Oregon, EPA approved the Oregon RH SIP in spite of those differences. In Wyoming, however, EPA used those differences to justify rejection of Wyoming's cost analyses.

Colorado -- In Colorado, the State's plan included a cost analysis that, according to EPA, "was not conducted … in accordance with EPA's Control Cost Manual." 77 Fed. Reg. 76,871, 76,875. In addition, EPA explained that Colorado "should have more thoroughly considered the visibility impacts of controlling emissions from Craig [Unit 1] on the various impacted Class I areas and not just have focused on the most impacted Class I area." *Id.* Nevertheless, after noting "there is room for disagreement about the State's analyses and appropriate limits" and admitting that EPA "may have reached different conclusions," EPA approved the State's RH SIP, explaining that "Colorado's plan achieves a reasonable result overall." *Id.* Again, in Colorado EPA met the requirement that it afford deference to states in the RH SIP process even when EPA may not agree with the methods used by the state to conduct a BART analysis. EPA should afford Wyoming the same degree of deference it afforded Colorado and Oregon, and failure to do so violates the CAA and regional haze program. As demonstrated by the impacts of the Wyoming RH SIP, it "achieves a reasonable result overall."

Wyoming -- EPA's inconsistency is not just limited to its disparate actions between states. In Wyoming, EPA acted inconsistently in its BART determinations between sources

[7] Remarkably, EPA rejected Wyoming's NO_x BART analyses for Naughton Units 1 and 2, even though the cost per ton between EPA's and Wyoming's numbers are less than $700 per ton. 78 Fed. Reg. 34,781,-82. While EPA respected Oregon's discretion to weigh the costs of BART controls despite not following the Control Cost Manual, here EPA ignored the State's discretion on the pretext it hadn't followed the Control Cost Manual.

within the state. For example, EPA accepted Wyoming's cost and visibility BART analyses for FMC Westvaco and General Chemical, along with the PM BART analyses for PacifiCorp's and Basin Electric's BART Units. At the same time, EPA rejected the NO_x BART cost and visibility analyses for PacifiCorp's and Basin Electric's BART Units. Wyoming, however, used the same BART analysis methodology for those BART Units at which EPA accepted the Wyoming BART analysis as it did at those BART Units for which EPA did not. The BART analysis employed by Wyoming was the same for all BART Units. By rejecting some cost and visibility analyses on the basis that they were improperly performed, while accepting others that were performed in the same manner, EPA acted arbitrarily and capriciously.

D. EPA Erred by not Analyzing Whether the BART Controls Required by its RH FIP are Necessary to Make Reasonable Progress

EPA should have judged Wyoming's BART determinations on the basis of whether or not the Wyoming BART determinations are "necessary" to make "reasonable progress."

EPA's Regional Haze Rules provide two regulatory paths to address regional haze. (*See* 77 Fed. Reg. 30,953, 30,957 (May 24, 2012).) "One is 40 CFR 51.308, requiring states to perform individual point source BART determinations and evaluate the need for other control strategies." *Id.* "The other method for addressing regional haze is through 40 CFR 51.309, and is an option for nine states termed the 'Transport Region States' which include: . . . Wyoming, . . . By meeting the requirements under 40 CFR 51.309, states are making reasonable progress toward the national goal of achieving natural visibility conditions for the 16 Class I areas on the Colorado Plateau." *Id.* Wyoming submitted the Wyoming RH SIPs under Section 309. Therefore, the requirements of Section 308 only apply to the extent required by Section 309.[8]

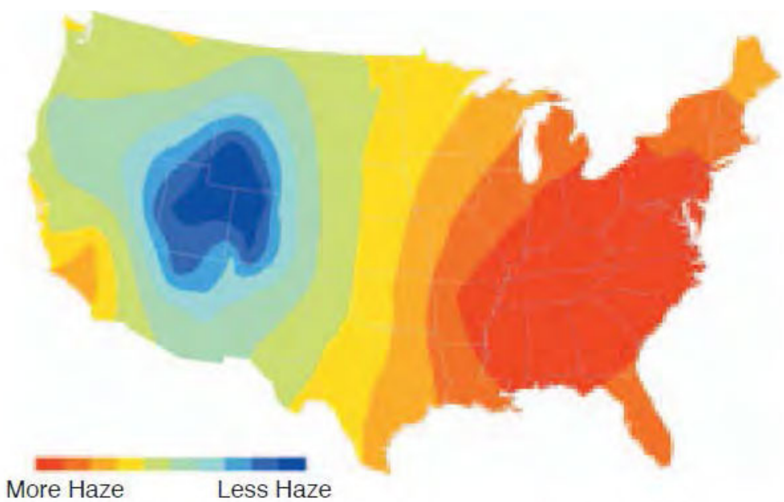
Importantly, NO_X emissions and controls under Section 309 are treated differently than NO_X emissions and controls under Section 308. This is because Congress and EPA purposefully focused Section 309 on addressing the issue of SO_2 emissions, the predominant cause of regional haze on the Colorado Plateau in the western US. By contrast, Section 309 recognizes that NO_X emissions have a significantly smaller impact on visibility on the Colorado Plateau. In fact, the WRAP estimated that "stationary source NO_X emissions result in nitrates that probably cause about 2 to 5 percent of the impairment on the Colorado Plateau." [9] Several illustrations in the WRAP NO_X report

[8] Section 51.309 "requires participating states to adopt regional haze strategies that are based on recommendations from the Grand Canyon Visibility Transport Commission (GCVTC)" which was established in 1991 to protect the 16 Class I areas on the Colorado Plateau. 77 Fed. Reg. at 30,957. These strategies included "Strategies for addressing smoke emissions from wildland fires and agricultural burning; provisions to prevent pollution by encouraging renewable energy development; and provisions to manage clean air corridors (CACs), mobile sources, and wind-blown dust, among other things." *Id.*

[9] "Stationary Source NO_X and PM Emissions in the WRAP Region: An Initial Assessment of Emissions, Controls, and Air Quality Impacts," October 1, 2003, at I-3, *found at* http://www.wrapair.org/forums/mtf/nox-pm.html. The state of Wyoming relied upon this

show that nitrate emissions have very little impact on Class I areas in or near Utah and Wyoming. (*See id. at* III-3 to III-6.) The WRAP report also explains that "NO_X controls will have a relatively small impact on PM and visibility in the West." (*Id.* at IV-20 and IV-21.)

The Wyoming RH SIP, including BART determinations for NO_X, is consistent with the WRAP's NO_X information, and also properly acknowledges the relatively small impact nitrates from stationary sources like PacifiCorp's BART Units have on visibility impairment in Wyoming. Wyoming's RH SIP, page 62, states that "the majority of nitrate stems from mobile sources." The RH SIP also explains that in all but one Class I area "contributions from other states and Canada are much larger than contributions from inside Wyoming." *Id.* Wyoming correctly determined, consistent with the WRAP reports and other data, that controlling NO_X emissions from stationary sources like PacifiCorp's BART Units would yield very little visibility improvement in Wyoming. EPA's own regional haze visibility map shows that visibility in Wyoming is among the best in the country. (*See below and* Attachment 1, EPA Regional Haze Map.)



Haze conditions vary across the country. Eastern U.S. areas have more haze due to higher pollutant and humidity levels.

In light of the above information, it is understandable that Section 309 focuses on addressing SO_2 emissions. Indeed, GCVTC and WRAP focused their efforts primarily on SO_2 emissions because the research indicated this pollutant had the greatest impact on visibility. "Recommendations for Improving Western Vistas," authored by GCVTC, (June 10, 1996) at page 32 (identifying sulfates as "the most significant contributor to visibility impairment" from stationary sources).[10] In a separate action, EPA

information in formulating its NO_X and PM BART control strategy. January 7, 2011 309(g) RH SIP, pages 61-66 and 188-196. Additionally, to the extent NO_X controls would be required, WRAP stated that "substantial reduction may be feasible with commercially-available technologies for about $300 to $1,200 per ton." *Id.* at I-4.

[10] *Found at* http://www.wrapair.org/WRAP/reports/GCVTCFinal.PDF.

acknowledged that Wyoming has complied with the Section 309's SO_2 requirements and made great progress[11] towards improving and protecting visibility as a result.

For all of these reasons, Section 309 takes a different approach to NO_X emissions than does Section 308, placing much less emphasis on the need for significant reductions in NO_X emissions and instead focusing almost all attention and resources in the western U.S. on reducing SO_2 emissions. EPA's RH FIP Action, with its incredibly expensive and unneeded NO_X control equipment, ignored the focus and intent of Section 309 and refused to acknowledge the discretion available to Wyoming to balance this information in making its BART determinations.

Additionally, as a result of the lesser emphasis in Section 309 on NO_X emissions, Section 51.309(d)(4)(vii) requires a RH SIP to "contain any necessary long term strategies and BART requirements for stationary source . . . NO_X emissions." Section 308, by contrast, does not include a similar "necessary to achieve reasonable progress" threshold for BART. The difference between the two requirements is both intentional and meaningful. If a state like Wyoming finds that a particular BART requirement is not "necessary" to make "reasonable progress," then that BART requirement should not be required as part of the RH SIP. This interpretation is supported by EPA's own position in *Central Arizona Water Conservancy District v. United States*, 990 F.2d 1531 (9th Cir. 1993). There, "EPA chose not to adopt the emission control limits indicated by the BART analysis, but instead to adopt an emissions limitations standard that would produce greater visibility improvement at a lower cost." *Id.* at 1543 (emphasis added). The court agreed with EPA, stating that "Congress's use of the term 'including' in § 7491(b)(2) prior to its listing BART as a method of attaining 'reasonable progress' supports EPA's position that it has the discretion to adopt implementation plan provisions other than those provided by BART analyses in situations where the agency reasonably concludes that more 'reasonable progress' will thereby be attained." *Id.* (emphasis added). This same rationale applies to the term "necessary" in Section 309. Therefore, in rejecting Wyoming's RH SIP and adopting a RH FIP, EPA is required to show that the Wyoming RH SIP will not achieve "necessary reasonable progress" towards the visibility goal, EPA's RH FIP will. EPA has failed to provide any support for such a position.

As previously noted, with the exception of the controls required on Naughton Unit 3, PacifiCorp has installed all of the BART controls required by the Wyoming RH SIP and BART Permits. These controls were installed from 2005 through 2012. The charts[12] included as Attachment 2 identify the visibility improvement that has been made through 2009 at the Mount Zirkel Wilderness Area (used in the Jim Bridger BART evaluations) and Wind Cave National Park (used in the Wyodak and Dave Johnston BART evaluations). The charts in the attachment, which are based on actual monitored visibility impairment, demonstrate that the Wyoming RH SIP already has made significant progress in reducing nitrate concentrations and further demonstrate that Wyoming's

[11] PacifiCorp's timely installation of required SO_2 controls at its Wyoming BART Units has been a large part of this success.

[12] http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx

reasonable progress goal is on track through the 2008 - 2017 planning period. These charts provide graphic evidence that EPA's RH FIP Action is not "necessary" to meet reasonable progress goals for nitrates in these Class I areas. As a result, EPA should withdraw its RH FIP.

(3) EPA Exceeded its Authority Under Section 110 of the CAA.

EPA does not have the authority under the CAA to issue a RH FIP in this instance. EPA contends its review of the Wyoming RH SIP is "pursuant to section 110 of the CAA." 7 Fed. Reg. 34,738. Section 110(a)(2) provides the general requirements that a SIP must contain. Importantly, EPA's role under Section 110 in reviewing states' RH SIPs is narrow: "With regard to implementation, the (CAA) confines the EPA to the ministerial function of reviewing SIPs for consistency with the (CAA)'s requirements." *Luminant Generation Co., LLC v. EPA,* 675 F.3d 917, 921 (5th Cir. 2012) (citing § 110(k)(3)).

As the court in *Luminant* explained, if the State's submissions "satisfy those basic requirements (found in § 110), the EPA must approve them," and "(t)hat is the full extent of the EPA's authority in the SIP-approval process because that is all the authority that the CAA confers." *Id.* at 932. Here, Wyoming submitted a RH SIP that met the requirements of Section 309 and included all the required elements. The Wyoming RH SIP submittals are well developed and comprehensive. EPA admits that Wyoming considered all five BART factors. 78 Fed. Reg. at 34,748. Therefore, EPA's role was to review whether Wyoming followed the regional haze requirements, including Appendix Y, and provided factual support for the Wyoming RH SIP. Congress did not authorize EPA to "second guess" Wyoming's BART decision making, or to substitute its own judgment, simply because EPA would prefer different BART and Reasonable Progress NO_X controls.

EPA should not impose a RH FIP until it has issued a final rule disapproving the Wyoming RH SIP. 42 U.S.C. § 7410(c)(1)(B). EPA should first conduct a rulemaking and take public comment on the Wyoming RH SIP submission, issue its determination on the RH SIP, and then seek input from the State. (*See* 42 U.S.C. § 7410(c)(1)(B); *see also* 42 U.S.C. § 7607(d)(B) (rulemaking provisions apply to "the promulgation or revision of an implementation plan by the Administrator under section 7410(c)") Otherwise, EPA removes the State from its assigned role as the one determining BART.

The facts here illustrate this problem. EPA initially agreed with Wyoming's BART determinations for Naughton Units 1 and 2, and Dave Johnston Unit 3. EPA then reversed itself, supposedly on the basis of new cost and visibility information. Without offering Wyoming any chance to review the new information and issue a new BART determination, EPA disapproved Wyoming's BART determination for these units, and instituted new BART determinations for these units through a RH FIP. EPA's failure to provide Wyoming an opportunity to review this new information, and address it through a revised BART determination, violates the applicable Clean Air Act statutes.

The CAA defines a "Federal Implementation Plan" or FIP as "a plan (or portion thereof) promulgated by the (EPA) Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan (or SIP)." 42 U.S.C. § 7602(y) (emphasis added). Until EPA first assesses the Wyoming RH SIP, develops a proposed rule to approve or disapprove the Wyoming RH SIP, solicits and receives public comment on that proposed rule, considers the comments and information, and takes final action on whether (and to what extent) to approve the Wyoming RH SIP, EPA cannot know whether there is a "gap" in the Wyoming RH SIP that needs to be filled or whether (and to what extent) there is an "inadequacy" in the Wyoming RH SIP that needs to be corrected. *Id.* Moreover, EPA's failure to obtain public comments prior to proposing a RH FIP deprives Wyoming of an opportunity to correct any "deficiencies" identified by EPA. Here, where EPA claims to have obtained new cost and visibility information but did not allow Wyoming an opportunity to review and act on the new information, EPA's final determination regarding the Wyoming RH SIP ignores the State's authority under the CAA (including the regulatory programs implicated by CAA § 169A) to design and implement plans to control air pollution control within its borders. (*See* 42 U.S.C. § 7401(a)(3).) Therefore, EPA illegally seeks to impose its RH FIP and should withdraw the same.

(4) EPA Proposed a Rulemaking (the RH FIP) Without Completing the Required Legal Analysis.

A. EPA Failed to Follow the Requirements of Executive Orders 13211 and 12866.

EPA's RH FIP Action states that EPA's proposed action is not subject to Executive Order 13211, "Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use" (66 Fed. Reg. 28,355 (May 22, 2001)), because the proposed action "is not a significant regulatory action under Executive Order 12866." 78 Fed. Reg. at 34,790. EPA further claims the proposed RH FIP is not a "significant regulatory action" under Executive Order 12866 because the "proposed FIP applies to only five facilities" and is "therefore not a rule of general applicability." EPA is incorrect, and should withdraw its RH FIP on these grounds.

Executive Order 13211 provides that agencies shall submit a statement of energy effects for matters "identified as significant energy actions." A "significant energy action" is defined as "any action by an agency … that promulgates or is expected to lead to the promulgation of a final rule or regulation … that is a significant regulatory action under Executive Order 12866 or any successor order" and "likely to have a significant adverse effect on the supply, distribution, or use of energy"; or is "designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action." *Id.* § 4(b) (emphasis added).

Executive Order 12866, in turn, which concerns Regulatory Planning and Review, defines a "significant regulatory action" as any regulatory action that is likely to result in a rule that may:

> (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities; . . .

58 Fed. Reg. 51,735, 51,738 (Oct. 4, 1993) (emphasis added).

According to PacifiCorp's current estimates (excluding allowance for funds used during construction "AFUDC"), it will spend more than $100 million dollars in capital costs alone in 2014 ($225 million), 2015 ($139 million), 2017 ($146 million) and 2018 ($118 million) to comply with EPA's RH FIP for Wyoming (based on alternative "one" for the Jim Bridger plant). If regional haze compliance costs currently imposed or approved by EPA on PacifiCorp's BART Units in Arizona and Colorado are factored in, the total capital cost impacts to PacifiCorp in any given year would be significantly higher; increasing to approximately $246 million in 2014, $190 million in 2015, $168 million in 2016, $181 million in 2017, and $118 million in 2018. Also, because the BART NO_X and PM determinations have not yet been approved by EPA for PacifiCorp's BART Units in Utah, EPA's ultimate BART requirements in Utah likely will add even more costs in overlapping installation and compliance years, with total project costs for SCR installations on PacifiCorp's Utah units currently estimated to cost in excess of $150 million per unit to install (again, excluding AFUDC). Based upon these basic costs alone, there is no doubt that EPA's RH FIP Action meets the definition of a "significant regulatory action." Other large costs, including those related to EPA's BART determinations for Basin Electric, also should be factored into this analysis together with PacifiCorp's costs because they are part of the same "sector of the economy." Also, as demonstrated by PacifiCorp's July 12, 2012, submittal in this docket, EPA's RH FIP Action will have an adverse effect on the supply and distribution of electricity within PacifiCorp's system. Therefore, EPA's determination that Executive Order 13211 did not apply is incorrect, and arbitrary and capricious.

Moreover, EPA has admitted in the proposed rule that system-wide "affordability" costs should be part of the BART analysis. 78 Fed. Reg. at 34,756. Because EPA's RH FIP Action is a "significant regulatory action," EPA must prepare a "Statement of Energy Effects" for the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget. (*See* Executive Order 13211, § 2. Because EPA did not do so, the RH FIP Action is improper.

B. EPA Also Failed to Follow the Requirements of the Unfunded Mandates Reform Act.

EPA also failed to perform other necessary, regulatory analyses before issuing the RH FIP Action. The Unfunded Mandates Reform Act of 1995 ("UMRA"), Public Law 104-4, requires federal agencies to identify unfunded federal mandates in proposed legislation or regulatory processes imposing costs greater than a statutorily defined amount ($100 million) on State, local or tribal governments in the aggregate, or on the private sector. UMRA was intended to provide more information on, and prompt more careful consideration of, the costs and benefits of federal mandates that affect nonfederal parties, including private entities. 2 U.S.C. §1501. For rules that contain federal mandates, such as EPA's RH FIP Action requiring expensive pollution controls, title II of UMRA requires the agencies to prepare written statements, or "regulatory impact statements," ("RIS") containing specific descriptions and estimates, including a qualitative and quantitative assessment of the anticipated costs and benefits of the mandate. This requirement is triggered by any rule that "may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more (adjusted annually for inflation) in any 1 year…" 2 U.S.C. §1532(a).

When this provision is triggered, the agency is specifically required to provide in a RIS several analyses, including "<u>a qualitative and quantitative assessment of the anticipated costs and benefits of the Federal mandate</u>, including the costs and benefits to State, local, and tribal governments or the <u>private sector</u>," estimates of "the <u>future compliance costs of the Federal mandate</u>," "any disproportionate budgetary effects of the Federal mandate upon any particular regions of the nation," and "the effect on the national economy, such as the effect on productivity, economic growth, full employment, creation of productive jobs." 2 U.S.C. § 1532(a) (emphasis added). When the written statement in Section 1532 is required, the agency is also required to "identify and <u>consider a reasonable number of regulatory alternatives and from those alternatives select the least costly, most cost effective, or least burdensome alternative</u> that achieves the objectives of the rule" or explain why that alternative was not selected. 2 USCA §1535 (emphasis added).

Here, EPA has failed to comply with the UMRA, arguing that the RH FIP "does not contain a federal mandate that may result in expenditures that exceed the inflation adjusted UMRA threshold of $100 million." (*See* 78 Fed. Reg. at 34,790.) EPA is wrong. As discussed above, PacifiCorp currently estimates spending more than $100 million dollars in capital cost alone in 2014 ($225 million), 2015 ($139 million), 2017 ($146 million) and 2018 ($118 million) to comply with EPA's RH FIP for Wyoming (based on alternative "one" for the Jim Bridger plant). If the regional haze compliance costs imposed by EPA's RH FIP in Arizona and EPA's approval of the Colorado RH SIP are factored in, the costs to PacifiCorp in a given year would be significantly higher. Also, when the BART NO_X and Particulate Matter ("PM") determinations are finalized by EPA for Utah, regional haze compliance costs to PacifiCorp in a given year could be much, much higher.[13] Additionally, if costs to others in the "private sector," such as the

[13] The UMRA has been applied to EPA actions where the costs to regulated entities in numerous states have been aggregated. Office of Management and Budget, "2011 Report to Congress on the Benefits and Costs of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities (June 2011)" *available at* http://www.whitehouse.gov/omb/inforeg_regpol_reports_congress (draft Notice of Availability 76 Fed. Reg. 18,260); *see also* GAO-04-637. Based upon this precedent, PacifiCorp believes that EPA should aggregate all regional haze compliance costs across Wyoming, Utah, Colorado and Arizona for PacifiCorp, which would easily exceed the $100 million threshold. At a minimum, EPA should aggregate costs that will be incurred

cost of SCR on Basin Electric's BART Units, are added to PacifiCorp's costs, then the $100 million threshold will be exceeded by an even larger margin.

(5) EPA Improperly Proposed to Reject Wyoming's BART Determinations for NO_X which were Based on Wyoming's Thorough and Well-supported Five-factor BART Analyses.

A. Wyoming Appropriately Considered all Five BART Factors Together.

In reaching its BART determinations, Wyoming properly relied on EPA's Appendix Y Guidelines and conducted an analysis of each of the required five factors.[14] Although EPA acknowledged that "Wyoming considered all five steps above in its BART determinations," it found that Wyoming's "consideration of the costs of compliance and visibility improvement for the EGUs was inadequate and did not properly follow the requirements in the BART Guidelines and statutory requirements…"[15] Specifically, EPA noted that "because the visibility improvement associated with each of the State's control scenarios was due to the combined emission reductions associated with SO_2, NO_X, and PM controls" that "it was not possible for EPA, or any other party, to ascertain the visibility improvement that would be from an individual NO_X or PM control option."[16] *Id.* As a result, EPA proposed to disapprove the Wyoming NO_X BART determinations for certain of PacifiCorp units, and issue a RH FIP instead. However, EPA's rejection of Wyoming's BART NO_X determinations is improper for several reasons.

1. Wyoming provided the required visibility improvement information for SCR.

Although the various BART application analyses conducted by Wyoming for PacifiCorp's BART Units note that Wyoming conducted a "comprehensive visibility analysis covering all three visibility impairing pollutants,"[17] the analyses also state:

> "While visibility impacts were addressed in a cumulative analysis of all three pollutants, Post-Control Scenario B is directly comparable to Post-Control Scenario A as the only difference is directly attributable to the installation of

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due to EPA's FIPs in Wyoming and Arizona, which would also exceed the $100 million threshold.

[14] Appendix Y was adopted as law after notice-and-comment rulemaking (70 Fed. Reg. 39,104), and states are justified in relying on it when crafting their RH SIPs. Indeed, EPA made clear that the Appendix Y guidelines "are designed to help states and others . . . determine the level of control technology that represents BART for each source." 70 Fed. Reg. at 39,157

[15] 78 Fed. Reg. at 34,748

[16] 78 Fed. Reg. at 34,749

[17] *See, for example*, May 28, 2009, WDAQ BART Analysis for Jim Bridger at page 15; Attachment A of Wyoming 309(g) RH SIP.

> SCR. Subtracting the modeled values from each other yield the incremental visibility improvement from SCR."[18]

In other words, Wyoming clearly considered – and made available to EPA – the very specific NO_X information that EPA claims it "was not possible for EPA, or any other party, to ascertain." Simply c*laiming* it "was not possible for EPA" to ascertain results from available information does not justify EPA in rejecting Wyoming's NO_X BART determinations. Wyoming had, and considered, SCR-specific visibility information. EPA cannot use the alleged lack of this information to justify requiring SCR as BART.

2. *Wyoming's BART NO_X determinations were based on all five BART factors, including an appropriate visibility improvement assessment.*

When considering BART NO_X controls for the four BART Units at the Jim Bridger plant, Dave Johnston Units 3 and 4, and Wyodak, Wyoming properly based its BART NO_X decisions upon all BART factors in combination, including (1) costs of compliance (total capital costs and cost effectiveness), (2) power losses (energy impacts) caused by post-combustion NO_X controls and environmental considerations related to chemical reagents used with post-combustion NO_X controls (non-air quality environmental impacts), (3) existing pollution control technology in use at the source, (4) the remaining useful life of the source, and (5) visibility improvement information.[19]

In addition, Wyoming's BART NO_X determinations for the Naughton power plant further demonstrate Wyoming's consideration and balancing of all five factors, including visibility improvement, and its individualized consideration for each unit. For Naughton Units 1 and 2, Wyoming found that costs of compliance (total capital costs and cost effectiveness), power losses (energy impacts) caused by post-combustion NO_X controls, environmental considerations related to chemical reagents used with post-combustion NO_X controls (non-air quality environmental impacts), and visibility improvement information indicated that low NO_X burners ("LNBs") and over-fire air ("OFA") are BART NO_X.[20] However, for Naughton Unit 3, based upon its much greater "visibility improvement", Wyoming determined that SCR is BART NO_X. *Id.* Wyoming's BART NO_X analyses across the Naughton Plant's three units demonstrate Wyoming's consideration and weighing of all five BART factors, including the decision to require different levels of BART NO_X controls across various units at the same plant when Wyoming determined that the visibility improvements and other factors at one unit justified more stringent control. This example is yet one more indication, contrary to

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[18] *Id.* at page 50

[19] S*ee* May 28, 2009, WDAQ BART Analysis for Jim Bridger, pages 49-50, Attachment A of Wyoming 309(g) RH SIP; May 28, 2009, WDAQ BART Analysis for Dave Johnston, pages 47-48, Attachment A of Wyoming 309(g) RH SIP; and May 28, 2009 WDAQ BART Analysis for Wyodak, pages 35-36, Attachment A of Wyoming 309(g) RH SIP; and January 7, 2011, Wyoming 309(g) RH SIP, pages 102-105 and 108-09.

[20] May 28, 2009, WDAQ BART Analysis for Naughton, pages 49-50, Attachment A of Wyoming 309(g) RH SIP.

EPA's assertions, that Wyoming did adequately consider "visibility improvement" information in each of its BART determinations, including Wyoming deciding in its discretion the "weight and significance" appropriate for each BART factor at each BART Unit.

3. *Wyoming's analyses of SCR costs were not flawed.*

EPA inappropriately claimed that "Wyoming's SCR capital costs on a $/kW basis often exceeded real-world industry costs"[21] and then refers to industry studies conducted between 2002 and 2007 that report installed unit capital costs actually incurred by owners broadly ranging "from $79/kW to $316/kW (2010 dollars)." *Id.* EPA also noted "instances" in its proposed RH FIP "in which Wyoming's source-based cost analyses did not follow the methods set forth in the EPA Control Cost Manual." Apart from the irony of EPA failing to follow its own Control Cost Manual as explained in Section 6 below, the information in Tables 4 and 5 shows that EPA is simply incorrect in stating that Wyoming's analyses were flawed and did not reflect real-world industry costs for the units being analyzed. These tables reflect "real-world" costs for the upcoming Jim Bridger Units 3 and 4 SCR projects, which recently were competitively bid for engineering, procurement, and construction contracts to be installed in accordance with the requirements in the Wyoming RH SIP. These real-world costs, in turn, can easily be compared to the costs assessed by Wyoming and by EPA in their BART determinations.

Table 4

Jim Bridger Unit 3 SCR Cost Assessments Comparison (LNB w/ SOFA Baseline) (excludes AFUDC)			
Project Cost Assessment	**Wyoming SIP Cost Basis***	**EPA RH FIP Cost Basis**	**Competitive Market Cost Basis**
Total Capital Costs	$153,000,000	$134,146,938	$176,129,704
Annualized Capital Costs	$14,550,300	$11,049,338	$18,740,200[22]
Annual Operating Costs	$3,370,460	$7,918,786	$2,654,500
Total Annual Cost	**$17,920,760**	**$18,968,124**	**$21,394,700**
Agency Costs versus Real-World Annual Costs (Competitive Market)	**-$3,473,940**	**-$2,426,576**	**-**

* Wyoming SIP SCR cost including AFUDC was $166,500,000 resulting in an Annualized Capital Cost of $15,839,145 and a Total Annual Cost of $19,209,605. The Wyoming SIP information presented above has been adjusted to reflect removal of an estimated $13,500,000 of AFUDC with the corresponding adjustment to Total Annual Cost for comparison purposes.

[21] *See* 78 Fed. Reg. at 34,748

[22] Assumes capital recovery factor of 10.64%; consistent with EPA Control Cost Manual Method and Andover Report cost recovery factor for comparison purposes.

Table 5

Jim Bridger Unit 4 SCR Cost Assessments Comparison (LNB w/ SOFA Baseline) (excludes AFUDC)			
Project Cost Assessment	**Wyoming SIP Cost Basis***	**EPA RH FIP Cost Basis**	**Competitive Market Cost Basis**
Total Capital Costs	$153,000,000	$112,650,287	$186,663,655
Annualized Capital Costs	$14,550,300	$9,289,920	$19,861,013[23]
Annual Operating Costs	$3,370,460	$7,255,120	$2,654,500
Total Annual Cost	**$17,920,760**	**$16,545,040**	**$22,515,513**
Agency Costs versus Real-World Annual Costs (Competitive Market)	**-$4,594,753**	**-$5,970,473**	**-**

* Wyoming SIP SCR cost including AFUDC was $166,500,00 resulting in an Annualized Capital Cost of $15,839,145 and a Total Annual Cost of $19,209,605. The Wyoming SIP information presented above has been adjusted to reflect removal of an estimated $13,500,000 of AFUDC with the corresponding adjustment to Total Annual Cost for comparison purposes.

As shown in Tables 4 and 5 above, see Attachment 3, when adjusted to exclude AFUDC as EPA argues should be done to eliminate flaws in the Wyoming RH SIP analyses, the Wyoming RH SIP cost basis aligns with EPA's RH FIP cost basis and both agencies understate the real-world costs that will be incurred on the Jim Bridger Units 3 and 4 SCR projects. For that matter, even when including AFUDC, the Wyoming RH SIP cost basis aligns closely with the EPA's cost basis, with each agency again understating real-world costs for these projects. By extension, this real-world cost information for Jim Bridger Units 3 and 4 validates the methodology used by Wyoming to determine cost information for each of PacifiCorp's BART Units. This information clearly disputes EPA's claims in its RH FIP Action that Wyoming "did not properly or reasonably take into consideration the costs of compliance" and that its SCR cost analyses exceeded real-world industry costs and were flawed. *Id.* Similar information regarding Wyoming's control technology cost analyses completed in support of the Wyoming RH SIP will be presented separately in these comments.

B. EPA Acted Illegally by Relying on "Emissions Reductions" as a Sixth BART Factor.

EPA's RH FIP Action is also illegal, arbitrary, and capricious because it relies upon factors outside of the BART five-factor analysis. Nowhere in the five-factor analysis, or anywhere in the Appendix Y Guidelines, is there any support for EPA using an "emissions reduction" factor. But this is exactly what EPA has done in its RH FIP

[23] Assumes capital recovery factor of 9.44%; consistent with EPA Control Cost Manual Method information provided with these comments.

Action. For example, EPA cited "emission reductions" as the basis for the RH FIP BART NO_X decisions for Dave Johnston Unit 3 (*See* 77 Fed. Reg. at 33,052), Wyodak (*See* 77 Fed. Reg. at 33,055) and Laramie River (*See* 77 Fed. Reg. at 33,001), among others. In doing so, however, EPA failed to account for the fact that the regional haze program is not an emissions reduction program *per se*, but is a visibility improvement program.

EPA's over-reliance on "emissions reductions" outside of the mandated BART factors has caused EPA to overstep the boundaries of the Regional Haze Program.[24] This is evidenced by the virtually non-existent visibility improvements associated with SNCR controls at Wyodak and Dave Johnston Unit 4 as required in EPA's RH FIP Action. Instead, EPA required these controls because of the associated emission reductions. Additionally, it is improper for EPA to reject Wyoming's BART determinations, which relied upon the proper balancing of all five BART factors, and replace those BART determinations with EPA's analysis, which relied upon factors outside the five-factor analysis, such as emissions reductions. (*See e.g.,* 77 Fed. Reg. at 33,052.) Courts have held that when an agency relies on factors "which Congress has not intended it to consider," then such action is arbitrary and capricious. *Arizona Public Service Co. v. US EPA,* 562 F.3d 1116, 1123 (10th Cir. 2009).

(6) EPA Improperly Proposed a RH FIP Based on an Incomplete and Flawed Five-Factor BART Analyses.

On June 10, 2013, EPA published its re-proposed RH FIP that was purported to be based on new information that EPA claimed had come to light and that it needed to consider. In doing so, however, EPA only attempted to reconsider two of the five BART factors: (1) costs of compliance; and (2) modeled visibility impacts. EPA's own Appendix Y Guidelines do not support evaluating individual BART factors in a vacuum, and EPA's re-proposal should have considered all new information that was available for all five BART factors when proposing a new RH FIP. BART determinations are intended to be "composite" decisions, with many facts and data from each of the five BART factors playing a role in the ultimate BART determination.[25] EPA's proposal to cherry pick one or two BART factors as a reason for rejecting Wyoming's entire NO_X BART determination for certain BART Units is arbitrary and capricious because it makes these one or two BART factors more important than any of the others, and also more important than the composite BART determination as a whole. It also disregards each of the five BART factors as Wyoming evaluated them and ignores the "weight and significance" of

[24] Additionally, EPA pays undue attention to the "health" issues in its RH FIP Action. For reasons it does not explain, EPA's RH FIP Action discusses the asserted health impacts of $PM_{2.5}$, when health impacts are not part of the BART analysis. 77 Fed. Reg. at 33,024. The Regional Haze program is not a health-based program; rather, it is focused on aesthetics. 76 Fed. Reg. 81,728, 81,752 (noting that health issues are not considered "as part of the BART determination").

[25] *Cf.* 76 Fed. Reg. at 81,733; "We recognize the state's broad authority over BART determinations, and recognize the state's authority to attribute weight and significance to the statutory factors in making BART determinations." (emphasis added)

each factor alone, and in combination with the others, as Wyoming determined in its BART decisions. As a result, EPA's attempt to only re-evaluate two factors leads to a RH FIP proposal that is fatally flawed. The following addresses each of the five factors that Wyoming addressed in the Wyoming RH SIP, and that EPA should have addressed in EPA's RH FIP Action.

A. First BART Factor - Costs of Compliance.

1. *EPA's development and assessment of new information is flawed and inappropriate.*

In litigation concerning the deadline by which EPA must act on the Wyoming RH SIP and in its Motion to Modify Deadlines in Consent Decree in December 10, 2012, EPA states:

> "In response to EPA's solicitation of public comments on its proposed rule, a number of commenters challenged some of the cost and visibility information provided by owners of power plants on which EPA based its proposed action. These comments prompted EPA to undertake additional research in order to evaluate the commenters' contentions. EPA developed substantial new cost and visibility analyses for several of the units subject to emission controls under the regional haze requirements. EPA is still considering this new information. EPA believes that this new information is significant and the public, including the state of Wyoming and the owners of power plants subject to regional haze requirements, should have the opportunity to comment on the new information."

A review of the "substantial new cost and visibility analyses" included by EPA in the record does not support EPA's assertion that "this new information is significant." Rather EPA has simply provided a new set of cost estimates which are primarily based upon generalized industry information regarding the installation of post-combustion NO_X controls, along with *Google Earth* satellite images available to anyone on the internet, that purportedly help assess the availability of space at each site to install retrofit emission controls. In short, the "new" information provided by EPA is not new at all, and in fact is entirely deficient for purposes of BART analyses when compared to the site-specific cost and other information prepared by utility industry experts that Wyoming utilized in its BART analyses.

EPA's new cost information is included in a report by Andover Technology Partners initially dated October 23, 2012, with an updated revision dated February 7, 2013 (the "Andover Report").[26] The Andover Report relies on algorithms in EPA's Integrated Planning Model ("IPM") to develop the total project capital costs for the SCR control systems. The IPM model is a multi-regional, dynamic, deterministic linear programming model used by EPA to evaluate the cost and emissions impacts of proposed policies to

[26] Andover Technology Partners, Review of Estimated BART Compliance Costs for Wyoming Electricity Generating Units (EGUs), February 7, 2013.

limit emissions from the electric power sector. The input to the model is generic high-level costs for various air quality control systems that can be applied to the electric power sector on a system-wide basis with minimal unit-specific information. The IPM model is not appropriate for generating site-specific cost estimates to evaluate the cost effectiveness of BART projects because it does not account for those site-specific requirements that significantly impact overall project costs. As an example of the deficiencies in the Andover Report, the following items are not reasonably accounted for in the cost estimates, particularly for the Naughton Units 1 and 2 and Dave Johnston Unit 3:

Site Elevation: Algorithms in the IPM model were developed for a generic coal-fired power plant located at or near sea level. Site elevation can have a significant impact on control system sizing and design; thus elevation of the site must be considered separately and factored into the unit capacity (i.e. megawatts) accordingly due to its effects on the flue gas volume. PacifiCorp's Wyoming BART Units are located at elevations ranging from approximately 5,000 to 7,000 feet above mean sea level ("MSL"). At this elevation, flue gas flows will be 20-30% higher than similarly sized units at MSL. The higher flue gas flow requires larger ductwork, larger reactors, and more robust support structures, and these items have a profound influence on the overall project cost. Wyoming had this information available in the Wyoming RH SIP; EPA failed to account for site elevation in its RH FIP Action.

Site-specific Congestion and Construction Challenges: The IPM model applies a retrofit factor to account for the difficulty of fitting new BART equipment into the existing site configuration. The Andover Report states that site visits were not possible; thus, retrofit factors for Naughton Units 1 and 2, and Dave Johnston Unit 3 were determined based on a review of Google Earth images of the station. Accordingly, the Andover Report applied retrofit factors for the units that are highly subjective based on minimal site information. When preparing site-specific cost estimates, however site walkdowns must be conducted to evaluate the true complexity associated with the retrofit and assess specific modifications to the plant that would be required to overcome issues associated with congestion as well as difficulties associated with construction. Neither Andover nor EPA sought permission from PacifiCorp to visit the sites of the BART Units, nor did Andover explain it "wasn't possible" to do so. Both Sargent & Lundy ("S&L") and Babock and Wilcox ("B&W") have extensive experience with PacifiCorp's Naughton and Dave Johnston facilities. Just since 2005, S&L has been contracted by PacifiCorp to perform 14 projects at Dave Johnston station and over 25 projects at Naughton station. These projects range from site evaluations, studies, detailed engineering, or functioning as PacifiCorp's Owner's Engineer for major environmental retrofit engineer, procure, and construct ("EPC") projects. From having conducted many walkdowns at these stations, S&L is very aware of site-specific congestion and construction challenges that would affect SCR installations at Naughton 1, Naughton 2, and Dave Johnston 3. Similar to S&L's site specific experience, B&W has recently completed major environmental retrofit EPC projects on Naughton Units 1 and 2 (wet scrubber additions) and Dave Johnston Unit 3 (dry scrubber and baghouse addition), making B&W uniquely positioned to offer budgetary cost estimates for further retrofits to those facilities with significant first-hand knowledge. Wyoming had much of this information available in the Wyoming RH SIP; EPA failed to account for site-specific information in its RH FIP Action

Missing Scope Items: Additional project-specific scope concerns (related to addition of SCR onsite) include limited capacity of the existing induced-draft ("ID") fans and auxiliary power system, as well as National Fire Protection Association ("NFPA") related equipment reinforcement requirements. Larger, more powerful, ID fans may overload existing electrical systems, and the electrical systems may require significant modifications. Structural stiffening of the duct work, and equipment downstream of the boiler and upstream of the new ID fans may also be required by NFPA regulations to operate at more negative pressures due to the installation of the SCR. These types of costs are not generally reflected in the base case IPM cost algorithms, but they must be taken into consideration in the development of a project-specific cost estimate. Wyoming had this information available in the Wyoming RH SIP; EPA failed to account for this important cost information in its RH FIP Action.

Owner's Costs: Worksheets attached to the Andover Report[27] show that Owner's Costs were inappropriately excluded from the Andover Report's capital cost estimate. Owner's Costs include a variety of non-financial costs incurred by the owner to support implementation of the air pollution control project. Owner's Costs are project-specific, but generally include costs incurred by the owner to manage the project, hire and retain staff to support the project, and costs associated with third party assistance associated with project development and financing. Owner's Costs include, but may not necessarily be limited to:

- site investigations (geotechnical, hydrology, etc.) for project design;
- environmental permitting/approvals;
- insurance during construction;
- site security during construction;
- transmission interconnection (if applicable);
- fuel interconnection (if applicable);
- owner's mobilization costs;
- owner's project management and support staff;
- insurance advisor;
- labor relations consultant;
- tax consultant;
- financial advisor;
- legal advisor;
- market consultant; and
- community relations/community outreach program.

Owner's Costs are real costs that the owner will incur during the project and are typically included in cost estimates prepared for large air pollution control retrofit projects. In fact, U.S. EPA's Coal Quality Environmental Cost (CUECost) model includes Owner's Costs

[27] See, EPA-R08-OAR-2012-0026-0085 and -0087 for examples.

(or "Home Office" costs) in its air pollution control system cost estimating workbook and interrelated set of spreadsheets.[28] Wyoming had this information available in the Wyoming RH SIP; EPA failed to account for this important cost information in its RH FIP Action.

Regional Labor: Regional labor concerns are not accounted for in the IPM model. Regional labor characteristics must be taken into consideration in a site-specific cost estimate to account for factors including labor availability, project complexity, local climate and working conditions. Because the Naughton and Dave Johnston facilities are in relatively remote locations, higher labor rates must be paid to attract the kind of skilled workers required to construct an SCR project. In addition, the locations are subject to extreme cold and wind that can result in significant productivity and construction challenges and delays, adding to the overall project cost. Wyoming had this information available in the Wyoming RH SIP; EPA failed to account for this important cost information in its RH FIP Action.

As noted above, EPA's flawed analyses of incomplete "new" cost information directly resulted in EPA's proposed requirements for PacifiCorp to install SCR on Naughton Units 1 and 2 and Dave Johnston Unit 3. In contrast, to be responsive to EPA's request for additional information, PacifiCorp has solicited budgetary project-specific cost information from B&W, an active and uniquely positioned competitive market participant for SCR technology, for these same units. In conjunction with S&L's expertise, PacifiCorp has incorporated the site-specific budgetary cost information from B&W into updated EPA Control Cost Manual side-by-side comparisons with the Andover Report results to further demonstrate the inaccuracies in the new cost information developed by EPA. The following Tables 6 through 8 summarize the results of these comparisons, to these comments provides the detailed line-by-line cost manual method comparisons. It is important to note that PacifiCorp has utilized a 20-year remaining equipment life and has excluded AFUDC from the results in the following tables for comparison purposes. Remaining equipment life and AFUDC will be addressed separately in comments below. *(See* Attachment 4*)*

[28] See, Coal Utility Environmental Cost (CUECost) Workbook User's Manual Version 1.0, prepared by Raytheon Engineers & Contractors, Inc. and Eastern Research Group, Inc., EPA Contract No. 68-D7-0001, Appendix B, pages B-3 and B-6.

Table 6

Naughton Unit 1 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment (20-year life, excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$1,820,054	$3,148,690
Total Indirect Annual Cost	$4,692,935	$8,855,555
Total Annual Cost	$6,504,803	$12,004,246
Annual NO_x Tons Removed	1,109	1,109
Cost Effectiveness ($/ton)	**$5,867**	**$10,824**

Table 7

Naughton Unit 2 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment (20-year life, excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$1,597,635	$3,474,571
Total Indirect Annual Cost	$5,814,581	$8,802,316
Total Annual Cost	$7,959,487	$12,276,887
Annual NO_x Tons Removed	1,336	1,336
Cost Effectiveness ($/ton)	**$5,956**	**$9,189**

Table 8

Dave Johnston Unit 3 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment (20-year life, excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$2,398,216	$3,884,089
Total Indirect Annual Cost	$7,158,911	$9,601,020
Total Annual Cost	$9,562,381	$13,485,109
Annual NO_x Tons Removed	1,597	1,597
Cost Effectiveness ($/ton)	**$5,989**	**$8,444**

As demonstrated by the results in the tables above, EPA significantly understated costs per ton of pollutant removed. As such, EPA based its cost effectiveness conclusions on significantly inaccurate information. Before taking any final action on the proposed RH FIP, EPA must consider in its final BART analyses the additional cost information being provided by PacifiCorp. (*See* Attachment 4)

2. EPA's dismissal of owners costs and AFUDC is inappropriate.

EPA states in its RH FIP Action:[29]

> "For all control technologies, EPA has identified instances in which Wyoming's source-based cost analyses did not follow the methods set forth in the EPA Control Cost Manual. For example, Wyoming included an allowance for funds used during construction and for owners costs and did not provide sufficient documentation such as vendor estimates or bids."

With respect to AFUDC, another utility (OG&E) argued in a similar regional haze setting that:

> "AFUDC provides a way of measuring the real cost of interest over the construction period. AFUDC accounts for the time value of money associated with the distribution of construction cash flows over the construction period, which may be approximately 18 months for an SCR project. TCI, as defined in the *Control Cost Manual*, includes all costs required to purchase equipment needed for the control system (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and building, working capital, and off-site facilities.[30]

[29] See, 78 Fed. Reg. at 34,749

[30] *Control Cost Manual*, page 2-5.

A cost breakdown of TCI (as defined above) is presented in several examples in the *Control Cost Manual*. For example, Table 1.4 (page 1-32 of Section 4 – NO_X Controls) and Table 2.5 (page 2-44 of Section 4 – NO_X Controls) therein explicitly identify AFUDC as component "E" of the TCI, where TCI = D + E + F + G + H + I, where:

D = Total Plant Cost
E = AFUDC
F = Royalty Allowance
G = Preproduction Cost
H = Inventory Capital
I = Initial Catalyst and Chemicals

References 9 and 10 on page 2-38 of the *Control Cost Manual* explicitly include AFUDC as a cost component and reference two reports, by Shattuck and Kaplan, in support of its use.[31] [32] The report by Shattuck was published in connection with an EPRI funded research project and cost estimating software for FGD retrofits. The report by Kaplan was published by the EPA, Air and Energy Engineering Research Laboratory, in collaboration with EPRI, the U.S. Department of Energy, and an industry technical advisory committee represented by seven major utility companies. These FGD cost studies were developed from the most comprehensive industry experience of the late 1980's and early 1990's. The EPA built upon this knowledge base and costing methodology in its publication of the *Control Cost Manual* in 2002. Thus, the *Control Cost Manual* allows the time value of money, measured by the real discount rate, to be incorporated into the cost estimate.

Section 2.3.1 of the *Control Cost Manual* (Elements of Total Capital Investment) describes the need for TCI to include all expenditures incurred during the construction phase of the project, including direct costs, indirect costs, fuel and consumables expended during start-up and testing, and other capitalized expenses. The only items explicitly mentioned to be excluded are common facilities that already exist at the site. AFUDC is part of the expense that will be incurred with the installation of a large air pollution control system, and the accepted practice in the utility industry and by financial institutions is to treat AFUDC as a capitalized expenditure. This approach is recognized in publications by the U.S. Department of Energy – Energy Information Administration (DOE/EIA), such as the *Annual Energy Outlook,*[33] and in publications by the Electric Power Research Institute (EPRI), such as the *Technical Assessment Guide*.[34] As previously mentioned, the EPA clearly

[31]Shattuck, D. M., et al., Retrofit FGD Cost-Estimating Guidelines, Electric Power Research Institute, Palo Alto, CA (CS-3696, Research Project 1610-1), October 1984.
[32] Kaplan, N., et al., "Retrofit Costs of SO2 and NOx Control at 200 U.S. Coal-Fired Power Plants," Pittsburgh Coal Conference, 1990.
[33] See, DOE/EIA-0383 (2011), March 2011.
[34] See, *TAG Technical Assessment Guide*, EPRI, page 2-15.

> followed this approach in its studies of retrofit costs of SO_2 and NO_X in the years leading up to its publication of the *Control Cost Manual*. Furthermore, AFUDC has been included in several other coal-fired boiler BART determinations, and AFUDC is included as a line item in EPA's CUECost worksheets for FGD control systems.[35] In cases where the time value of money during the construction period would be significant (e.g., projects with longer construction periods such as the installation of SCR or FGD), the *Control Cost Manual* clearly allows inclusion of AFUDC."[36]

PacifiCorp supports and adopts by reference OG&E's argument regarding including AFUDC in project cost estimates. Whether or not AFUDC is included in project cost estimates does not materially impact the results reached under the EPA Control Cost Manual method, its inclusion should not constitute a basis for EPA to reject Wyoming's entire cost assessments. Tables 9 through 11 provide comparisons of PacifiCorp's project specific EPA Control Cost Manual method results where AFUDC is excluded in one set of costs and is included in the other to demonstrate this point. Attachment 4 to these comments provides the detailed line-by-line Control Cost Manual method comparisons.

Table 9

Naughton Unit 1 SCR Cost Assessment Impact of AFUDC on Project Specific Assessment		
SCR Cost Assessment	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (excludes AFUDC)	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (includes AFUDC)
Total Direct Annual Cost	$3,148,690	$3,368,040
Total Indirect Annual Cost	$8,855,555	$9,683,759
Total Annual Cost	$12,004,246	$13,051,799
Annual NO_x Tons Removed	1,109	1,109
Cost Effectiveness ($/ton)	**$10,824**	**$11,769**
Effect of AFUDC on Cost Effectiveness ($/ton)		**$945**

[35] Coal Utility Environmental Cost (CUECost) Worksheets, prepared by Raytheon Engineers & Contractors, Inc. and Easter Research Group, Inc., EPA Contract No. 68-D7-001.

[36] Docket EPA-R06- OAR-2010-0190

Table 10

Naughton Unit 2 SCR Cost Assessment Impact of AFUDC on Project Specific Assessment		
SCR Cost Assessment	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (excludes AFUDC)	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (includes AFUDC)
Total Direct Annual Cost	$3,474,571	$3,692,696
Total Indirect Annual Cost	$8,802,316	$9,625,894
Total Annual Cost	$12,276,887	$13,318,590
Annual NO_x Tons Removed	1,336	1,336
Cost Effectiveness ($/ton)	**$9,189**	**$9,969**
Effect of AFUDC on Cost Effectiveness ($/ton)		**$780**

Table 11

Dave Johnston Unit 3 SCR Cost Assessment Impact of AFUDC on Project Specific Assessment		
SCR Cost Assessment	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (excludes AFUDC)	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (includes AFUDC)
Total Direct Annual Cost	$3,884,089	$4,122,064
Total Indirect Annual Cost	$9,601,020	$10,499,546
Total Annual Cost	$13,485,109	$14,621,610
Annual NO_x Tons Removed	1,597	1,597
Cost Effectiveness ($/ton)	**$8,444**	**$9,156**
Effect of AFUDC on Cost Effectiveness ($/ton)		**$712**

3. *EPA's dismissal of Wyoming's results due to lack of appropriate documentation such as vendor estimates or bids is inappropriate.*

EPA's RH FIP Action also is flawed because it failed to provide sufficient documentation such as vendor estimates or bids to validate its estimates. EPA attempts to justify its approach by stating:[37]

> "In our revised cost analyses, we have followed the *structure* (emphasis added) of the EPA Control Cost Manual, though we have largely used the Integrated Planning Model cost calculations to estimate direct capital costs and operating and maintenance costs."

EPA did not explain what it meant by following the "structure" of the manual, versus simply following the manual. By contrast, PacifiCorp solicited and incorporated vendor estimates into these comments. This new information, which EPA must incorporate into new BART analyses to the extent EPA issues a final RH FIP, validates the state of Wyoming's BART analyses cost of controls estimates. In addition, it further quantifies the inaccuracies in EPA's development and use of purported new information that in no way qualifies as vendor estimates, bids, or any type of site specific vendor information.

B. Second BART Factor - Energy and Non-Air Quality Environmental Impacts of Compliance.

EPA's RH FIP Action is also defective because EPA failed to evaluate the "energy" and "non-air quality environmental" factors for the BART Units. Therefore, even if EPA were correct that Wyoming performed an improper BART analysis (which it is not) EPA's RH FIP Action is based upon an incorrect BART analysis because it fails to take into account this BART factor.

Three types of energy impacts should be considered. These include the energy associated with operating the controls, the energy that must be provided when the unit is removed from service in order to install the controls, and most importantly to the state of Wyoming and its citizens, the energy that must be replaced when the emissions controls prescribed for a given unit are not economically justifiable and result in accelerated unit retirements and replacements.[38]

The latter scenario is of particular concern because the EPA has now proposed SCR controls for PacifiCorp's Naughton Unit 1, Naughton Unit 2 and Dave Johnston Unit 3. Unlike the Wyoming RH SIP, the EPA's RH FIP requires controls that are not expected to be justifiable and would result in accelerated unit retirements and replacements, potential natural gas conversions, and the associated costs and socio-economic impacts of removing major coal-fueled generation resources from service in areas of Wyoming that rely heavily on these facilities.

[37] 78 Fed. Reg. at 34,749

[38] 40 CFR 50 Appendix Y D.IV.h.5

EPA's five-factor analysis must include a thorough analysis of the system-wide energy impacts individual unit compliance requirements will have on the states within which PacifiCorp serves customers, including the impacts to local jobs and state and local economies surrounding the affected facilities. EPA's analysis is incomplete and conclusions are flawed if these significant additional costs are not developed and considered.

EPA's energy impacts assessment should include coordination with state regulators, environmental agencies and elected officials. As a regulated utility, PacifiCorp regularly engages with state regulators, environmental agencies and elected officials to ensure that its resource planning and ultimate compliance approaches align with the interests of customers in the states it serves. These same state bodies and elected officials should be consulted by EPA to ensure that EPA's RH FIP Action is properly assessed in light of the issues described above.

As Powder River Basin Resource Council pointed out in its post-hearing brief filed in April 2013 before the Wyoming Public Service Commission in PacifiCorp's application filing to obtain approval for a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction systems on Jim Bridger Units 3 and 4, "it is evident that considering the cost and risk of these major environmental control projects up front, prior to installation, is a benefit to parties, ratepayers, and the public interest. These projects are significant undertakings – in some cases they are close to the financial equivalent of building new generation sources – and therefore they deserve a high level of scrutiny to ensure that the public's interests, and especially the specific financial interests of PacifiCorp ratepayers, are protected."[39]

PacifiCorp is required to obtain approval of its environmental plans and expenditures; regardless of EPA's position, the utility regulatory commissions are required to find that the installation of emission controls are necessary, used and useful, and the least-cost, risk adjusted alternative to comply with environmental regulations. While it is likely parties will take the position on EPA's proposed action in this docket that stringent controls and emission rates should be installed as quickly as possible without regard to system impacts and cost, their positions in other dockets have been that PacifiCorp should not install emissions controls because doing so "result[ed] in unnecessary capital expenses that were not the least cost alternative."[40]

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[39] See Powder River Basin Resource Council's Post-Hearing Brief in Wyoming Public Service Commission Docket No. 20000-418-EA-12 (RECORD NO. 13314) at: http://edocs.puc.state.or.us/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/FinalDownload/DownloadId-DCE8BAB12B5061CB4017455D76704E32/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/efdocs/HBC/ue246hbc75023.pdf

[40] See Sierra Club's prehearing brief in Oregon Public Utility Commission Docket UE 246 at: http://edocs.puc.state.or.us/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/FinalDownload/DownloadId-DCE8BAB12B5061CB4017455D76704E32/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/efdocs/HBC/ue246hbc75023.pdf

EPA must consider that its proposed RH FIP will "result in significant economic disruption and unemployment" due to accelerated unit retirements and replacements, potential natural gas conversion and removing coal-fired units from service.[41]

C. Third BART Factor - Any Existing Pollution Control Technology in Use at the Source Must be Considered.

In proposing the RH FIP based on its own BART analyses, EPA must evaluate current information, including all significant parameters that have changed since Wyoming completed its BART analyses. Specifically, EPA should take into account that, with the exception of Naughton Unit 3, PacifiCorp has installed and fully implemented the BART controls required under Wyoming's RH SIP. Some of this information was not available, or conditions have substantially changed, since Wyoming completed the Wyoming RH SIP. Table 1 in the "HISTORY OF THE WYOMING RH SIP" section identifies the controls that have been installed at each of PacifiCorp's BART Units in Wyoming.

EPA's RH FIP Action must take into account both the control equipment currently installed and operating on the BART Units as well as each unit's current emissions baseline. It is not appropriate for EPA to continue using a 2001-2003 emissions baseline that does not recognize the controls that have been installed. This is particularly relevant because EPA partially rejected Wyoming RH SIP, and then conducted its own BART analyses in 2013 based on "new information." EPA is well aware of the controls that PacifiCorp has installed in compliance with the Wyoming RH SIP, and in fact, utilized recent NO_X emission rates from PacifiCorp's units that are equipped with BART controls in order to identify appropriate SNCR rates in regard to its RH FIP Action.

To properly assess the visibility and costs associated with adding additional controls, EPA's BART analyses must take into account the control equipment currently operating on these BART Units. Both the annual NO_X emissions used in the cost effectiveness calculations and the hourly NO_X emissions used in the visibility modeling must be corrected to reflect the LNB/OFA controls currently in service on PacifiCorp's BART-eligible units.

D. Fourth BART Factor - The Remaining Useful Life of the Source.

PacifiCorp submitted its BART studies to Wyoming in 2007, and the state completed its BART analyses during 2008. At that time the remaining useful life of all PacifiCorp BART Units was considered to be at least 20 years. Primarily due to EPA's delays in dealing with the Wyoming RH SIP, this assumed twenty-year life span is no longer a valid basis for certain units. EPA now must take into account the current useful life of the units, rather than the useful life assumed under Wyoming's BART analyses completed at

[41] 78 Fed. Reg. at 34,749

a different point in time. Dave Johnston Unit 3's current depreciable life ends in 2027 and the life for Naughton Units 1 and 2 ends in 2029.

As a practical matter, the SCRs required under the RH FIP at Dave Johnston Unit 3 and Naughton Units 1 and 2 could not be installed until shortly before the end of 2018, due to the regulatory processes that apply to PacifiCorp's major investment decisions, as well as the associated permitting and competitive procurement timelines. Attachment 5 provides a general description of such a timeline. At that time, the useful life for Dave Johnston Unit 3 will be nine years, and for Naughton Unit 1 and 2 eleven years. EPA must use these shorter useful lives in its BART analyses. Tables 12 through 14 summarize the cost effectiveness results assuming the proper useful lives of these units, and Attachment 4 to these comments provides the detailed line-by-line cost manual method comparisons.

Table 12

Naughton Unit 1 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment Remaining Depreciable Life Basis (excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$1,820,054	$3,148,690
Total Indirect Annual Cost	$6,413,089	$12,510,995
Total Annual Cost	$8,233,143	$15,659,686
Annual NO_x Tons Removed	1,109	1,109
Cost Effectiveness ($/ton)	**$7,424**	**$14,121**

Table 13

Naughton Unit 2 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment Remaining Depreciable Life Basis (excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$1,597,635	$3,474,571
Total Indirect Annual Cost	$7,945,865	$12,435,779
Total Annual Cost	$9,543,500	$15,910,351
Annual NO_x Tons Removed	1,336	1,336
Cost Effectiveness ($/ton)	**$7,143**	**$11,909**

Table 14

Dave Johnston Unit 3 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment Remaining Depreciable Life Basis (excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$2,398,216	$3,884,089
Total Indirect Annual Cost	$11,135,336	$15,611,622
Total Annual Cost	$13,533,552	$19,495,711
Annual NO_x Tons Removed	1,597	1,597
Cost Effectiveness ($/ton)	**$8,474**	**$12,208**

Taking into consideration the remaining useful lives of these particular BART Units clearly demonstrates that EPA's current assessed cost effectiveness conclusions (whether using the Andover Report costs or PacifiCorp's updated information) do not support the installation of SCR on these units because they are not cost effective. To the extent EPA needs to include firm retirement dates commensurate with the depreciable lives for purposes of finalizing the RH FIP, then PacifiCorp requests that EPA do so.

E. The Fifth BART Factor - The Degree of Visibility Improvement which may Reasonably be Anticipated from the use of BART.

Finally, EPA's RH FIP Action must appropriately consider new information provided by PacifiCorp and others associated with visibility modeling. In comments provided in response to EPA's first proposal, PacifiCorp presented substantial information supporting the need to use improved and updated versions of the computer models used to predict visibility impacts. In addition, PacifiCorp provided substantial information on the effects that the nitrogen oxides to nitrogen dioxide conversion rate and background ammonia concentrations have on modeled visibility impacts. EPA's RH FIP Action is not complete without taking into account this new information about visibility. In particular, given that EPA has re-proposed its RH FIP based on cost and visibility information from certain groups, EPA should analyze and incorporate PacifiCorp's data in the same way.

Computerized air quality modeling plays two key roles in the regional haze program. First, unit-by-unit CALPUFF modeling is conducted to determine which BART-eligible units should be subject to BART[42]. Wyoming determined that a source modeled to impact a Class I area by more than 0.5 deciviews was subject to BART and required to conduct a BART analysis.

The unit-specific CALPUFF modeling results that EPA uses in its RH FIP Action do not provide the degree of visibility improvement that can be reasonably anticipated from the use of BART at a specific unit. Regional models that take into account all emission changes from all emissions sources are used for this purpose. EPA's reliance on miniscule modeled visibility improvements conducted at individual BART Units ignores the fact that (1) such small visibility improvements are not perceptible to the human eye, (2) CALPUFF modeling results are unreliable, imprecise, and over-predictive, especially when older versions of the model are used, and (3) the modeled improvements occur over just a few days per year. In other words, although running the computer models does create a predicted visibility outcome, it does not provide an outcome that qualifies as "reasonably anticipated."

EPA treats the results from computerized visibility modeling as being capable of accurately predicting visibility improvements down to the tenths or hundredths of a deciview (when one deciview is considered what is humanly perceptible). For example, EPA assumes that a difference of 0.1 or 0.2 deciviews between its model results and Wyoming's model results is material. It is not. The reality is that these computer models, including CALPUFF, are relatively imprecise. The inherent problems and limitations of the computerized visibility modeling EPA used here should be considered as part of EPA's BART determinations, but were not. Outlined below are the problems and

[42] 40 CFR Part 51 Appendix Y, III. How to Identify Sources "Subject to BART"

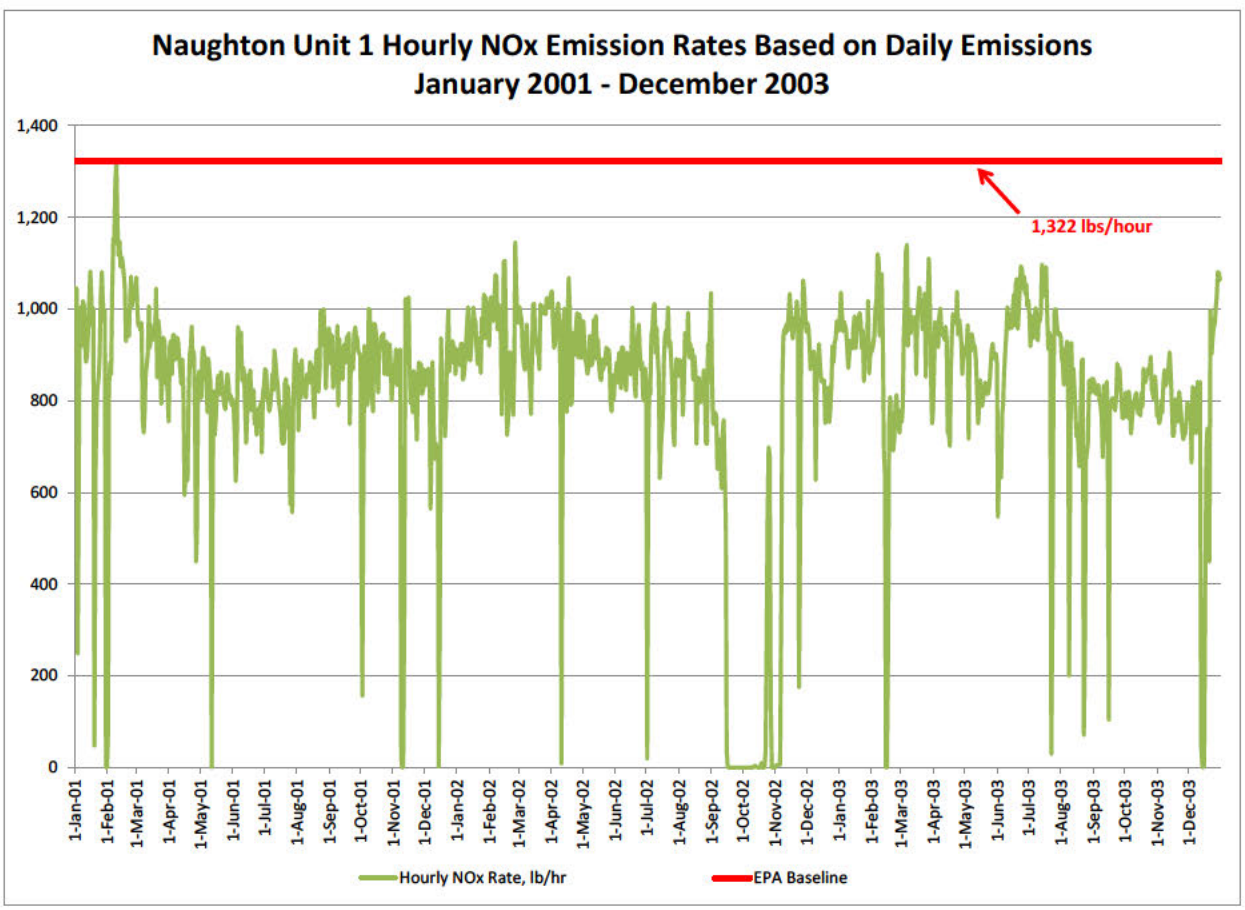
limitations with EPA's computerized modeling. EPA should redo its computer modeling, and reanalyze its modeling results, after taking these issues into account.

i) EPA's 2001-2003 baseline over-predicts the modeled visibility impacts and improvements

In its modeling, EPA created a baseline emission rate using the maximum 24-hour emission rate that occurred during the 2001-2003 period. This rate is then used in the CALPUFF models as if it occurs every hour of every day over the three-year period.

Chart 1, which is specific to Naughton Unit 1, provides a visual comparison of the baseline rate used by EPA to predict the visibility impacts to the actual emissions from this unit over the three-year time period. Noting the significant over-projection of emissions over the entire time period, it is unrealistic to imply that the model can be used to identify the visibility impacts and in turn, the visibility improvements that may reasonably be anticipated. At a minimum, EPA must recognize that CALPUFF's results will over predict improvements and will not lead to results that can be "reasonably anticipated" as compared to actual visibility improvement.

CHART 1



Similar charts for each of PacifiCorp's Wyoming units have been provided in Attachment 6.

In its BART determinations, Wyoming has balanced the modeling inputs and results against the criteria of what visibility improvement can be reasonably anticipated to occur. EPA's RH FIP Action, however, improperly focuses solely on the modeling results without accounting for whether its models reasonably anticipate the visibility impacts will occur.

ii) EPA's use of 2001-2003 historic emissions does not account for the controls that are currently installed and operating on PacifiCorp's units

Any existing pollution control technology in use at the source must be considered[43], and using historic emissions from a 10+ year old time period (2001-2003) to establish each unit's baseline emission rate is inappropriate. With the exception of Naughton Unit 3 and Dave Johnston Unit 1 and Unit 2, from 2005-2012 Low NO_X burners have been installed on every PacifiCorp coal-fueled unit in Wyoming. While EPA relies on recent historic unit emission data to predict and propose SNCR NO_X emissions rates, it improperly fails to recognize that the baseline visibility modeling also must be based on the current hourly emission rates of the units. EPA has recognized the need to adopt baseline emissions that reflect the installation of existing pollution control equipment. 77 Fed. Reg. at 72,526; 78 Fed. Reg. at 46,163. EPA should do so here.

iii) EPA has relied upon modeling that is out of date and does not meet EPA's own requirements.

Proper conclusions can be reached when evaluating the results of visibility modeling if one understands the limitations of the models, the characteristics and limitations of the inputs entered into the models, the capabilities of the model versions being used and then apply reasonable judgment to the results. Wyoming has conducted its RH SIP based on the modeling protocols and versions available at the time its RH SIP was completed. Because of this, there are limitations associated with the results obtained. However, in proposing its RH SIP, Wyoming has evaluated the model output with an understanding of the model's limitations. Wyoming then applied its judgment, as encouraged and required by EPA's guidelines and the CAA, which helped to mitigate the issues associated with models that over-predict the visibility improvement associated with BART controls being added.

Contrary to this approach EPA interprets the modeling results as an "absolute" and unquestioningly accurate number that it then relies on in an attempt to justify costly BART controls that in reality will provide no perceptible visible benefit. EPA gives no consideration to the limitations of the models it uses. In the absence of using good

[43] 40 CFR 51, Appendix Y. IV.A(2)

judgment to deal with over-predictive results, it is critical that EPA use the most up-to-date and scientifically accurate models available. The following comments are intended to provide insight into the limitations of specific models and encourage EPA to either recognize the limitations of the models that have been used in Wyoming or utilize the models that represent the best science available.

PacifiCorp and Wyoming originally conducted CALPUFF modeling in 2006-07 to determine which of PacifiCorp's units were "BART-eligible." In accordance with EPA guidance at the time, PacifiCorp and Wyoming used the CALPUFF model, Version 5.711a, with a background ammonia setting of 2 parts per billion ("ppb") and Method 6 of CALPOST. After this modeling was completed, EPA formally adopted CALPUFF Version 5.8 as the "approved version" of CALPUFF, and determined that Method 8 of CALPOST should be used. EPA also stated several times since 2007 that the background ammonia concentration used in CALPUFF modeling in the Intermountain West should be 1 ppb.

Since the time PacifiCorp and Wyoming conducted its CALPUFF modeling in 2006-07, air quality modeling has improved. Air modeling experts now have determined that CALPUFF version 6.42, with a variable ammonia background setting, updated chemistry module, and Method 8 of CALPOST are the "best" science when it comes to modeling for regional haze. However, EPA did not use the "best" modeling science in Wyoming, even when taking the extra time to re-propose its RH FIP based on new information. Instead, EPA used outdated and unreliable modeling techniques.

EPA's reliance upon its outdated modeling method is arbitrary and capricious because EPA's modeling fails to meet EPA's own standards, ignores the best science, and does not account for CALPUFF's tendency to overestimate results (i.e., visibility improvements).

1. *EPA's re-proposal, which was intended to update its conclusions based on new information, should have used the most recent version of CALPUFF, or at a minimum, should have used the version that EPA requires for other RH SIPs.*

EPA has taken the position that CALPUFF Version 5.8 must be used for regional haze modeling. For example, in regard to the Arizona RH SIP, EPA recently stated as follows:

> "EPA relied on version 5.8 of CALPUFF because it is the EPA-approved version promulgated in the Guideline on Air Quality Models (40 CFR part 51, Appendix W, section 6.2.1.e; 68 FR 18440, April 15, 2003). It was also the approved version when EPA promulgated the BART Guidelines (70 FR 39122, July 6, 2005). EPA updated the specific version to be used for regulatory purposes on June 29, 2007, including minor revisions as of that date; the approved CALPUFF modeling system includes CALPUFF version 5.8, level 070623, and CALMET version 5.8 level 070623. At this time, any other version of the CALPUFF modeling system would be considered an

> ''alternative model'', subject to the provisions of Guideline on Air Quality Models section 3.2.2(b), requiring a full theoretical and performance evaluation."

77 Fed. Reg. 42,834, 42,854 (emphasis added). However, EPA's unit-specific CALPUFF modeling in Wyoming initially completed in April 2012 and redone in February 2013, used CALPUFF Version 5.711a (originally released in 2004). (*See* Attachment 7, CH2M Hill Report on EPA Modeling Methods.) Version 5.711a is nine years old, and several CALPUFF versions behind Version 5.8. While PacifiCorp believes the more modern and realistic CALPUFF Version 6.42 should be used (see below), at a minimum EPA must abide by its own position and use Version 5.8 in evaluating the Wyoming RH SIP, which it failed to do. According to EPA's own statements, EPA's chosen modeling results should be discarded because EPA used an improper "alternative model" in Wyoming.

Moreover, EPA should have used the most recent version of CALPUFF (Version 6.42) in Wyoming because it produces more realistic and accurate results. (*See* Attachment 8, Paine, B, Connors, J, "Response to Prehearing Statements: Martin Drake Power Plant Best Available Retrofit Technology Rulemaking Hearing," November 20, 2010.) Version 6.42 contains needed refinements, such as a better "chemistry" module known as ISORROPIA (Version 2.1). *Id.* CALPUFF Version 6.42 is more accurate because, as the Federal Land Managers (FLMs) have noted, Version 5.8 does not have the required settings to perform the new Method 8 visibility analysis. (*See* Attachment 9, March 21, 2012 letter from Joe Scirie to Bill Lawson.)

Additionally, CALPUFF Version 6.42 has been maintained by TRC and has had many bug fixes and enhancements not included in CALPUFF Version 5.8. *Id.* Most importantly, the previous chemistry modules used in Version 5.8 (and in the 5.711a Version EPA used here) also have been shown to overestimate nitrate concentrations in Wyoming by a factor of 3-4 and substantial improvements have been made to eliminate this over-prediction using the ISORROPIA module. *Id.*; (*see also* Attachment 10, Scire, J., Strimaitis, D., and Zhong-Xiang Wu, "New Developments and Evaluations of the CALPUFF Model," March 14-16, 2012.) Despite all these advancements in modeling and modeling science, EPA conducted its modeling for its RH FIP Action in 2012 using the same (now outdated) CALPUFF version that PacifiCorp and Wyoming used 5 years ago, which has been shown to overestimate the visibility impacts and improvements by 300% to 400%.

Since 2012 EPA has taken an additional year to reconsider its initial FIP proposal. Disappointingly, EPA's RH FIP Action only considered using the outdated CALPUFF models rather than taking the opportunity to update the models to those that would represent the application of the best science available.

2. *EPA used a different background ammonia number for modeling than it requires of the states, and ignored current science on background ammonia.*

Regional haze modeling – and the resulting predicted visibility improvement – is greatly influenced by the background ammonia number used in the model. (*See* Exhibits 6 and 8.) EPA improperly used a constant 2 ppb background ammonia number for the Wyoming BART modeling. EPA has not provided any scientific proof showing the constant 2 ppb ammonia number is appropriate for Wyoming. The 2 ppb ammonia value overestimates visibility improvement, contrary to the approach used by Wyoming Land Use, IWAQM Guidance, WRAP protocols, and elsewhere. (*See* Attachments 7, 8 and 10.)

WRAP recommended the use of 1 ppb of ammonia year round for states in the region to account for seasonal variability. EPA has required states to use 1 ppb of background ammonia when conducting regional haze modeling. 76 Fed. Reg. at 52,434 (New Mexico criticized for not using 1 ppb background ammonia). While PacifiCorp disagrees with this view, at a minimum EPA should follow its own guidelines and use 1 ppb of background ammonia when conducting CALPUFF unit-specific modeling.

However, the "best" science requires the use of "variable ammonia" background numbers. IWAQM recommends 0.5 ppb for forest, 1ppb for dry/arid lands and 10ppb of ammonia for agriculture/grassland. Given its geographic location and elevation levels, Wyoming undergoes seasonal swings of dry-hot summers and snow covered ground in the winter. Therefore, the use of a single ammonia concentration for the entire year in a state where the land use and land cover changes significantly between seasons results in overestimation of visibility improvements. (*See e.g.,* Attachment 11, July 2, 2010 letter and attachment from Tri-State Generation to Colorado Air Pollution Control Division, discussing Mt. Zirkel area.) This is particularly true in winter when agricultural activity is minimal and meteorological conditions make visibility calculations particularly sensitive to ambient ammonia concentrations. (*See* Attachments 7 and 11.) EPA has approved the use of variable gaseous ammonia concentrations before, including the Addendum to Modeling Protocol for the Proposed Desert Rock Generating Station (ENSR, 2006),[44] and should have used them when conducting the CALPUFF modeling for Wyoming.

Sensitivity tests on ambient ammonia concentrations were performed by the Colorado Department of Public Health and Environment for an area in northwest Colorado. (*See* Attachment 8 and 11.) The analysis demonstrated that visibility calculations performed at Mount Zirkel Wilderness Area in northwest Colorado had limited impact when ambient ammonia concentrations were reduced from 100 to 1 ppb, but there was a significant reduction in visibility impacts when concentrations were further reduced to 0.1 ppb. Given the evidence presented above, the use of the monthly varying ammonia would provide accurate estimates of visibility impacts from the PacifiCorp RH Units. EPA's failure to use the "best science," variable background ammonia in its modeling, is arbitrary and capricious.

[44] The modeling files containing the ammonia concentrations for the Desert Rock Generating Station can be found on the EPA website under the administrative record for the project (http://www.epa.gov/region9/air/permit/desert-rock/administrative.html).

Moreover, EPA Region 8 has admitted the validity of using “variable ammonia” for CALPUFF modeling. In its federal implementation plan for Montana, EPA used “variable ammonia” in its modeling. 77 Fed. Reg. at 57,867. (“As a result, we did not assume a constant level of ammonia as asserted by the commenter, and we did represent seasonal variability in ammonia concentrations. Additionally, EPA used the POSTUTIL program ” with the Ammonia Limiting Method (ALM) to post-process the CALPUFF output to correct the assumption of constant ammonia availability in the model.”).

3. EPA used the wrong CALPOST Method.

EPA made another modeling error in Wyoming when it used CALPOST[45] version 5 with Method 6. Federal Land Manager recommendations in 2000 (FLAG) recommended the use of Method 6 to determine visibility impacts from BART eligible sources. However, for any recent PSD application and BART modeling since 2010, EPA has requested that Method 8 be used for determining impacts on visibility at nearby class I areas.

The previously preferred Method 6 simply computes background light extinction using monthly average relative humidity adjustment factors particular to each Class I area applied to background and modeled sulfate and nitrate. Six years after the development of Method 6 in 1999, EPA released enhancements to the background light extinction equations, which use the IMPROVE variable extinction efficiency formulation. These enhancements take into account the fact that sulfates, nitrates and organics and other types of particles have different light extinction coefficients. Also, the background concentrations at each Class I area have been updated by EPA to reflect natural background visibility condition estimates for each Class I area for each type of particle: ammonium sulfate, ammonium nitrate, organic matter, elemental carbon, soil, crustal material, sea salt and air molecules. Additionally, relative humidity adjustment factors have been tailored separately for: small particles, large particles, and to account for sea salt background concentrations. (*See* Attachment 7.)

These new enhancements to the calculation method, called Method 8, greatly improve the accuracy of the estimated visibility impact. Method 8 was added to CALPOST in 2008 and was adopted as the preferred option for determining impacts on visibility by the Federal Land Managers Air Quality Related Values Work Group (FLAG) guidance document in 2010 (FLAG 2010). The applicable background concentrations and relative humidity adjustment factors using Method 8 for each Class I area are identified in the FLAG 2010 manual. (*See* Attachment 7.)

Despite this update to Method 8 in 2008 and the stated preference by the FLMs in 2010 to use Method 8, EPA conducted the Wyoming BART modeling in 2012 using the long outdated and scientifically inferior Method 6. EPA’s use of Method 6, and not Method 8, is arbitrary and capricious. EPA should have used Method 8, the “best” modeling science.

[45] CALPOST is a post-processing program with options for the computation of time-averaged concentrations and deposition fluxes predicted by the CALPUFF model.

In EPA's RH FIP Action, EPA made several errors concerning modeling, including 1) given the general inaccuracy in CALPUFF unit-specific modeling, not allowing Wyoming the deference accorded it under the CAA; 2) relying upon an outdated CALPUFF method of visibility modeling, contrary to EPA precedent; 3) violating the applicable modeling guidance, Appendix W, by not using the "best" science; 4) violating the Data Quality Act by not using the "best" science; and 5) failing to recognize the gross overestimations and internal inconsistencies in EPA's modeling approach.

States are not only given great discretion in relation to modeling, they are encouraged by EPA guidance to apply the most realistic models. Contrary to its own guidance, EPA failed to do so. Appendix W, EPA's modeling guidance, demands that the "best" model should always be used. EPA failed to use the "best" model in Wyoming. Therefore, EPA failed to follow Appendix W's requirements. App. W.1.0.e ("(I)n all cases, the model applied to a given situation should be the one that provides the most accurate representation of atmospheric transport, dispersion, and chemical transformations in the area of interest."); App. W.1.0.d ("The model that most accurately estimates concentrations in the area of interest is always sought.") (emphasis added). EPA's outdated modeling approach fails to meet the requirements of Appendix W.

iv) EPA's use of the maximum dV improvement that occurs during the 2001-2003 period does not provide the degree of visibility improvement which may reasonably be anticipated from the use of BART.

In its BART determinations, EPA relied on the maximum annual visibility impacts and improvements occurring during any given year of the 2001-2003 time period over which the models were run. Standard practice has been, and continues to be, to average the results over the three year period. (*See* e.g., 76 Fed. Reg. 16,168, 16,182 (approving the averaging of three different years in Oklahoma)). EPA's use of the maximum value is no more supportable than if a state or regulated source used the minimum annual value.

Tables 15-25 below demonstrate the differences in the modeled visibility improvements when the standard method of using three-year averages is used rather than EPA's method of using the highest impacted year[46].

[46] Although PacifiCorp disagrees with the results of EPA's modeling, data for these tables come from EPA's spreadsheet "EPA-R08-2012-0026-0089 Feb 11, 2013 modeling results.xlsx" to demonstrate how using the average values vs. the maximum values should be considered in EPA's BART determinations.

Table 15
Dave Johnston 1

EPA Modeled Delta dV Improvements from EPA's Baseline, Wind Cave NP Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.204	0.110	0.308	0.21	0.31	0.10
SNCR	0.238	0.138	0.352	0.24	0.35	0.11
SCR	0.299	0.193	0.439	0.31	0.44	0.13

Table 16
Dave Johnston 2

EPA Modeled Delta dV Improvements from EPA's Baseline, Wind Cave NP Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.203	0.112	0.288	0.20	0.29	0.09
SNCR	0.228	0.139	0.333	0.23	0.33	0.10
SCR	0.274	0.192	0.418	0.29	0.42	0.12

Table 17
Dave Johnston 3

EPA Modeled Delta dV Improvements from EPA's Baseline, Wind Cave NP Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.500	0.395	0.639	0.51	0.64	0.13
SNCR	0.594	0.473	0.758	0.61	0.76	0.15
SCR	0.791	0.613	1.004	0.80	1.00	0.20
Improvement going from LNB to SCR	0.291	0.218	0.365	0.29	0.37	0.07

Table 18
Dave Johnston 4

EPA Modeled Delta dV Improvements from EPA's Baseline, Wind Cave NP Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.695	0.546	0.838	0.69	0.84	0.15
SNCR	0.696	0.614	0.946	0.75	0.95	0.19
SCR	0.815	0.737	1.213	0.92	1.21	0.29
Improvement going from LNB to SNCR	0.001	0.068	0.108	0.06	0.11	0.05

Table 19
Jim Bridger 1

EPA Modeled Delta dV Improvements from EPA's Baseline, Mt Zirkel Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.449	0.592	0.554	0.53	0.59	0.06
SNCR	0.525	0.694	0.651	0.62	0.69	0.07
SCR	0.724	0.964	0.873	0.85	0.96	0.11
Improvement going from LNB to SCR	0.275	0.372	0.319	0.32	0.37	0.05

Table 20
Jim Bridger 2

EPA Modeled Delta dV Improvements from EPA's Baseline, Mt Zirkel Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.412	0.549	0.508	0.49	0.55	0.06
SNCR	0.495	0.654	0.612	0.59	0.65	0.07
SCR	0.714	0.951	0.861	0.84	0.95	0.11
Improvement going from LNB to SCR	0.302	0.402	0.353	0.35	0.40	0.05

Table 21
Jim Bridger 3

EPA Modeled Delta dV Improvements from EPA's Baseline, Mt Zirkel Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.375	0.501	0.463	0.45	0.50	0.05
SNCR	0.460	0.608	0.569	0.55	0.61	0.06
SCR	0.688	0.918	0.829	0.81	0.92	0.11
Improvement going from LNB to SCR	0.313	0.417	0.366	0.37	0.42	0.05

Table 22
Jim Bridger 4

EPA Modeled Delta dV Improvements from EPA's Baseline, Mt Zirkel Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.491	0.629	0.551	0.56	0.63	0.07
SNCR	0.583	0.753	0.658	0.66	0.75	0.09
SCR	0.834	1.011	0.939	0.93	1.01	0.08
Improvement going from LNB to SCR	0.343	0.382	0.388	0.37	0.39	0.02

Table 23
Naughton 1

EPA Modeled Delta dV Improvements from EPA's Baseline, Bridger Wilderness Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.835	0.675	0.734	0.75	0.84	0.09
SNCR	0.985	0.793	0.866	0.88	0.99	0.10
SCR	1.230	0.982	1.079	1.10	1.23	0.13
Improvement going from LNB to SCR	0.395	0.307	0.345	0.35	0.40	0.05

Table 24
Naughton 2

EPA Modeled Delta dV Improvements from EPA's Baseline, Bridger Wilderness Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
Baseline	--	--	--	--	--	--
LNB/OFA	0.969	0.788	0.903	0.89	0.97	0.08
SNCR	1.148	0.922	1.063	1.04	1.15	0.10
SCR	1.421	1.134	1.316	1.29	1.42	0.13
Improvement going from LNB to SCR	0.452	0.346	0.413	0.40	0.45	0.05

Table 25
Wyodak

EPA Modeled Delta dV Improvements from EPA's Baseline Wind Cave NP Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
Baseline	--	--	--	--	--	--
LNB/OFA	0.192	0.207	0.242	0.21	0.24	0.03
SNCR	0.282	0.321	0.376	0.33	0.38	0.05
SCR	0.518	0.593	0.707	0.61	0.71	0.10
Improvement going from LNB to SNCR	0.090	0.114	0.134	0.11	0.13	0.02

From a visibility perspective these small differences are irrelevant. However, because EPA relies on very small modeled differences in visibility to justify the addition of hundreds of millions of dollars of BART controls these differences become very significant. EPA's use of the maximum annual improvement rather than the average value in its BART determinations results in the use of inflated visibility impacts and over-estimated improvements. For example, if EPA were to make no other change in interpreting the modeling results other than use the average dV improvement rather than the maximum annual value, the incremental visibility impact between installing LNB technology and SCR at Dave Johnston Unit 3 drops from 0.37 dV to 0.29 dV. SCR installation for this size of unit cannot be justified for a 0.37 dV improvement let alone a 0.29 dV improvement. Yet EPA chooses to rely on the inflated improvement values in an attempt to justify the installation of SCR on this unit. As a result, EPA's BART NO_X determinations are flawed and invalid. Similar conclusions can be reached for the other units that EPA addresses in its FIP.

v) EPA's use of the cumulative dV from several parks does not provide the degree of visibility improvement which may reasonably be anticipated from the use of BART.

In its disapproval of Wyoming's BART analyses, EPA uses an improper and illegal visibility analysis technique: the cumulative visibility analysis. 78 Fed. Reg. at 34,738. ("Although the cost-effectiveness and visibility improvement are within the range of other EPA RH FIP actions, we find that the *cumulative visibility improvement* of 1.16 deciviews for new LNBs with OFA plus SCR is low compared to *the cumulative visibility benefits* that will be achieved by requiring SCR at Dave Johnston Unit 3 (2.92 dv), Laramie River Unit 1 (2.12 dv), Laramie River Unit 2 (1.97 dv), Laramie River Unit 3 (2.29 dv), Naughton Unit 1 (3.54 dv), and Naughton Unit 2 (4.18 dv).") (emphasis added). Clearly, EPA considered "cumulative visibility improvement" when it rejected Wyoming's BART NO_X analyses and required SCR at Dave Johnston Unit 3 (78 Fed. Reg. at 34,778), Naughton Unit 1, and Naughton Unit 2. 78 Fed. Reg. at 34,782 ("In addition, the installation of SCR will also have substantial visibility benefits for other Class I areas, besides the most impacted area. The *cumulative visibility improvement* is 3.54 dv for Unit 1 and 4.18 dv for Unit 2.") EPA's use of the cumulative visibility analysis is incorrect for several reasons.

1. *The EPA's cumulative visibility analysis is deceptive, and unreliable.*

EPA fails to mention when presenting its cumulative visibility analyses that the modeled deciview improvements that are added together occur on different days, weeks, or even months. In spite of this, EPA adds together these disparate deciview improvements to arrive at a single deciview number as if that can somehow represent the true deciview improvements to be attained every day of the year at each of the Class I areas. *See e.g.* Tables 54 and 56, 78 Fed. Reg. at 34,782. This representation is totally false and deceptive.

For example, if modeling for a given control projected a visibility improvement at Area A of 0.1 dv on January 1st, at Area B of 0.2 dv on January 15th, at Area C of 0.2 dv on January 30th, at Area D of 0.2 dv on February 2nd, at Area E of 0.2 dv on February 8th, and at Area F of 0.1dv on February 16th, the "cumulative approach" would suggest a 1.0 dv improvement (the sum of all modeled improvements) could be attained at a Class I area. Because one deciview is considered the amount of visibility improvement perceptible to the human eye, the "cumulative approach" would suggest that the required technology would yield a perceptible visibility improvement. It is clear from this simple example, however, that the modeled control did not produce a perceptible visibility improvement at any of the Class I areas. In fact, based upon this example, the proposed control would not result in a perceptible difference anywhere. Likewise, adding the numbers in Tables 47, 54, and 56 Fed. Reg. at 34,778 and 34,782 of EPA's proposed RH FIP leads to the impression that a perceptible visibility improvement will occur, when in reality none of the modeled visibility improvements would be perceptible to the human eye.

2. EPA's cumulative visibility analyses ignore the discretion given to States.

The CAA provides that the States are to conduct the five-factor BART analysis of their stationary sources, which includes the determination of "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." 42 U.S.C. § 7491(g)(2). EPA has stated that because "each Class I area is unique, . . . *States should have flexibility to assess visibility improvements due to BART controls by one or more methods,* or by a combination of methods," and that "*States should have flexibility when evaluating the fifth statutory factor (degree of visibility improvement).*" 70 Fed. Reg. at 39,107. When discussing visibility improvement in the Preamble, EPA made it clear that States are to determine the "weight and significance" of each of the five BART factors. "*The State makes a BART determination based on the estimates available for each criterion, and as the CAA does not specify how the State should take these factors into account, the States are free to determine the weight and significance to be assigned to each factor.*" *Id.* at 39,123 (emphasis added); *see also* 77 Fed. Reg. 24,768, 24,774 (Apr. 25, 2012) ("States are free to determine the weight and significance to be assigned to each (BART) factor.").

Here, Wyoming reviewed and analyzed visibility modeling, and conducted an analysis of the "visibility improvement" BART factor. EPA ignored Wyoming's discretion, and is attempting to substitute its visibility analysis, including the deceptive and incorrect cumulative visibility analysis, for Wyoming's visibility analysis.

3. EPA's cumulative visibility analysis lacks support in the Regional Haze Rules.

The BART rules provide no support for EPA's "summation of cumulative impacts" approach. Rather, the BART rules first make clear that the initial focus is expected to be on the "nearest Class I area" to the facility in question. 70 Fed. Reg. 39,104, 39,162 (Sept. 6, 2005) ("One important element of the (modeling) protocol is in establishing the receptors that will be used in the model. The receptors that you (i.e., the state) use should be located in the *nearest* Class I area with sufficient density to identify the likely visibility effects of the source." (emphasis added)). The rules then indicate that it is appropriate to take account of impacts at not only the nearest Class I area but also impacts at other nearby Class I areas, not for the purposing of *summing* impacts at all of those areas, but rather for the purpose of "determin(ing) whether effects at those (other) areas *may be greater than* at the *nearest* Class I area." *Id.* (emphases added). Critically, "(i)f the highest modeled effects are observed at the nearest Class I area, *you (*i.e.*, the state) may choose not to analyze the other Class I areas any further* as additional analyses might be unwarranted." *Id*. (emphasis added).

Admittedly, the BART rules do not *preclude* a state from taking into account, as part of a BART assessment for a given facility, visibility impacts projected to occur in two or more Class I areas that are attributable to that facility's emissions. However, nothing in the rules requires such an analysis, and as explained herein, such analyses are deceptive when used in a cumulative fashion. Wyoming's visibility analyses should be upheld because Wyoming took "into consideration . . . the degree of improvement in visibility which may reasonably be anticipated to result from the use of" BART. 40 C.F.R. § 51.308(e)(1)(ii)(A). Regardless of EPA's empty statements to the contrary, EPA did not have the authority to disapprove Wyoming's visibility improvement analyses on the grounds that EPA prefers a different approach than the lawful and permissible approach taken by Wyoming. *See Train v. Natural Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975).

4. The "Cumulative Approach" distorts the visibility improvement analysis and is not a useful tool

Although EPA may prefer the use of the cumulative visibility analysis, there is no required, compelling, legal or even sound public policy reason for adopting such a methodology here. The metric by which visibility improvement is determined for purposes of assessing BART for a particular facility must reflect actual human perception of visibility. The terms "visibility impairment" and "impairment of visibility" are both defined by conditions (reduction in visual range and atmospheric discoloration) that are perceptible to the human eye. 42 U.S.C. §7491(g)(6).

The "cumulative approach" has no tie to human perception because it adds together modeled improvement that different people may (or may not) see at different places and different times, and then assumes the aggregate improvements can be perceived by all people at all places and at all times. In the end, the "cumulative approach" serves only to distort a BART analysis so it appears to justify expensive emission controls that do not improve visibility in any one Class I area to a degree that justifies the cost. It is unreasonable to assume that an individual can perceive visibility impacts in more than one Class I area simultaneously, or even within relatively short periods of time. Further, the "cumulative approach" incorrectly and arbitrarily multiplies the benefit that might be associated with emission limitations at a single source.

Similarly, the arbitrary nature of this approach is illustrated by the fact that it would equate an accumulation of vanishingly small – indeed, merely theoretical – visibility "benefits" in several different areas with a much larger and plainly perceptible improvement in a single area. It cannot reasonably be asserted that visibility improvements that are imperceptible in each of several Class I areas can somehow be the equivalent of – or even deemed more significant than – a much larger and humanly perceptible improvement in a single area.

The fallacy of the "cumulative approach" also can be illustrated by an analogy. If a weight loss drug company were to advertise that "A study shows 20 lbs. weight loss achievable in 30 days" by using its expensive drugs, it would be considered misleading if the study was “cumulative,” i.e. 100 people each lost 0.2 lbs. on the drug over 30 days. However, if the weight loss drug truthfully advertised “A study shows 100 people each lost 0.2 lb in 30 days,” while truthful, it is doubtful that the product would be sold to people expecting to lose 20 pounds. Likewise, EPA adding up the small, modeled visibility improvements at a number of Class I areas does not magically result in improved visibility as perceived by the human eye in all such Class I areas or in any one Class I area.

A modeled visibility benefit that no one can perceive and that is subject to arbitrary manipulation is not a real, quantifiable benefit. It is a fabricated value with no clear tie to the public interest that the CAA seeks to protect: human perception of visibility impairment in Class I areas.

vi) EPA ignores the days per year of improvement identified in the models they use, leaving the impression that the modeled visibility improvement occurs continuously.

In addition to improperly considering and weighing the magnitude of the modeled visibility impacts, EPA has improperly failed to account for the very few number of days of visibility impacts or the seasonal timing of when those few impacts occur. Table 26 below, created for Dave Johnston Unit 3, identifies the number of days per year that have been modeled to impact the identified Class I area by 0.5 deciviews or more. Although EPA does not specifically identify the number of days that were modeled to be above 0.5 dV in its FIP, the days were obtained by re-running EPA’s models and model inputs.

Table 26

Dave Johnston Unit 3 Wind Cave NP – Days Modeled with Impacts <0.5 dV				
Model Year	2001	2002	2003	AVG
2001 – 2003 Baseline	22	21	24	22
LNB/OFA – Current Baseline	9	5	10	8
SNCR	3	4	10	6
SCR	1	0	2	1
Days Above 0.5dV That Are Eliminated by adding the Identified Controls				
SNCR	6	1	0	2
SCR	8	5	8	7

As can be seen from the results in the table, prior to the installation of LNB/OFA, EPA’s models indicated that, on average, there would be 22 days per year where the impacts in Wind Cave National Park would be greater than 0.5 dV. The number of days impacting the park by more than 0.5 dV drops to eight days per year following the installation of the LNB/OFA, which is the current emissions configuration. EPA’s proposed RH FIP Action, which requires the installation of SCR, will reduce the number of days that impact the park by < 0.5 dV from eight days to one day, just a seven day per year decrease.

Tables 27–30 provide similar information for the other units identified in EPA's RH FIP

Table 27

Dave Johnston Unit 4 Wind Cave NP – Days Modeled with Impacts <0.5 dV				
Model Year	2001	2002	2003	AVG
2001 – 2003 Baseline	31	24	26	27
LNB/OFA – Current Baseline	7	9	12	9
SNCR	7	7	9	8
SCR	3	3	7	4
Days Above 0.5dV That Are Eliminated by adding the Identified Controls				
SNCR	0	2	3	1
SCR	4	6	5	5

Table 28

Naughton Unit 1 Jim Bridger Wilderness Area– Days Modeled with Impacts <0.5 dV				
Model Year	2001	2002	2003	AVG
2001 – 2003 Baseline	42	26	33	34
LNB/OFA – Current Baseline	17	11	13	14
SNCR	10	8	10	9
SCR	5	3	4	4
Days Above 0.5dV That Are Eliminated by adding the Identified Controls				
SNCR	7	3	3	5
SCR	12	8	9	10

Table 29

Naughton Unit 2 Jim Bridger Wilderness Area – Days Modeled with Impacts <0.5 dV				
Model Year	2001	2002	2003	AVG
2001 – 2003 Baseline	45	34	43	41
LNB/OFA – Current Baseline	22	16	15	18
SNCR	16	11	13	13
SCR	10	6	9	8
Days Above 0.5dV That Are Eliminated by adding the Identified Controls				
SNCR	6	5	2	5
SCR	12	10	6	10

Table 30

Wyodak* Wind Cave NP – Days Modeled with Impacts <0.5 dV				
Model Year	2001	2002	2003	AVG
2001 – 2003 Baseline	41	38	37	39
LNB/OFA – Current Baseline	11	17	19	16
SNCR	11	14	11	12
SCR	0	3	8	4
Days Above 0.5dV That Are Eliminated by adding the Identified Controls				
SNCR	0	3	8	4
SCR	11	14	11	12
*Additional modeling for Wyodak has not been completed using EPA's revised model inputs. Data in this table on the modeling results included in Wyodak's Wyoming BART Application Analysis, AP-6043 page 32				

The LNB/OFA controls already installed on each BART-eligible unit in Wyoming ensure the 20% best days continue to be protected during this planning period. EPA's proposed FIP incurs millions of dollars of additional costs without moving the state any closer to being able to meet its reasonable progress goals.

vii) EPA has improperly required additional visibility controls with little to no associated visibility improvement.

A review of the unit-specific CALPUFF modeling results developed for the Mount Zirkel Wilderness Area provides a vivid example of the over-estimation of the visibility improvement that EPA is relying on to justify the installation of hundreds of millions of dollars in additional SCR controls. The following table summarizes the unit-specific CALPUFF visibility improvements that have been modeled for eight of PacifiCorp's coal-fired units in Colorado and Wyoming. The table identifies EPA's modeled ΔdV improvements associated with reducing the NO_X emissions from each unit's EPA NO_X baseline to the NO_X emissions associated with the installation of SCR:

Table 31

EPA Modeled Improvements at Mount Zirkel for Eight of PacifiCorp Owned Facilities	
Facility	Modeled ΔdV Improvement
Jim Bridger 1	0.80
Jim Bridger 2	0.80
Jim Bridger 3	0.80
Jim Bridger 4	0.82
Craig 1	1.01
Craig 2	0.98
Hayden 1	1.12
Hayden 2	0.85
Total Modeled Visibility Improvement	7.18

The unit specific CALPUFF modeling would indicate that adding SCR to these units would improve visibility in Mount Zirkel by over seven deciviews.

However, the monitored data at Mount Zirkel tells a completely different story. Table 32[47] below is a summary of the visibility impairment actually measured at the Mount Zirkel Wilderness area from 2001-2003. This is the same time period used in the CALPUFF models to develop the deciview impacts for each Wyoming BART-eligible unit and to project the visibility improvements associated with the addition of control devices. The ammonium nitrates values have been highlighted since the contribution associated with nitrates is what is of interest in this evaluation.

[47] The table compares the monitored light extinction with deciviews so that the monitored impacts can be properly compared to the modeled results. In order to develop the deciview impact of each parameter, the light extinction associated with each parameter was removed one parameter at a time and the resulting dV impact calculated. The difference between the total impact and this value provides the dV improvement that is associated with completely removing the specified parameter. The relationship between light extinction and deciviews is: Deciview (dV) = 10 x ln (bext(Mm-1)/10).

Table 32

Mount Zirkel Wilderness Area - 2001-2003 Reconstructed Extinction Values MOZI1 Monitoring Data - 20% Worst Visibility Days[48]			
Parameter	bext Mm^{-1}	% Of Total bext	Deciview Improvement if Parameter is Completely Removed
Ammonium Nitrate	**2.3**	**8.9%**	**0.94**
Ammonium Sulfate	5.5	21.4%	2.41
Course Material	3.6	14.0%	1.51
Elemental Carbon	2.0	7.8%	0.81
Organic Material	11.3	43.9%	5.79
Sea Salt	0.0	0.1%	0.01
Soil	1.0	3.9%	0.40
Total Impact	25.7	100.0%	9.45

Looking at the 3-year average results, and assuming that the nitrates associated with the emissions from <u>all</u> sources (not just the BART-eligible EGUs) are completely eliminated, only a 0.94 deciview improvement would be expected. EPA attempts to justify over a billion dollars in controls at eight PacifiCorp Units by assuming more than 7 deciviews of improvement could be obtained from these eight units when the actual <u>monitored</u> data indicates that only a 0.94 dV improvement would be possible if all nitrate was removed from all sources. In essence, EPA's RH FIP Action fails to recognize that, given the monitored nitrate impacts, the modeled visibility impacts are obviously grossly exaggerated. For this reason alone, EPA should withdraw its RH FIP and approve the Wyoming RH SIP in total.

Moreover, in its RH FIP Action, EPA ignores Wyoming's discretion to consider, and account for in its BART determinations, the admitted "overestimation" of CALPUFF results. As EPA itself has stated, Wyoming should be free to make its own judgment about which modeling approaches are valid and appropriate.

Determining "visibility improvement" for regional haze program purposes is challenging, and extreme caution must be exercised when conducting visibility-related modeling and interpreting the modeling results. Modeling mistakes and misinterpretation of the data can lead to poor decision-making with expensive consequences.

The unit-specific CALPUFF modeled visibility impacts on the Grand Canyon from the former Mojave power plant are another example of how CALPUFF can incorrectly attribute visibility impacts. For years, computerized models (the same CALPUFF model used in Wyoming) showed that closing the Mojave power plant would improve visibility by 5% or more. (*See* Attachment 12, Terhorst, J., Berkman, M., "Effect of Coal-Fired

[48] <u>http://vista.cira.colostate.edu/dev/web/AnnualSummarydev/Composition.aspx</u>

Power Generation on Visibility in a Nearby National Park," Atmospheric Environment (2010), page 15.) The CALPUFF unit-specific models, however, were wrong. Mojave was closed in 2005, but scientists "found virtually no evidence that the (Mojave) closure improved visibility in the Grand Canyon; or, equivalently, that the plant's operation degraded it." *Id.* at 14. These same scientists believed that the Mojave study raises "questions about the reliability of CALPUFF." *Id.* at 15. Likewise, EPA should question its use of CALPUFF unit-specific modeling results in Wyoming.

viii) EPA is not affording Wyoming's BART decisions the proper deference when it comes to the modeling and applying the modeling results.

The CAA provides that the states are to conduct the five-factor BART analysis of their stationary sources, which includes the determination of "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." 42 U.S.C. § 7491(g)(2). EPA explained that "we must permit States to take into account the degree of improvement in visibility that would result from imposition of BART on each individual source when deciding on particular controls." 70 Fed. Reg. 39,107, 39,129. Additionally, EPA has stated that because "each Class I area is unique, . . . States should have flexibility to assess visibility improvements due to BART controls by one or more methods, or by a combination of methods," and that "States should have flexibility when evaluating the fifth statutory factor." 70 Fed. Reg. at 39,107 (emphasis added). Wyoming exercised that discretion here, but, once again, EPA failed to grant it the proper deference.

1. *EPA failed to allow Wyoming to account for CALPUFF's overestimation of NO_X impacts.*

EPA recognized that states are accorded significant "modeling" discretion because CALPUFF chronically overestimates modeled visibility improvements. The Preamble recognizes that states can make judgments regarding the use of modeling results due to the very real problems with CALPUFF.

> At a minimum, CALPUFF can be used to estimate the relative impacts of BART-eligible sources. We are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results. States can make judgments concerning the conservativeness or overestimation, if any, of the results.
> . . .
> We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range transport. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches and

determine whether they are sufficiently documented, technically valid, and reliable to approve for general use. In the meantime, as the Guideline makes clear, States are free to make their own judgments about which of these or other alternative approaches are valid and appropriate for their intended applications.

70 Fed. Reg. at 39123 (emphasis added). As the Mojave power plant study illustrates, there are serious questions about CALPUFF's credibility. (*See* Exhibit 4.) The Mojave study suggests that, at a minimum, visibility improvements modeled by CALPUFF may be greatly overstated. As EPA stated in the Arizona RH FIP, the "Terhorst & Berkman study cited by the commenter is worthy of consideration as the Regional Haze program evolves. . ." 78 Fed. Reg. at 72,534.

EPA's own studies document that CALPUFF overstates results. In a May 2012 study of CALPUFF, an EPA sponsored study found "the current and past CALPUFF model performance evaluations were consistent with CALPUFF tending to overestimate the plume maximum concentrations and underestimate plume horizontal dispersion." Documentation of the Evaluation of CALPUFF and Other Long Range Transport Models Using Tracer Field Experiment Data, May 2012, EPA-454/R-12-003, page 29. The study also recognized that modeling results were widely variable, depending on the options used, and that such variability is "not a desirable attribute for regulatory modeling." *Id. at* 11; *see also* page 18 (."By varying CALMET inputs and options through the range of plausibility, CALPUFF can produce a wide range of concentrations estimates."). Therefore, EPA's own recent studies suggest CALPUFF overestimates results and, therefore, its results should not be accorded scientific precision. Problems with CALPUFF unit-specific modeling reliability in Wyoming, and its tendency to grossly overestimate results, are discussed in the succeeding section below.

ix) EPA's modeling was inadequate and reliance on the modeling violates The Data Quality Act.

EPA's modeling for its RH FIP Action was inadequate for all the reasons stated above. Therefore, EPA's RH FIP Action violates the Information Quality Act[49] and the implementing guidelines issued, respectively, by the U.S. Office of Management and Budget (OMB)[50] and the EPA which require information disseminated by EPA to be accurate, complete, reliable and unbiased.[51] The Act and EPA Information Quality Guidelines place a heightened standard on "influential" information,[52] including

[49] Section 515(a) of the Treasury and General Government Appropriations Act for Fiscal Year 2001, P.L. 106-554; 44 U.S.C. §3516

[50] OMB Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information Disseminated by Federal Agencies (hereinafter "OMB Guidelines"), 67 Fed. Reg. 8,452 (Feb. 22, 2002).

[51] OMB Guidelines 8,453.

[52] EPA Guidelines define "influential," when used in the phrase "influential scientific, financial, or statistical information," as information that "will have or does have a clear

scientific information regarding health, safety or environmental risk assessments. EPA's inaccurate and incomplete visibility modeling is by definition "influential," because EPA could "reasonably determine that dissemination of the information will have or does have a clear and substantial impact on important public policies or important private sector decisions," such as the BART NO_X determinations in EPA's RH FIP. OMB Guidelines at 8455. Therefore, this "influential" information must be based on best available science and data and supporting studies must be conducted in accordance with sound objective scientific practices and methods. EPA Information Quality Guidelines at 22. As explained above, EPA did not use the "best available science and data" when conducting its modeling in Wyoming.

EPA's Guidelines implementing the Information Quality Act expressly contemplate the correction of information disseminated by EPA that falls short of the "basic standard of quality, including objectivity, utility, and integrity," established by either EPA's own Guidelines or those issued by OMB. PacifiCorp herein seeks correction to a number of errors and omissions in EPA's RH FIP Action with regard to CALPUFF modeling PacifiCorp requests that EPA withdraw its RH FIP until these issues are resolved. [53]

x) EPA's Modeling Approaches are Inconsistent

EPA rejected Oklahoma's visibility analyses which "relied upon pollutant specific modeling to evaluate the benefits from the use of available SO_2 emission controls." 76 Fed. Reg. 81,728, 81,740. Rather, EPA modeled in Oklahoma "all visibility impairing pollutants to fully assess the visibility improvement anticipated from the use of controls." *Id.* EPA argued this modeling took into account "the complexity of atmospheric chemistry and chemical transformation among pollutants." *Id.* In Wyoming, EPA noted that Wyoming provided "visibility improvement modeling results that combine(d) the visibility improvement from NO_X, PM and SO_2 control options" and that "EPA could not ascertain what the visibility improvement would be from an individual NO_X or PM control option." 77 Fed. Reg. at 33,031. EPA appears to take contrary positions in Oklahoma and Wyoming. EPA's inconsistent positions are arbitrary and capricious.

In EPA's RH FIP Action, the alleged "visibility improvements" for DJ 3 and 4, Naughton 1 and 2, and Wyodak do not justify "overruling" the State's discretionary BART NO_X determinations. EPA found that SCR provided only a 0.36 ΔdV incremental visibility improvement for DJ3, using EPA modeling, with an incremental cost of $7,163.00. 78 Fed. Reg. 34,777-78. EPA failed to justify in its proposed rule how a 0.36 ΔdV improvement, or approximately one-third that humanly detectible, justifies the tremendous cost of SCR. Likewise, EPA found that installing SNCR at DJ 4 results in an incremental 0.11 ΔdV improvement over Wyoming's BART determination at an

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and substantial impact (i.e., potential change or effect) on important public policies or private sector decisions." EPA Information Quality Guidelines at 19.

[53] EPA should treat PacifiCorp's public comments herein as a formal "Request for Correction" pursuant to the EPA Information Quality Guidelines at 32 because the EPA's Proposed RH FIP Proposal is open for Public Comment.

incremental cost of $4,655. 78 Fed. Reg. 34,781-82. The alleged incremental visibility benefit of installing SNCR at Wyodak is 0.12 ΔdV at an incremental cost of $3,725. 78 Fed. Reg. 34,784-85. EPA provides no justification for requiring such tremendous costs for such an inconsequential visibility improvement that likely falls within CALPUFF's margin of error. However, these alleged "visibility improvements" do not justify requiring SCR and SNCR for BART, particularly when the air quality model's ("CALPUFF'S) propensity to exaggerate visibility improvements is considered. (*See* Section 6.)

EPA has determined in other states that visibility improvements greater than those used to justify SNCR at Wyodak are too small or inconsequential to justify additional pollution controls. (*See* 77 Fed. Reg. 24,794 (0.27 dV improvement termed "small" and did not justify additional pollution controls in New York); 77 Fed. Reg. 11,879, 11,891 (0.043 to 0.16 ΔdV improvements considered "very small additional visibility improvements" that did not justify NO_X controls in Mississippi); 77 Fed. Reg. 18,052, 18,066 (agreeing with Colorado's determination that "low visibility improvement (under 0.2 ΔdV)" did not justify SCR for Comanche units)) Tellingly, the "low visibility improvements" that Colorado found at the Comanche units not to justify post-combustion NO_X controls -- as agreed to by EPA -- were 0.17 and 0.14 ΔdV. 77 Fed. Reg. at 18,066.

In Montana, where EPA issued a RH FIP directly, it found that a 0.18 ΔdV improvement to be a "low visibility improvement" that "did not justify proposing additional controls" for SO_2 on the source. 77 Fed. Reg. 23,988, 24,012. Here, EPA's actions requiring additional NO_X controls based on little-to-no additional visibility improvement are arbitrary and capricious, especially when EPA did not require additional NO_X controls in other states based on similar visibility improvements. This is particularly true in Montana where EPA had direct responsibility for the regional haze program.

Moreover, the modeled visibility improvements for the Jim Bridger units resulting from the requirement to install SCR (as BART under the EPA RH FIP Action and as part of the LTS under the Wyoming RH SIP) are too small to justify the overall expense of requiring these controls, as are the less than 0.5 ΔdV visibility improvements for Naughton Units 1 and 2 at an incremental cost of approximately $7,000. EPA has upheld state BART discretion in other instances of high incremental cost and low incremental visibility improvement. *See* 76 Fed. Reg. 80754, 80,757 (Kansas); Spending hundreds of millions of dollars for imperceptible visibility changes does not meet the intent, or purpose, of the regional haze program.

(7) "Combustion Controls" are BART, as Explained by EPA's Guidance and Applicable Regional Haze Rules.

A. NO_X BART Controls for The Subject Units are Combustion Controls.

EPA's RH FIP Action is improper because it requires post-combustion NO_X controls as BART, when EPA guidelines make clear that only combustion controls for NO_X are contemplated. (*See e.g.* 77 Fed. Reg. at 33,053.) EPA's Preamble and other guidance confirm that the combustion controls of LNBs and OFA (in some form) are "BART technology" for the BART Units. In the Preamble and the Regional Haze Rules, EPA stated that, except for cyclone boilers, the "types of current combustion control technology options assumed include low NO_X burners, over-fire air, and coal reburning." 70 Fed. Reg. 39,134; *see also* 39,144 ("For all other coal-fired units, our analysis assumed these units will install current combustion control technology.") (emphasis added). In fact, in the Technical Support Document used to develop the presumptive BART NO_X emissions limits, EPA explained that the "methodology EPA used in applying current combustion control technology to BART-eligible EGUs" included applying "a complete set of combustion controls. A complete set of combustion controls for most units includes a low NO_X burner and over-fire air." ("Technical Support Document, Methodology for Developing NO_X Presumptive Limits," EPA Clean Air Markets Division, pg. 1 (dated June 15, 2005) (emphasis added)).

EPA's Preamble and Appendix Y identify post-combustion controls for NO_X, such as SCR and SNCR, as "BART technology" for only "cyclone" units. EPA made it clear that for "other units, we are not establishing presumptive limits based on the installation of SCR." 70 Fed. Reg. 39,136 (emphasis added). Therefore, EPA's presumptive "BART technology" is LNBs and some type of OFA. EPA further elaborated in the Preamble on SCR costs, stating that although "States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types." *Id.* (emphasis added)*; see also* 40 C.F.R. Part 51, Appendix Y, Section IV.E.5. Because EPA improperly requires post-combustion controls in its RH FIP Action, EPA should withdraw this requirement and approve the Wyoming RH SIP. If EPA desires to impose post-combustion controls as BART NO_X, it must first amend Appendix Y through a proper rulemaking procedure.

B. Post Combustion Controls Are Not Cost Effective Or Required.

EPA's RH FIP Action also is improper because it assumes BART NO_X controls over \$5,000 per ton are "cost effective." (*See e.g.,* 77 Fed. Reg. at 33,053.) Appendix Y, on the other hand, states that BART NO_X control costs per ton above \$1,500 are not "cost effective." In the Preamble, EPA suggests that 75% of the EGUs would have BART NO_X removal costs between \$100 and \$1,000 per ton, and almost all of the remaining EGUs could install sufficient BART NO_X control technology for less than \$1,500 per ton.[54] EPA also recognized in the Preamble that SCR was generally not cost effective for

[54] "The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over \$ 100 to \$ 1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating over fire air ("ROFA"), which has already been demonstrated on

EGUs, except for EGUs with cyclone boilers (where the cost per ton was less than $1,500 per ton, with an average of $900 per ton). 70 Fed. Reg. at 39,135-36. Based upon EPA's Preamble, BART NO_X control technology that costs more than $1,500 per ton should not be considered "cost effective." Here, EPA found BART NO_X controls with a "cost effectiveness" number much more than $1,500 per ton to be "cost effective." 77 Fed. Reg. at 33,053. Therefore, EPA should withdraw its RH FIP Action.

(8) <u>EPA's RH FIP Action is Arbitrary Because it Employs a "Reasonable Progress" Test For DJ 1 & 2 that is not used for other Wyoming Sources or For Sources in other States</u>

Additional evidence of EPA's failure to give Wyoming the proper deference relates to DJ 1 & 2 and the reasonable progress factors. EPA acknowledged that, for a Reasonable Progress analysis, only four factors must be analyzed. (*See* 78 Fed. Reg. at 34,763.) Indeed, the Clean Air Act clearly requires only four factors be analyzed. 42 U.S.C. § 7491(g)(1).[55] EPA employed the four-factor Reasonable Progress analysis for the other two Wyoming Reasonable Progress sources: oil and gas sources and the Mountain Cement Company plant.[56] *Id.* at 34,763-4 and 34,765-6. EPA has approved other RH SIPs where the state employed this same four-factor analysis, including Nevada. (*See* 77 Fed. Reg. 36,044, 36,070; *see e.g.* 77 Fed Reg. 20,894, 20,934 ("As we have noted, our regulations require consideration of four factors in reasonable progress determinations; visibility improvement is not one of the specified factors.")) Also, EPA has approved other RH SIPs where the state is not meeting the Uniform Rate of Progress, but has determined that no Reasonable Progress controls are required for the initial planning period. (*See* 77 Fed. Reg. 30,248, 30,256-57; RH SIP Approval for Idaho).

Here, EPA admitted that Wyoming "provided four-factor analyses that evaluated the required factors" for DJ 1 & 2. 78 Fed. Reg. 34,785. However, EPA decided to do its own cost analyses and found it is "also appropriate to consider a fifth factor for these

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a variety of coal-fired units. Based on the data before us, the costs of such controls in most cases are less than $ 1500 per ton." 70 Fed. Reg. at 39,135.

[55] "[I]n determining reasonable progress there shall be taken into consideration the costs of compliance, the time necessary for compliance, and the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements." 42 U.S.C.§ 7491(g)(1).

[56] For both the oil and gas sources and the Mountain Cement Company plant, EPA disagreed with Wyoming's reasonable progress analysis and found "cost effective" NO_X controls could be employed, but EPA did not require those NO_X controls because the costs were "not so low that we are prepared to disapprove the State's conclusion in the reasonable progress context." *Id.* at 34,765 and at 34,766. EPA does not differentiate PacifiCorp's DJ Units 1 & 2 from the oil and gas sources or the Mountain Cement Company plant in any meaningful way that would suggest a different Reasonable Progress analysis should be applied. It is unclear why EPA required allegedly "cost effective" NO_X controls at Dave Johnston Unit 1 and 2, but not at the other two reasonable progress sources.

units . . .the degree of visibility improvement." *Id.* EPA justified its decision by citing to EPA guidance on states setting Reasonable Progress goals.

However, the referenced guidance (Appendix T, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," June 2007) does not support EPA's position for several reasons:

- The guidance concedes it is "merely guidance and <u>that States or the</u> . . . <u>(EPA) may elect to follow or deviate from this guidance</u>, as appropriate." *Id.* at 1-1. (emphasis added). EPA cannot find Wyoming acted "unreasonably" when it chose not to apply discretionary guidance.

- The guidance identifies several factors that EPA did not include in its proposed RH FIP, such as the "control measures and associated emission reductions that are expected to result from compliance with existing rules." *Id.* at 2-3. EPA cannot criticize Wyoming for not following the guidance when EPA itself chose not to apply part of the same guidance in the EPA RH FIP Action.

- The guidance suggests that air quality models be used to estimate "the improvement in visibility that would result from the implementation of the control measures you have found to be reasonable and compare this to the uniform rate of progress." *Id.* Here, EPA has no "modeling results" demonstrating the alleged improvement in visibility from the suggested NO_x controls and the impact on the uniform rate of progress. 77 Fed. Reg. at 33,057.

- The States -- not EPA -- are to determine the "reasonableness" of Reasonable Progress Goals and are given flexibility to do so. Appendix T at 4-2 ("you [states] have considerable flexibility in how you take these factors into consideration.").

- The guidance clearly indicates that a state must support its RPG "based on the statutory factors," which EPA admits Wyoming did. *Id.*

- Finally, the guidance explains that no additional "Reasonable Progress" controls may be needed for the first planning period. *Id.* at 4-1. ("Given the significant emissions reductions that we anticipate will result from BART, the CAIR, and the implementation of other programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, <u>and it may be all that is necessary to achieve reasonable progress</u>

in the first planning period for some States.") (emphasis added). This is exactly the determination Wyoming made. [57]

Therefore, the referenced guidance supports Wyoming's Reasonable Progress analysis for Dave Johnston Units 1 & 2 and Wyoming's finding that significant emissions reductions from BART and other CAA programs are sufficient for Reasonable Progress.

Moreover, EPA rejected Wyoming's Reasonable Progress determinations for Dave Johnston Units 1 & 2, in part, because EPA stated the "RHR does not allow for commitments to potentially implement strategies at some later date that are identified under reasonable progress or for the State to take credit for such commitments." 78 Fed. Reg. at 34,787. However, this is exactly what EPA allowed for other Reasonable Progress sources, such as the cement plant and oil and gas sources, to do. EPA's approach to the various Reasonable Progress sources is inconsistent and arbitrary.

Finally, EPA's Reasonable Progress analysis for Dave Johnston Units 1 & 2 is improper because it interferes with Wyoming's deference given under the CAA and applicable Regional Haze regulations. EPA disagrees with Wyoming's balancing of the costs and visibility, stating that EPA found it "unreasonable" for the State to reject "inexpensive controls" when there was a predicted visibility improvement of approximately 0.30 deciviews. 78 Fed. Reg. at 34,788. However, States, not EPA, are given the discretion and authority to balance the four Reasonable Progress factors. Appendix T at 4-2 ("you [states] have considerable flexibility in how you take these factors into consideration.").

(9) EPA Failed to take into Account the Impact of EPA's other Regional Haze Actions on PacifiCorp.

In making any BART determinations on a large, multi-jurisdictional system such as PacifiCorp's, the regulating agency must consider the broad scope of the impacts of its decisions on customers and generating system reliability as a whole. Wyoming considered these factors in developing its RH SIP. "The Division believes that the size of PacifiCorp's fleet of coal-fired units presents unique challenges when reviewing costs, timing of installations, customer needs, and state regulatory commission requirements. Information has been supplied by PacifiCorp elaborating on additional factors to be considered in PacifiCorp's BART determination (*see* 'PacifiCorp's Emissions Reductions Plan' in Chapter 6 of the Wyoming TSD)." RH SIP, at page 102. Wyoming's consideration of these factors was appropriate.

[57] In fact, Wyoming's RH FIP finds that the WRAP modeling showed a "significant decrease in nitrate by 2018," which was largely attributable to "the numerous Federal and state "'on-the-books' requirements for mobile sources." RH SIP at page 62.

As EPA's Regional Haze guidance, Appendix Y, explains:

> 1. Even if the control technology is cost effective, there may be cases where the installation of controls would affect the viability of continued plant operations.
>
> 2. There may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include effects on product prices. . . Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process. . .

Appendix Y. IV.E.3. (emphasis added).

In EPA's June 2012 proposed RH FIP, EPA requested public comment, including economic impact and system reliability information, regarding three "alternative" proposals for the Jim Bridger plant. (*See* 77 Fed. Reg. at 33053-54.) PacifiCorp submitted additional material regarding this request on July 12, 2012 (included herein as Attachment 13), including discussion of additional exposure to market power purchases, impacts on management of planned outages, enhanced risk associated with resource availability, planning for adequate generation and reasonable costs, and planning for grid reliability in light of unprecedented retrofit activity. Given the large number of BART Units owned by PacifiCorp in different states, including Arizona, Colorado, Utah and Wyoming, PacifiCorp believes "unusual circumstances" justify Wyoming and EPA considering the impact of EPA's BART decision-making in the Western United States on PacifiCorp and its customers. The same concerns expressed in its July 12, 2012, filing apply in EPA's RH FIP Action, where even more controls are being required.

In its RH FIP Action, EPA relied upon PacifiCorp's July 12, 2012, filing to conclude that, "based on the points made by PacifiCorp and noting the additional requirements in the proposed FIP for Wyoming, the finalized FIP for Arizona, and the possibility of additional requirements in a future FIP or SIP for Utah, EPA is proposing that the additional time to install controls under the State's LTS on Jim Bridger Unit 1 and Unit 2 is warranted under the affordability provisions in the BART Guidelines discussed above." *See,* 78 Fed. Reg. at 34756.

PacifiCorp supports EPA's proposed action to afford "considerable deference" to the Wyoming RH SIP with respect to what controls are reasonable and when they should be implemented at Jim Bridger Units 1 and 2—and that it would be unreasonable to require any further retrofits at this source within five years of EPA's final action. This is especially true given the extremely limited visibility improvement that would be achieved if SCRs were installed within the BART time period at Jim Bridger Units 1 and 2.

Further, PacifiCorp does not believe EPA, having reached the conclusion that it would be unreasonable to require further retrofits at Jim Bridger within five years, can reverse its decision simply by inviting comment on an alternative proposal without further consideration of the broader impacts of forcing more aggressive controls within a five year period.

While PacifiCorp agrees with EPA's proposed conclusions regarding the reasonableness and timing of installation of controls at Jim Bridger Units 1 and 2, EPA's focus on affordability impermissibly fails to consider the unusual circumstances and broader impacts of its action on PacifiCorp's other BART Units. EPA's selection of SCR controls at Naughton Units 1 and 2 and at Dave Johnson Unit 3 will affect the viability of continued unit operations. As discussed herein, installation of SCR controls at these three units, particularly given the cost of controls and their remaining useful life, create such "unusual circumstances" that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology.

EPA, in failing to consider the unusual circumstances it has created in proposing SCR and in failing to consider those actions in light of the timing and reasonableness of controls at Jim Bridger Units 1 and 2, has acted in a manner that is arbitrary and capricious in its overall assessment (or lack thereof) of the effects of its actions on PacifiCorp's generation fleet. EPA's increasingly stringent requirements on PacifiCorp's fleet are summarized in Table 33.

Table 33

Unit	Wyoming SIP	2012 FIP	2013 FIP
Naughton 1	LNB	LNB	SCR (within 5 years)
Naughton 2	LNB	LNB	SCR (within 5 years)
Naughton 3	SCR (12/31/14)	SCR (12/31/14)	SCR (12/31/14)
Jim Bridger 1	SCR (12/31/22)	SCR (within 5 years)	SCR (12/31/22)
Jim Bridger 2	SCR (12/31/21)	SCR (within 5 years)	SCR (12/31/21)
Jim Bridger 3	SCR (12/31/15)	SCR (12/31/15)	SCR (12/31/15)
Jim Bridger 4	SCR (12/31/16)	SCR (12/31/16)	SCR (12/31/16)
Dave Johnston 1	LNB	LNB	LNB (within 5 years)
Dave Johnston 2	LNB	LNB	LNB (within 5 years)
Dave Johnston 3	LNB	SNCR (within 5 years)	SCR (within 5 years)
Dave Johnston 4	LNB	LNB	SNCR (within 5 years)
Wyodak	LNB	SNCR (within 5 years)	SNCR (within 5 years)

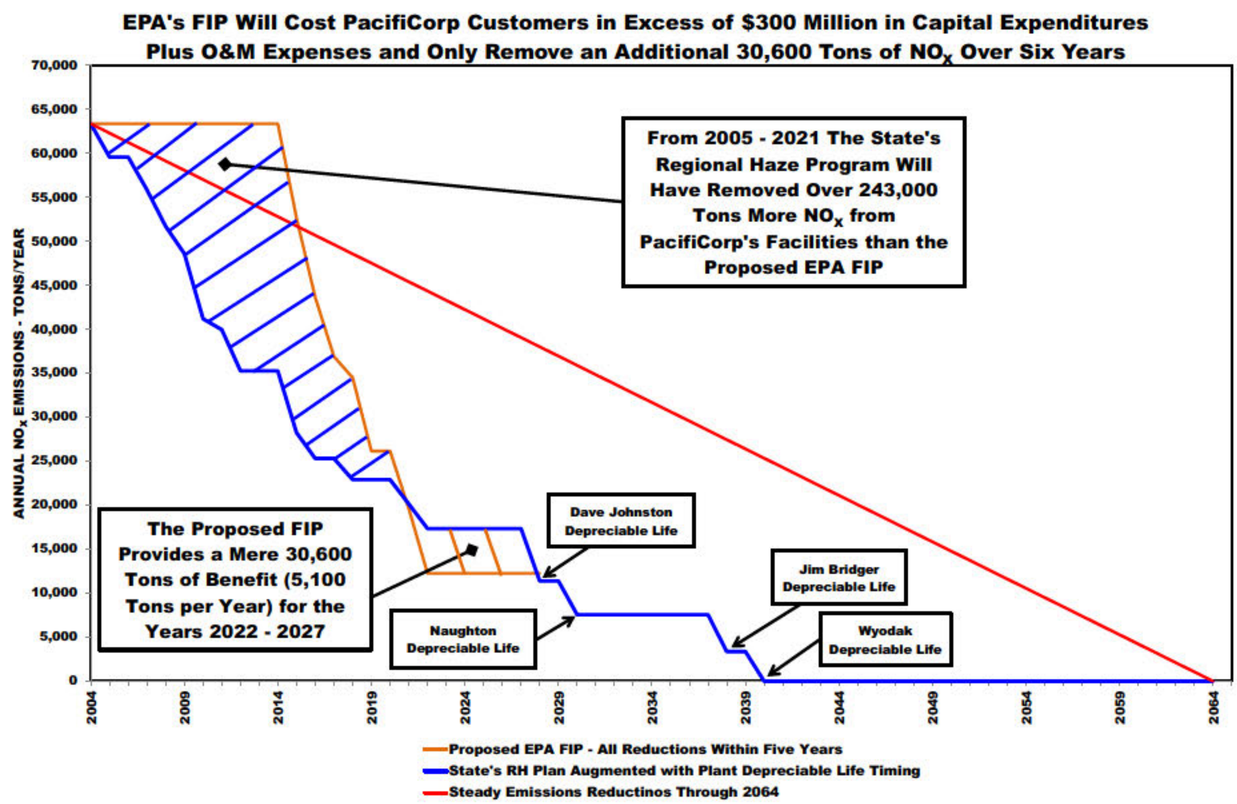
The eight SCR, two SNCR and low-NO_X burners required in EPA's proposed action must be considered in the context of the additional controls required at PacifiCorp's units in Arizona (Cholla Unit 4 with SCR required by 2017) and its share of units in Colorado (Hayden 1 with SCR in 2015, Hayden 2 with SCR in 2016, Craig Unit 1 with SNCR in 2017 and Craig Unit 2 with SCR required in 2016) and the potential for additional controls required at four of PacifiCorp's BART-eligible units in Utah within five years after final action. EPA's failure to consider the "unusual circumstances" contemplated under its Appendix Y Guidance when PacifiCorp ultimately has financial responsibility for achieving compliance with the Regional Haze requirements at 21 units, 16 of which may include the installation of SCR within a five to eight year period of time, is improper.

(10) <u>EPA's Untimely Review of the Wyoming RH SIP was to the Extreme Detriment of PacifiCorp and its Customers.</u>

Wyoming's regional haze program has been underway for several years. Under EPA's initial regional haze rules, BART controls were expected to be installed by the end of 2013. Wyoming appropriately and effectively developed and implemented a regional haze program that met the 2013 timeline. As required by the Wyoming RH SIP, and with the one exception of Naughton Unit 3 which has a deadline of 2014, PacifiCorp has fully implemented Wyoming's BART requirements for its Wyoming BART Units. As a result, in 2013 alone, there will be 76,000 fewer tons of visibility impairing pollutants emitted by PacifiCorp BART Units than was emitted in 2004.

Had Wyoming waited for EPA's final RH FIP, none of these reductions would have occurred to date. In other words, the Wyoming RH SIP required regional haze reductions to begin earlier and extend over a longer period of time than EPA's RH FIP Action.

The following chart provides a graphical representation of the emission reductions



achieved as a result of the Wyoming RH SIP at PacifiCorp's BART Units.

For purposes of this graphic, the emissions reductions used are those that EPA identified in its Regional Haze FIP Action for the various technologies applied to each BART Unit by either Wyoming or EPA.

The solid blue line on the chart represents the annual NO_X emission reductions from PacifiCorp's units associated with the Wyoming RH plan. As the chart demonstrates, significant NO_X emissions reductions occurred between 2004 and 2012 under the state's plan. Additional NO_X reductions will occur under the state's plan as Naughton Unit 3 complies with the RH requirements, SCR is installed on Jim Bridger Unit 1 (2022), Unit 2 (2021), Unit 3 (2015) and Unit 4 (2016), and low NO_X burners are installed on Dave Johnston Unit 1 and Unit 2 as a part of the state's long-term reduction plan.

The solid orange line on the chart represents the NO_X emission reductions that would occur if no action were taken until EPA takes final action on its proposed FIP[58] (effectively no NO_X reductions until 2014). The blue hash-marked area on the chart represents the beneficial NO_X emissions that occur under the state's program, and the orange hash-marked area represents the beneficial NO_X emissions that occur under the EPA's FIP.

It is striking to note that from 2005-2021 the state's RH program will have removed 243,000 tons more NO_X from PacifiCorp's Wyoming facilities than EPA's proposed FIP. In 2022, the EPA's FIP begins providing an annual benefit of 5,100 tons per year. Ironically this benefit only lasts for six years, when the units at which EPA's proposed FIP requires more stringent controls are retired.

By 2027, the Wyoming RH SIP will have removed over 210,000 more tons of NO_X from PacifiCorp's units than the EPA's proposed FIP, with a significantly lower cost (more than $300M less in capital) and will require significantly lower expenditures in operation and maintenance between 2022 and 2027. Notwithstanding these significant NO_X emission reductions achieved by the Wyoming RH SIP, implementation of the Wyoming RH SIP has also resulted in significant reductions of SO_2 and particulate matter emissions.

Importantly, the Wyoming RH SIP appropriately balances all five BART factors, examining the reasonableness and timing of controls, in conjunction with management of planned outages, resource availability and other consequences of requiring costly emission controls. As discussed in Section 6 above, unlike the Wyoming RH SIP, the EPA's RH FIP requires controls that are not expected to be justifiable when aggregated and would result in accelerated unit retirements and replacements, potential natural gas conversions, and the associated costs and socio-economic impacts of removing major

[58] This chart has been created assuming that the Naughton Unit 3, Jim Bridger Unit 3 and Jim Bridger Unit 4 SCR projects would occur on the same schedule as that proposed by the state. In fact, this would not be possible had not all the planning and approvals already been received as a requirement of Wyoming's SIP.

coal-fueled generation resources from service in areas of Wyoming that rely heavily on these facilities.

As discussed herein, to date, PacifiCorp's actions to install control equipment on its BART Units in Wyoming have been taken in compliance with the Wyoming RH SIP and BART permits, along with the CAA, which requires major sources to "procure, install, and operate (BART) as expeditiously as practicable." CAA § 169A(b)(2)(A). Moreover, EPA chose not to participate in the Wyoming BART permit process and the resulting appeals, despite knowing that the very NO_X control equipment at issue in the RH FIP Action was being determined by Wyoming. As an alternative to the points made above, and under the principles of comity, EPA should be barred from now addressing these issues at this late period. "Under a statutory scheme which gives initial authority to a state agency, subject to approval of its recommendations by a federal agency, considerations of comity require the reviewing agency to consider the findings of the initiating agency." *The Cleveland Electric Illuminating Co. v. Environmental Protection Agency*, 603 F.2d 1 (6th Cir. 1979)(finding EPA acted arbitrarily and capriciously in rejecting Ohio's issuance of NPDES permits and for ignoring factors relied on by the state in approving the permits); *see also Ass'n of Irritated Residents v. US EPA,* 632 F.3d 584 (9th Cir. 2011)(holding EPA has an "affirmative duty" to evaluate information, including an older, approved SIP and that the agency does not have "unlimited discretion" to ignore evidence).

Moreover, unlike other programs, the regional haze program requires regular updates and reviews to ensure that reasonable progress is being made towards the ultimate goal ending in 2064. (*See* Attachment 14, June 26, 2012 Regional Haze hearing testimony by Steve Dietrich, Wyoming's Air Quality Administrator.) In fact, Wyoming will be required to submit a progress report to EPA in 2013 and a RH SIP update in 2018. *Id.* Wyoming's initial RH SIP addressing BART-eligible units was intended to be fully implemented by 2013 and was delayed solely by EPA's inaction. EPA should approve the Wyoming RH SIP, and reserve most of its concerns expressed in its RH FIP Action for consideration in Wyoming's 2018 RH SIP submittals. In the meantime, EPA can be assured that the significant emission reductions required under the Wyoming RH SIP, nearly all of which already have been installed, will continue to contribute to visibility improvement.

(11) PacifiCorp's Response to EPA's Request for Control Technology Options.

PacifiCorp recognizes that EPA has specifically requested under its RH FIP Action comments regarding "BART control technology option(s) that could be finalized either instead of, or in conjunction with, BART as proposed". *Id.* Considering the controls already installed on PacifiCorp's BART Units, the only control technologies available for consideration is SNCR or SCR. In this section PacifiCorp has updated the costs and cost effectiveness calculations. Any FIP determinations should be based on the information provided in this section. The ΔdV and days of impairment > 0.5 dV are from the models included in EPA's proposed FIP Action and do not reflect updated modeling.

After its review, PacifiCorp believes that Wyoming's BART determinations are correct. Nonetheless, PacifiCorp suggests the following control technology options as the less costly alternate solution to the EPA's proposed RH FIP. While the options discussed in this section provide NO_X emissions reductions greater than those achieved under the Wyoming RH SIP, the costs are too high to justify the benefits that will be achieved, especially when considering the additional information that PacifiCorp has presented in these comments. However, there is a significant reduction in the cost of compliance for these proposed alternatives when compared against EPA's proposed RH FIP. As stated above, PacifiCorp continues to believe that the Wyoming RH SIP is fully supportable and has been reasonably and appropriately established with the best interests of Wyoming and PacifiCorp's customers in mind.

Note: To facilitate the alternatives discussed for each unit, the proposed emission rates and emission reductions are those that EPA identified and utilized in the development of its proposed RH FIP. The identified visibility improvements are based on EPA's modeling and modeling results.

<u>Control Technology for Naughton Units 1 and 2</u> - Naughton Unit 1 was retrofitted with low NO_X burners ("LNB") and separated over-fire air ("OFA") in early 2012, and Unit 2 was retrofitted with the same technology in late 2011. EPA recognizes that these units have a current annual NO_X emission rate of about 0.21 lb/MMBtu.

The potential additional NO_X controls that may be added to these units include SNCR and SCR. Tables 35 and 36 below provide additional information with respect to these specific control technologies for Naughton Units 1 and 2. The tables take into consideration the LNB/OFA controls that are required by the state SIP and already installed, as well as the updated information that PacifiCorp has provided in these comments.

The information presented in the tables further supports Wyoming's BART determination and RH SIP for Naughton Units 1 and 2; however, should an alternate control technology be prescribed by EPA for Naughton Units 1 and 2 in conjunction with EPA's RH FIP, SNCR is a preferable BART technology to SCR. Even though the cost of SNCR for each unit is unacceptably high (more than \$9,600 per ton NO_X removed), it is still far less than the cost of SCR (approximately \$14,000 for Unit 1, approximately \$12,000 for Unit 2), particularly when taking into account the incrementally small modeled visibility improvement between the technologies. (*See* Attachments 3 and 15)

Table 34

	Naughton Unit 1 Alternate BART Control Technology Assessment (excludes AFUDC)							
Controls	**Annual Emission Rate (lb/mmBtu)**	**Emission Reduction (tpy)**	**Capital Costs**	**Annualized Costs**	**Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**ΔdV for the max. 98th percentile improvement)**	**Annual Days of Impacts > 0.5 dV**
SNCR	0.16	363	$8,445,100	$3,516,265	$9,687	-----	0.15	9
SCR	0.05	1,108	$93,815,880	$15,659,686	$14,129	$16,293	0.39	4

Table 35

	Naughton Unit 2 Alternate BART Control Technology Assessment (excludes AFUDC)							
Controls	**Annual Emission Rate (lb/mmBtu)**	**Emission Reduction (tpy)**	**Capital Costs**	**Annualized Costs**	**Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**ΔdV for the max. 98th percentile improvement)**	**Annual Days of Impacts > 0.5 dV**
SNCR	0.16	438	$8,761,397	$4,305,484	$9,830	-----	0.18	13
SCR	0.05	1,336	$93,251,860	$15,910,351	$11,913	$12,929	0.44	8

Compliance Alternative for Naughton Unit 3 –Rather than install the control equipment required by the Wyoming RH SIP, PacifiCorp will convert the unit to fire natural gas by the end of 2017. A construction permit allowing the conversion has been issued by Wyoming (included as Attachment 16), and PacifiCorp is moving ahead with a request for Wyoming to modify the Wyoming RH SIP to accommodate this change. The construction permit issued by Wyoming requires Naughton Unit 3 to cease burning coal by December 31, 2017 and to be retrofitted to natural gas as its fuel source by June 30, 2018. PacifiCorp requests that EPA's final RH FIP include this compliance alternative for Naughton Unit 3.

Control Technology for Dave Johnston Units 3 and 4 –Dave Johnston Unit 3 was retrofitted with LNB and separated OFA in the spring of 2010, and Unit 4 was retrofitted with the same technology in early 2009. EPA recognizes that Unit 3 has a current annual NO_X emission rate of about 0.22 lb/MMBtu, and Unit 4 has a rate of about 0.14 lb/MMBtu.

The potential additional NO_X controls that may be added to these units include SNCR and SCR. Tables 37 and 38 below provide additional information with respect to these specific control technologies for Dave Johnston Units 3 and 4. The tables take into consideration the LNB/OFA controls that are required by the state SIP and already installed, as well as the updated information that PacifiCorp has provided in these comments.

The information presented in the Tables 37 and 38 further supports Wyoming's BART determination and RH SIP for Dave Johnston Units 3 and 4. However, should an alternate control technology be considered by EPA for Dave Johnston Unit 3 in conjunction with EPA's RH FIP, SNCR is preferable to SCR for Dave Johnston Unit 3 when considering all currently available information and the current emissions performance of the unit. Even though the cost of SNCR is unacceptably high for Unit 3 (approximately $5,500 per ton NO_X removed), it is still far less than the tremendously expensive cost of SCR ($15,769 per ton NO_X removed for Unit 3), particularly when taking into account the incrementally small modeled visibility improvement between the technologies.

With respect to Dave Johnston Unit 4, EPA has concluded that SNCR is BART for that unit. As such, PacifiCorp has only provided updated SNCR information for Unit 4, considering all currently available information and the current emissions performance of the unit. The cost of SNCR for Unit 4 is unacceptably high and not cost effective (approximately $12,000 per ton NO_X removed) as shown below. (*See also* Attachments 3 and 15). The alternate control technology for Dave Johnston Unit 4 would be LNB/OFA, as is currently installed today.

Table 36

	Dave Johnston Unit 3 Alternate BART Control Technology Assessment (excludes AFUDC)							
Controls	**Annual Emission Rate (lb/mmBtu)**	**Emission Reduction (tpy)**	**Capital Costs**	**Annualized Costs**	**Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**ΔdV for the max. 98th percentile improvement)**	**Annual Days of Impacts > 0.5 dV**
SNCR	0.16	519	$8,996,000	$2,880,289	$5,550	-----	0.12	8
SCR	0.05	1,596	$101,713,340	$19,495,711	$12,217	$15,431	0.36	1

Table 37

	Dave Johnston Unit 4 Alternate BART Control Technology Assessment (excludes AFUDC)							
Controls	**Annual Emission Rate (lb/mmBtu)**	**Emission Reduction (tpy)**	**Capital Costs**	**Annualized Costs**	**Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**ΔdV for the max. 98th percentile improvement)**	**Annual Days of Impacts > 0.5 dV**
SNCR	0.16	391	$8,726,000	$4,624,769	$11,828	-----	0.11	9

Alternate BART Control Technology for Jim Bridger Units 1 and 2 – As generally described in EPA's RH FIP Action, EPA is proposing that the time (i.e. compliance as prescribed by the Wyoming SIP by December 31, 2021, for Unit 2 and December 31, 2022, for Unit 1) to install SCR controls under the Wyoming's long term strategy for Jim Bridger Units 1 and 2 is warranted under the affordability provisions in the BART Appendix Y Guidelines. Considering that EPA's proposed RH FIP is generally aligned with the Wyoming SIP in this regard, PacifiCorp does not propose an alternative technology solution. As discussed earlier in PacifiCorp's comments, the affordability arguments that PacifiCorp made in its July 12, 2012 submittal referenced by EPA in its

RH FIP Action, as well as the additional information provided herein, remain applicable to this discussion and support the Wyoming RH SIP compliance timeline. This point becomes even more critical if EPA's final BART actions taken on the PacifiCorp units discussed above remains as currently proposed.

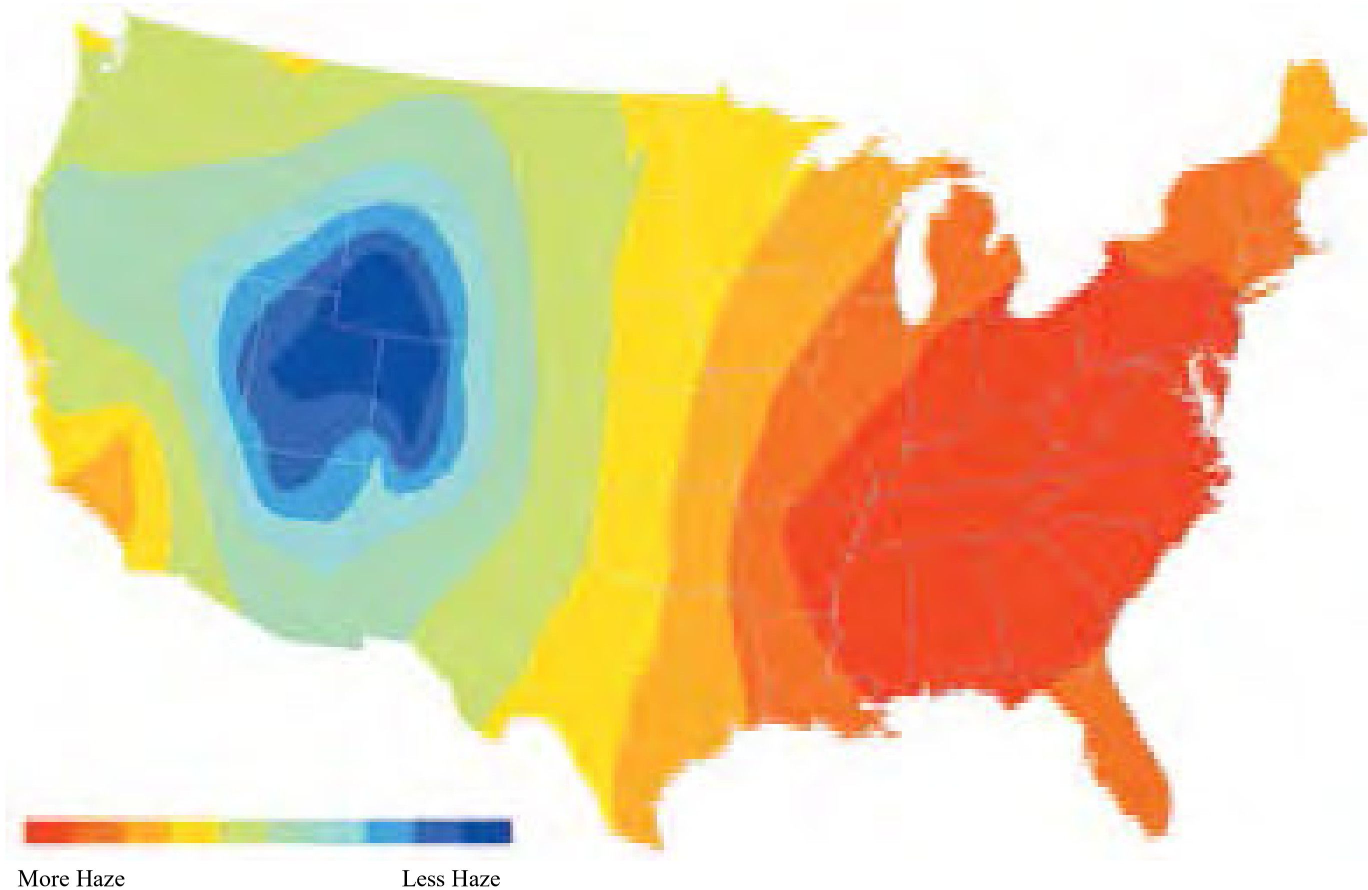
CONCLUSION

EPA's RH FIP Action distorts the Regional Haze program in an illegal attempt to attain some other goal, such as requiring post-combustion controls like SCR or SNCR on all western coal units, or attempting to assist with an unstated, undocumented and nebulous health concern. The Regional Haze program, however, is not a health-based program; rather, its sole focus is on aesthetics in Class 1 areas. 76 Fed. Reg. at 81,752 (noting that health issues are not considered "as part of the BART determination"). Additionally, the Regional Haze program's goal is to achieve "natural visibility" by 2064, 52 years from now. 40 C.F.R. § 51.308(d)(1)(i)(B).

Based on the foregoing, PacifiCorp encourages EPA to reconsider and withdraw its RH FIP and honor Wyoming's discretion under the CAA, Regional Haze Rules, Appendix Y, and Preamble by issuing a full approval of the Wyoming RH SIP.

Attachment 1

ATTACHMENT 1
EPA REGIONAL HAZE MAP



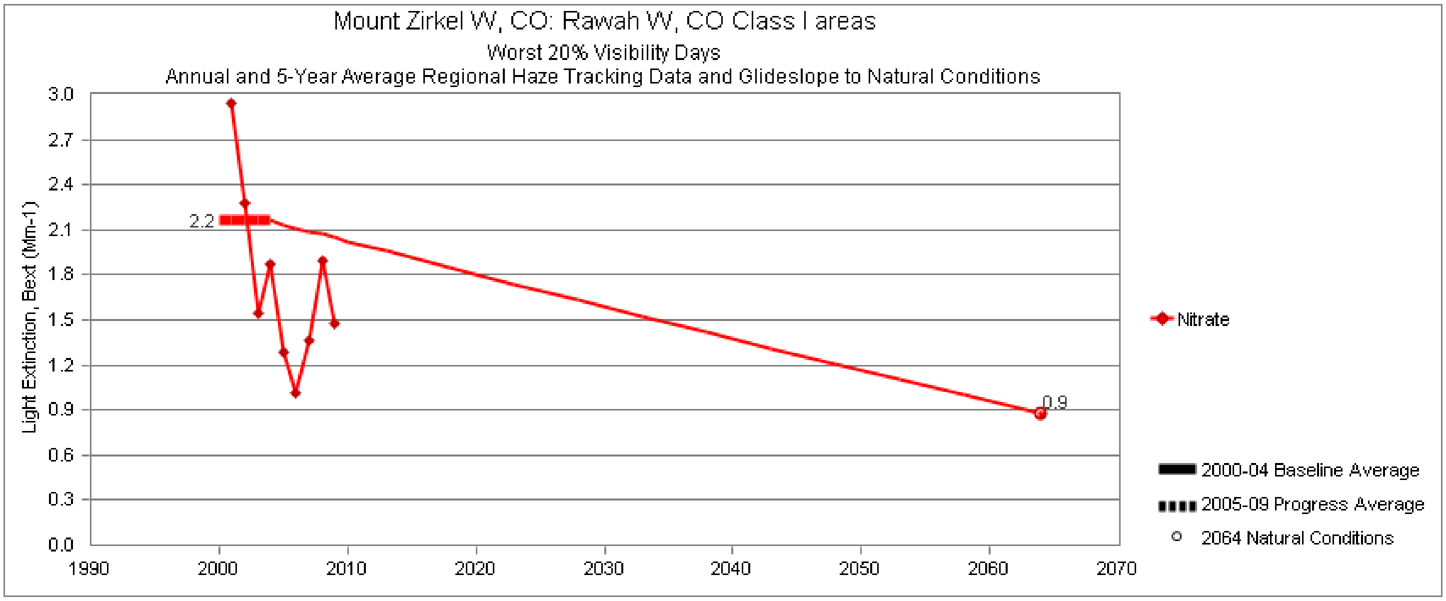
Haze conditions vary across the country. Eastern U.S. areas
Have more haze due to higher pollutant and humidity levels.

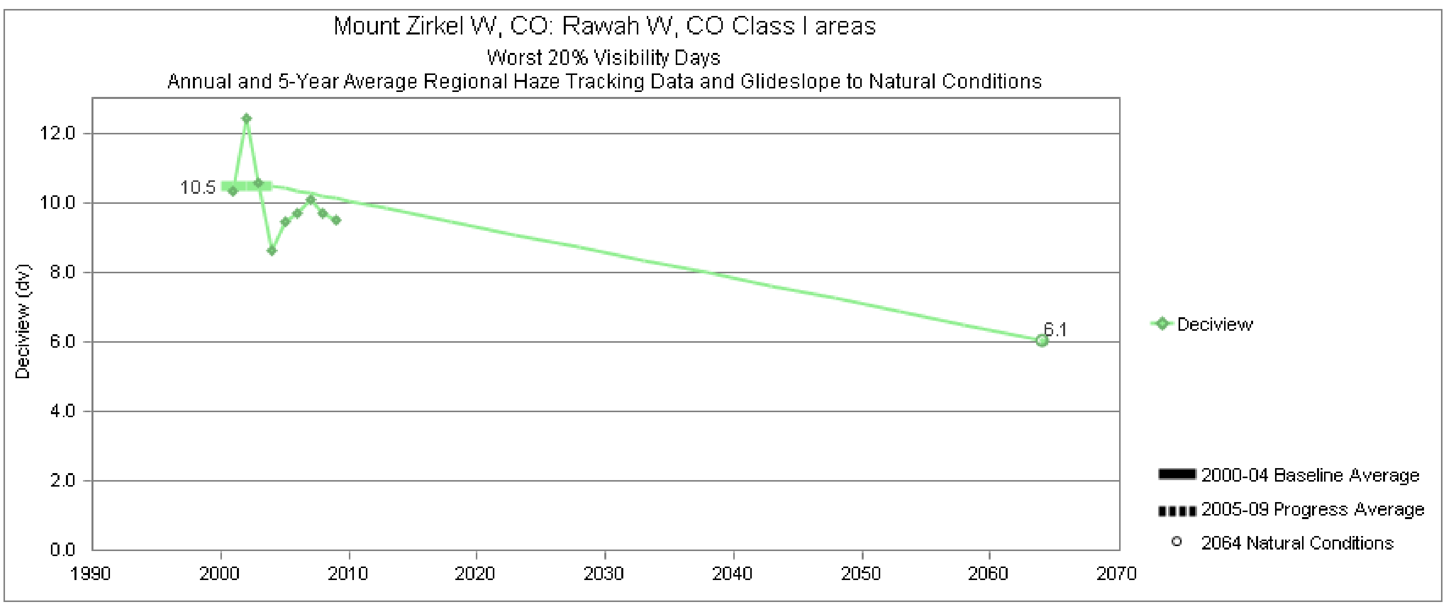
How Air Pollution Affects the View, http://www.epa.gov/oar/visibility/pdfs/haze_brocure_20060426.pdf

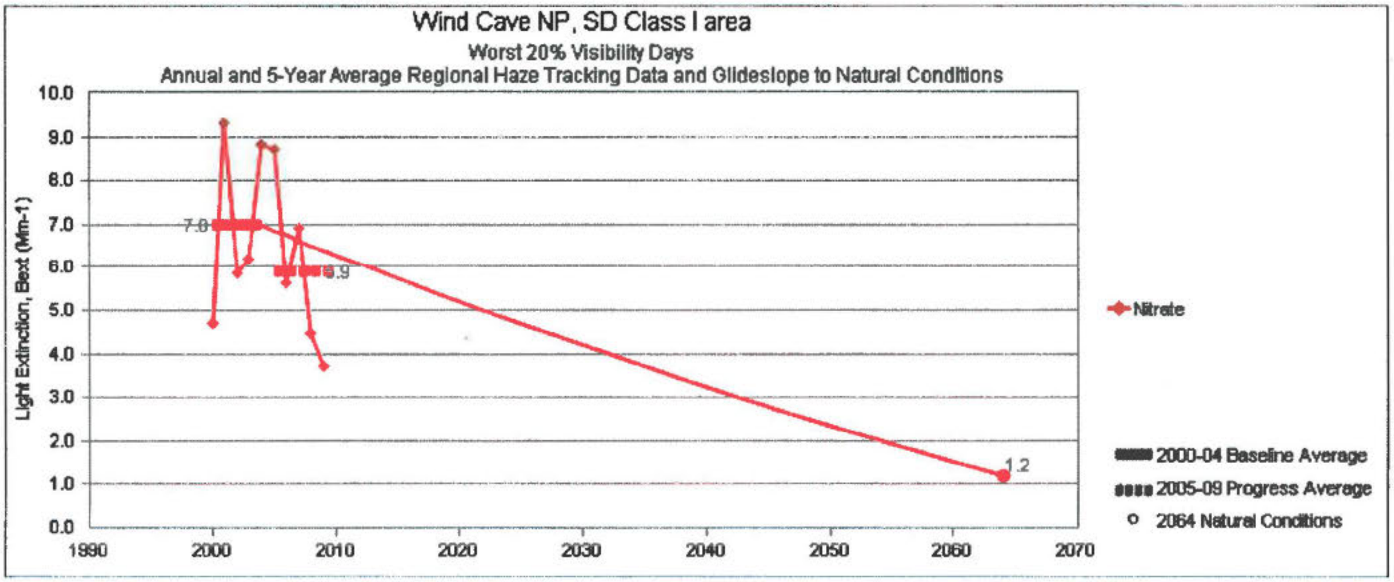
Attachment 2

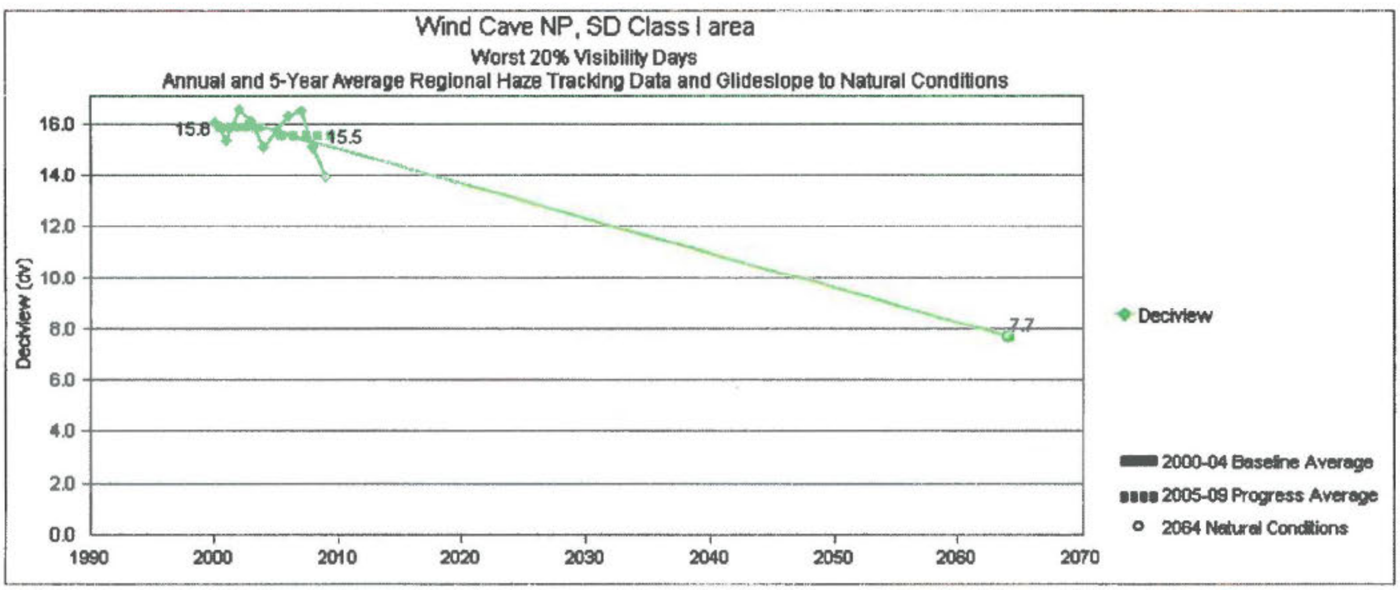
EXHIBIT 2
Monitored Visibility Impairment: Mt Zirkel & Wind Caves

Source of Data: http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx






Wind Cave NP, SD Class I area
Worst 20% Visibility Days
Annual and 5-Year Average Regional Haze Tracking Data and Glideslope to Natural Conditions
Light Extinction, Bext (Mm-1)
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1990
2000
2010
2020
2030
2040
2050
2060
2070
7.0
5.9
1.2
Nitrate
2000-04 Baseline Average
2005-09 Progress Average
2064 Natural Conditions


Wind Cave NP, SD Class I area
Worst 20% Visibility Days
Annual and 5-Year Average Regional Haze Tracking Data and Glideslope to Natural Conditions
Deciview (dv)
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
1990
2000
2010
2020
2030
2040
2050
2060
2070
15.8
15.5
7.7
Deciview
2000-04 Baseline Average
2005-09 Progress Average
2064 Natural Conditions

Attachment 3

Summary of Wyoming SIP Cost Effectiveness Calculations for PacifiCorp's Wyoming Units
(20-yr life / excluding AFUDC / WAQD emission rates)
PacifiCorp Comments

JIM BRIDGER 3														
	Unit Characteristics		Control Technology Emissions		Control Technology Capital and O&M Costs								Dollars per Ton Removed	
Control Technologies	Unit Capacity (Net MW)	Unit Capacity Factor (%)	Annual Emission Rate (lb/MMBtu)	Baseline Emission Reductions (tons/yr)	Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	530	90.0%	0.26											
LNB with advanced OFA & & SNCR	530	90.0%	0.20	1,265	$9,952,239	20	9.51%			$946,458	$535,837	$1,482,295	$1,172	
LNB with advanced OFA & SCR	530	90.0%	0.07	4,006	$153,000,000	20	9.51%			$14,550,300	$3,370,460	$17,920,760	$4,474	
Incremental Costs	530	90.0%	0.13	2,741	$143,047,761	20	9.51%	$0.00	$0.00	$13,603,842	$2,834,623	$16,438,465		$5,998

JIM BRIDGER 4														
	Unit Characteristics		Control Technology Emissions		Control Technology Capital and O&M Costs								Dollars per Ton Removed	
Control Technologies	Unit Capacity (Net MW)	Unit Capacity Factor (%)	Annual Emission Rate (lb/MMBtu)	Baseline Emission Reductions (tons/yr)	Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	530	90.0%	0.26											
LNB with advanced OFA & & SNCR	530	90.0%	0.20	1,231	$9,952,239	20	9.51%			$946,458	$535,837	$1,482,295	$1,204	
LNB with advanced OFA & SCR	530	90.0%	0.07	3,898	$153,000,000	20	9.51%			$14,550,300	$3,370,460	$17,920,760	$4,597	
Incremental Costs	530	90.0%	0.13	2,667	$143,047,761	20	9.51%	$0.00	$0.00	$13,603,842	$2,834,623	$16,438,465		$6,163

Summary of PacifiCorp's 2013 Cost Effectiveness Calculations for PacifiCorp's Wyoming Units
(remaining life / excluding AFUDC / EPA emission rates)
PacifiCorp Comments

DAVE JOHNSTON 3

	Unit Characteristics		Control Technology Emissions		Control Technology Capital and O&M Costs								Dollars per Ton Removed	
Control Technologies	Unit Capacity (Net MW)	Unit Capacity Factor (%)	Annual Emission Rate (lb/MMBtu)	Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA (Baseline)	220	89.8%	0.22											
LNB with advanced OFA & & SNCR	220	89.8%	0.16	519	$8,996,000	9	16.55%	$1.48	$0.62	$1,488,838	$1,391,451	$2,880,289	$5,550	
LNB with advanced OFA & SCR	220	89.8%	0.05	1,596	$101,713,340	9						$19,495,711	$12,217	
Incremental Costs - SNCR to SCR	220	89.8%	0.11	1,077	$92,717,340	9						$16,615,422		$15,431

DAVE JOHNSTON 4

	Unit Characteristics		Control Technology Emissions		Control Technology Capital and O&M Costs								Dollars per Ton Removed	
Control Technologies	Unit Capacity (Net MW)	Unit Capacity Factor (%)	Annual Emission Rate (lb/MMBtu)	Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	330	87.4%	0.14											
LNB with advanced OFA & & SNCR	330	87.4%	0.11	391	$8,726,000	9	16.55%	$1.02	$1.13	$1,444,153	$3,180,616	$4,624,769	$11,828	

JIM BRIDGER 3

	Unit Characteristics		Control Technology Emissions		Control Technology Capital and O&M Costs								Dollars per Ton Removed	
Control Technologies	Unit Capacity (Net MW)	Unit Capacity Factor (%)	Annual Emission Rate (lb/MMBtu)	Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	530	87.2%	0.20											
LNB with advanced OFA & & SNCR	530	87.2%	0.16	829		20	10.64%			$0	$0	$0	$0	
LNB with advanced OFA & SCR	530	87.2%	0.05	3,089	$176,129,704	20	10.64%	$0.58	$0.59	$18,740,201	$2,654,500	$21,394,701	$6,926	
Incremental Costs - SNCR to SCR	530	87.2%	0.11	2,260	$176,129,704	20	10.64%	$0.58	$0.59	$18,740,201	$2,694,138	$21,434,339		$9,485

JIM BRIDGER 4

	Unit Characteristics		Control Technology Emissions		Control Technology Capital and O&M Costs								Dollars per Ton Removed	
Control Technologies	Unit Capacity (Net MW)	Unit Capacity Factor (%)	Annual Emission Rate (lb/MMBtu)	Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	530	84.4%	0.19											
LNB with advanced OFA & & SNCR	530	84.4%	0.15	795		20	10.64%			$0	$0	$0	$0	
LNB with advanced OFA & SCR	530	84.4%	0.05	2,946	$186,663,655	20	10.64%	$0.60	$0.61	$19,861,013	$2,654,500	$22,515,513	$7,642	
Incremental Costs - SNCR to SCR	530	84.4%	0.10	2,151	$186,663,655	20	10.64%	$0.60	$0.61	$19,861,013	$2,704,343	$22,565,356		$10,490

NAUGHTON 1

	Unit Characteristics		Control Technology Emissions		Control Technology Capital and O&M Costs								Dollars per Ton Removed	
Control Technologies	Unit Capacity (Net MW)	Unit Capacity Factor (%)	Annual Emission Rate (lb/MMBtu)	Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	160	90.7%	0.21											
LNB with advanced OFA & & SNCR	160	90.7%	0.16	363	$8,445,100	11	14.54%	$2.02	$1.55	$1,227,918	$2,288,348	$3,516,265	$9,687	
LNB with advanced OFA & SCR	160	90.7%	0.05	1,108	$93,815,880	11						$15,659,686	$14,129	
Incremental Costs - SNCR to SCR	160	90.7%	0.11	745	$85,370,780	11						$12,143,421		$16,293

NAUGHTON 2

	Unit Characteristics		Control Technology Emissions		Control Technology Capital and O&M Costs								Dollars per Ton Removed	
Control Technologies	Unit Capacity (Net MW)	Unit Capacity Factor (%)	Annual Emission Rate (lb/MMBtu)	Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	210	84.4%	0.21											
LNB with advanced OFA & & SNCR	210	84.4%	0.16	438	$8,761,397	11	14.54%	$1.66	$1.73	$1,273,907	$3,031,577	$4,305,484	$9,830	
LNB with advanced OFA & SCR	210	84.4%	0.05	1,336	$93,251,860	11						$15,910,351	$11,913	
Incremental Costs - SNCR to SCR	210	84.4%	0.11	898	$84,490,463	11						$11,604,867		$12,929

Attachment 4

Dave Johnston Unit 3

Row	B: NAME OF VARIABLE	C: VARIABLE	D: UNITS	E: EQUATION NUMBER	F: EQUATION	G: EXAMPLE PROBLEM VERBATIM	I: S&L CORRECTED EPA EXAMPLE	J: Comment
2								
3								
4	Fuel High Heating Value	HHV	Btu/lb	-		10,000	10,000	
5	Maximum Fuel Consumption Rate	$\dot{m}_{fuel}$	lb/hr	-	$\dot{m}_{fuel} = \frac{Q_B}{HHV}\times 10^{-6}$	100,000	100,000	
7	Max Generating Capacity		MW		$m_{fuel} = \frac{AnnualHeat\ \ Input}{HHV}\times 10^{6}$			
10	Average Number of Plant Operating Hours per Year		hr					
11	Number of SCR Operating Days	t(scr)	days	-		155	155	
12	Plant Capacity Factor	CF_{plant}		-		50%	50%	
13	Uncontrolled NOx Concentration	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86	
14	NOx Concentration used for Reagent Consumption	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86	
15	Required Controlled NOx Concentration	NOx_{out}	lbNO2/MMBtu	-		0.13	0.13	
16	Acceptable Ammonia Slip	Slip	ppm	-		2.00	2.00	
17	Coal Type			-		Eastern Bituminous	Eastern Bituminous	
18	Fuel Volumetric Flow Rate	q_{fuel}	ft³/min-MMBtu/hr	-		484.00	484.00	
19	Fuel Heating Value		Btu/lb	-		12696.00	12696.00	
20	Sulfur Content of Fuel	S	wt%	-		1.0	1.0	
21	Fuel Ash Content	A	wt%	-		7.7%	7.7%	
22	Actual Stoichiometric Ratio	ASR		-		1.05	1.05	
23	Concentration of Reagent	C_{sol}	%	-		29%	29%	
24	Days of Storage of Reagent	t	days	-		14.00	14.00	
25	Pressure Drop for SCR Ductwork	ΔP_{duct}	in. w.g.	-		3.00	3.00	
26	Pressure Drop for each Catalyst Layer	$\Delta P_{catalyst}$	in. w.g.	-		1.00	1.00	
27	Number of SCR Reactors	N(scr)				1.00	1.00	
28	Temperature at Reactor Inlet	T	°F	-		650.00	650.00	
29								
30	Cost Year			-		Dec-98	Dec-98	
31	Equipment Life	n	yr	-		20.00	20.00	
32	Annual Interest Rate	i		-		7%	7%	
33	Chemical Engineering Plant Cost Index Value 1998							
34	Chemical Engineering Plant Cost Index Value 2011							
35	Catalyst Cost, Initial	$CC_{initial}$	$/ft³	-		$240.00	$240.00	
36	Catalyst Cost, Replacement	$CC_{replace}$	$/ft³	-	$CC_{replace} = CC_{initial}(1.065)^{3}$	$290.00	$290.00	
37	Electrical Power Cost	$Cost_{elect}$	$/kWh	-		0.05	0.05	
38	Reagent Cost	$Cost_{reagent}$	$/lb	-	irc	0.101	0.101	
39	Operating Life of Catalyst	$h_{catalyst}$	hr	-		24,000	24,000	
40	Catalyst Layers Full	n_{full}	#	-		2	2	
41	Catalyst Layers Empty	n_{empty}	#	-		1	1	
42	Cost of Water		$/1000-gal					
43								

Row	B: NAME OF VARIABLE	K: DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	L: Comment	M: DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH UREA	N: Comment	O: DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	P: Comment
4	Fuel High Heating Value	10,000	Based on assumed typical DJ coal	10,000		10,000	
5	Maximum Fuel Consumption Rate	257,100	Calculated from maximum heat input and fuel high heating value	257,100		257,100	
7	Max Generating Capacity	230	Provided by PC	230		230	
10	Average Number of Plant Operating Hours per Year	7884	Estimated to achieve 90% capacity factor in Row 12	7884		7884	
11	Number of SCR Operating Days	365	SCR operated year round	365		365	
12	Plant Capacity Factor	90%	Operating hours divided by 8760	-		-	
13	Uncontrolled NOx Concentration	0.27		0.27		0.27	
14	NOx Concentration used for Reagent Consumption	0.27		0.27		0.27	
15	Required Controlled NOx Concentration	0.07		0.07		0.07	
16	Acceptable Ammonia Slip	2.00		2.00		2.00	
17	Coal Type	Bituminous		Bituminous		Bituminous	
18	Fuel Volumetric Flow Rate	484.00		484.00		484.00	
19	Fuel Heating Value	-		-		-	
20	Sulfur Content of Fuel	1.2		1.2		1.2	
21	Fuel Ash Content	-		-		-	
22	Actual Stoichiometric Ratio	1.05		1.05		1.05	
23	Concentration of Reagent	29%		50%	To account for a U2A system	50%	
24	Days of Storage of Reagent	14.00		14.00		14.00	
25	Pressure Drop for SCR Ductwork	3.00		3.00		4.00	More Typical for SCR systems
26	Pressure Drop for each Catalyst Layer	1.00		1.00		1.00	
27	Number of SCR Reactors	1.00		1.00		1.00	
28	Temperature at Reactor Inlet	665.00		665.00		665.00	
30	Cost Year	Dec-98		Dec-98		Dec-98	
31	Equipment Life	20.00		20.00		20.00	Year the Cost is Incurred
32	Annual Interest Rate	7%		7%		7%	
33	Chemical Engineering Plant Cost Index Value 1998					389.50	Chemical Engineering Magazine Plant Cost Index value from 1998
34	Chemical Engineering Plant Cost Index Value 2011					600.60	Chemical Engineering Magazine Plant Cost Index value from 2011
35	Catalyst Cost, Initial	$240.00		$240.00		$240.00	
36	Catalyst Cost, Replacement	$290.00		$290.00		$290.00	
37	Electrical Power Cost	0.05		0.05		0.05	
38	Reagent Cost	0.101		0.200	Cost of Reagent adjusted to pricing for $/lb of Dry Urea Based on PC target of 4-year operation cycle	0.200	
39	Operating Life of Catalyst	24,000		32,000		32,000	
40	Catalyst Layers Full	3		3		3	
41	Catalyst Layers Empty	1	Empty layer for addition of extra catalyst layer in future to boost performance	1		1	
42	Cost of Water			5	Price of water per 1000 gallons	5	

Row	B: NAME OF VARIABLE	Q: DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	R: Comment	S: DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	T: Comment
7	Max Generating Capacity	220	As reported in Andover Report attachment.	220	
10	Average Number of Plant Operating Hours per Year			7884	
11	Number of SCR Operating Days			365	
12	Plant Capacity Factor	89.8%	As reported in Andover Report attachment.	-	
13	Uncontrolled NOx Concentration	0.22	As reported in Andover Report attachment.	0.22	Aligned with Andover Report assumption for cost-effectiveness comparison.
14	NOx Concentration used for Reagent Consumption	0.22	As reported in Andover Report attachment.	0.22	Aligned with Andover Report assumption for reagent cost comparison.
15	Required Controlled NOx Concentration	0.05	Based on 76.9% Removal used in Andover Report attachment.	0.05	Aligned with Andover Report assumption for comparison purposes.
16	Acceptable Ammonia Slip			2.00	
17	Coal Type	PRB	As reported in Andover Report attachment.	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4
18	Fuel Volumetric Flow Rate				Not used, Vendor performed combustion calculation to arrive at volume
19	Fuel Heating Value			-	
20	Sulfur Content of Fuel			1.2	
21	Fuel Ash Content			-	
22	Actual Stoichiometric Ratio			1.05	
23	Concentration of Reagent	50%	As reported in Andover Report attachment.	100%	
24	Days of Storage of Reagent			14.00	
25	Pressure Drop for SCR Ductwork			4.00	
26	Pressure Drop for each Catalyst Layer			1.00	
27	Number of SCR Reactors			1.00	
28	Temperature at Reactor Inlet			763.00	
31	Equipment Life			20.00	
32	Annual Interest Rate			7%	
35	Catalyst Cost, Initial				Included in Vendor Budgetary Pricing
36	Catalyst Cost, Replacement	$155.74	Based on 5500 per m3 used in Andover Report attachment.	$290.00	
37	Electrical Power Cost	0.06	As reported in Andover Report attachment.	0.03	Price Provided by PC
38	Reagent Cost	0.225	Based on 450 per tonused in Andover Report attachment.	0.375	Price Provided by PC from DASCO quote July 2012
39	Operating Life of Catalyst			32,000	
40	Catalyst Layers Full			3	
41	Catalyst Layers Empty			1	
42	Cost of Water			5	

Row	B: NAME OF VARIABLE	U: DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	V: Comment	W: DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (9-yr life / excluding AFUDC)	X: Comment	Y: DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (9-yr life / excluding AFUDC)	Z: Comment
7	Max Generating Capacity	220		220	As reported in Andover Report attachment.	220	
10	Average Number of Plant Operating Hours per Year	7884				7884	
11	Number of SCR Operating Days	365				365	
12	Plant Capacity Factor	-		89.8%	As reported in Andover Report attachment.	-	
13	Uncontrolled NOx Concentration	0.22	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.22	As reported in Andover Report attachment.	0.22	Aligned with Andover Report assumption for cost-effectiveness comparison.
14	NOx Concentration used for Reagent Consumption	0.22	Aligned with Andover Report assumption for reagent cost comparison.	0.22	As reported in Andover Report attachment.	0.22	Aligned with Andover Report assumption for reagent cost comparison.
15	Required Controlled NOx Concentration	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Based on 76.9% Removal used in Andover Report attachment.	0.05	Aligned with Andover Report assumption for comparison purposes.
16	Acceptable Ammonia Slip	2.00				2.00	
17	Coal Type	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	PRB	As reported in Andover Report attachment.	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4
18	Fuel Volumetric Flow Rate		Not used, Vendor performed combustion calculation to arrive at volume				Not used, Vendor performed combustion calculation to arrive at volume
19	Fuel Heating Value	-				-	
20	Sulfur Content of Fuel	1.2				1.2	
21	Fuel Ash Content	-				-	
22	Actual Stoichiometric Ratio	1.05				1.05	
23	Concentration of Reagent	100%		50%	As reported in Andover Report attachment.	100%	
24	Days of Storage of Reagent	14.00				14.00	
25	Pressure Drop for SCR Ductwork	4.00				4.00	
26	Pressure Drop for each Catalyst Layer	1.00				1.00	
27	Number of SCR Reactors	1.00				1.00	
28	Temperature at Reactor Inlet	763.00				763.00	
31	Equipment Life	20.00		9.00		9.00	
32	Annual Interest Rate	7%				7%	
35	Catalyst Cost, Initial		Included in Vendor Budgetary Pricing				Included in Vendor Budgetary Pricing
36	Catalyst Cost, Replacement	$290.00		$155.74	Based on 5500 per m3 used in Andover Report attachment.	$290.00	
37	Electrical Power Cost	0.03	Price Provided by PC	0.06	As reported in Andover Report attachment.	0.03	Price Provided by PC
38	Reagent Cost	0.375	Price Provided by PC from DASCO quote July 2012	0.225	Based on 450 per tonused in Andover Report attachment.	0.375	Price Provided by PC from DASCO quote July 2012
39	Operating Life of Catalyst	32,000				32,000	
40	Catalyst Layers Full	3				3	
41	Catalyst Layers Empty	1				1	
42	Cost of Water	5				5	

	B	C	D	E	F	G	I	J	K	L	M	N	O
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA
44													
47	Max Heat Input Rate	Q_B	MMBtu/hr	2.3	$Q_B = \frac{HV \times \dot{m}_{fuel}}{10^6}$	1,000	1,000		2,571	Provided by PC	2,571		2,571
48	Plant Capacity Factor	CF_{plant}		2.7	$CF_{Plant} = \frac{actual\ m_{fuel}}{\dot{m}_{fuel} \times 8760}$	50%	50%		90%	90% from Permit Calculation	90%		90%
49	SCR Capacity Factor	CF_{SCR}		2.8	$CF_{SCR} = \frac{t_{SCR}}{365\ days}$	42%	42%		100%		100%		100%
50	Total Capacity Factor	CF_{total}		2.6	$CF_{total} = CF_{plant}\ CF_{SCR}$	27%	21%	Fixed EPA calculation error	90%		90%		90%
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor	$q_{fluegas}$	acfm	2.12	$q_{fluegas} = \frac{q_{fuel}\ Q_B\ (460+T)}{(460+700^\circ F)\ n_{SCR}}$	463,138	463,138		1,206,819		1,206,819		1,206,819
52	NOx Removal Efficient for Cost-Effectiveness					0.85	0.85		0.74		0.74		0.74
53	NOx Removal Efficiency for Reagent Consumption	η_{NOx}		2.9	$\eta_{NO_x} = \frac{NO_{x_{in}} - NO_{x_{out}}}{NO_{x_{in}}}$	0.85	0.85		0.74		0.74		0.74
54													
55	Catalyst Volume/Reactor	$Vol_{catalyst}$	ft³	2.19	$Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NO_{x_{adj}} \times S_{adj} \times \frac{T_{adj}}{N_{SCR}}$	5089	5089		9470		9470		9470
56	where:	-	-	-									
57	NOx Efficiency Adjustment	η_{adj}		2.20	$\eta_{adj} = 0.2869 + (1.058 \times \eta)$	1.19	1.19		1.07		1.07		1.07
58	NOx Adjustment Factor for Inlet NOx	NOx_{adj}		2.21	$NO_{x_{adj}} = 0.8524 + (0.3208 \times NO_{x_{in}})$	1.13	1.13		0.94		0.94		0.94
59	Ammonia Slip Adjustment Factor	$Slip_{adj}$		2.22	$Slip_{adj} = 1.2835 - (0.0567 \times Slip)$	1.17	1.17		1.17		1.17		1.17
60	Sulfur in Coal Adjustment Factor	S_{adj}		2.23	$S_{adj} = 0.9636 + (0.0455 \times S)$	1.01	1.01		1.02		1.02		1.02
61 62	Temperature Adjustment Factor (for temps other than 700°F)	T_{adj}	ºF	2.24	$T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$	1.15	1.15		1.10		1.10		1.10
63	Catalyst Cross-Sectional Area	$A_{catalyst}$	ft²	2.25	$A_{catalyst} = \frac{q_{fluegas}}{16\left(\frac{ft}{sec}\right) \times \left(\frac{60\ sec}{min}\right)}$	482	482		1257		1257		1257
64	SCR Reactor Cross-Sectional Area	A_{SCR}	ft²	2.26	$A_{SCR} = 1.15 \times A_{catalyst}$	554	554		1446		1446		1446
65	length	l	ft	2.27	$l = w = (A_{SCR})^{1/2}$	23.50	23.50		38		38		38
66	width	w											
67	Estimate Number of Catalyst Layers	n_{layer}		2.28	$n_{layer} = \frac{Vol_{catalyst}}{3.1 \times A_{catalyst}}$	3	3	Estimated number of layers is less than input. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too low. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3
68	Height of Catalyst Layer	h_{layer}	ft	2.29		4.50	4.50		3.50		3.50		3.50
69	Total Number of Catalyst Layers	n_{total}	#	2.30	$n_{total} = n_{layer} + n_{empty}$	4	4		4		4		4
70	Height of SCR Reactor	h_{SCR}	ft	2.31	$h_{SCR} = n_{total}(c_1 + h_{layer}) + c_2$	55	55		51		51		51

	B	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (9-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (9-yr life / excluding AFUDC)	Comment
44												
47	Max Heat Input Rate		2,440	As reported in Andover Report attachment.	2,571		2,571		2,440	As reported in Andover Report attachment.	2,571	
48	Plant Capacity Factor		89.8%	As reported in Andover Report attachment.	90%		90%		89.8%	As reported in Andover Report attachment.	90%	
49	SCR Capacity Factor				100%		100%				100%	
50	Total Capacity Factor				90%		90%				90%	
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor				1,842,000	Per Vendor's Combustion Calculation	1,842,000	Per Vendor's Combustion Calculation			1,842,000	Per Vendor's Combustion Calculation
52	NOx Removal Efficient for Cost-Effectiveness				0.77		0.77				0.77	
53	NOx Removal Efficiency for Reagent Consumption				0.77		0.77				0.77	
54												
55	Catalyst Volume/Reactor		Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	25745	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.	25745	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.	Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	25745	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.
56	where:											
57	NOx Efficiency Adjustment					Catalyst Cost in vendor estimate, this is not used.		Catalyst Cost in vendor estimate, this is not used.				Catalyst Cost in vendor estimate, this is not used.
58	NOx Adjustment Factor for Inlet NOx					(see above)		(see above)				(see above)
59	Ammonia Slip Adjustment Factor					(see above)		(see above)				(see above)
60	Sulfur in Coal Adjustment Factor					(see above)		(see above)				(see above)
61 62	Temperature Adjustment Factor (for temps other than 700°F)					(see above)		(see above)				(see above)
63	Catalyst Cross-Sectional Area					(see above)		(see above)				(see above)
64	SCR Reactor Cross-Sectional Area					(see above)		(see above)				(see above)
65	length					(see above)		(see above)				(see above)
66	width											
67	Estimate Number of Catalyst Layers	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)				Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
68	Height of Catalyst Layer					Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
69	Total Number of Catalyst Layers				4		4				4	
70	Height of SCR Reactor					Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.

Exhibit PAC/4002
Owen/87

	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (9-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (9-yr life / excluding AFUDC)	Comment
71																								
72	Ammonia Mass Flow Rate	$m_{reagent}$	lb/hr of NH_3	2.32	$\dot{m}_{reagent} = \frac{NO_{x_{in}}\ Q_B\ NSR\ \eta_{NO_x}\ M_{reagent}}{M_{NO_2}\ SR_T}$ $\dot{m}_{reagent} = \frac{NOx_{in} \times Q_B \times ASR \times 17.03}{46.01}$	34	284	in the example problem (2.5 Example Problem), EPA does not use NOx efficiency in their calculation, yet the equation (2.32) on pg 2-39 requires it	200		200		200		159	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	170		170		159	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	170	
73	Mass Flow Rate of Aqueous Reagent Solution	$m_{solution}$	lb/hr of NH3 solution	2.33	$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}}$	1,153	980		689			Not used as urea is the reagent					170		170				170	
74	Equivalent Dry Urea Consumption Rate		lb/hr		$m_{urea} = \frac{m_{sol}}{0.56}$						357	S&L added formulas and calculations to include U2A system. Value calculated for reagent costing	357		284						284			
75	Mass Flow Rate of Urea Solution	$m_{solution}$	lb/hr of NH3 solution	2.33	$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}}$						714		714		568		0		0		568		0	
76	Solution Volumetric Flow	q_{sol}	gph	2.34	$q_{sol} = \frac{\dot{m}_{sol} \times 7.481}{71.1}$	154.00	131.00		92.00		75.00	Volumetric flow rate of 50% urea solution with a density of 71.1 lb/ft3	75.00		60		23.00		23.00		60		23.00	
77	Storage Tank Volume	V_{tank}	gal	2.35	$Tank\ Volume = q_{sol}\ t$	51,744	44,016		30,912		25,200		25,200			Tank volume included in Andover estimate unknown.	7,728		7,728			Tank volume included in Andover estimate unknown.	7,728	
78																								
80	Direct Capital Cost	DC	$	2.36		$6,832,000	$6,799,443		$12,265,691		$12,265,691		$20,768,412	Since no adjustment factor exists for urea systems, S&L added the estimated capital cost for the urea system by scaling the Huntington estimate.	$51,756,152	As reported in Andover Report attachment.	$72,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)	$72,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)	$51,756,152	As reported in Andover Report attachment.	$72,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)
81	Adjustment for the SCR Reactor Height	$f(h_{SCR})$	$/MMBtu/hr	2.37	$DC = Q_B\left[\frac{\$3{,}380}{\left(\frac{MMBtu}{hr}\right)} + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass)\right]\left(\frac{3500}{Q_B}\right)^{0.35} + f(Vol_{catalyst})$	49.00	$149.00		$124.00		$124.00		$124.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
82	Adjustment for the Ammonia Flow Rate	$f(NH_{3rate})$	$/MMBtu/hr	2.38	$f(NH_3rate) = \left[\frac{\$411}{lb/hr}\ \frac{\dot{m}_{reagent}}{Q_B}\right] - \frac{\$47.3}{\left(\frac{MMBtu}{hr}\right)}$	$90.00	$69.00		-$15.00		-$15.00		-$15.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
83	Adjustment for Retrofit or New Boiler	f(new)	$/MMBtu/hr	2.39 + 2.40	Is it a retrofit or new boiler?	$0.00	$0.00		$0.00		$0.00		$0.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
84	Adjustment for SCR Bypass	f(bypass)	$/MMBtu/hr	2.41 + 2.42	Is a bypass installed?	$0.00	$0.00		$0.00		$0.00		$0.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
85	Capital Cost for the Initial Charge of Catalyst	$f(Vol_{catalyst})$	$/MMBtu/hr	2.43	$f(Vol_{catalyst}) = Vol_{catalyst}\ CC_{initial}$	$1,221,360	$1,221,360		$2,272,800		$2,272,800		$2,272,800			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
86	Indirect Installation Costs Due to General Facilities		$	Table 2.5	0.05xDC	$341,600	$339,972		$613,285		$613,285		$1,038,421			Unknown because EPA cost manual not used	$3,605,000		$3,605,000			Unknown because EPA cost manual not used	$3,605,000	
87	Indirect Installation Costs Due to Engineering and Home Office Fees		$	Table 2.6	0.10xDC	$683,200	$679,944		$1,226,569		$1,226,569		$2,076,841			Unknown because EPA cost manual not used	$7,210,000		$7,210,000			Unknown because EPA cost manual not used	$7,210,000	
88	Indirect Installation Costs Due to Process Contingency		$	Table 2.7	0.05xDC	$341,600	$339,972		$613,285		$613,285		$1,038,421			Unknown because EPA cost manual not used	$3,605,000		$3,605,000			Unknown because EPA cost manual not used	$3,605,000	
89	Total Indirect Installation Costs	IIC	$	Table 2.8	DCx(0.05+0.10+0.05)	$1,366,400	$1,359,889		$2,453,138		$2,453,138		$4,153,682		$15,526,846	As reported in Andover Report attachment.	$14,420,000		$14,420,000		$15,526,846	As reported in Andover Report attachment.	$14,420,000	
90	Project Contingency		$	Table 2.9	(DC+IIC)x0.15	$1,229,760	$1,223,900		$2,207,824		$2,207,824		$3,738,314			Unknown because EPA cost manual not used	$12,978,000		$12,978,000			Unknown because EPA cost manual not used	$12,978,000	
91	Total Plant Costs	PC	$	Table 2.10	DC+IIC+Project Contingency	$9,428,160	$9,383,231		$16,926,653		$16,926,653		$28,660,408		$67,282,998		$99,498,000		$99,498,000		$67,282,998		$99,498,000	
92	Allowance for Funds During Construction	AFUDC	$												$0	As reported in Andover Report attachment.	$9,519,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. Note that this value is not included in the TCI, but is shown for information since this item does represent an actual cost to PacifiCorp	$9,519,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. Included in the TCI as an actual cost to PacifiCorp for comparative purposes.	$0	As reported in Andover Report attachment.	$9,519,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. Note that this value is not included in the TCI, but is shown for information since this item does represent an actual cost to PacifiCorp
93	Preproduction Cost	PrePro	$	Table 2.11	0.02 x (PC+Construction)	$188,563	$187,665		$338,533		$338,533		$573,208				$2,180,340		$2,180,340				$2,180,340	
94	Inventory Capital	Inventory	$	Table 2.12	$m_{solution}$ x daysx24x irc	$39,128	$33,257		$23,382		$23,981		$23,981				$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost	$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost			$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost
95	Initial Catlayst and Chemicals		$														$35,000	Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.	$35,000	Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.			$35,000	Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.
96	**Total Capital Investment**	**TCI**	**$**	**Table 2.13**	**PC+Construction+PrePro+Inventory+Catalyst**	**$9,655,851**	**$9,604,153**		**$17,288,568**		**$17,289,167**		**$29,257,597**		**$67,282,997**	As reported in Andover Report attachment.	**$101,713,340**		**$111,232,340**		**$67,282,997**	As reported in Andover Report attachment.	**$101,713,340**	

	B	C	D	E	F	G	I	J
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment
97	Maintenance Cost		$/yr	2.46	$Annual\ Maintenance\ Cost = 0.015\ TCI$	$144,838	$144,062	
98	Power	P	kW	2.48		444	444	
99	Electricity Cost		$/yr	2.49	$Power = 0.105\,Q_B\left[NO_{x_{in}}\,\eta_{NO_x} + 0.5\,(\Delta P_{duct} + n_{total}\,\Delta P_{catalyst})\right]$ $Annual\ Electricity\ Cost = Power\ Cost_{elect}\ t_{op}$	$52,538	$41,316	
100	Reagent Solution Cost		$/yr	2.47	$ReagentCost = \dot{m}_{sol} \times 8760 \times CF_{total} \times Cost_{reagent}$	$275,435	$184,103	
101	Future Worth Factor	FWF		2.52	$FWF = i\left[\frac{1}{(1+i)^Y - 1}\right]$	0.14	0.14	
102	Years	Y	yr	2.53	$Y = \frac{h_{catalyst}}{CF_{SCR} \times 8760}$	6	6	
103	Factor for Catalyst Replacement	R_{layer}				3	3	
104	Annual Catalyst Replacement Cost		$/yr	2.50 + 2.51	$Annual\ Catalyst\ Replacement\ Cost = FWF \times \left[1 \times Vol_{catalyst} \times \frac{CC_{replace}}{R_{layer}}\right]$	68,871	$68,871	
105	Annual Additional Water for Urea		$/yr		Volumetric flow rate of water, Dry Urea Consumption Rate * 1 lb H2O * 7.48 gal / (62.4 lb/ft3 * 1 lb urea)			
106	Annual Additional Steam for Urea Hydrolyzer		$/yr					
107	Total Variable Direct Cost				=Electricity Cost+Reagent Solution Cost + Annual Catalyst Replacement Cost + Water Cost	$396,843	$294,290	
108	Total Direct Annual Cost			2.45	=Maintenance Cost +Total Variable Direct Cost	$541,681	$438,352	
109	Property Tax Factor	F(tax)		2.5.5.8		0.00	0.00	
110	Overhead Factor	F(ovhd)				0.00	0.00	
111	Capital Recovery Factor	CRF		2.55	$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$	0.0944	0.0944	
112	Indirect Annual Costs	IDAC	$/yr	2.54	$IDAC = CRF\ TCI$	$911,444	$906,564	
113	Total Annual Cost	TAC	$/yr	2.56	$Total\ Annual\ Cost = \begin{pmatrix}Direct\\Annual\\Cost\end{pmatrix} + \begin{pmatrix}Indirect\\Annual\\Cost\end{pmatrix}$	**$1,453,125**	**$1,344,916**	
114	Annual NOx Removed		tons/yr	2.57	NOx Removed $= NO_{x_{in}}\,\eta_{NO_x}\,Q_B\,t_{op}$	864	680	
115	Cost Effectiveness		$/ton	2.58	$Cost\ Effectiveness = \frac{TAC}{NO_x\ Removed}$	**$1,681**	**$1,978**	

B	K	L	M	N	O	P	Q	R
NAME OF VARIABLE	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment
Maintenance Cost	$259,329		$259,338		$438,864		$363,000	Based on $1.65/kw-yr as reported in Andover Report attachment.
Power	999		999		1,134			
Electricity Cost	$393,740		$393,740	Increase in power consumption for U2A system is negligible, thus no adjustment needed	$446,948	Increased due to additional pressure drop associated with ductwork	$623,025	Based on $0.36/MW-hr as reported in Andover Report attachment.
Reagent Solution Cost	$548,640		$562,694		$562,694		$1,003,763	Based on $0.58/MW-hr as reported in Andover Report attachment.
Future Worth Factor	0.31		0.23		0.23			
Years	3		4		4			
Factor for Catalyst Replacement	3		3		3			
Annual Catalyst Replacement Cost	$283,784		$210,550		$210,550		$398,044	Based on $0.23/MW-hr as reported in Andover Report attachment.
Annual Additional Water for Urea	$0		$1,686	Additional water would be needed for a U2A solid urea system in comparison with any other system because need the water to dissolve the solid urea. Value is based on gph flow rate of 50% urea solution.	$1,686			Not included in Andover Report attachment.
Annual Additional Steam for Urea Hydrolyzer	$0		$84,404	Naughton 3 had 0.006MMBtu/hr of steam guaranteed per pound of urea consumed.	$84,404		$10,384	Based on $0.006/MW-hr as reported in Andover Report attachment.
Total Variable Direct Cost	$1,226,164		$1,253,074		$1,306,282		$2,035,216	
Total Direct Annual Cost	$1,485,493		$1,512,412		$1,745,146		$2,398,216	
Property Tax Factor	0.00		0.00		0.00			
Overhead Factor	0.00		0.00		0.00			
Capital Recovery Factor	0.0944		0.0944		0.0944		0.1064	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%, Total Charge Rate = 10.64%.
Indirect Annual Costs	$1,631,919		$1,631,975		$2,761,710		$7,158,911	
Total Annual Cost	**$3,117,411**		**$3,144,387**		**$4,506,857**		**$9,562,381**	As reported in Andover Report attachment.
Annual NOx Removed	2,025		2,025		2,025		1,597	As reported in Andover Report attachment.
Cost Effectiveness	**$1,540**		**$1,553**		**$2,226**		**$5,989**	**As reported in Andover Report attachment.**

B	S	T	U	V	W	X	Y	Z
NAME OF VARIABLE	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (9-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (9-yr life / excluding AFUDC)	Comment
Maintenance Cost	$1,525,700		$1,668,485		$363,000	Based on $1.65/kw-yr as reported in Andover Report attachment.	$1,525,700	
Power	1,126		1,126				1,126	
Electricity Cost	$266,253		$266,253		$623,025	Based on $0.36/MW-hr as reported in Andover Report attachment.	$266,253	
Reagent Solution Cost	$502,605		$502,605		$1,003,763	Based on $0.58/MW-hr as reported in Andover Report attachment.	$502,605	
Future Worth Factor	0.23		0.23				0.23	
Years	4		4				4	
Factor for Catalyst Replacement	3		3				3	
Annual Catalyst Replacement Cost	$572,397	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.	$572,397	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.	$398,044	Based on $0.23/MW-hr as reported in Andover Report attachment.	$572,397	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.
Annual Additional Water for Urea	$0		$0			Not included in Andover Report attachment.	$0	
Annual Additional Steam for Urea Hydrolyzer	$0		$0		$10,384	Based on $0.006/MW-hr as reported in Andover Report attachment.	$0	
Total Variable Direct Cost	$1,341,256		$1,341,256		$2,035,216		$1,341,256	
Total Direct Annual Cost	$3,884,089	+ Property Tax Factor	$4,122,064	+ Property Tax Factor	$2,398,216		$3,884,089	+ Property Tax Factor
Property Tax Factor	$1,017,133	PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.	$1,112,323	PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.			$1,017,133	PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.
Overhead Factor	0.00		0.00				0.00	
Capital Recovery Factor	0.0944		0.0944		0.1655	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%, Total Charge Rate = 10.64%.	0.1535	
Indirect Annual Costs	$9,601,020		$10,499,546		$11,135,336		$15,611,622	
Total Annual Cost	**$13,485,109**		**$14,621,610**		**$13,533,552**	As reported in Andover Report attachment.	**$19,495,711**	
Annual NOx Removed	1,597	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,597	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,597	As reported in Andover Report attachment.	1,597	Aligned with Andover Report assumption for cost-effectiveness comparison.
Cost Effectiveness	**$8,444**		**$9,156**		**$8,474**	**As reported in Andover Report attachment.**	**$12,208**	

116 **Note 1 - In attachment EPA-R08-OAR-2012-0026-0087, Andover calculates SCR cost effectiveness in two ways: a) starting from baseline emissions of 0.22, assuming combustion controls already in place (see worksheet "NOx - SCR_01_03")and b) starting from baseline emissions of 0.52, assuming combustion controls are not in place (see worksheet "Dave Johnston"). This worksheet reports Andover's results assuming combustion controls are already in place since this is consistent with current operation at Dave Johnston.**

117

Naughton Unit 1

	B	C	D	E	F	G	I	J	K	L	M	N	O
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA
3													
4	Fuel High Heating Value	HHV	Btu/lb	-		10,000	10,000		10,000	Based on typical Naughton coal	10,000		10,000
5	Maximum Fuel Consumption Rate	$\dot{m}_{fuel}$	lb/hr	-	$\dot{m}_{fuel} = \frac{Q_B}{HHV} \times 10^{-6}$	100,000	100,000		171,900	Calculated from maximum heat input and fuel high heating value	171,900		171,900
7	Max Generating Capacity		MW		$m_{fuel} = \frac{AnnualHeat\ \ Input}{HHV} \times 10^{6}$				160	Provided by PC	160		160
10	Average Number of Plant Operating Hours per Year		hr						7884	Estimated to achieve 90% capacity factor in Row 12	7884		7884
11	Number of SCR Operating Days	t(scr)	days	-		155	155		365	SCR operated year round	365		365
12	Plant Capacity Factor	CF_{plant}		-		50%	50%		90%	Operating hours divided by 8760	-		-
13	Uncontrolled NOx Concentration	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86		0.26		0.26		0.26
14	NOx Concentration used for Reagent Consumption	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86		0.26		0.26		0.26
15	Required Controlled NOx Concentration	NOx_{out}	lbNO2/MMBtu	-		0.13	0.13		0.07		0.07		0.07
16	Acceptable Ammonia Slip	Slip	ppm	-		2.00	2.00		2.00		2.00		2.00
17	Coal Type			-		Eastern Bituminous	Eastern Bituminous		Bituminous		Bituminous		Bituminous
18	Fuel Volumetric Flow Rate	q_{fuel}	ft³/min-MMBtu/hr	-		484.00	484.00		484.00		484.00		484.00
19	Fuel Heating Value		Btu/lb	-		12696.00	12696.00		-		-		-
20	Sulfur Content of Fuel	S	wt%	-		1.0	1.0		1.2		1.2		1.2
21	Fuel Ash Content	A	wt%	-		7.7%	7.7%		-		-		-
22	Actual Stoichiometric Ratio	ASR		-		1.05	1.05		1.05		1.05		1.05
23	Concentration of Reagent	C_{sol}	%	-		29%	29%		29%		50%	To account for a U2A system	50%
24	Days of Storage of Reagent	t	days	-		14.00	14.00		14.00		14.00		14.00
25	Pressure Drop for SCR Ductwork	ΔP_{duct}	in. w.g.	-		3.00	3.00		3.00		3.00		4.00
26	Pressure Drop for each Catalyst Layer	$\Delta P_{catalyst}$	in. w.g.	-		1.00	1.00		1.00		1.00		1.00
27	Number of SCR Reactors	N(scr)				1.00	1.00		1.00		1.00		1.00
28	Temperature at Reactor Inlet	T	°F	-		650.00	650.00		665.00		665.00		665.00
29													
30	Cost Year			-		Dec-98	Dec-98		Dec-98		Dec-98		Dec-98
31	Equipment Life	n	yr	-		20.00	20.00		20.00		20.00		20.00
32	Annual Interest Rate	i		-		7%	7%		7%		7%		7%
33	Chemical Engineering Plant Cost Index Value 1998												389.50
34	Chemical Engineering Plant Cost Index Value 2011												600.60
35	Catalyst Cost, Initial	$CC_{initial}$	$/ft³	-		$240.00	$240.00		$240.00		$240.00		$240.00
36	Catalyst Cost, Replacement	$CC_{replace}$	$/ft³	-	$CC_{replace} = CC_{initial}(1.065)^{t}$	$290.00	$290.00		$290.00		$290.00		$290.00
37	Electrical Power Cost	$Cost_{elect}$	$/kWh	-		0.05	0.05		0.05		0.05		0.05
38	Reagent Cost	$Cost_{reagent}$	$/lb	-	irc	0.101	0.101		0.101		0.200	Cost of Reagent adjusted to pricing for $/lb of Dry Urea	0.200
39	Operating Life of Catalyst	$h_{catalyst}$	hr	-		24,000	24,000		24,000		32,000	Based on PC target of 4-year operation cycle	32,000
40	Catalyst Layers Full	n_{full}	#	-		2	2		3		3		3
41	Catalyst Layers Empty	n_{empty}	#	-		1	1		1	Empty layer for addition of extra catalyst layer in future to boost performance	1		1
42	Cost of Water		$/1000-gal								5	Price of water per 1000 gallons	5
43													

	B	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excluding AFUDC)	Comment
3												
4	Fuel High Heating Value											
5	Maximum Fuel Consumption Rate											
7	Max Generating Capacity		160	As reported in Andover Report attachment.	160		160		160	As reported in Andover Report attachment.	160	
10	Average Number of Plant Operating Hours per Year				7884		7884				7884	
11	Number of SCR Operating Days				365		365				365	
12	Plant Capacity Factor		90.7%	As reported in Andover Report attachment.	-		-		90.7%	As reported in Andover Report attachment.	-	
13	Uncontrolled NOx Concentration		0.21	As reported in Andover Report attachment.	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.21	As reported in Andover Report attachment.	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.
14	NOx Concentration used for Reagent Consumption		0.21	As reported in Andover Report attachment.	0.21	Aligned with Andover Report assumption for reagent cost comparison.	0.21	Aligned with Andover Report assumption for reagent cost comparison.	0.21	As reported in Andover Report attachment.	0.21	Aligned with Andover Report assumption for reagent cost comparison.
15	Required Controlled NOx Concentration		0.05	Based on 76.3% Removal used in Andover Report attachment.	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Based on 76.3% Removal used in Andover Report attachment.	0.05	Aligned with Andover Report assumption for comparison purposes.
16	Acceptable Ammonia Slip				2.00		2.00				2.00	
17	Coal Type		PRB	As reported in Andover Report attachment.	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	PRB	As reported in Andover Report attachment.	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4
18	Fuel Volumetric Flow Rate					Not used, Vendor performed combustion calculation to arrive at volume		Not used, Vendor performed combustion calculation to arrive at volume				Not used, Vendor performed combustion calculation to arrive at volume
19	Fuel Heating Value				-		-				-	
20	Sulfur Content of Fuel				1.2		1.2				1.2	
21	Fuel Ash Content				-		-				-	
22	Actual Stoichiometric Ratio				1.05		1.05				1.05	
23	Concentration of Reagent		50%	As reported in Andover Report attachment	100%		100%		50%	As reported in Andover Report attachment	100%	
24	Days of Storage of Reagent				14.00		14.00				14.00	
25	Pressure Drop for SCR Ductwork	More Typical for SCR systems			4.00		4.00				4.00	
26	Pressure Drop for each Catalyst Layer				1.00		1.00				1.00	
27	Number of SCR Reactors				1.00		1.00				1.00	
28	Temperature at Reactor Inlet				763.00		763.00				763.00	
29												
30	Cost Year											
31	Equipment Life	Year the Cost is Incurred			20.00		20.00		11.00		11.00	
32	Annual Interest Rate				7%		7%				7%	
33	Chemical Engineering Plant Cost Index Value 1998	Chemical Engineering Magazine Plant Cost Index value from 1998										
34	Chemical Engineering Plant Cost Index Value 2011	Chemical Engineering Magazine Plant Cost Index value from 2011										
35	Catalyst Cost, Initial					Included in Vendor Budgetary Pricing		Included in Vendor Budgetary Pricing				Included in Vendor Budgetary Pricing
36	Catalyst Cost, Replacement		$155.74	Based on 5500 per m3 used in Andover Report attachment.	$290.00		$290.00		$155.74	Based on 5500 per m3 used in Andover Report attachment.	$290.00	
37	Electrical Power Cost		0.06	As reported in Andover Report attachment.	0.03	Price Provided by PC	0.03	Price Provided by PC	0.06	As reported in Andover Report attachment.	0.03	Price Provided by PC
38	Reagent Cost		0.225	Based on 450 per tonused in Andover Report attachment.	0.375	Price Provided by PC from DASCO quote July 2012	0.375	Price Provided by PC from DASCO quote July 2012	0.225	Based on 450 per tonused in Andover Report attachment.	0.375	Price Provided by PC from DASCO quote July 2012
39	Operating Life of Catalyst				32,000		32,000				32,000	
40	Catalyst Layers Full				3		3				3	
41	Catalyst Layers Empty				1		1				1	
42	Cost of Water				5		5				5	
43												

	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excluding AFUDC)	Comment
44																								
47	Max Heat Input Rate	Q_B	MMBtu/hr	2.3	$Q_B = \frac{HV \times \dot{m}_{fuel}}{10^6}$	1,000	1,000		1,719	Provided by PC	1,719		1,719		1,740	As reported in Andover Report attachment.	1,719		1,719		1,740	As reported in Andover Report attachment.	1,719	
48	Plant Capacity Factor	CF_{plant}		2.7	$CF_{plant} = \frac{actual\ \dot{m}_{fuel}}{\dot{m}_{fuel} \times 8760}$	50%	50%		90%	90% from Permit Calculation	90%		90%		90.7%	As reported in Andover Report attachment.	90%		90%		90.7%	As reported in Andover Report attachment.	90%	
49	SCR Capacity Factor	CF_{SCR}		2.8	$CF_{SCR} = \frac{t_{SCR}}{365\ days}$	42%	42%		100%		100%		100%				100%		100%				100%	
50	Total Capacity Factor	CF_{total}		2.6	$CF_{total} = CF_{plant}\ CF_{SCR}$	27%	21%	Fixed EPA calculation error	90%		90%		90%				90%		90%				90%	
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor	$q_{fluegas}$	acfm	2.12	$q_{fluegas} = \frac{q_{fuel}\ Q_B\ (460+T)}{(460+700°F)\ n_{SCR}}$	463,138	463,138		806,893		806,893		806,893				1,188,000	Per Vendor's Combustion Calculation	1,188,000	Per Vendor's Combustion Calculation			1,188,000	Per Vendor's Combustion Calculation
52	NOx Removal Efficient for Cost-Effectiveness					0.85	0.85		0.73		0.73		0.73				0.76		0.76				0.76	
53	NOx Removal Efficiency for Reagent Consumption	η_{NOx}		2.9	$\eta_{NO_x} = \frac{NO_{x_{in}} - NO_{x_{out}}}{NO_{x_{in}}}$	0.85	0.85		0.73		0.73		0.73				0.76		0.76				0.76	
54																								
55	Catalyst Volume/Reactor	$Vol_{catalyst}$	ft³	2.19	$Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NO_{x_{adj}} \times S_{adj} \times \frac{T_{adj}}{N_{SCR}}$	5089	5089		6248		6248		6248		Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	13914	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.	13914	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.	Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	13914	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.
56	where:	-	-	-																				
57	NOx Efficiency Adjustment	η_{adj}		2.20	$\eta_{adj} = 0.2869 + (1.058 \times \eta)$	1.19	1.19		1.06		1.06		1.06					Catalyst Cost in vendor estimate, this is not used.		Catalyst Cost in vendor estimate, this is not used.				Catalyst Cost in vendor estimate, this is not used.
58	NOx Adjustment Factor for Inlet NOx	NOx_{adj}		2.21	$NO_{x_{adj}} = 0.8524 + (0.3208 \times NO_{x_{in}})$	1.13	1.13		0.94		0.94		0.94					(see above)		(see above)				(see above)
59	Ammonia Slip Adjustment Factor	$Slip_{adj}$		2.22	$Slip_{adj} = 1.2835 - (0.0567 \times Slip)$	1.17	1.17		1.17		1.17		1.17					(see above)		(see above)				(see above)
60	Sulfur in Coal Adjustment Factor	S_{adj}		2.23	$S_{adj} = 0.9636 + (0.0455 \times S)$	1.01	1.01		1.02		1.02		1.02					(see above)		(see above)				(see above)
61	Temperature Adjustment Factor (for temps other than 700°F)	T_{adj}	°F	2.24	$T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$	1.15	1.15		1.10		1.10		1.10					(see above)		(see above)				(see above)
62																								
63	Catalyst Cross-Sectional Area	$A_{catalyst}$	ft²	2.25	$A_{catalyst} = \frac{q_{fluegas}}{16\left(\frac{ft}{sec}\right) \times \left(\frac{60\ sec}{min}\right)}$	482	482		841		841		841					(see above)		(see above)				(see above)
64	SCR Reactor Cross-Sectional Area	A_{SCR}	ft²	2.26	$A_{SCR} = 1.15 \times A_{catalyst}$	554	554		967		967		967					(see above)		(see above)				(see above)
65	length	l	ft	2.27	$l = w = (A_{SCR})^{1/2}$	23.50	23.50		31		31		31					(see above)		(see above)				(see above)
66	width	w																						
67	Estimate Number of Catalyst Layers	n_{layer}		2.28	$n_{layer} = \frac{Vol_{catalyst}}{3.1 \times A_{catalyst}}$	3	3	Estimated number of layers is less than input. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too low. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)				Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
68	Height of Catalyst Layer	h_{layer}	ft	2.29		4.50	4.50		3.50		3.50		3.50					Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
69	Total Number of Catalyst Layers	n_{total}	#	2.30	$n_{total} = n_{layer} + n_{empty}$	4	4		4		4		4				4		4				4	
70	Height of SCR Reactor	h_{SCR}	ft	2.31	$h_{SCR} = n_{total}(c_1 + h_{layer}) + c_2$	55	55		51		51		51					Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.

	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excluding AFUDC)	Comment
71																								
72	Ammonia Mass Flow Rate	$m_{reagent}$	lb/hr of NH_3	2.32	$\dot{m}_{reagent} = \frac{NO_{x_{in}} Q_B NSR\, \eta_{NO_x} M_{reagent}}{M_{NO_2} SR_T}$ $\dot{m}_{reagent} = \frac{NOx_{in} \times Q_B \times ASR \times 17.03}{46.01}$	34	284	In the example problem (2.5 Example Problem), EPA does not use NOx efficiency in their calculation, yet the equation (2.32) on pg 2-39 requires it	127		127		127		109	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	107		107		109	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	107	
73	Mass Flow Rate of Aqueous Reagent Solution	$m_{solution}$	lb/hr of NH3 solution	2.33	$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}}$	1,153	980		438			Not used as urea is the reagent					107		107				107	
74	Equivalent Dry Urea Consumption Rate		lb/hr		$\dot{m}_{urea} = \frac{\dot{m}_{sol}}{0.56}$						227	S&L added formulas and calculations to include U2A system. Value calculated for reagent costing	227		195						195			
75	Mass Flow Rate of Urea Solution	$m_{solution}$	lb/hr of NH3 solution	2.33	$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}}$						453		453		390		0		0		390		0	
76	Solution Volumetric Flow	q_{sol}	gph	2.34	$q_{sol} = \frac{\dot{m}_{sol} \times 7.481}{71.1}$	154.00	131.00		59.00		48.00	Volumetric flow rate of 50% urea solution with a density of 71.1 lb/ft3	48.00		41		14.00		14.00		41		14.00	
77	Storage Tank Volume	V_{tank}	gal	2.35	$Tank\ Volume = q_{sol}\ t$	51,744	44,016		19,824		16,128		16,128			Tank volume included in Andover estimate unknown.	4,704		4,704			Tank volume included in Andover estimate unknown.	4,704	
78																								
80	Direct Capital Cost	DC	$	2.36		$6,832,000	$6,799,443		$9,187,373		$9,187,373		$15,585,717	Since no adjustment factor exists for urea systems, S&L added the estimated capital cost for the urea system by scaling the Huntington estimate.	$33,928,100	As reported in Andover Report attachment.	$66,500,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)	$66,500,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)	$33,928,100	As reported in Andover Report attachment.	$66,500,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)
81	Adjustment for the SCR Reactor Height	$f(h_{SCR})$	$/MMBtu/hr	2.37	$DC = Q_B\left[\frac{\$3{,}380}{\left(\frac{MMBtu}{hr}\right)} + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass)\right]\left(\frac{3500}{Q_B}\right)^{0.35} + f(Vol_{catalyst})$	49.00	$149.00		$124.00		$124.00		$124.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
82	Adjustment for the Ammonia Flow Rate	$f(NH_{3rate})$	$/MMBtu/hr	2.38	$f(NH_3rate) = \left[\frac{\$411}{lb/hr}\frac{\dot{m}_{reagent}}{Q_B}\right] - \frac{\$47.3}{\left(\frac{MMBtu}{hr}\right)}$	$90.00	$69.00		-$17.00		-$17.00		-$17.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
83	Adjustment for Retrofit or New Boiler	f(new)	$/MMBtu/hr	2.39 + 2.40	Is it a retrofit or new boiler?	$0.00	$0.00		$0.00		$0.00		$0.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
84	Adjustment for SCR Bypass	f(bypass)	$/MMBtu/hr	2.41 + 2.42	Is a bypass installed?	$0.00	$0.00		$0.00		$0.00		$0.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
85	Capital Cost for the Initial Charge of Catalyst	$f(Vol_{catalyst})$	$/MMBtu/hr	2.43	$f(Vol_{catalyst}) = Vol_{catalyst}\ CC_{initial}$	$1,221,360	$1,221,360		$1,499,520		$1,499,520		$1,499,520			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
86	Indirect Installation Costs Due to General Facilities		$	Table 2.5	0.05xDC	$341,600	$339,972		$459,369		$459,369		$779,286			Unknown because EPA cost manual not used	$3,325,000		$3,325,000			Unknown because EPA cost manual not used	$3,325,000	
87	Indirect Installation Costs Due to Engineering and Home Office Fees		$	Table 2.6	0.10xDC	$683,200	$679,944		$918,737		$918,737		$1,558,572			Unknown because EPA cost manual not used	$6,650,000		$6,650,000			Unknown because EPA cost manual not used	$6,650,000	
88	Indirect Installation Costs Due to Process Contingency		$	Table 2.7	0.05xDC	$341,600	$339,972		$459,369		$459,369		$779,286			Unknown because EPA cost manual not used	$3,325,000		$3,325,000			Unknown because EPA cost manual not used	$3,325,000	
89	Total Indirect Installation Costs	IIC	$	Table 2.8	DCx(0.05+0.10+0.05)	$1,366,400	$1,359,889		$1,837,475		$1,837,475		$3,117,143		$10,178,430	As reported in Andover Report attachment.	$13,300,000		$13,300,000		$10,178,430	As reported in Andover Report attachment.	$13,300,000	
90	Project Contingency		$	Table 2.9	(DC+IIC)x0.15	$1,229,760	$1,223,900		$1,653,727		$1,653,727		$2,805,429			Unknown because EPA cost manual not used	$11,970,000		$11,970,000			Unknown because EPA cost manual not used	$11,970,000	
91	Total Plant Costs	PC	$	Table 2.10	DC+IIC+Project Contingency	$9,428,160	$9,383,231		$12,678,575		$12,678,575		$21,508,290		$44,106,530		$91,770,000		$91,770,000		$44,106,530		$91,770,000	
92	Allowance for Funds During Construction	AFUDC	$												$0	As reported in Andover Report attachment.	$8,774,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. Note that this value is not included in the TCI, but is shown for information since this item does represent an actual cost to PacifiCorp	$8,774,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. Included in the TCI as an actual cost to PacifiCorp for comparative purposes.	$0	As reported in Andover Report attachment.	$8,774,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. Note that this value is not included in the TCI, but is shown for information since this item does represent an actual cost to PacifiCorp
93	Preproduction Cost	PrePro	$	Table 2.11	0.02 x (PC+Construction)	$188,563	$187,665		$253,572		$253,572		$430,166				$2,010,880		$2,010,880				$2,010,880	
94	Inventory Capital	Inventory	$	Table 2.12	$m_{solution}$ x daysx24x irc	$39,128	$33,257		$14,864		$15,232		$15,232				$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost	$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost			$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost
95	Initial Catlayst and Chemicals		$														$35,000	Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.	$35,000	Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.			$35,000	Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.
96	**Total Capital Investment**	**TCI**	**$**	**Table 2.13**	**PC+Construction+PrePro+Inventory+Catalyst**	**$9,655,851**	**$9,604,153**		**$12,947,011**		**$12,947,379**		**$21,953,688**		**$44,106,530**	As reported in Andover Report attachment.	**$93,815,880**		**$102,589,880**		**$44,106,530**	As reported in Andover Report attachment.	**$93,815,880**	
97	Maintenance Cost		$/yr	2.46	$Annual\ Maintenance\ Cost = 0.015\ TCI$	$144,838	$144,062		$194,205		$194,211		$329,305		$363,200	Based on $2.27/kw-yr as reported in Andover Report attachment.	$1,407,238		$1,538,848		$363,200	Based on $2.27/kw-yr as reported in Andover Report attachment.	$1,407,238	
98	Power	P	kW	2.48		444	444		666		666		756				751		751				751	

Exhibit PAC/4002
Owen/93

Row	B NAME OF VARIABLE	C VARIABLE	D UNITS	E EQUATION NUMBER	F EQUATION	G EXAMPLE PROBLEM VERBATIM	I S&L CORRECTED EPA EXAMPLE	J Comment
99	Electricity Cost		$/yr	2.49	$Power = 0.105\, Q_B \left[NO_{x_{in}}\, \eta_{NO_x} + 0.5\left(\Delta P_{duct} + n_{total}\, \Delta P_{catalyst}\right)\right]$; $Annual\ Electricity\ Cost = Power\ Cost_{elect}\ t_{op}$	$52,538	$41,316	
100	Reagent Solution Cost		$/yr	2.47	$ReagentCost = \dot{m}_{sol} \times 8760 \times CF_{total} \times Cost_{reagent}$	$275,435	$184,103	
101	Future Worth Factor	FWF		2.52	$FWF = i\left[\frac{1}{(1+i)^Y - 1}\right]$	0.14	0.14	
102	Years	Y	yr	2.53	$Y = \frac{h_{catalyst}}{CF_{SCR} \times 8760}$	6	6	
103	Factor for Catalyst Replacement	R_{layer}				3	3	
104	Annual Catalyst Replacement Cost		$/yr	2.50 + 2.51	$Annual\ Catalyst\ Replacement\ Cost = FWF \times \left[1 \times Vol_{catalyst} \times \frac{CC_{replace}}{R_{layer}}\right]$	$68,871	$68,871	
105	Annual Additional Water for Urea		$/yr		Volumetric flow rate of water, Dry Urea Consumption Rate * 1 lb H2O * 7.48 gal / (62.4 lb/ft3 * 1 lb urea)			
106	Annual Additional Steam for Urea Hydrolyzer		$/yr					
107	Total Variable Direct Cost				=Electricity Cost+Reagent Solution Cost + Annual Catalyst Replacement Cost + Water Cost	$396,843	$294,290	
108	Total Direct Annual Cost			2.45	=Maintenance Cost +Total Variable Direct Cost	$541,681	$438,352	
109	Property Tax Factor	F(tax)		2.5.5.8		0.00	0.00	
110	Overhead Factor	F(ovhd)				0.00	0.00	
111	Capital Recovery Factor	CRF		2.55	$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$	0.0944	0.0944	
112	Indirect Annual Costs	IDAC	$/yr	2.54	$IDAC = CRF\ TCI$	$911,444	$906,564	
113	Total Annual Cost	TAC	$/yr	2.56	$Total\ Annual\ Cost = \left(\begin{matrix}Direct\\ Annual\\ Cost\end{matrix}\right) + \left(\begin{matrix}Indirect\\ Annual\\ Cost\end{matrix}\right)$	**$1,453,125**	**$1,344,916**	
114	Annual NOx Removed		tons/yr	2.57	NOx Removed $= NO_{x_{in}}\, \eta_{NO_x}\, Q_B\, t_{op}$	864	680	
115	Cost Effectiveness		$/ton	2.58	$Cost\ Effectiveness = \frac{TAC}{NO_x\ Removed}$	**$1,681**	**$1,978**	

Row	B NAME OF VARIABLE	K NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	L Comment	M NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH UREA	N Comment	O NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	P Comment
99	Electricity Cost	$262,548		$262,548	Increase in power consumption for U2A system is negligible, thus no adjustment needed	$298,123	Increased due to additional pressure drop associated with ductwork
100	Reagent Solution Cost	$348,772		$357,413		$357,413	
101	Future Worth Factor	0.31		0.23		0.23	
102	Years	3		4		4	
103	Factor for Catalyst Replacement	3		3		3	
104	Annual Catalyst Replacement Cost	$187,232		$138,914		$138,914	
105	Annual Additional Water for Urea	$0		$1,071	Additional water would be needed for a U2A solid urea system in comparison with any other system because need the water to dissolve the solid urea. Value is based on gph flow rate of 50% urea solution.	$1,071	
106	Annual Additional Steam for Urea Hydrolyzer	$0		$53,612	Naughton 3 had 0.006MMBtu/hr of steam guaranteed per pound of urea consumed.	$53,612	
107	Total Variable Direct Cost	$798,552		$813,557		$849,133	
108	Total Direct Annual Cost	$992,757		$1,007,768		$1,178,438	
109	Property Tax Factor	0.00		0.00		0.00	
110	Overhead Factor	0.00		0.00		0.00	
111	Capital Recovery Factor	0.0944		0.0944		0.0944	
112	Indirect Annual Costs	$1,222,106		$1,222,141		$2,072,273	
113	Total Annual Cost	**$2,214,863**		**$2,229,909**		**$3,250,711**	
114	Annual NOx Removed	1,286		1,286		1,286	
115	Cost Effectiveness	**$1,722**		**$1,734**		**$2,527**	

Row	B NAME OF VARIABLE	Q NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	R Comment	S NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	T Comment	U NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	V Comment	W NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excluding AFUDC)	X Comment	Y NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excluding AFUDC)	Z Comment
99	Electricity Cost	$457,650	Based on $0.36/MW-hr as reported in Andover Report attachment.	$177,593		$177,593		$457,650	Based on $0.36/MW-hr as reported in Andover Report attachment.	$177,593	
100	Reagent Solution Cost	$699,188	Based on $0.55/MW-hr as reported in Andover Report attachment.	$316,346		$316,346		$699,188	Based on $0.55/MW-hr as reported in Andover Report attachment.	$316,346	
101	Future Worth Factor			0.23		0.23				0.23	
102	Years			4		4				4	
103	Factor for Catalyst Replacement			3		3				3	
104	Annual Catalyst Replacement Cost	$292,388	Based on $0.23/MW-hr as reported in Andover Report attachment.	$309,355	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.	$309,355	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.	$292,388	Based on $0.23/MW-hr as reported in Andover Report attachment.	$309,355	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.
105	Annual Additional Water for Urea	$0	Not included in Andover Report attachment.	$0		$0		$0	Not included in Andover Report attachment.	$0	
106	Annual Additional Steam for Urea Hydrolyzer	$7,628	Based on $0.006/MW-hr as reported in Andover Report attachment.	$0		$0		$7,628	Based on $0.006/MW-hr as reported in Andover Report attachment.	$0	
107	Total Variable Direct Cost	$1,456,854		$803,293		$803,293		$1,456,854		$803,293	
108	Total Direct Annual Cost	$1,820,054		$3,148,690	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.	$3,368,040	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.	$1,820,054		$3,148,690	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.
109	Property Tax Factor			$938,159		$1,025,899				$938,159	
110	Overhead Factor			0.00		0.00				0.00	
111	Capital Recovery Factor	0.1064	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%, Total Charge Rate = 10.64%.	0.0944		0.0944		0.1454	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%, Total Charge Rate = 10.64%.	0.1334	
112	Indirect Annual Costs	$4,692,935		$8,855,555		$9,683,759		$6,413,089		$12,510,995	
113	Total Annual Cost	**$6,504,803**	As reported in Andover Report attachment.	**$12,004,246**		**$13,051,799**		**$8,233,143**	As reported in Andover Report attachment.	**$15,659,686**	
114	Annual NOx Removed	1,109	As reported in Andover Report attachment.	1,109	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,109	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,109	As reported in Andover Report attachment.	1,109	Aligned with Andover Report assumption for cost-effectiveness comparison.
115	Cost Effectiveness	**$5,867**	**As reported in Andover Report attachment.**	**$10,824**		**$11,769**		**$7,424**	**As reported in Andover Report attachment.**	**$14,121**	

Note 1 - In attachment EPA-R08-OAR-2012-0026-0087, Andover calculates SCR cost effectiveness in two ways: a) starting from baseline emissions of 0.21, assuming combustion controls already in place (see worksheet "NOx - SCR_01_03")and b) starting from baseline emissions of 0.52, assuming combustion controls are not in place (see worksheet "Naughton"). This worksheet reports Andover's results assuming combustion controls are already in place since this is consistent with current operation at Naughton

Naughton Unit 2

Row	NAME OF VARIABLE (B)	VARIABLE (C)	UNITS (D)	EQUATION NUMBER (E)	EQUATION (F)	EXAMPLE PROBLEM VERBATIM (G)	S&L CORRECTED EPA EXAMPLE (I)	Comment (J)	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA (K)	Comment (L)
4	Fuel High Heating Value	HHV	Btu/lb	-		10,000	10,000		10,000	Based on typical Naughton coal
5	Maximum Fuel Consumption Rate	$\dot{m}_{fuel}$	lb/hr	-	$\dot{m}_{fuel} = \frac{Q_B}{HHV} \times 10^{-6}$	100,000	100,000		234,900	Calculated from maximum heat input and fuel high heating value
7	Max Generating Capacity		MW		$m_{fuel} = \frac{AnnualHeat\ \ Input}{HHV} \times 10^{6}$				220	Provided by PC
10	Average Number of Plant Operating Hours per Year		hr						7884	Estimated to achieve 90% capacity factor in Row 12
11	Number of SCR Operating Days	t(scr)	days	-		155	155		365	SCR operated year round
12	Plant Capacity Factor	CF_{plant}		-		50%	50%		90%	Operating hours divided by 8760
13	Uncontrolled NOx Concentration	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86		0.26	
14	NOx Concentration used for Reagent Consumption	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86		0.26	
15	Required Controlled NOx Concentration	NOx_{out}	lbNO2/MMBtu	-		0.13	0.13		0.07	
16	Acceptable Ammonia Slip	Slip	ppm	-		2.00	2.00		2.00	
17	Coal Type			-		Eastern Bituminous	Eastern Bituminous		Bituminous	
18	Fuel Volumetric Flow Rate	q_{fuel}	ft³/min-MMBtu/hr	-		484.00	484.00		484.00	
19	Fuel Heating Value		Btu/lb	-		12696.00	12696.00		-	
20	Sulfur Content of Fuel	S	wt%	-		1.0	1.0		1.2	
21	Fuel Ash Content	A	wt%	-		7.7%	7.7%		-	
22	Actual Stoichiometric Ratio	ASR		-		1.05	1.05		1.05	
23	Concentration of Reagent	C_{sol}	%	-		29%	29%		29%	
24	Days of Storage of Reagent	t	days	-		14.00	14.00		14.00	
25	Pressure Drop for SCR Ductwork	ΔP_{duct}	in. w.g.	-		3.00	3.00		3.00	
26	Pressure Drop for each Catalyst Layer	$\Delta P_{catalyst}$	in. w.g.	-		1.00	1.00		1.00	
27	Number of SCR Reactors	N(scr)				1.00	1.00		1.00	
28	Temperature at Reactor Inlet	T	°F	-		650.00	650.00		665.00	
30	Cost Year			-		Dec-98	Dec-98		Dec-98	
31	Equipment Life	n	yr	-		20.00	20.00		20.00	
32	Annual Interest Rate	i		-		7%	7%		7%	
33	Chemical Engineering Plant Cost Index Value 1998									
34	Chemical Engineering Plant Cost Index Value 2011									
35	Catalyst Cost, Initial	$CC_{initial}$	$/ft³	-		$240.00	$240.00		$240.00	
36	Catalyst Cost, Replacement	$CC_{replace}$	$/ft³	-	$CC_{replace} = CC_{initial}(1.065)^{t}$	$290.00	$290.00		$290.00	
37	Electrical Power Cost	$Cost_{elect}$	$/kWh	-		0.05	0.05		0.05	
38	Reagent Cost	$Cost_{reagent}$	$/lb	-	irc	0.101	0.101		0.101	
39	Operating Life of Catalyst	$h_{catalyst}$	hr	-		24,000	24,000		24,000	
40	Catalyst Layers Full	n_{full}	#	-		2	2		3	
41	Catalyst Layers Empty	n_{empty}	#	-		1	1		1	Empty layer for addition of extra catalyst layer in future to boost performance
42	Cost of Water		$/1000-gal							

Row	NAME OF VARIABLE (B)	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH UREA (M)	Comment (N)	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA (O)	Comment (P)	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excludes AFUDC) (Q)	Comment (R)
4	Fuel High Heating Value	10,000		10,000			
5	Maximum Fuel Consumption Rate	234,900		234,900			
7	Max Generating Capacity	220		220		210	As reported in Andover Report attachment, net reliable
10	Average Number of Plant Operating Hours per Year	7884		7884			
11	Number of SCR Operating Days	365		365			
12	Plant Capacity Factor	-		-		-	
13	Uncontrolled NOx Concentration	0.26		0.26		0.21	As reported in Andover Report attachment. (See Note 1)
14	NOx Concentration used for Reagent Consumption	0.26		0.26		0.21	As reported in Andover Report attachment. (See Note 1)
15	Required Controlled NOx Concentration	0.07		0.07		0.05	Based on 76.3% Removal used in Andover Report attachment.
16	Acceptable Ammonia Slip	2.00		2.00			
17	Coal Type	Bituminous		Bituminous		PRB	As reported in Andover Report attachment.
18	Fuel Volumetric Flow Rate	484.00		484.00			
19	Fuel Heating Value	-		-			
20	Sulfur Content of Fuel	1.2		1.2			
21	Fuel Ash Content	-		-			
22	Actual Stoichiometric Ratio	1.05		1.05			
23	Concentration of Reagent	50%	To account for a U2A system	50%		50%	As reported in Andover Report attachment.
24	Days of Storage of Reagent	14.00		14.00			
25	Pressure Drop for SCR Ductwork	3.00		4.00	More Typical for SCR systems		
26	Pressure Drop for each Catalyst Layer	1.00		1.00			
27	Number of SCR Reactors	1.00		1.00			
28	Temperature at Reactor Inlet	665.00		665.00			
30	Cost Year	Dec-98		Dec-98	Year the Cost is Incurred		
31	Equipment Life	20.00		20.00			
32	Annual Interest Rate	7%		7%			
33	Chemical Engineering Plant Cost Index Value 1998			389.50	Chemical Engineering Magazine Plant Cost Index value from 1998		
34	Chemical Engineering Plant Cost Index Value 2011			600.60	Chemical Engineering Magazine Plant Cost Index value from 2011		
35	Catalyst Cost, Initial	$240.00		$240.00			
36	Catalyst Cost, Replacement	$290.00		$290.00		$155.74	Based on 5500 m3 used in Andover Report attachment.
37	Electrical Power Cost	0.05		0.05		0.06	As reported in Andover Report attachment.
38	Reagent Cost	0.200	Cost of Reagent adjusted to pricing for $/lb of Dry Urea	0.200		0.225	Based on 450 per tonused in Andover Report attachment.
39	Operating Life of Catalyst	32,000	Based on PC target of 4-year operation cycle	32,000			
40	Catalyst Layers Full	3		3			
41	Catalyst Layers Empty	1		1			
42	Cost of Water	5	Price of water per 1000 gallons	5			

Row	NAME OF VARIABLE (B)	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excludes AFUDC) (S)	Comment (T)	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / includes AFUDC) (U)	Comment (V)	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excludes AFUDC) (W)	Comment (X)	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excludes AFUDC) (Y)	Comment (Z)
4	Fuel High Heating Value								
5	Maximum Fuel Consumption Rate								
7	Max Generating Capacity	220		220		210	As reported in Andover Report attachment, net reliable	220	
10	Average Number of Plant Operating Hours per Year	7884		7884				7884	
11	Number of SCR Operating Days	365		365				365	
12	Plant Capacity Factor	-		-		-		-	
13	Uncontrolled NOx Concentration	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.21	As reported in Andover Report attachment. (See Note 1)	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.
14	NOx Concentration used for Reagent Consumption	0.21	Aligned with Andover Report assumption for reagent cost comparison.	0.21	Aligned with Andover Report assumption for reagent cost comparison.	0.21	As reported in Andover Report attachment. (See Note 1)	0.21	Aligned with Andover Report assumption for reagent cost comparison.
15	Required Controlled NOx Concentration	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Based on 76.3% Removal used in Andover Report attachment.	0.05	Aligned with Andover Report assumption for comparison purposes.
16	Acceptable Ammonia Slip	2.00		2.00				2.00	
17	Coal Type	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	PRB	As reported in Andover Report attachment.	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4
18	Fuel Volumetric Flow Rate		Not used, Vendor performed combustion calculation to arrive at volume		Not used, Vendor performed combustion calculation to arrive at volume				Not used, Vendor performed combustion calculation to arrive at volume
19	Fuel Heating Value	-		-				-	
20	Sulfur Content of Fuel	1.2		1.2				1.2	
21	Fuel Ash Content	-		-				-	
22	Actual Stoichiometric Ratio	1.05		1.05				1.05	
23	Concentration of Reagent	100%		100%		50%	As reported in Andover Report attachment.	100%	
24	Days of Storage of Reagent	14.00		14.00				14.00	
25	Pressure Drop for SCR Ductwork	4.00		4.00				4.00	
26	Pressure Drop for each Catalyst Layer	1.00		1.00				1.00	
27	Number of SCR Reactors	1.00		1.00				1.00	
28	Temperature at Reactor Inlet	763.00		763.00				763.00	
30	Cost Year								
31	Equipment Life	20.00		20.00		11.00		11.00	
32	Annual Interest Rate	7%		7%				7%	
33	Chemical Engineering Plant Cost Index Value 1998								
34	Chemical Engineering Plant Cost Index Value 2011								
35	Catalyst Cost, Initial		Included in Vendor Budgetary Pricing		Included in Vendor Budgetary Pricing				Included in Vendor Budgetary Pricing
36	Catalyst Cost, Replacement	$290.00		$290.00		$155.74	Based on 5500 m3 used in Andover Report attachment.	$290.00	
37	Electrical Power Cost	0.03	Price Provided by PC	0.03	Price Provided by PC	0.06	As reported in Andover Report attachment.	0.03	Price Provided by PC
38	Reagent Cost	0.375	Price Provided by PC from DASCO quote July 2012	0.375	Price Provided by PC from DASCO quote July 2012	0.225	Based on 450 per tonused in Andover Report attachment.	0.375	Price Provided by PC from DASCO quote July 2012
39	Operating Life of Catalyst	32,000		32,000				32,000	
40	Catalyst Layers Full	3		3				3	
41	Catalyst Layers Empty	1		1				1	
42	Cost of Water	5		5				5	

	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / includes AFUDC)	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excludes AFUDC)	Comment
44																								
47	Max Heat Input Rate	Q_B	MMBtu/hr	2.3	$Q_B = \frac{HV \times \dot{m}_{fuel}}{10^6}$	1,000	1,000		2,349	Provided by PC	2,349		2,349		2,250	As reported in Andover Report attachment.	2,349		2,349		2,250	As reported in Andover Report attachment.	2,349	
48	Plant Capacity Factor	CF_{plant}		2.7	$CF_{Plant} = \frac{actual\ m_{fuel}}{\dot{m}_{fuel} \times 8760}$	50%	50%		90%	90% from Permit Calculation	90%		90%		84.4%	As reported in Andover Report attachment.	90%		90%		84.4%	As reported in Andover Report attachment.	90%	
49	SCR Capacity Factor	CF_{SCR}		2.8	$CF_{SCR} = \frac{t_{SCR}}{365\ days}$	42%	42%		100%		100%		100%				100%		100%				100%	
50	Total Capacity Factor	CF_{total}		2.6	$CF_{total} = CF_{plant}\ CF_{SCR}$	27%	21%	Fixed EPA calculation error	90%		90%		90%				90%		90%				90%	
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor	$q_{fluegas}$	acfm	2.12	$q_{fluegas} = \frac{q_{fuel}\ Q_B\ (460+T)}{(460+700^{\circ}F)\ n_{SCR}}$	463,138	463,138		1,102,613		1,102,613		1,102,613				1,522,000	Per Vendor's Combustion Calculation	1,522,000	Per Vendor's Combustion Calculation			1,522,000	Per Vendor's Combustion Calculation
52	NOx Removal Efficient for Cost-Effectiveness					0.85	0.85		0.73		0.73		0.73				0.76		0.76				0.76	
53	NOx Removal Efficiency for Reagent Consumption	η_{NOx}		2.9	$\eta_{NO_x} = \frac{NO_{x_{in}} - NO_{x_{out}}}{NO_{x_{in}}}$	0.85	0.85		0.73		0.73		0.73				0.76		0.76				0.76	
54																								
55	Catalyst Volume/Reactor	$Vol_{catalyst}$	ft³	2.19	$Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NO_{x_{adj}} \times S_{adj} \times \frac{T_{adj}}{N_{SCR}}$	5089	5089		8538		8538		8538		Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	21083	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.	21083	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.	Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	21083	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.
56	where:	-	-	-																				
57	NOx Efficiency Adjustment	η_{adj}		2.20	$\eta_{adj} = 0.2869 + (1.058 \times \eta)$	1.19	1.19		1.06		1.06		1.06					Catalyst Cost in vendor estimate, this is not used.		Catalyst Cost in vendor estimate, this is not used.				Catalyst Cost in vendor estimate, this is not used.
58	NOx Adjustment Factor for Inlet NOx	NOx_{adj}		2.21	$NO_{x_{adj}} = 0.8524 + (0.3208 \times NO_{x_{in}})$	1.13	1.13		0.94		0.94		0.94					(see above)		(see above)				(see above)
59	Ammonia Slip Adjustment Factor	$Slip_{adj}$		2.22	$Slip_{adj} = 1.2835 - (0.0567 \times Slip)$	1.17	1.17		1.17		1.17		1.17					(see above)		(see above)				(see above)
60	Sulfur in Coal Adjustment Factor	S_{adj}		2.23	$S_{adj} = 0.9636 + (0.0455 \times S)$	1.01	1.01		1.02		1.02		1.02					(see above)		(see above)				(see above)
61	Temperature Adjustment Factor (for temps other than 700°F)	T_{adj}	°F	2.24	$T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$	1.15	1.15		1.10		1.10		1.10					(see above)		(see above)				(see above)
62																								
63	Catalyst Cross-Sectional Area	$A_{catalyst}$	ft²	2.25	$A_{catalyst} = \frac{q_{fluegas}}{16\left(\frac{ft}{sec}\right) \times \left(\frac{60\ sec}{min}\right)}$	482	482		1149		1149		1149					(see above)		(see above)				(see above)
64	SCR Reactor Cross-Sectional Area	A_{SCR}	ft²	2.26	$A_{SCR} = 1.15 \times A_{catalyst}$	554	554		1321		1321		1321					(see above)		(see above)				(see above)
65	length	l	ft	2.27	$l = w = (A_{SCR})^{1/2}$	23.50	23.50		36		36		36					(see above)		(see above)				(see above)
66	width	w																						
67	Estimate Number of Catalyst Layers	n_{layer}		2.28	$n_{layer} = \frac{Vol_{catalyst}}{3.1 \times A_{catalyst}}$	3	3	Estimated number of layers is less than input. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too low. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)				Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
68	Height of Catalyst Layer	h_{layer}	ft	2.29		4.50	4.50		3.50		3.50		3.50					Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
69	Total Number of Catalyst Layers	n_{total}	#	2.30	$n_{total} = n_{layer} + n_{empty}$	4	4		4		4		4				4		4				4	
70	Height of SCR Reactor	h_{SCR}	ft	2.31	$h_{SCR} = n_{total}(c_1 + h_{layer}) + c_2$	55	55		51		51		51					Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.

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Owen/97

	B	C	D	E	F	G	I	J	K	L	M	N	O	P
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment
71														
72	Ammonia Mass Flow Rate	$m_{reagent}$	lb/hr of NH_3	2.32	$\dot m_{reagent} = \frac{NO_{x_{in}}\, Q_B\, NSR\, \eta_{NO_x}\, M_{reagent}}{M_{NO_x}\, SR_T}$ $\dot m_{reagent} = \frac{NOx_{in} \times Q_B \times ASR \times 17.03}{46.01}$	334	284	in the example problem (2.5 Example Problem), EPA does not use NOx efficiency in their calculation, yet the equation (2.32) on pg 2-39 requires it	173		173		173	
73	Mass Flow Rate of Aqueous Reagent Solution	$m_{solution}$	lb/hr of NH3 solution	2.33	$\dot m_{sol} = \frac{\dot m_{reagent}}{C_{sol}}$	1,153	980		598			Not used as urea is the reagent		
74	Equivalent Dry Urea Consumption Rate		lb/hr		$\dot m_{urea} = \frac{\dot m_{sol}}{0.56}$						310	S&L added formulas and calculations to include U2A system. Value calculated for reagent costing	310	
75	Mass Flow Rate of Urea Solution	$m_{solution}$	lb/hr of NH3 solution	2.33	$\dot m_{sol} = \frac{\dot m_{reagent}}{C_{sol}}$						619		619	
76	Solution Volumetric Flow	q_{sol}	gph	2.34	$q_{sol} = \frac{\dot m_{sol} \times 7.481}{71.1}$	154.00	131.00		80.00		65.00	Volumetric flow rate of 50% urea solution with a density of 71.1 lb/ft3	65.00	
77	Storage Tank Volume	V_{tank}	gal	2.35	Tank Volume = $q_{sol}\, t$	51,744	44,016		26,880		21,840		21,840	
78														
80	Direct Capital Cost	DC	$	2.36		$6,832,000	$6,799,443		$11,466,926		$11,466,926		$19,392,734	Since no adjustment factor exists for urea systems, S&L added the estimated capital cost for the urea system by scaling the Huntington estimate.
81	Adjustment for the SCR Reactor Height	$f(h_{SCR})$	$/MMBtu/hr	2.37	$DC = Q_B\left[\frac{\$3{,}380}{\left(\frac{MMBtu}{hr}\right)} + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass)\right]\left(\frac{3500}{Q_B}\right)^{0.35} + f(Vol_{catalyst})$	49.00	$149.00		$124.00		$124.00		$124.00	
82	Adjustment for the Ammonia Flow Rate	$f(NH_{3rate})$	$/MMBtu/hr	2.38	$f(NH_3rate) = \left[\frac{\$411}{lb/hr}\,\frac{\dot m_{reagent}}{Q_B}\right] - \frac{\$47.3}{\left(\frac{MMBtu}{hr}\right)}$	$90.00	$69.00		-$17.00		-$17.00		-$17.00	
83	Adjustment for Retrofit or New Boiler	f(new)	$/MMBtu/hr	2.39 + 2.40	Is it a retrofit or new boiler?	$0.00	$0.00		$0.00		$0.00		$0.00	
84	Adjustment for SCR Bypass	f(bypass)	$/MMBtu/hr	2.41 + 2.42	Is a bypass installed?	$0.00	$0.00		$0.00		$0.00		$0.00	
85	Capital Cost for the Initial Charge of Catalyst	$f(Vol_{catalyst})$	$/MMBtu/hr	2.43	$f(Vol_{catalyst}) = Vol_{catalyst}\, CC_{initial}$	$1,221,360	$1,221,360		$2,049,120		$2,049,120		$2,049,120	
86	Indirect Installation Costs Due to General Facilities		$	Table 2.5	0.05xDC	$341,600	$339,972		$573,346		$573,346		$969,637	
87	Indirect Installation Costs Due to Engineering and Home Office Fees		$	Table 2.5	0.10xDC	$683,200	$679,944		$1,146,693		$1,146,693		$1,939,273	
88	Indirect Installation Costs Due to Process Contingency		$	Table 2.5	0.05xDC	$341,600	$339,972		$573,346		$573,346		$969,637	
89	Total Indirect Installation Costs	IIC	$	Table 2.5	DCx(0.05+0.10+0.05)	$1,366,400	$1,359,889		$2,293,385		$2,293,385		$3,878,547	
90	Project Contingency		$	Table 2.5	(DC+IIC)x0.15	$1,229,760	$1,223,900		$2,064,047		$2,064,047		$3,490,692	
91	Total Plant Costs	PC	$	Table 2.5	DC+IIC+Project Contingency	$9,428,160	$9,383,231		$15,824,357		$15,824,357		$26,761,973	
92	Allowance for Funds During Construction	AFUDC	$											
93	Preproduction Cost	PrePro	$	Table 2.5	0.02 x (PC+Construction)	$188,563	$187,665		$316,487		$316,487		$535,239	
94	Inventory Capital	Inventory	$	Table 2.5	$m_{solution}$ x daysx24x irc	$39,128	$33,257		$20,294		$20,815		$20,815	
95	Initial Catlayst and Chemicals		$											
96	**Total Capital Investment**	**TCI**	**$**	**Table 2.5**	**PC+Construction+PrePro+Inventory+Catalyst**	**$9,655,851**	**$9,604,153**		**$16,161,138**		**$16,161,659**		**$27,318,028**	
97	Maintenance Cost		$/yr	2.46	Annual Maintenance Cost = 0.015 TCI	$144,838	$144,062		$242,417		$242,425		$409,770	
98	Power	P	kW	2.48		444	444		910		910		1,033	

	B	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / includes AFUDC)	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excludes AFUDC)	Comment
71											
72	Ammonia Mass Flow Rate	142	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	146		146		142	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	146	
73	Mass Flow Rate of Aqueous Reagent Solution			146		146				146	
74	Equivalent Dry Urea Consumption Rate	253						253			
75	Mass Flow Rate of Urea Solution	506						506			
76	Solution Volumetric Flow	53		20.00		20.00		53		20.00	
77	Storage Tank Volume		Tank volume included in Andover estimate unknown.	6,720		6,720			Tank volume included in Andover estimate unknown.	6,720	
78											
80	Direct Capital Cost	$42,037,165	As reported in Andover Report attachment.	$66,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)	$66,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)	$42,037,165	As reported in Andover Report attachment.	$66,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)
81	Adjustment for the SCR Reactor Height		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.
82	Adjustment for the Ammonia Flow Rate		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.
83	Adjustment for Retrofit or New Boiler		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.
84	Adjustment for SCR Bypass		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.
85	Capital Cost for the Initial Charge of Catalyst		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.
86	Indirect Installation Costs Due to General Facilities		Unknown because EPA cost manual not used	$3,305,000		$3,305,000			Unknown because EPA cost manual not used	$3,305,000	
87	Indirect Installation Costs Due to Engineering and Home Office Fees		Unknown because EPA cost manual not used	$6,610,000		$6,610,000			Unknown because EPA cost manual not used	$6,610,000	
88	Indirect Installation Costs Due to Process Contingency		Unknown because EPA cost manual not used	$3,305,000		$3,305,000			Unknown because EPA cost manual not used	$3,305,000	
89	Total Indirect Installation Costs	$12,611,149	As reported in Andover Report attachment.	$13,220,000		$13,220,000		$12,611,149	As reported in Andover Report attachment.	$13,220,000	
90	Project Contingency		Unknown because EPA cost manual not used	$11,898,000		$11,898,000			Unknown because EPA cost manual not used	$11,898,000	
91	Total Plant Costs	$54,648,314		$91,218,000		$91,218,000		$54,648,314		$91,218,000	
92	Allowance for Funds During Construction	$0	As reported in Andover Report attachment.	$8,725,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. <u>Note that this value is not included in the TCI, but is shown for information since this item does represent an actual cost to PacifiCorp</u>	$8,725,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. <u>Included in the TCI as an actual cost to PacifiCorp for comparative purposes.</u>	$0	As reported in Andover Report attachment.	$8,725,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. <u>Note that this value is not included in the TCI, but is shown for information since this item does represent an actual cost to PacifiCorp</u>
93	Preproduction Cost			$1,998,860		$1,998,860				$1,998,860	
94	Inventory Capital			$0	This item reflects urea only, which is not be part of vendor pricing. Initial Catalyst Fills included as part of vendor pricing, therefore excluded in this item.	$0	This item reflects urea only, which is not be part of vendor pricing. Initial Catalyst Fills included as part of vendor pricing, therefore excluded in this item.			$0	This item reflects urea only, which is not be part of vendor pricing. Initial Catalyst Fills included as part of vendor pricing, therefore excluded in this item.
95	Initial Catlayst and Chemicals			$35,000		$35,000				$35,000	
96	**Total Capital Investment**	**$54,648,314**	As reported in Andover Report attachment.	**$93,251,860**		**$101,976,860**		**$54,648,314**	As reported in Andover Report attachment.	**$93,251,860**	
97	Maintenance Cost	$363,300	Based on $1.73/kw-yr as reported in Andover Report attachment.	$1,398,778		$1,529,653		$363,300	Based on $1.73/kw-yr as reported in Andover Report attachment.	$1,398,778	
98	Power			1,026		1,026				1,026	

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Owen/98

	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / includes AFUDC)	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excludes AFUDC)	Comment
99	Electricity Cost		$/yr	2.49	$Power = 0.105\,Q_B\left[NO_{x_{in}}\,\eta_{NO_x} + 0.5\left(\Delta P_{duct} + n_{total}\,\Delta P_{catalyst}\right)\right]$ $Annual\ Electricity\ Cost = Power\ Cost_{elect}\ t_{op}$	$52,538	$41,316		$358,769		$358,769	Increase in power consumption for U2A system is negligible, thus no adjustment needed	$407,383	Increased due to additional pressure drop associated with ductwork	$0	Based on $0.35/MW-hr as reported in Andover Report attachment.	$242,680		$242,680		$0	Based on $0.35/MW-hr as reported in Andover Report attachment.	$242,680	
100	Reagent Solution Cost		$/yr	2.47	$ReagentCost = m_{sol} \times 8760 \times CF_{total} \times Cost_{reagent}$	$275,435	$184,103		$476,178		$488,401		$488,401		$838,416	Based on $0.54/MW-hr as reported in Andover Report attachment.	$431,850		$431,850		$838,416	Based on $0.54/MW-hr as reported in Andover Report attachment.	$431,850	
101	Future Worth Factor	FWF		2.52	$FWF = i\left[\frac{1}{(1+i)^Y - 1}\right]$	0.14	0.14		0.31		0.23		0.23				0.23		0.23				0.23	
102	Years	Y	yr	2.53	$Y = \frac{h_{catalyst}}{CF_{SCR} \times 8760}$	6	6		3		4		4				4		4				4	
103	Factor for Catalyst Replacement	R_{layer}				3	3		3		3		3				3		3				3	
104	Annual Catalyst Replacement Cost		$/yr	2.50 + 2.51	$Annual\ Catalyst\ Replacement\ Cost = FWF \times \left[1 \times Vol_{catalyst} \times \frac{CC_{replace}}{R_{layer}}\right]$	$68,871	$68,871		$255,855		$189,828		$189,828		$388,156	Based on $0.25/MW-hr as reported in Andover Report attachment.	$468,745	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.	$468,745	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.	$388,156	Based on $0.25/MW-hr as reported in Andover Report attachment.	$468,745	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.
105	Annual Additional Water for Urea		$/yr		Volumetric flow rate of water, Dry Urea Consumption Rate * 1 lb H2O * 7.48 gal / (62.4 lb/ft3 * 1 lb urea)				$0		$1,464	Additional water would be needed for a U2A solid urea system in comparison with any other system because need the water to dissolve the solid urea. Value is based on gph flow rate of 50% urea solution. Naughton 3 had 0.006MMBtu/hr of steam guaranteed per pound of urea consumed.	$1,464		$0	Not included in Andover Report attachment.	$0		$0		$0	Not included in Andover Report attachment.	$0	
106	Annual Additional Steam for Urea Hydrolyzer		$/yr						$0		$73,260		$73,260		$7,763	Based on $0.005/MW-hr as reported in Andover Report attachment.	$0		$0		$7,763	Based on $0.005/MW-hr as reported in Andover Report attachment.	$0	
107	Total Variable Direct Cost				=Electricity Cost+Reagent Solution Cost + Annual Catalyst Replacement Cost + Water Cost	$396,843	$294,290		$1,090,803		$1,111,723		$1,160,337		$1,234,335		$1,143,275		$1,143,275		$1,234,335		$1,143,275	
108	Total Direct Annual Cost			2.45	=Maintenance Cost +Total Variable Direct Cost	$541,681	$438,352		$1,333,220		$1,354,148		$1,570,107		$1,597,635		$3,474,571	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.	$3,692,696	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.	$1,597,635		$3,474,571	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.
109	Property Tax Factor	F(tax)		2.5.5.8		0.00	0.00		0.00		0.00		0.00		0.00		$932,519		$1,019,769		0.00		$932,519	
110	Overhead Factor	F(ovhd)				0.00	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00	
111	Capital Recovery Factor	CRF		2.55	$CRF = \frac{i\,(1+i)^n}{(1+i)^n - 1}$	0.0944	0.0944		0.0944		0.0944		0.0944		0.1064	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%, Total Charge Rate = 10.64%.	0.0944		0.0944		0.1454	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%, Total Charge Rate = 10.64%.	0.1334	
112	Indirect Annual Costs	IDAC	$/yr	2.54	$IDAC = CRF\ TCI$	$911,444	$906,564		$1,525,497		$1,525,546		$2,578,629		$5,814,581		$8,802,316		$9,625,894		$7,945,865		$12,435,779	
113	Total Annual Cost	TAC	$/yr	2.56	$Total\ Annual\ Cost = \left(\begin{array}{c}Direct\\Annual\\Cost\end{array}\right) + \left(\begin{array}{c}Indirect\\Annual\\Cost\end{array}\right)$	**$1,453,125**	**$1,344,916**		**$2,858,717**		**$2,879,694**		**$4,148,735**		**$7,959,487**	As reported in Andover Report attachment.	**$12,276,887**		**$13,318,590**		**$9,543,500**	As reported in Andover Report attachment.	**$15,910,351**	
114	Annual NOx Removed		tons/yr	2.57	NOx Removed $= NO_{x_{in}}\,\eta_{NO_x}\,Q_B\,t_{op}$	864	680		1,758		1,758		1,758		1,336	As reported in Andover Report attachment. (See Note 1)	1,336	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,336	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,336	As reported in Andover Report attachment. (See Note 1)	1,336	Aligned with Andover Report assumption for cost-effectiveness comparison.
115	Cost Effectiveness		$/ton	2.58	$Cost\ Effectiveness = \frac{TAC}{NO_x\ Removed}$	**$1,681**	**$1,978**		**$1,627**		**$1,639**		**$2,361**		**$5,956**	**As reported in Andover Report attachment. (See Note 1)**	**$9,189**		**$9,969**		**$7,143**	**As reported in Andover Report attachment. (See Note 1)**	**$11,909**	
116	**Note 1 - In attachment EPA-R08-OAR-2012-0026-0087, Andover calculates SCR cost effectiveness in two ways: a) starting from baseline emissions of 0.21, assuming combustion controls already in place (see worksheet "NOx - SCR_01_03")and b) starting from baseline emissions of 0.52, assuming combustion controls are not in place (see worksheet "Naughton"). This worksheet reports Andover's results assuming combustion controls are already in place since this is consistent with current operation at Naughton**																							

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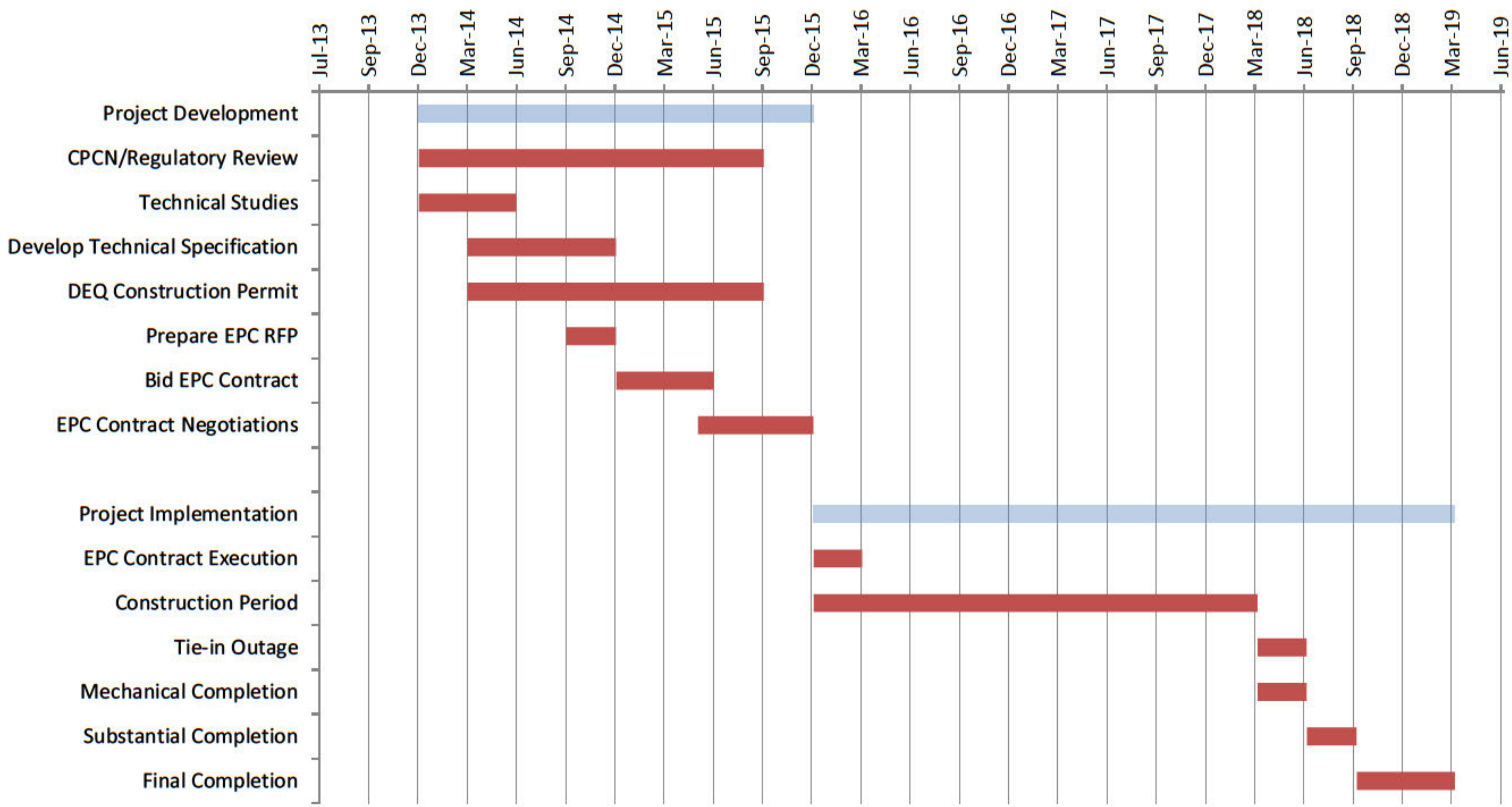
Attachment 5

General SCR Project Timeline – 2018 In-service



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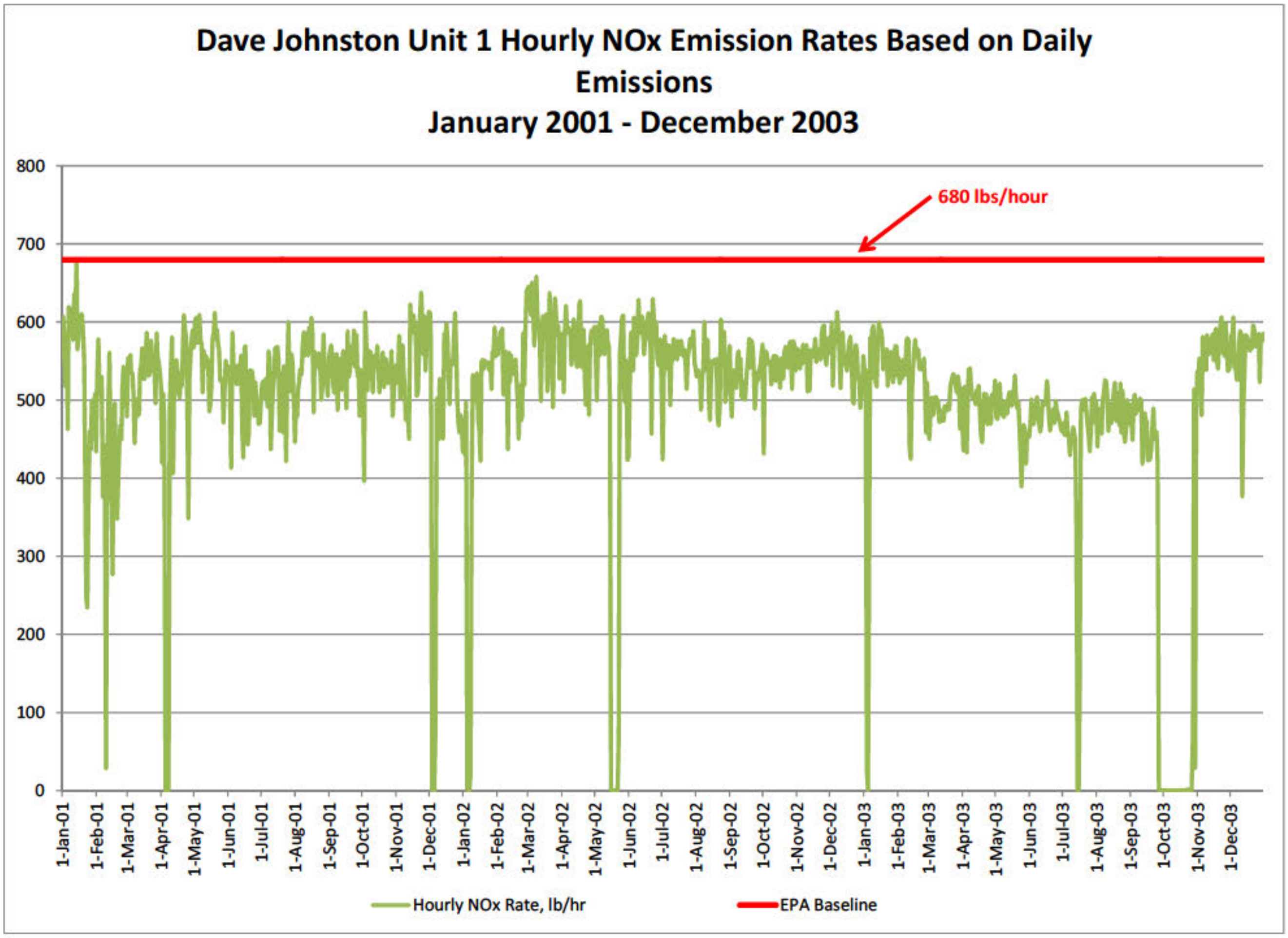
Attachment 6


Dave Johnston Unit 1 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
680 lbs/hour
0
100
200
300
400
500
600
700
800
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
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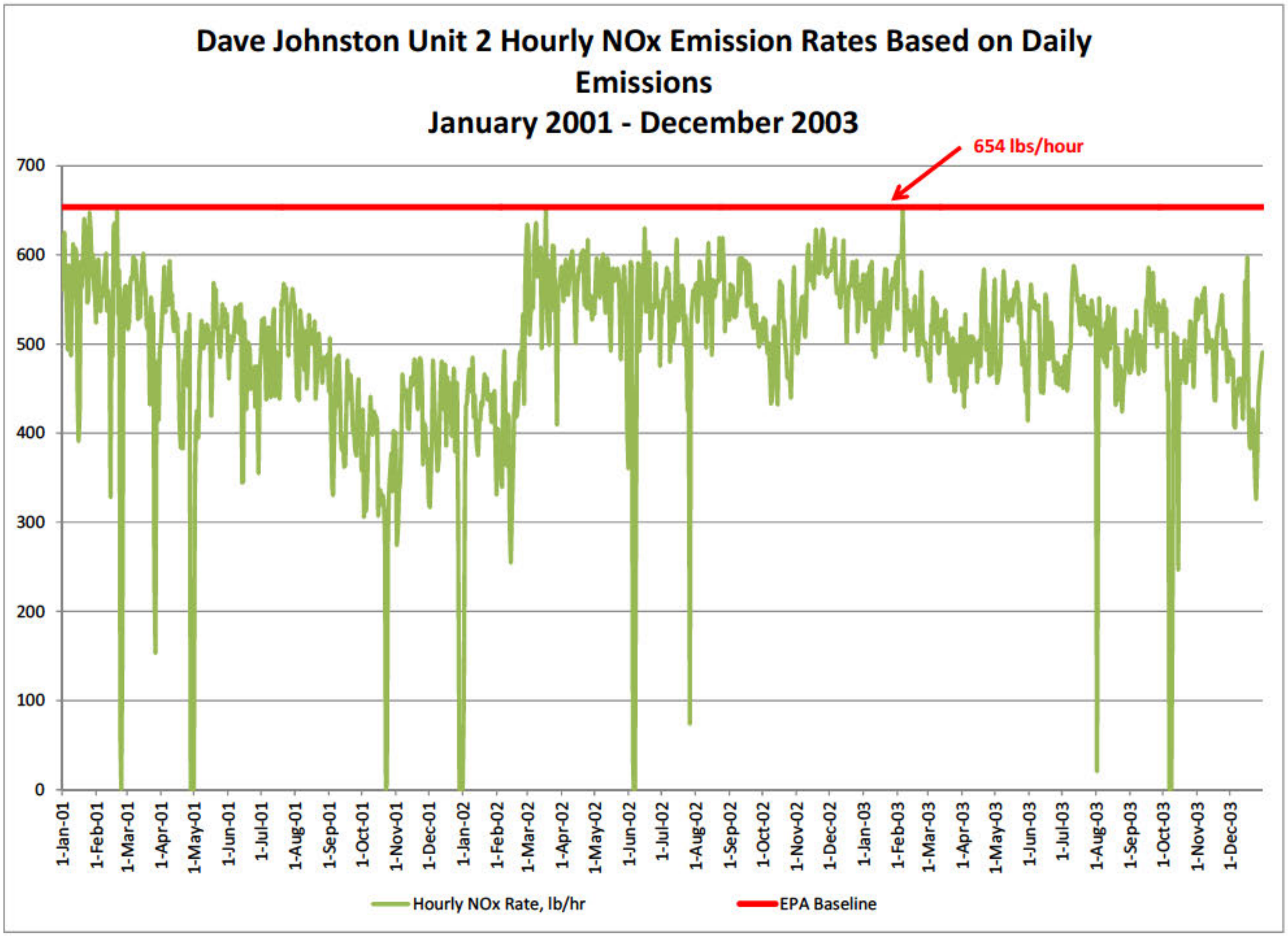
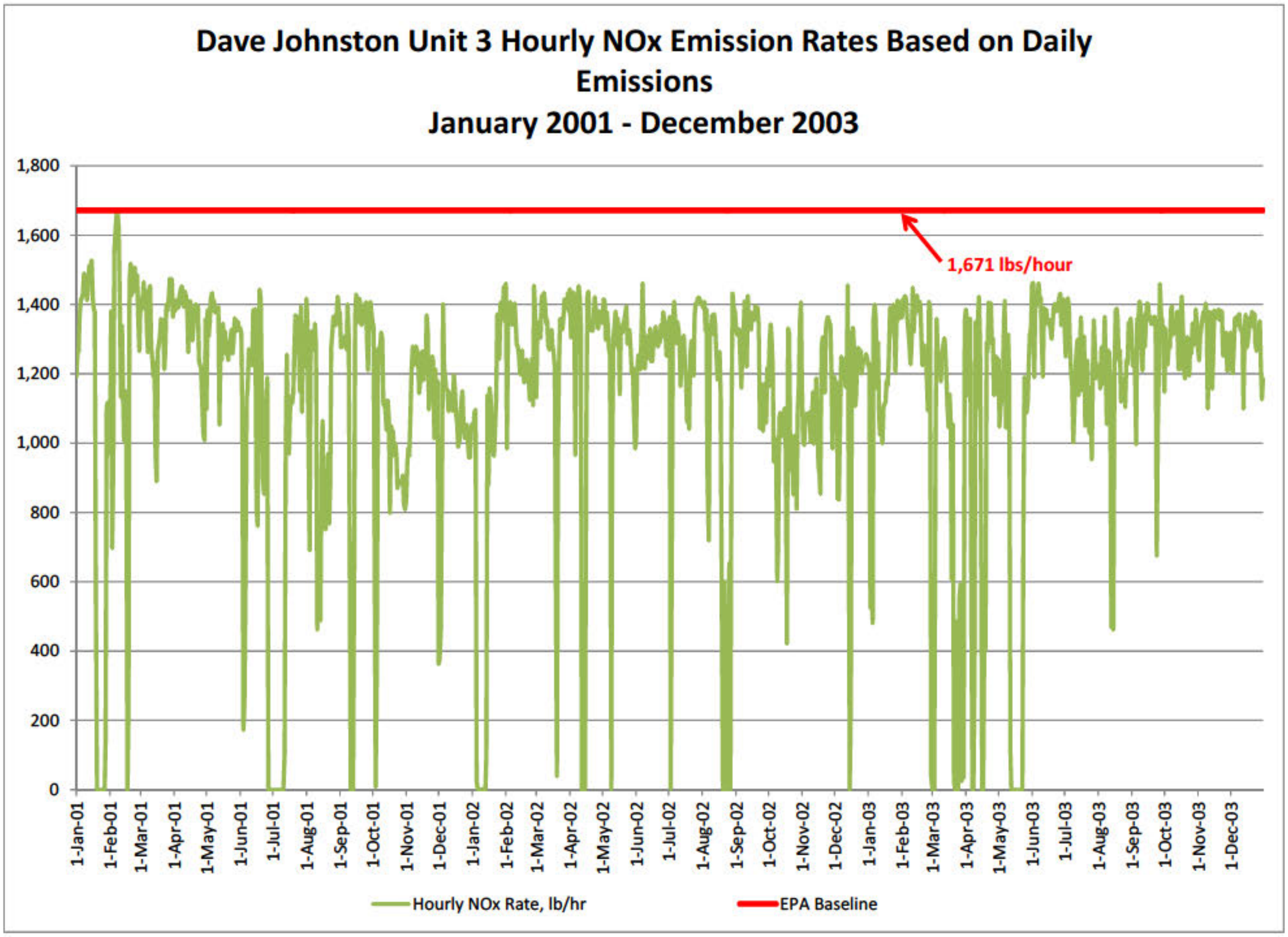
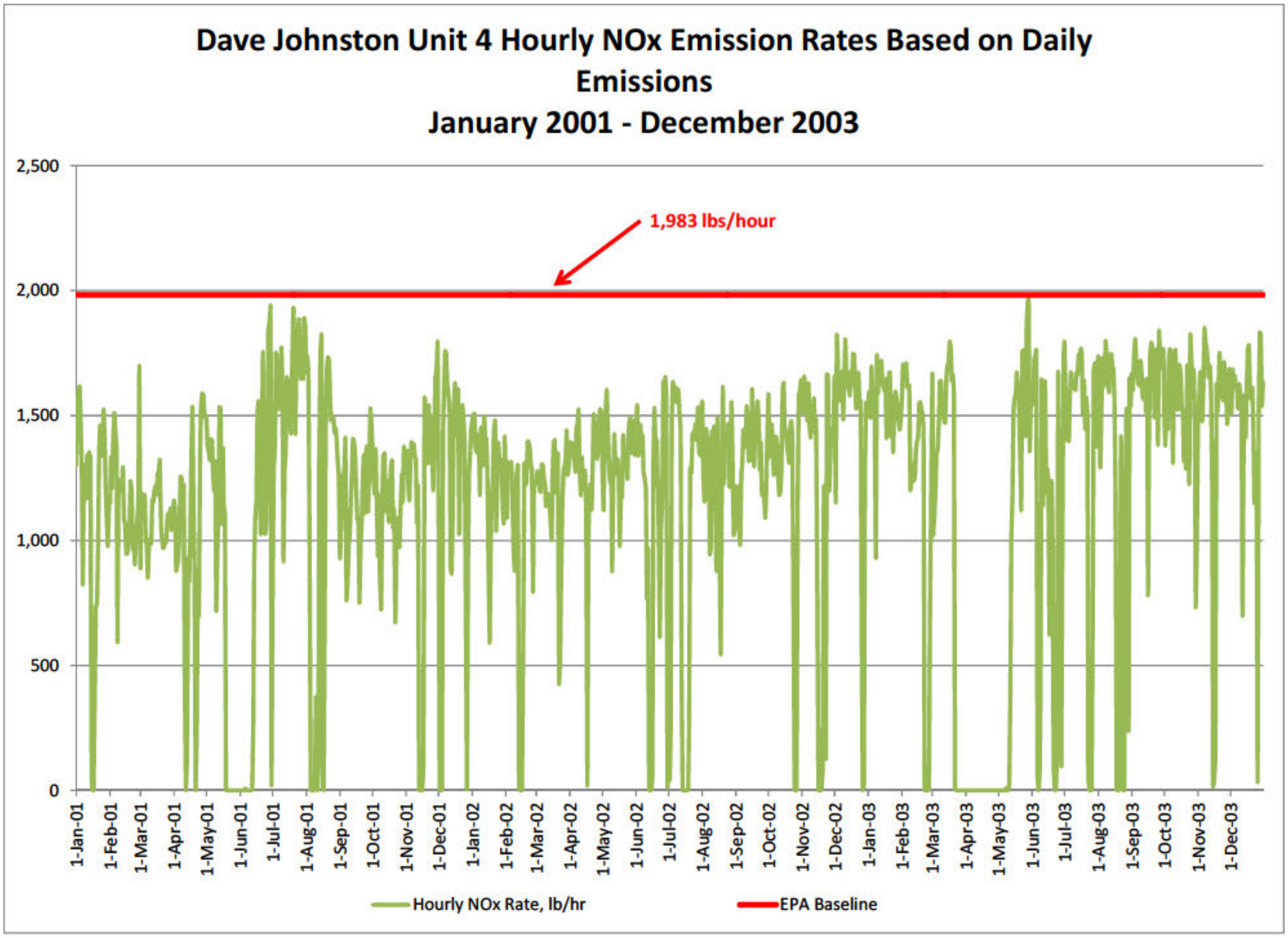
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Dave Johnston Unit 2 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
654 lbs/hour
700
600
500
400
300
200
100
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Dave Johnston Unit 3 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
1,671 lbs/hour
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Dave Johnston Unit 4 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
1,983 lbs/hour
2,500
2,000
1,500
1,000
500
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
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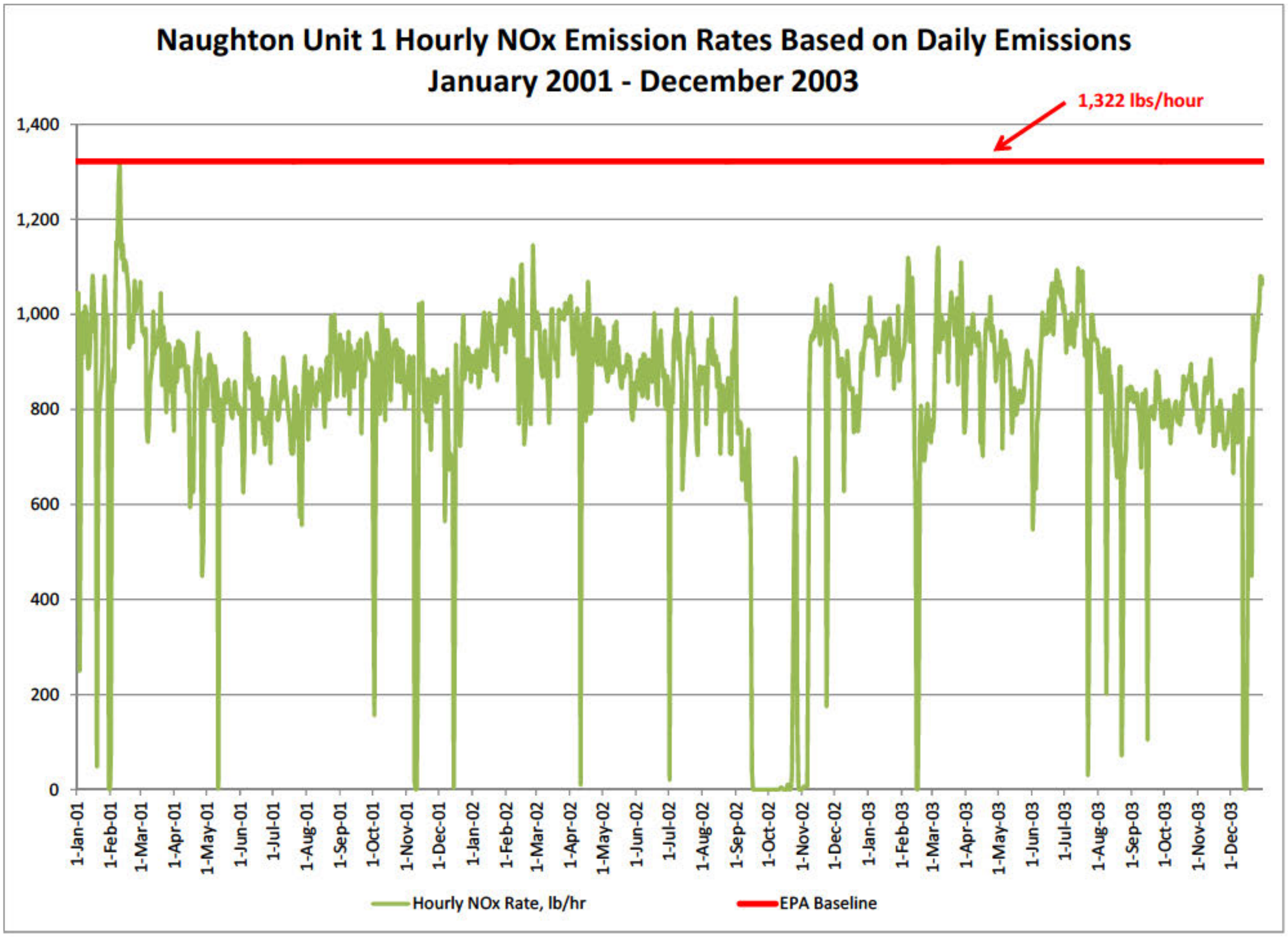
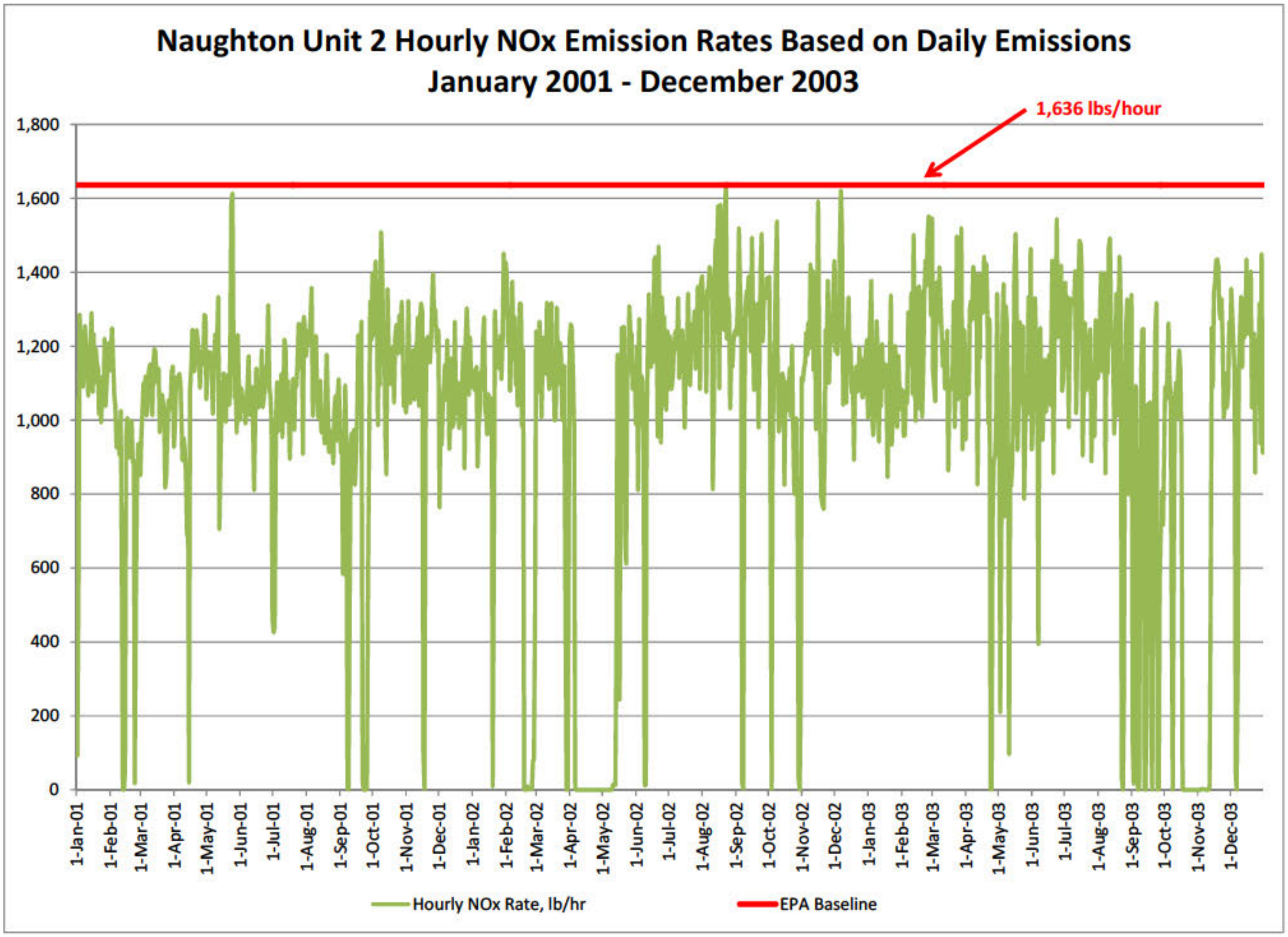
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Naughton Unit 1 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
1,322 lbs/hour
1,400
1,200
1,000
800
600
400
200
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Naughton Unit 2 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
1,636 lbs/hour
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
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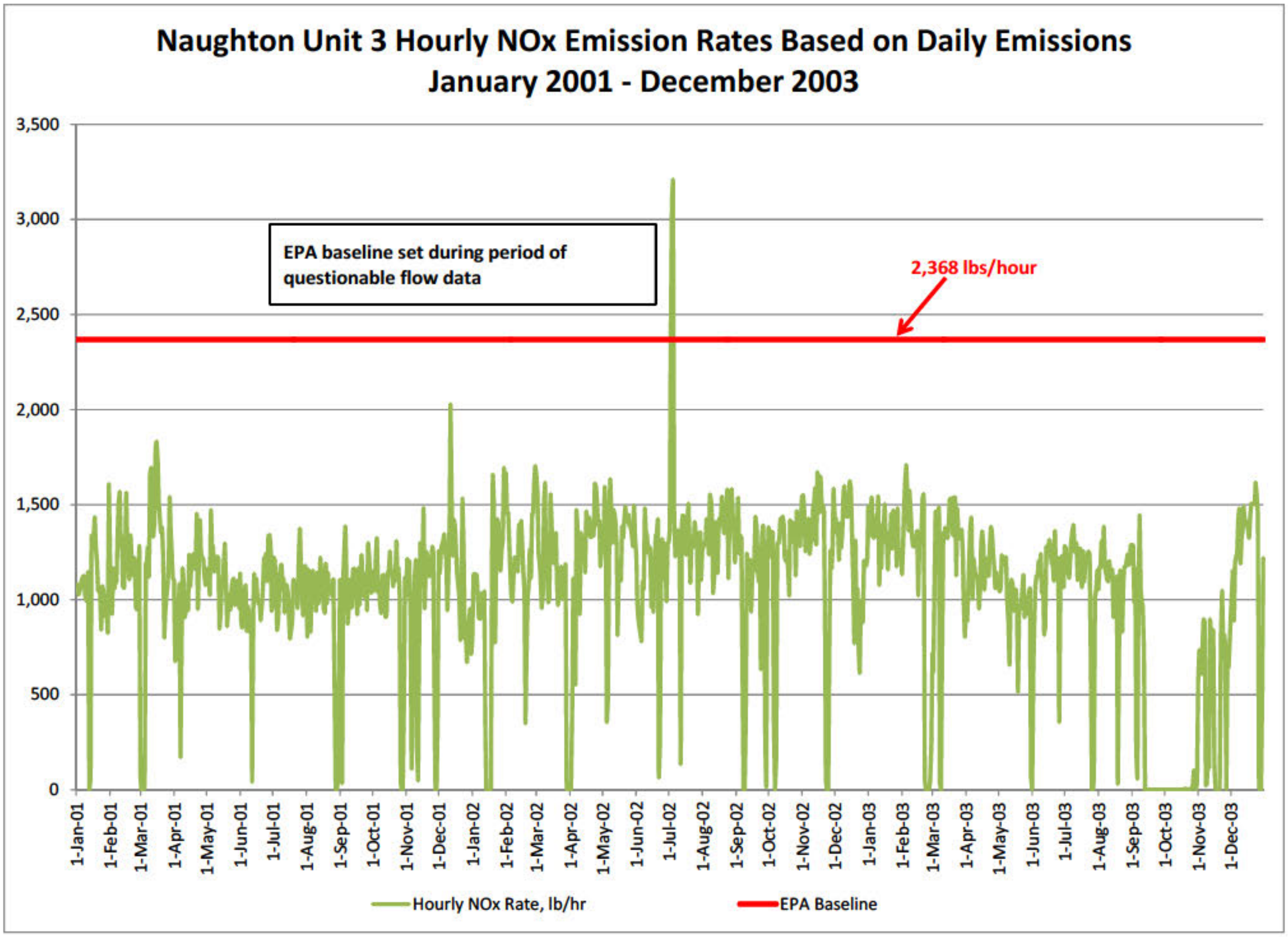
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Naughton Unit 3 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
EPA baseline set during period of questionable flow data
2,368 lbs/hour
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
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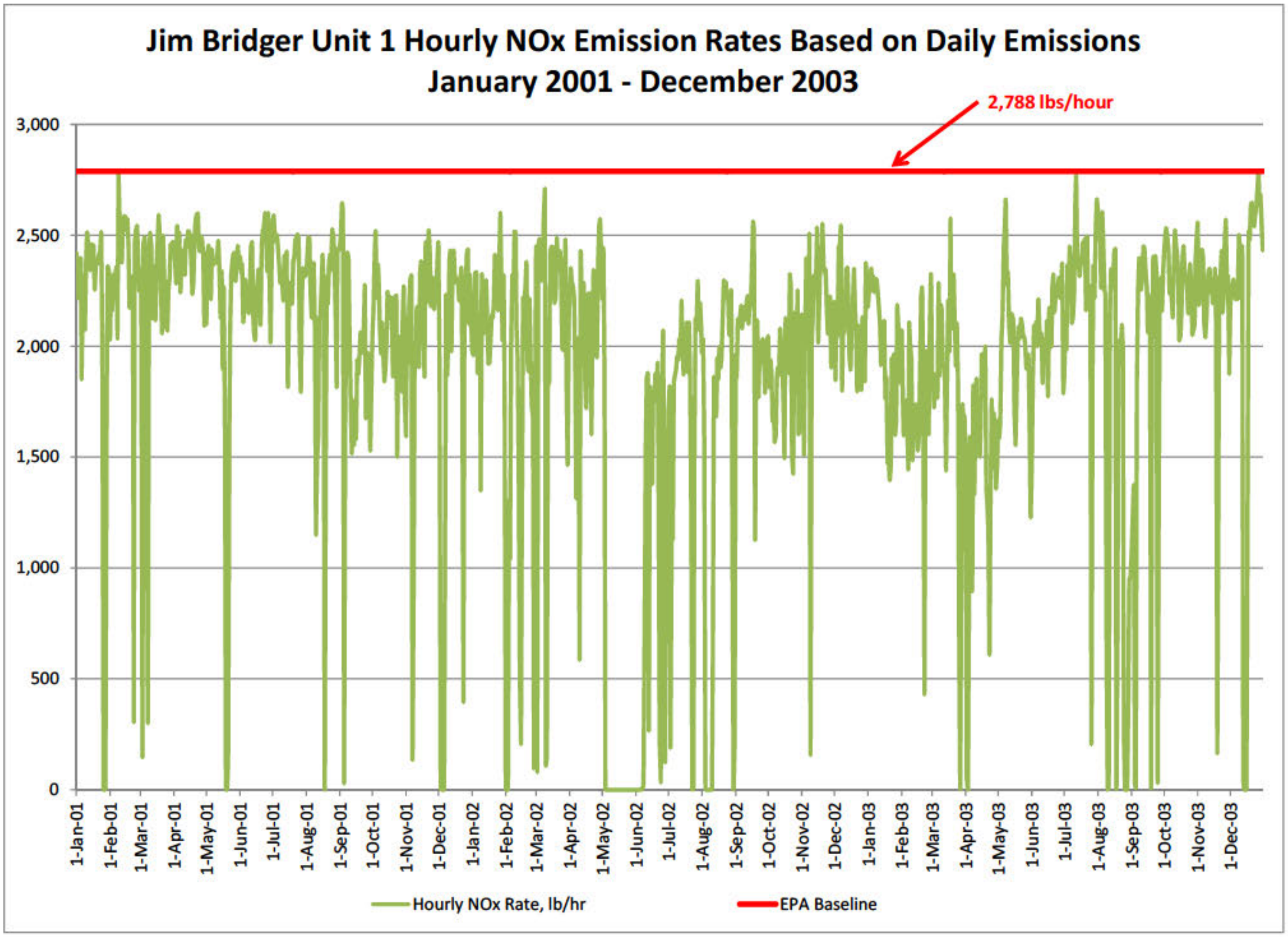
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Jim Bridger Unit 1 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
2,788 lbs/hour
3,000
2,500
2,000
1,500
1,000
500
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
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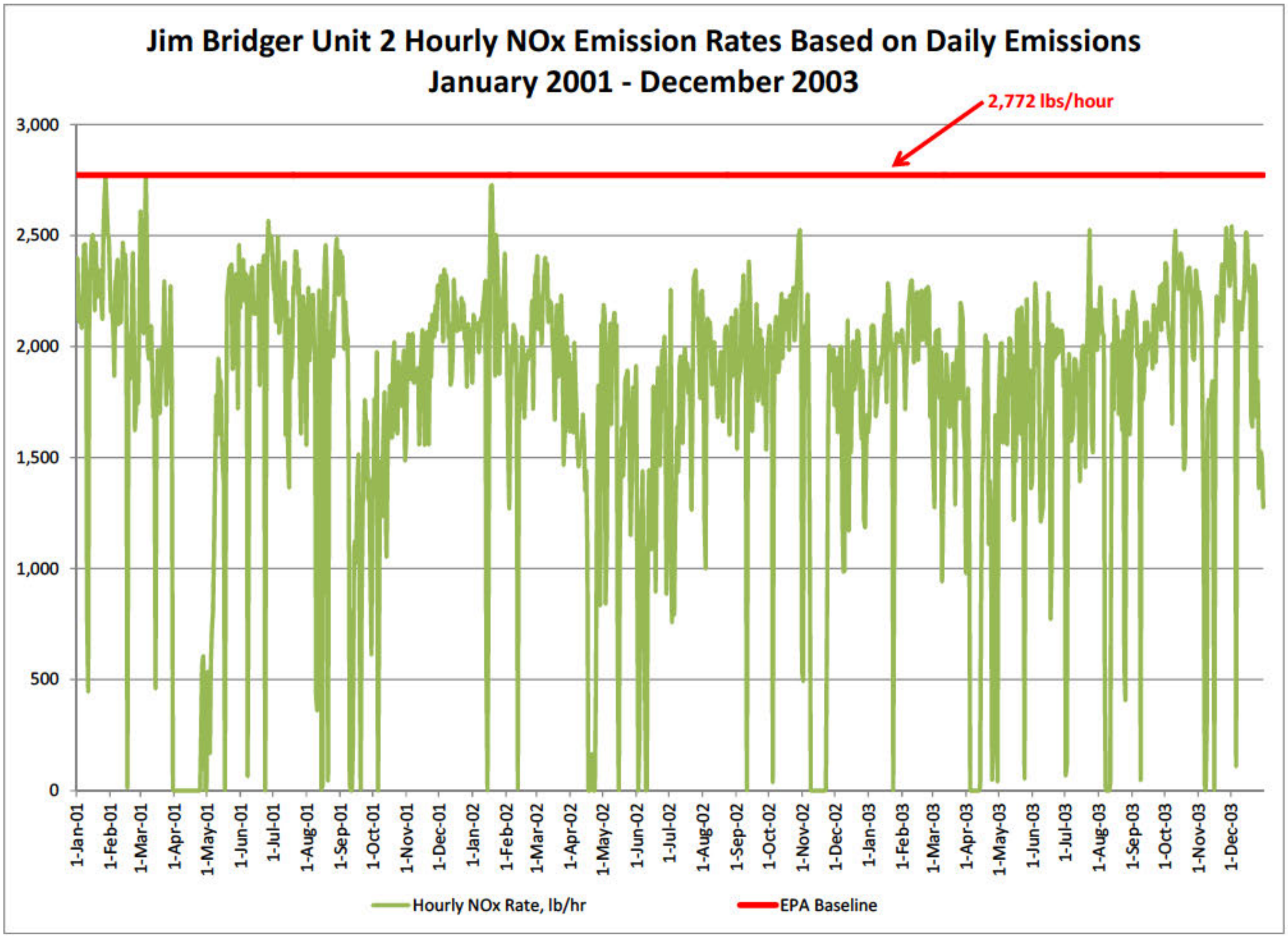
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Jim Bridger Unit 2 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
2,772 lbs/hour
3,000
2,500
2,000
1,500
1,000
500
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
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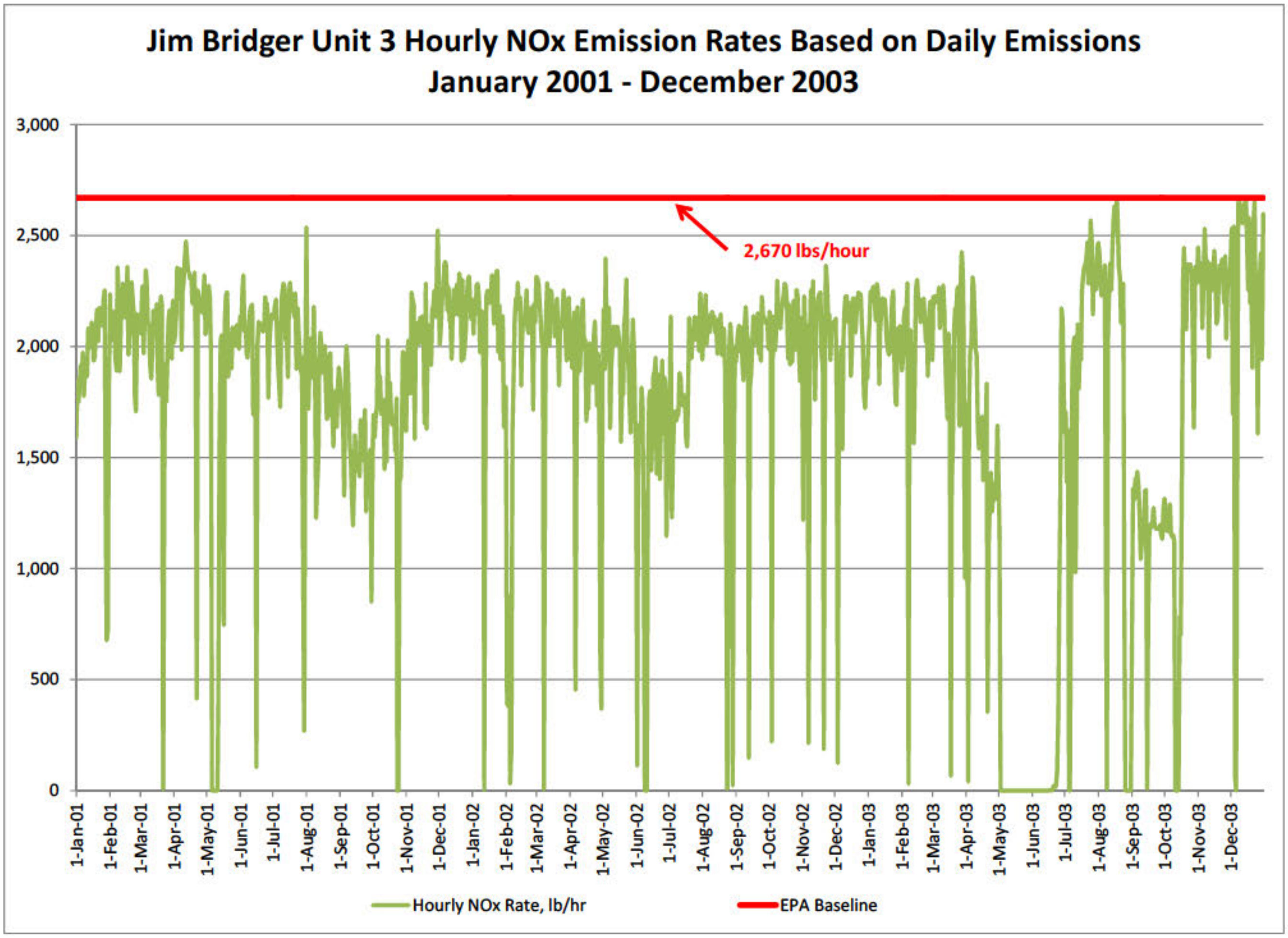
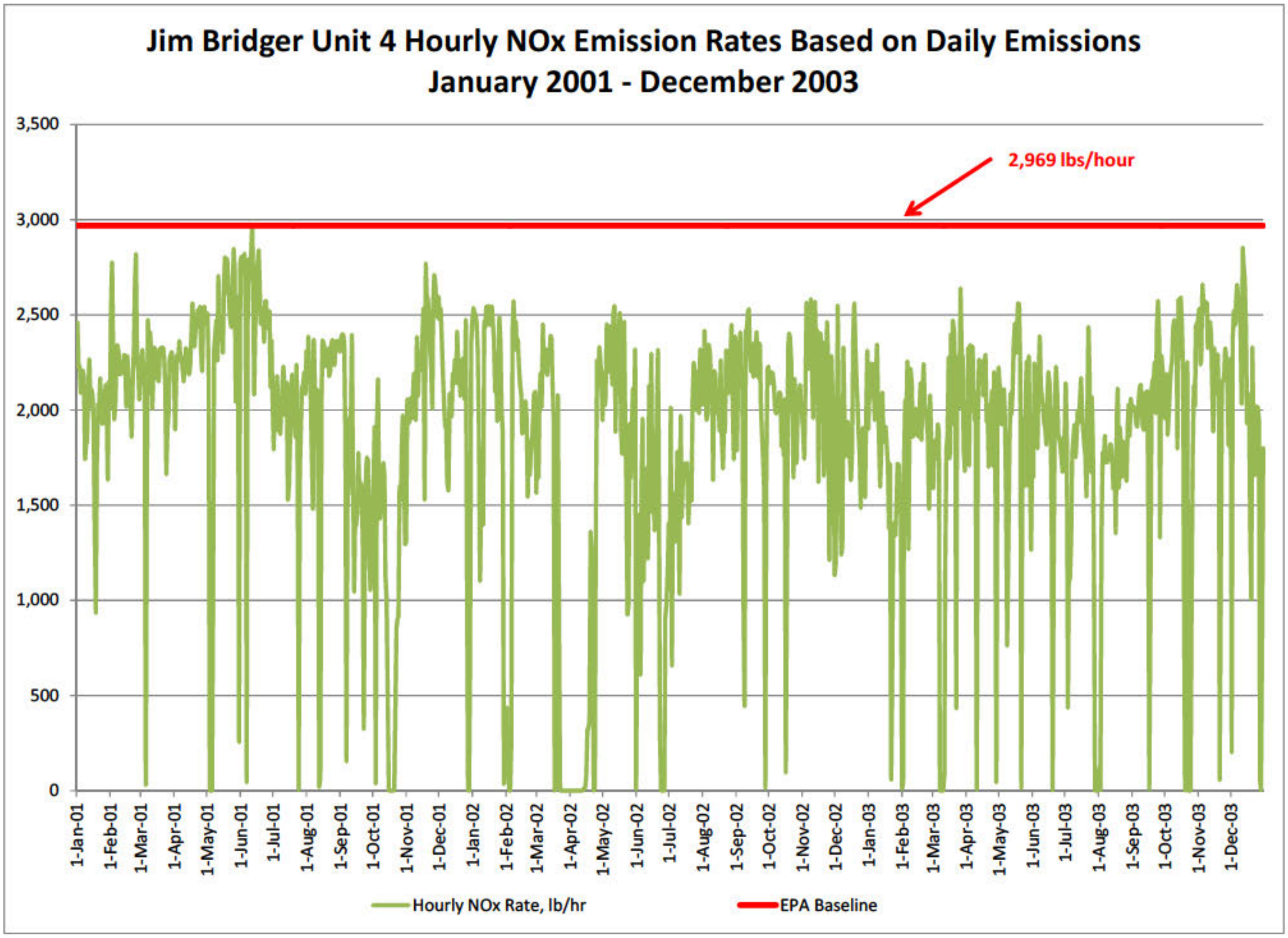
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Jim Bridger Unit 3 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
3,000
2,500
2,000
1,500
1,000
500
0
2,670 lbs/hour
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Jim Bridger Unit 4 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
2,969 lbs/hour
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
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1-Sep-03
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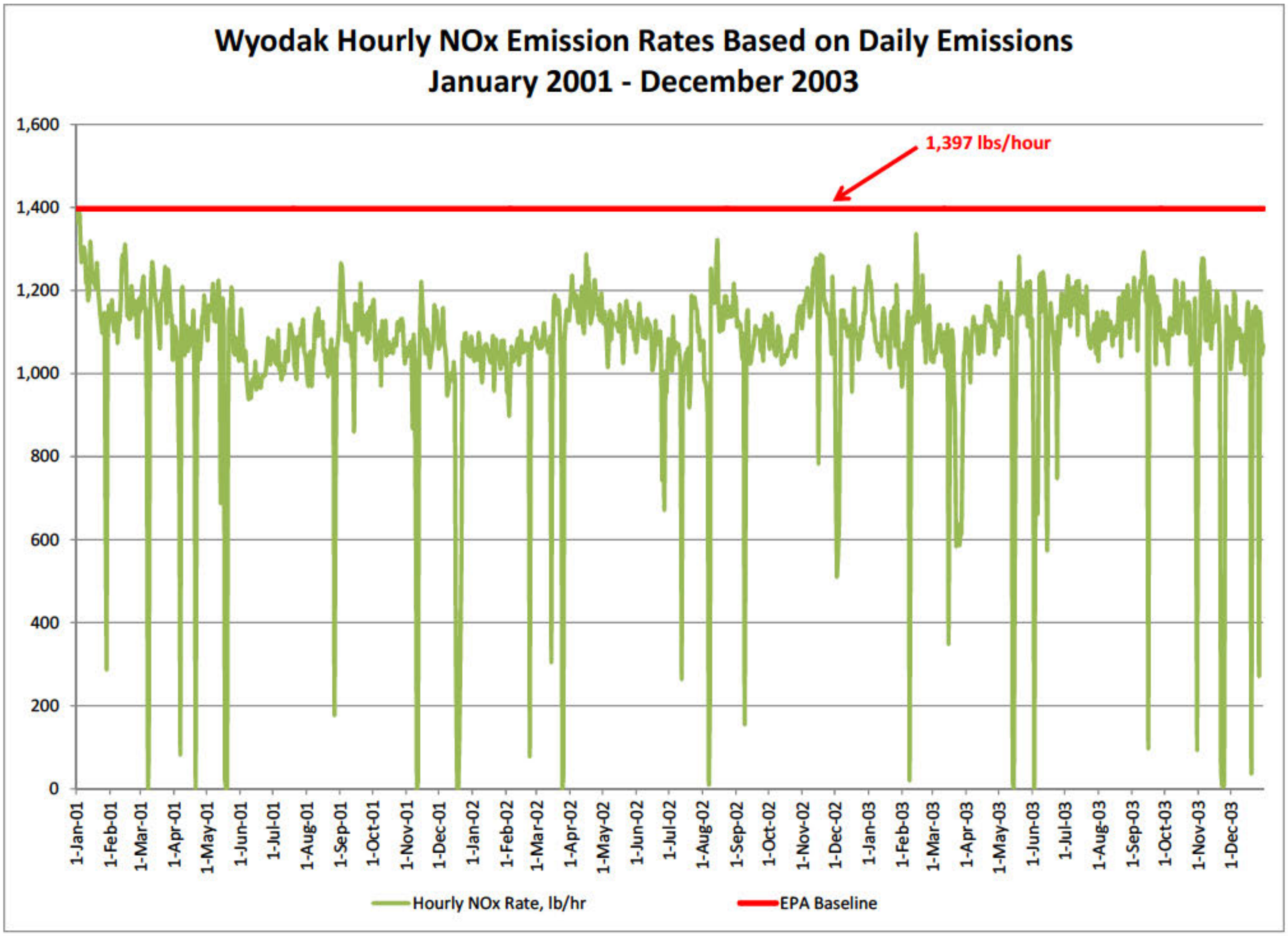
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Wyodak Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
1,397 lbs/hour
1,600
1,400
1,200
1,000
800
600
400
200
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline

Attachment 7

TECHNICAL MEMORANDUM

CH2MHILL®

Preliminary Analysis of EPA Wyoming BART Modeling

PREPARED FOR: Bill Lawson, PacifiCorp

COPY TO:

PREPARED BY: CH2M Hill

DATE: August 3, 2012

PROJECT NUMBER:

CH2M Hill has obtained the modeling files from EPA Region 8 that they used to model the impact to regional visibility from PacifiCorp power plants in Wyoming. In reviewing these files, we have noted the following issues with the methods and data that EPA chose to use in performing this modeling.

Background Ammonia Concentration:
EPA conservatively used a constant 2 ppb ammonia for the WY BART modeling. This value is conservative based on Wyoming Land Use, IWAQM Guidance, WRAP protocols, and nearby State's BART modeling using monthly/seasonally varying ammonia.

IWAQM recommends 0.5 ppb for forest, 1ppb for dry/arid lands and 10ppb for agriculture/grassland. The state undergoes seasonal swings of dry-hot summers and snow covered ground in the winter. Therefore, the use of a single ammonia concentration for the entire year in a state where the land use and land cover changes significantly between seasons could result in unrealistic seasonal results. This would be particularly true in winter time when agricultural activity is minimal and meteorological conditions would make visibility calculations particularly sensitive to ambient ammonia concentrations.

WRAP recommended the use of 1 ppb year round for states in the region to account for the seasonal variability. Other states have allowed for the use of monthly varying ammonia concentrations to better reflect the monthly variations observed in monitored ambient data.

CALPUFF Model Version 5.7:
The most recent EPA approved version of CALPUFF is version 5.8 and was released on June 23, 2007. The EPA modeling of the WY coal plants used version 5.711a, released July 16, 2004. Since version 5.711a, EPA has subsequently released versions 5.711b, version 5.756, and the now currently approved version 5.8. EPA also released a Model update report (available at www.epa.gov/ttn/scram) demonstrating that the bugs fixed and enhancements put into in version 5.8 warrant EPA using the recommend version 5.8 as the approved version of CALPUFF.

The modeling conducted by EPA with version 5.711a was completed in April 2012. This is eight years and three more recent CALPUFF model versions since the release of version 5.711a by EPA.

EPA has in recent years recommended the use of V5.8 for BACT analyses. Specifically, EPA Region 9 requested Catalyst Paper use V5.8 for their units in Arizona in a letter dated November 17, 2011. Also, the State of Utah (through guidance from EPA) has requested that PacifiCorp use V5.8 for recent BACT studies in Utah. The use of V5.7 in the WY coal plant studies is incongruent with recent EPA guidance.

CALPOST Method 6:

The previously preferred Method 6 simply computes background light extinction using monthly average relative humidity adjustment factors particular to each Class I Area applied to background and modeled sulfate and nitrate. Six years after the development of Method 6 in 1999, EPA released enhancements to the background light extinction equations, which use the IMPROVE variable extinction efficiency formulation. These enhancements take into account the fact that sulfates, nitrates and organics and other types of particles have different light extinction coefficients. Also the background concentrations at each Class I area have been updated by EPA to reflect natural background visibility condition estimates for each Class I area for each type of particle: ammonium sulfate, ammonium nitrate, organic matter, elemental carbon, soil, crustal material, sea salt and air molecules. Also, relative humidity adjustment factors have been tailored separately for: small particles, large particles, and sea salt background concentrations.

These new enhancements to the calculation method greatly improve the accuracy of the estimated visibility impact and are called Method 8. Method 8 was added to CALPOST in 2008 and was adopted as the preferred option for determining impacts on visibility by the Federal Land Managers Air Quality Related Values Work Group (FLAG) guidance document in 2010 (FLAG 2010) . The applicable background concentrations and relative humidity adjustment factors using Method 8 for each Class I area are identified in the FLAG 2010 manual.

Despite this update to Method 8 in 2008 and the stated preference by the FLMs in 2010 to use Method 8, EPA updated the WY BART modeling in 2012 using the long outdated and scientifically inferior Method 6. This modeling by EPA was done two years after the FLM recommendation to use Method 8 was published in 2010 and four years after Method 8 was incorporated into CALPOST by EPA. EPA’s use of Method 6, and not Method 8, is arbitrary and capricious. EPA should have used Method 8, the “best” modeling science.

Attachment 8

Response to Prehearing Statements

Martin Drake Power Plant Best Available Retrofit Technology Rulemaking Hearing

AECOM, Bob Paine
AECOM, Jeffrey Connors
November 10, 2010

Mr. Paine has 35 years experience in the design and implementation of air quality models, meteorological analyses, permitting studies, field investigations, impact analysis of airborne toxic releases and expert witness testimony. Mr. Paine is a Certified Consulting Meteorologist, Qualified Environmental Professional and a member of the American Meteorological Society and of the Air and Waste Management Association. He holds a BS in Atmospheric Science from the State University of New York at Alabany and an MS in Meteorology from the Massachusetts Institute of Technology.

Over the course of his career, Mr. Paine has published over 100 articles for peer reviewed journals and technical conferences. His has also contributed to the development of technical portions of widely used models such as ISC and AERMOD.

As a recognized expert in atmospheric dispersion modeling, Mr. Paine has conducted the modeling required for the permitting of numerous facilities. His experience with a wide variety of air dispersion models and CALPUFF in particular makes him well-qualified to speak to issues involved in the use of CALPUFF modeling.

Colorado Springs Utilities requested that AECOM provide additional technical discussions for their rebuttal statement being submitted to the State of Colorado Air Quality Control Commission (The Commission) regarding Colorado's Regional Haze State Implementation Plan and Regulation No. 3, Part F Best Available Retrofit Technology (BART) Requirements. AECOM's technical discussion focuses on two key areas:

(1) Evaluation of potential benefits for regional haze from additional NO_X emission control on Drake; and
(2) Conservatism in the CALPUFF model related to particulate nitrate formation.

Evaluation of Potential Benefits for Regional Haze from Additional NO_X Control

In order to determine whether additional NO_X controls to Drake would result in improved regional haze at Rocky Mountain National Park, several back-trajectory analyses were conducted for days in which some elevated nitrate particulate was observed at the IMPROVE monitor. However, on many of those days, much of the haze was likely contributed by uncontrollable sources such as windblown dust and wildfire emissions. The back-trajectory analyses were conducted with the NOAA Air Resources Laboratory's HYSPLIT Trajectory Model. Access to the interactive trajectory model is available at: http://ready.arl.noaa.gov/HYSPLIT.php. A total of ten high nitrate days (which were designated as among the 20% worst haze days) were examined from during 2007 and 2008. The associated IMPROVE data composition plots are presented in Figures 1 and 2.

The NAM (Eta) 12 km forecast meteorological data was used to calculate back trajectories for the ten days; this database is not available prior to May 2007, so the events reviewed were for periods during or after May 2007. The back-trajectory starting point was set as the Rocky Mountain National Park IMPROVE monitor, shown in Figure 3 as a blue triangle. The back-trajectory analysis for each high nitrate day was started 24 hours prior to the event.

The resulting trajectory for each of the ten days is depicted in Figure 3. Figure 3 shows that none of the calculated trajectories originated at or near the Drake Power Plant. Most of the trajectories originated from the west and southwest of the Rocky Mountain National Park, and could be associated with areas of wildfire emissions. We did not find any events for which the trajectories led back to the Drake Plant location. Therefore, installing NO_x controls on Drake would not likely result in reduced concentrations of nitrates (and improvements to regional haze) at Rocky Mountain National Park.

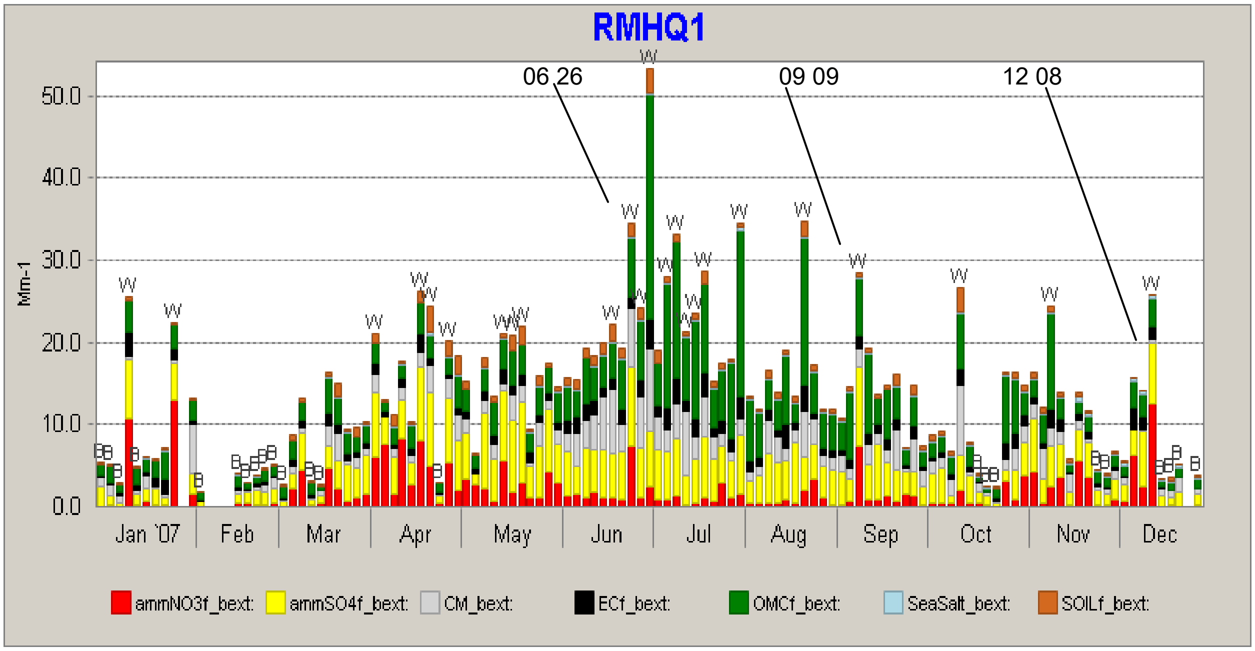


Figure 1. 2007 IMPROVE Composition Data for Rocky Mountain NP and High Nitrate Days.

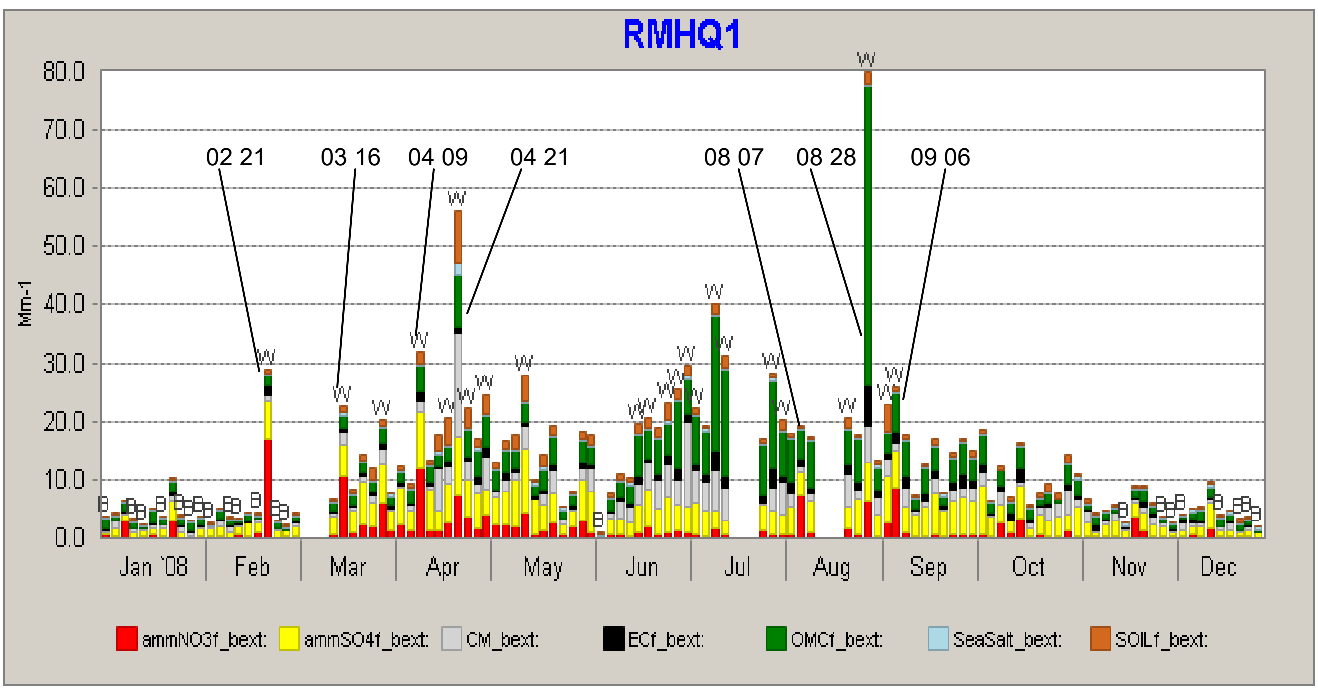


Figure 1. 2008 IMPROVE Composition Data for Rocky Mountain NP and High Nitrate Days.

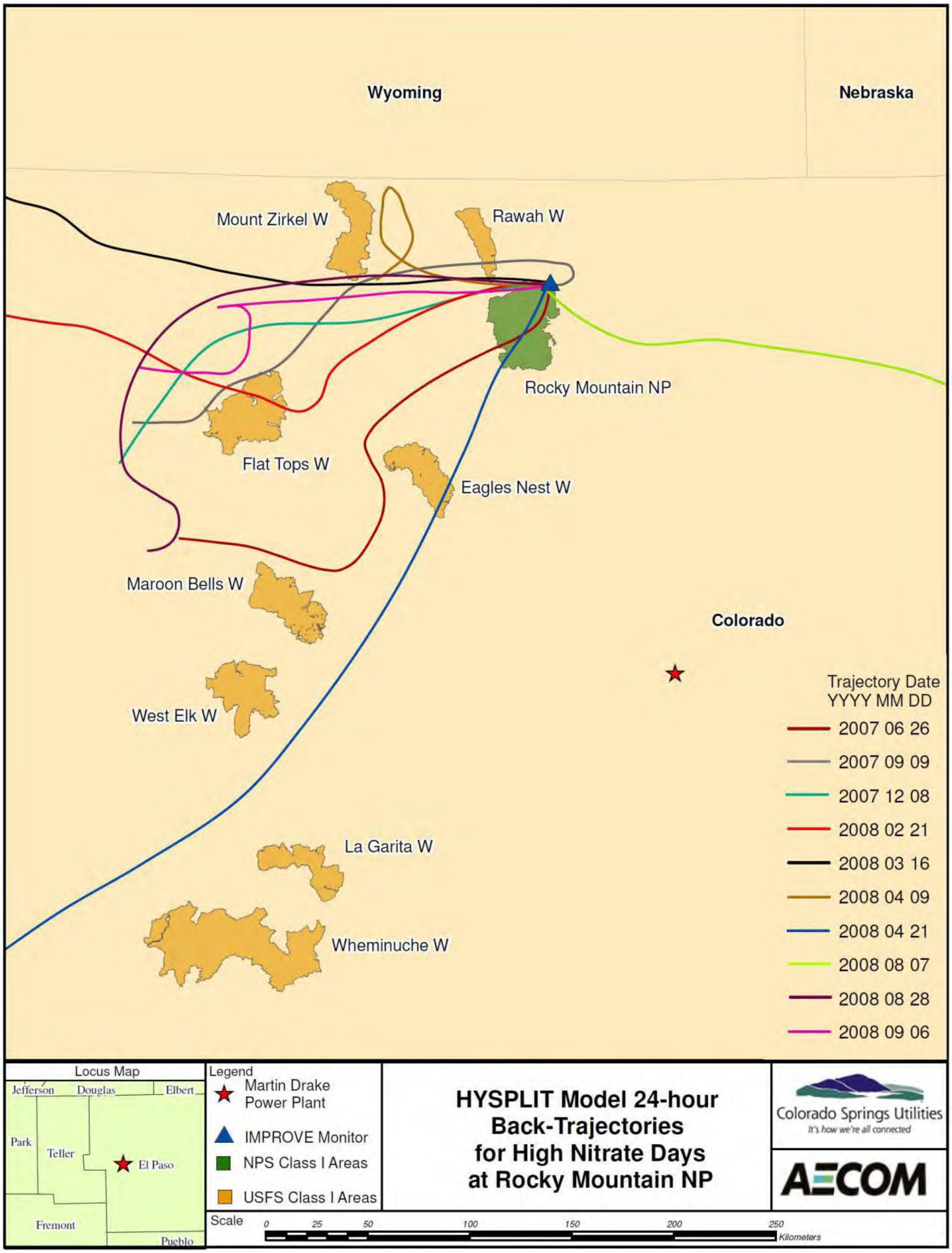


Figure 3. HYSPLIT Model 24-hour Back-Trajectories for High Nitrate Days in 2007 and 2008.

CALPUFF Model Conservatism Related to Nitrate Formation

The focus of the technical discussion is on CALPUFF's conservatism in predicting nitrate and the importance of background ammonia in the ability of CALPUFF to more accurately predict nitrate formation. In addition, this section discusses a recent model enhancement to CALPUFF designed to improve CALPUFF's ability to predict nitrate formation.

Secondary pollutants such as nitrates and sulfates contribute to light extinction in Class I areas. The CALPUFF model was approved by EPA for use in BART determinations to evaluate the effect of these pollutants on visibility in Class I areas. CALPUFF uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO_2 and NO_x emissions to secondary sulfates and nitrates. This section describes how secondary pollutants, specifically nitrates, are formed and the factors affecting their formation, especially as formulated in CALPUFF.

In the CALPUFF model, the oxidation of NO_x to nitric acid (HNO_3) depends on the NO_x concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 4 (taken from the CALPUFF user's guide).

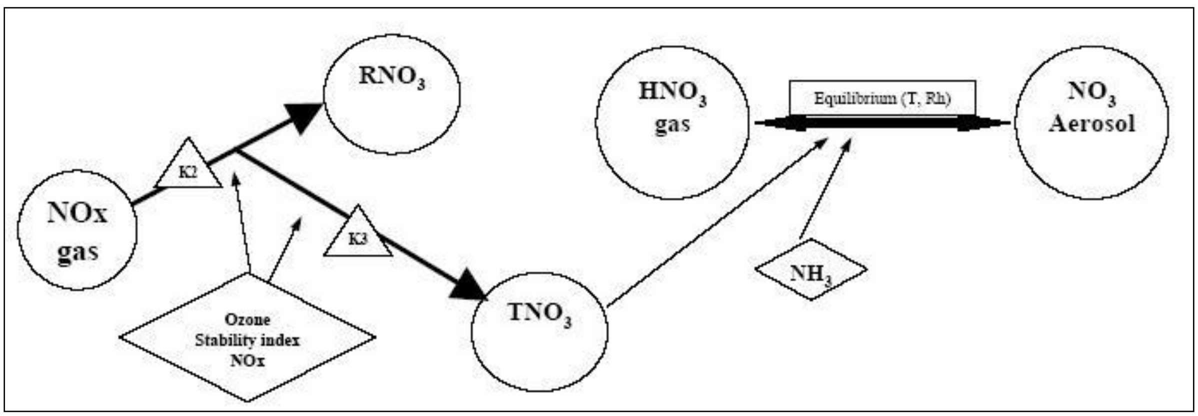


Figure 4. MESOPUFF II NOx Oxidation.

Role of Background Ammonia in CALPUFF

In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 and NO_3 particles according to the equilibrium relationship between the two species. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate particles *strongly* depends on availability of NH_3 to form ammonium nitrate, as shown in Figure (taken from CALPUFF courses given by TRC). In Figure 5, the graph on the left[1] shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 K and 80% humidity), only 50% of the total nitrate forms particulate matter. When the available ammonia is increased to 2 ppb, as shown in the graph on the right, as much as 80% of the total nitrate is in the particulate form. Figure 5 also shows that colder temperatures and higher relative humidity significantly favor nitrate formation and vice versa.

[1] A larger image of the left panel appears in Figure 2.

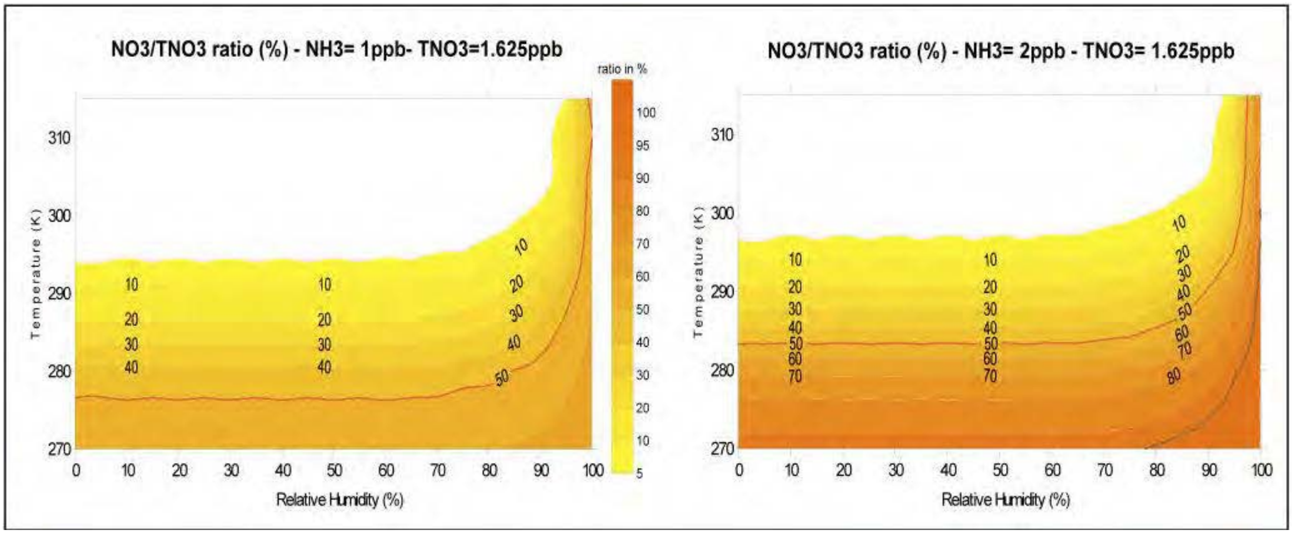


Figure 5. NO_3/HNO_3 Equilibrium Dependency on Temperature and Humidity.

A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates. In areas where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and therefore less ammonium nitrate is formed.

The effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_x control options. For the reasons discussed above, the periods of low temperatures are the most likely to be sensitive to ammonium nitrate formation.

Sensitivity of CALPUFF Predictions to Ammonia Concentration Input

In an independent analysis, the Colorado Department of Public Health and Environment (CDPHE) performed a sensitivity modeling analysis to explore the effect of the ammonia concentration input to CALPUFF on the predicted visibility impacts for a source with high NO_x emissions relative to SO_2 emissions[2]. The results of the sensitivity modeling are shown in Figure 6. It is noteworthy that the largest sensitivity occurs for ammonia input values between 1 and 0.1 ppb. In that range, the difference in the peak visibility impacts predicted by CALPUFF is slightly more than a factor of 3 between ammonia concentration input values of 1 and 0.1 ppb. This sensitivity analysis shows that the choice of background ammonia is very important in terms of the magnitude of visibility impacts predicted by CALPUFF.

[2] Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at http://www.colorado.gov/airquality/documents/Draft-ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf.

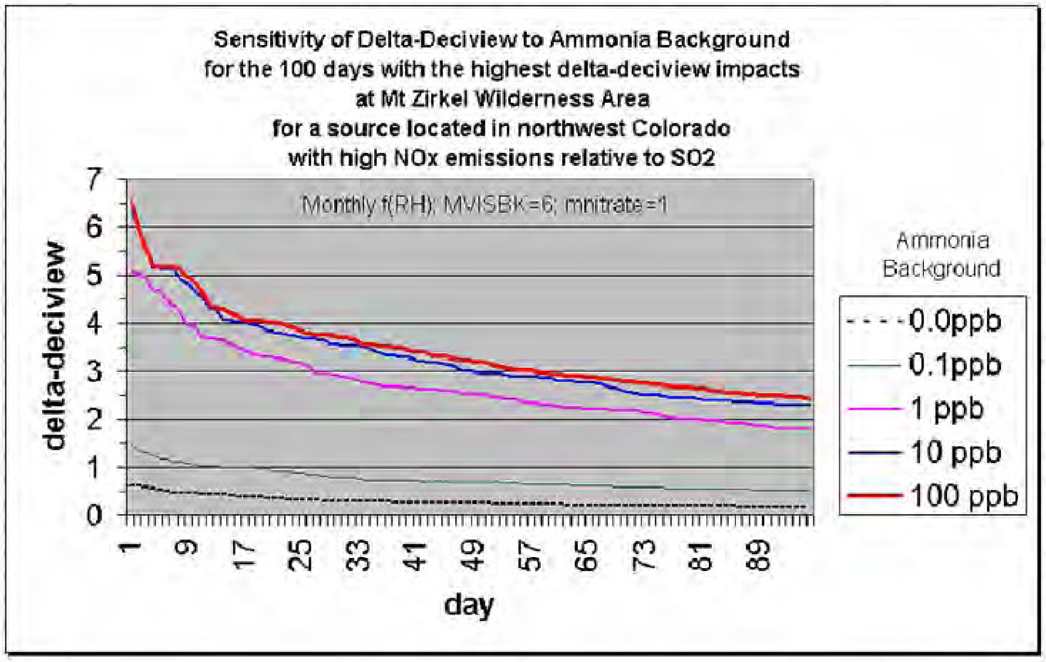


Figure 6. CDPHE Plot of Sensitivity of Visibility Impacts Modeled by CALPUFF for Different Ammonia Backgrounds.

Enhancement to CALPUFF's Model Chemistry

Morris et al.[3] reported that the CALPUFF MESOPUFF II transformation rates were developed using temperatures of 86, 68 and 50°F. Therefore, the 50°F minimum temperature used in development of the model could result in overestimating sulfate and nitrate formation in colder conditions. These investigators found that CALPUFF tended to overpredict nitrate concentrations during winter by a factor of about 3.

A recent independent study that is relevant to the CALPUFF performance for nitrate prediction was performed by Atmospheric and Environmental Research, Inc. (AER) and presented at the October 2009 Air & Waste Management Association Specialty Conference in Raleigh, North Carolina, by Karamchandani et al.[4] ("the KCBB study"). This study presented several improvements to the RIVAD chemistry option in CALPUFF, an alternative treatment that was more amenable to an upgrade than the MESOPUFF II chemistry option. Among other items, the improvements included the replacement of the original CALPUFF secondary particulate matter (PM) modules by newer algorithms that are used in current state-of-the-art regional air quality models such as CMAQ, CMAQ-MADRID, CAMx and REMSAD, and in advanced puff models such as SCICHEM. In addition, the improvements included the incorporation of an aqueous-phase chemistry module based on the treatment in CMAQ. Excerpts from the study papers describing each of the improvements made to CALPUFF in the KCBB study are repeated below.

[3] Morris, R., Steven Lau and Bonyoung Koo, 2005. Evaluation of the CALPUFF Chemistry Algorithms. Presented at A&WMA 98th Annual Conference and Exhibition, June 21-25, 2005 Minneapolis, Minnesota.

[4] Karamchandani, P., S. Chen, R. Bronson, and D. Blewitt, 2009. Development of an Improved Chemistry Version of CALPUFF and Evaluation Using the 1995 SWWYTAF Data Base. Presented at the Air & Waste Management Association Specialty Conference on Guideline on Air Quality Models: Next Generation of Models, October 28-30, 2009, Raleigh, NC.

Gas-Phase Chemistry Improvements

The KCBB study applied a correction to CALPUFF in that the upgraded model was modified to keep track of the puff ozone concentrations between time steps. The authors also updated the oxidation rates of SO_2 and nitrogen dioxide (NO_2) by the hydroxide ion (OH^-) to the rates employed in contemporary photochemical and regional PM models.

Treatment of Inorganic Particulate Matter

The KCBB study scientists noted that the EPA-approved version of CALPUFF currently uses a simple approach to simulate the partitioning of nitrate and sulfate between the gas and particulate phases. In this approach, sulfate is appropriately assumed to be entirely present in the particulate phase, while nitrate is assumed to be formed by the reaction between nitric acid and ammonia.

The KCBB study implemented an additional treatment for inorganic gas-particle equilibrium, based upon an advanced aerosol thermodynamic model referred to as the ISORROPIA model. [5] This model is currently used in several state-of-the-art regional air quality models. With this new module, the improved CALPUFF model developed in the KCBB study includes a treatment of inorganic PM formation that is consistent with the state of the science in air quality modeling, and is critical for the prediction of regional haze due to secondary nitrate formation from NO_x emissions.

Treatment of Organic Particulate Matter

The KCBB study added a treatment for secondary organic aerosols (SOA) that is coupled with the corrected RIVAD scheme described above. The treatment is based on the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID)[6,7], which treats SOA formation from both anthropogenic and biogenic volatile organic compound emissions.

Aqueous-Phase Chemistry

The current aqueous-phase formation of sulfate in both CALPUFF's RIVAD and MESOPUFFII schemes is currently approximated with a simplistic treatment that uses an arbitrary pseudo-first order rate in the presence of clouds (0.2% per hour), which is added to the gas-phase rate. There is no explicit treatment of aqueous-phase SO_2 oxidation chemistry. The KCBB study incorporated into CALPUFF a treatment of sulfate formation in clouds that is based on the treatment that is used in EPA's CMAQ model.

CALPUFF Model Evaluation and Sensitivity Tests

The EPA-approved version of CALPUFF and the version with the improved chemistry options were evaluated using the 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database[8], available from the Wyoming Department of Environmental Quality. The database includes MM5 output for 1995, CALMET and CALPUFF codes and control files, emissions for the Southwest Wyoming Regional

[5] Nenes A., Pilinis C., and Pandis S.N. (1998) Continued Development and Testing of a New Thermodynamic Aerosol Module for Urban and Regional Air Quality Models, *Atmos. Env.*, **33**, 1553-1560.

[6] Zhang, Y., B. Pun, K. Vijayaraghavan, S.-Y. Wu, C. Seigneur, S. Pandis, M. Jacobson, A. Nenes and J.H. Seinfeld, 2004. Development and Application of the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID), *J. Geophys. Res.*, 109, D01202, doi:10.1029/2003JD003501.

[7] Pun, B., C. Seigneur, J. Pankow, R. Griffin, and E. Knipping, 2005. An upgraded absorptive secondary organic aerosol partitioning module for three-dimensional air quality applications, 24th Annual American Association for Aerosol Research Conference, Austin, TX, October 17-21, 2005.

[8] Background and database description are available at http://deq.state.wy.us/aqd/prop/2003AppF.pdf.

modeling domain, and selected outputs from the CALPUFF simulations. Several sensitivity studies were also conducted to investigate the effect of background NH_3 concentrations on model predictions of PM nitrate.

Twice-weekly background NH_3 concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH_3 concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

1. MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH_3 concentration of 1 ppb for arid land. As discussed previously, the MESOPUFF II algorithm is the basis for the currently approved version of CALPUFF that is being used in the BART determination for NGS.

2. Improved CALPUFF RIVAD/ARM3 chemistry using background values of NH_3 concentrations based on measurements in the Pinedale, Wyoming area, as described above.

PM sulfate and nitrate were predicted by the two models and compared with actual measured values obtained at the Bridger Wilderness Area site from the IMPROVE network and the Pinedale site from the Clean Air Status and Trends Network (CASTNET). For the two model configurations evaluated in this study, the results for PM sulfate were very similar, which was expected since the improvements to the CALPUFF chemistry were anticipated to have the most impact on PM nitrate predictions. Therefore, the remaining discussion focuses on the performance of each model with respect to PM nitrate.

The EPA-approved CALPUFF model was found to significantly overpredict PM nitrate concentrations at the two monitoring locations, by a factor of 2 to 3. The performance of the version of CALPUFF with the improved RIVAD chemistry was much better, with an overprediction of about 4% at the Pinedale CASTNET site and of about 28% at the Bridger IMPROVE site.

In an important sensitivity analysis conducted within the KCBB study, both the EPA-approved version of CALPUFF and the improved version were run with a constant ammonia background of 1 ppb. [9] The results were similar to those noted above: the improved CALPUFF predictions were about 2-3 times lower than those from the EPA-approved version of CALPUFF. This result is similar to the results using the seasonal observed values of ammonia, and indicates that the sensitivity of the improved CALPUFF model to the ammonia input value is potentially much less than that of the current EPA-approved model.

Similar sensitivity was noted by Scire et al. in their original work in the SWWYATF study[10], in which they tested seasonally varying levels of background ammonia in CALPUFF (using 0.23 ppb in winter, for example; see Figure 77). The sensitivity modeling for predicting levels of nitrate formation shows very similar results to those reported in the KCBB study.

<u>Availability of a CALPUFF Version 6.4 with Enhanced Chemistry</u>

Recently, TRC implemented the KCBB chemistry improvements into a new version (6.4) of CALPUFF. The following information include excerpts from the "CALPUFF Chemistry Updates Users Guide for API Chemistry Options" issued by TRC on October 25, 2010.

Two chemical transformation module options were recently introduced into the CALPUFF modeling system; they include:

[9] This is a recommendation from the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Long-Range Transport Modeling, EPA-454/R-98-019, 1998.
[10] Scire, J.S., Z-X Wu, D.G. Strimaitis and G.E. Moore, 2001: The Southwest Wyoming Regional CALPUFF Air Quality Modeling Study – Volume I. Prepared for the Wyoming Dept of Environmental Quality.

For the first module:

- Modification of the existing RIVAD chemical mechanism for the transformation of SO_2 to SO_4 and NO/NO_2 to HNO_3 and NO_3
- Replacement of the MESOPUFF-II CHEMEQ model with the ISORROPIA (Version 1.7) model for inorganic gas-particle equilibrium

  Addition of a new option for aqueous-phase transformation adapted from the RADM cloud implementation in CMAQ/SCICHEM

For the second module:

- Addition of a new option for anthropogenic secondary organic aerosol (SOA) formation based on the CalTech SOA routines implemented in CMAQ-MADRID.

TRC has implemented these modules as options in the current CALPUFF Version 6.4. The first module option is implemented as the 6th CALPUFF chemical transformation option (MCHEM = 6), and the second module is implemented as the 7th CALPUFF chemical transformation option (MCHEM = 7). TRC has also updated the gas-particle equilibrium model for nitrates from ISORROPIA v1.7 to ISORROPIA-II v2.1. Both module options replace the MESOPUFF-II CHEMEQ gas-particle equilibrium model for nitrates with the ISORROPIA-II model. Since total nitrate (TNO3) is partitioned into the gas (HNO3) and particulate (NO3) phases based in part on the ammonia available after preferential scavenging by sulfate, the equilibrium should be determined using the total amount of sulfate and nitrate (due to all sources, background, etc.) present at a particular location and time. This is accomplished using the ammonia-limiting method (ALM) of an updated POSTUTIL postprocessor in the CALPUFF modeling system.

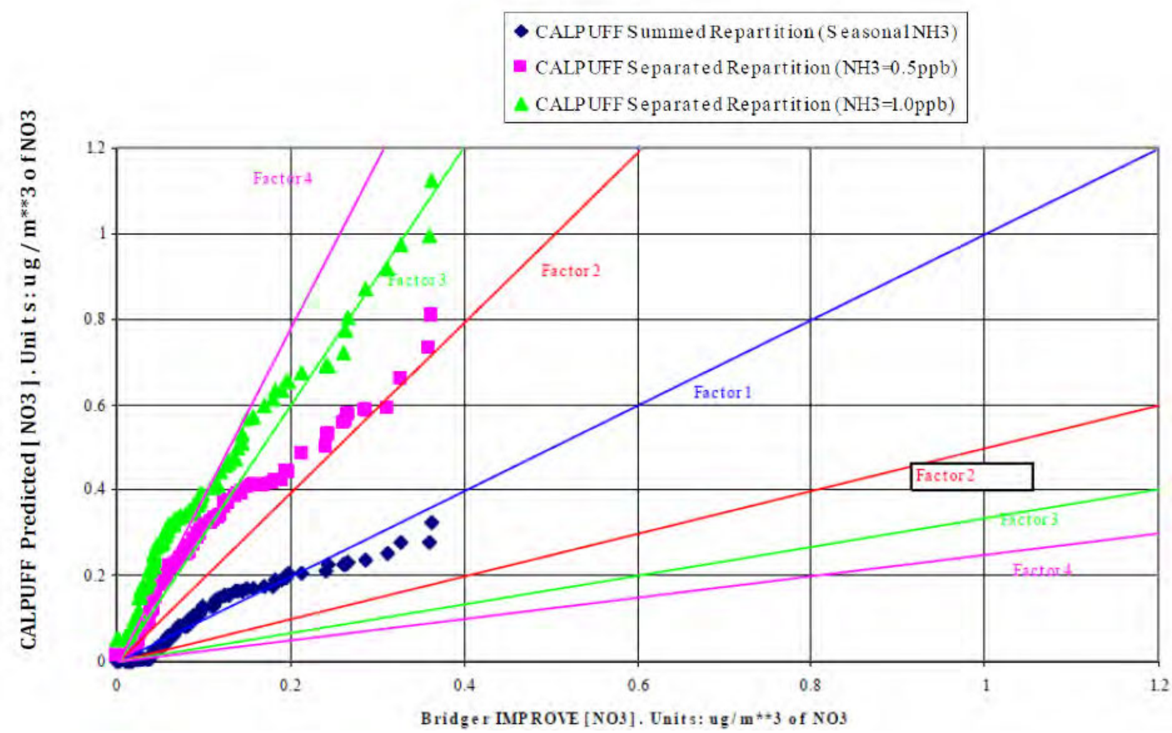


Figure 7. Sensitivity Study of Nitrate Predictions at Bridger Wilderness Area as a Function of Input Ammonia Concentrations to CALPUFF (0.23, 0.5, and 1.0 ppb).

Attachment 9

Exponent, Inc.
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Natick, MA 01760

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www.exponent.com

March 21, 2012

Via E-mail (Bill.Lawson@PacifiCorp.com)

Mr. William Lawson
PacifiCorp Energy
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116

Re: Recommended CALPUFF Version for BART Analyses

Dear Mr.Lawson,

CALPUFF Version 5.8 (v5.8) is the current regulatory version of the CALPUFF model (Scire et al., 2000). The chemical modules in v5.8 of CALPUFF date back to the 1980s. EPA, the Federal Land Managers, and others have acknowledged the deficiencies in the CALPUFF v5.8 chemistry and its tendency to overestimate predicted concentrations of nitrate (Karamchandani et al., 2008, 2009) and potentially to underestimate sulfate from aqueous phase chemical processes in clouds and rainwater (IWAQM (1998)).

Karamchandani et al., (2009) demonstrates overpredictions of nitrate measured at monitoring sites in Wyoming using the v5.8 CALPUFF chemistry by factors of 3-4. Substantial improvements eliminating the overprediction bias of the v5.8 chemistry is found by using the improved ISORROPIA chemistry.

The IWAQM (1998) report acknowledges the lack of aqueous phase chemistry is a substantial limitation of the CALPUFF model:

> "The algorithms currently do not adequately account for the aqueous phase oxidation of sulfur dioxide to sulfate. The aqueous phase chemistry can dominate the formation of sulfate. Therefore, in many applications sulfate is likely to be underestimated."

As a result of work performed for the Electric Power Research Institute (EPRI) and WEST Associates, I very recently presented the results of additional research at the EPA 10th Modeling Conference in RTP, North Carolina describing the improvements in the CALPUFF v6.42 chemistry. This presentation is attached. A summary of the progressive improvements to the model performance with the addition of the new model algorithms is summarized as Figure 1.

As a result of significant improvements made to Version 6.42 (v6.42) series of the CALPUFF model chemistry, it is my recommendation that CALPUFF model v6.42 series code be used for Best Available Retrofit Technology (BART) modeling analyses. This version of the model incorporates state-of-the science aerosol equilibrium chemistry with the addition of the ISOPROPIA chemistry module. In addition, an aqueous phase chemistry model has been added to the model to more properly account for precipitation and wet deposition.

The ISORROPIA gas-particle equilibrium model for nitrate (Nenes et al., 1998; Fountoukis and Nenes, 2007) implemented in CALPUFF v6.42 is widely-used and accepted in the scientific community as is the aqueous phase chemistry model in CALPUFF v6.42 which is based on the EPA CMAQ model aqueous phase chemistry.

In addition to the benefit of significantly improved chemistry, v6.42 of the model represents the latest updated model software with all Model Change Bulletins (MCBs) fully implemented. The EPA version of the model v5.8 contains MCB-A through MCB-D but as indicated on the CALPUFF distribution web site (www.src.com), v5.8 does not contain MCB-E, F, and G and it is therefore out-of-date.

If you have any questions or require additional information, please do not hesitate to contact me at (508) 652-8562 (office) or (508) 808-3821 (mobile) or by e-mail at jscire@exponent.com.

Sincerely,

Joseph S. Scire, CCM
Principal Scientist

Enc.: Scire presentation EPA 10th Conference, March 15, 2012

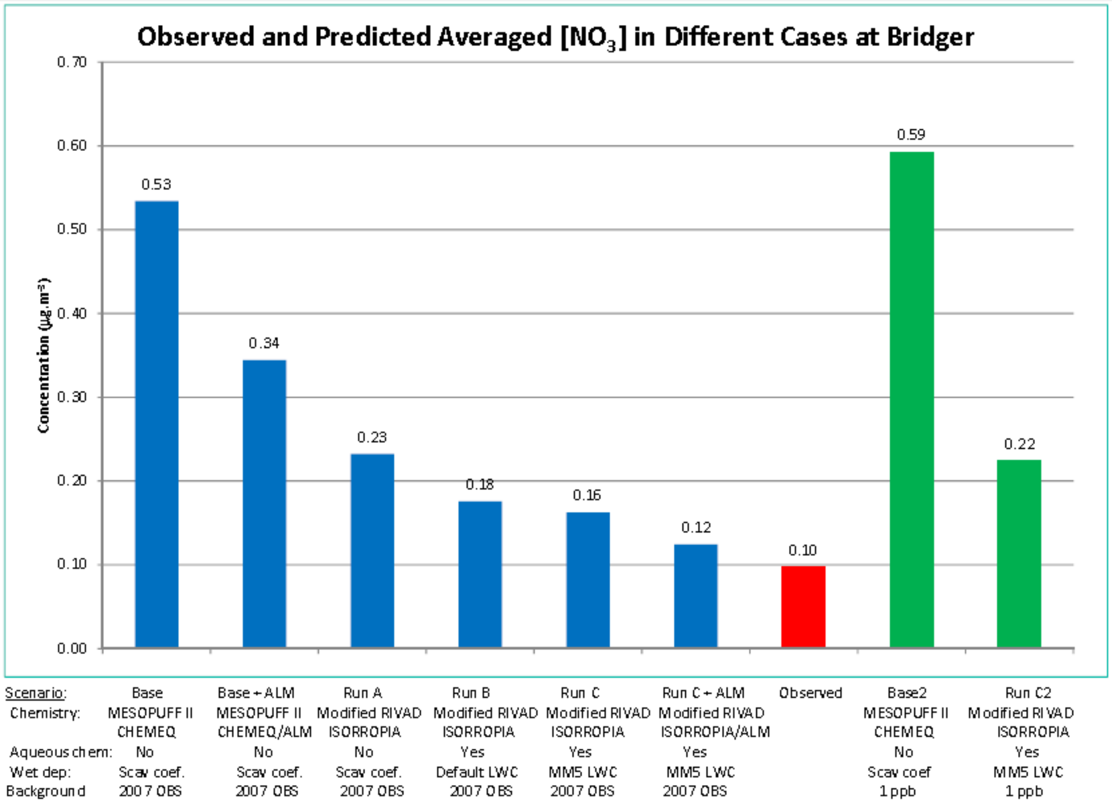

Figure 1. Summary of CALPUFF v6.42 model performance relative to observations of nitrate at the Bridger IMPROVE monitor in Wyoming. Run C is recommended as the model configuration for new regulatory BART analyses (Scire et al., 2012). The Base and Base 2 runs use the v5.8 CALPUFF chemistry and show large overpredictions of nitrate.

References

Fountoukis, C. and A. Nenes, 2007: ISORROPIA II: A Computationally Efficient Aerosol Thermodynamic Equilibrium Model for K+, Ca2+, Mg2+, NH4+, Na+, SO42-, NO3-, Cl-, H2O Aerosols, *Atmos.Chem.Phys*., **7**, 4639–4659

IWAQM, 1998: Interagency Workgroup on Air Quality Modeling (IWAQM): Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. U.S. EPA, RTP, NC. EPA-454/R-98-019.

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Scire, J.S., F.R. Robe, M.E. Fernau and R.J. Yamartino, 2000: A User's Guide for the CALMET Meteorological Model. (Version 5.0). Earth Tech., Inc. Concord, MA. (Available from http://www.src.com).

Scire, J.S. D.G. Strimaitis and Z-X Wu, 2012: New Developments and Evaluations of the CALPUFF Model. 10th EPA Modeling Conference, RTP, NC. 14-16 March 2012.

Attachment 10

New Developments and Evaluations of the CALPUFF Model

Joseph S. Scire, David G. Strimaitis and Zhong-Xiang Wu

Exponent, Inc.

Natick, Massachusetts

March 14-16, 2012

10th Conference of Air Quality Models

RTP, North Carolina

Acknowledgements

- Implementation funded by WEST Associates
- Evaluation co-funded by the Electric Power Research Institute (EPRI) and WEST Associates
- Work performed by CALPUFF model authors while at TRC (Phase I) and now at Exponent, Inc. (Phase II)
- Original implementation of modules conducted by AER (Karamchandani et al., 2008, 2009) under sponsorship of the American Petroleum Institute (API)

Overview of Changes

- **CALPUFF v6.42b Chemical Module Updates**
  - ISORROPIA II (v2.1) used for nitric acid/nitrate aerosol partition
    - ISORROPIA used in Eulerian models such as CMAQ and CAMx
  - Aqueous-phase chemical transformation (adapted from RADM cloud module in CMAQ/SCICHEM)
    - Oxidation of SO_2 in cloud water and rain water
    - V6.42b couples CALPUFF with MM5/WRF liquid water content
    - Tracks location of plume and overlap with cloud layer
  - New RIVAD module tracks depleted O_3 and H_2O_2 in each puff
  - Anthropogenic secondary organic aerosol (SOA) formation (from CalTech SOA routines implemented in CMAQ-MADRID)

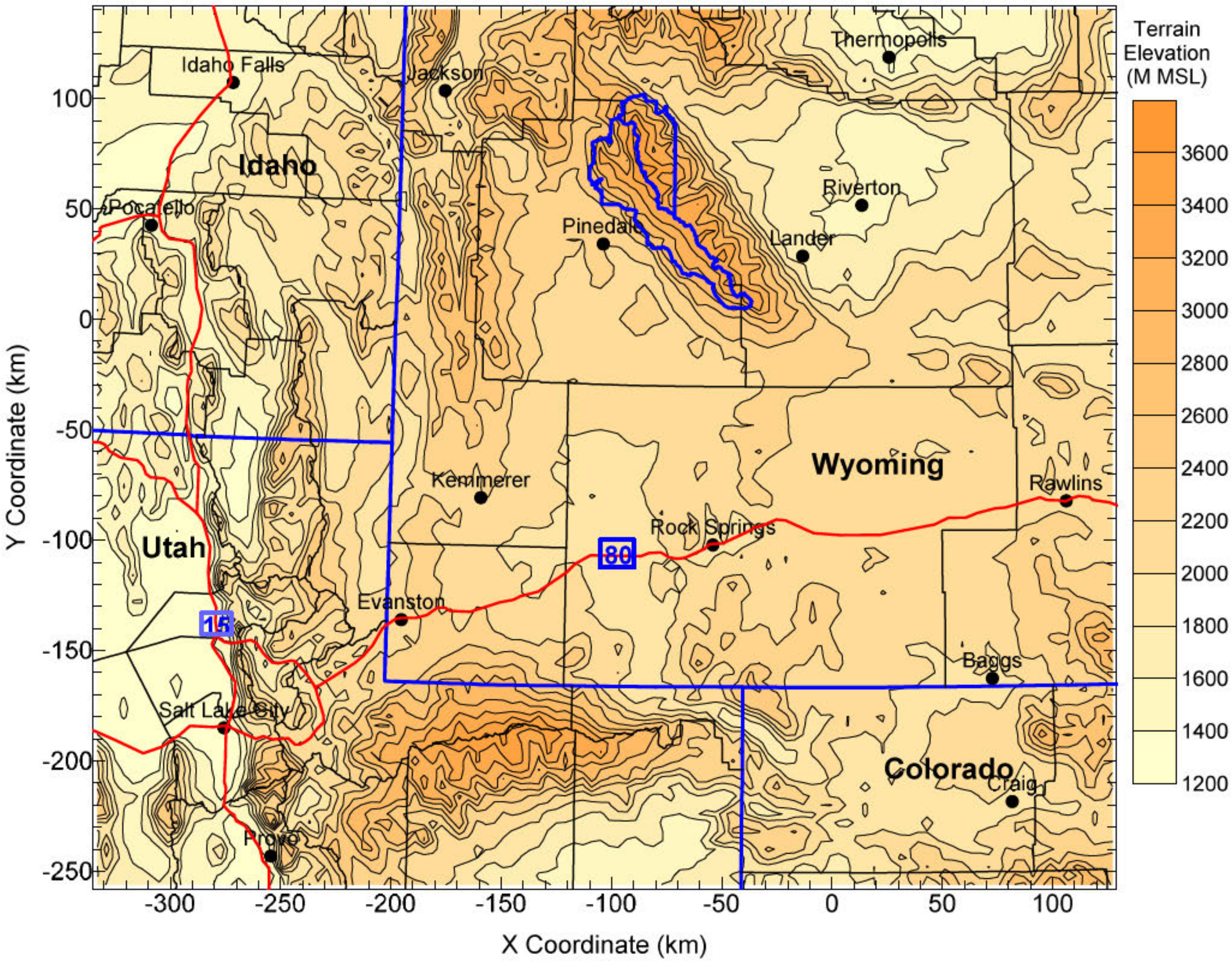
Evaluation and Testing of v6.42b

- **SWWYTAF 1995 dataset**
  - Evaluation of actual emissions in SW Wyoming and surrounding area
  - Large-scale, long range transport for a full year (1995)
  - Concentrations at Bridger IMPROVE and Pinedale CASTNet monitors
- **Cumberland Plume Study Dataset (1999)**
  - In-plume/single-event
- **Intercomparison tests with ISORROPIA II in CMAQ v5.0**
  - Over three million Monte Carlo cases evaluated for a wide range of conditions

SWWYTAF Model Evaluation

- **Meteorological Data:**
  - MM5 4-km data
  - CALMET run in no-observations mode for all scenarios
  - 24 vertical layers
- **Total sources: 1776**
  - Point, area, and boundary sources
  - Constant annual, monthly variable sources
  - Time variable (CEM) sources
- **Air Quality Data:**
  - Bridger IMPROVE and Pinedale CASTNet Sites
  - NADP Deposition Sites

SWWYTAF CALMET Domain



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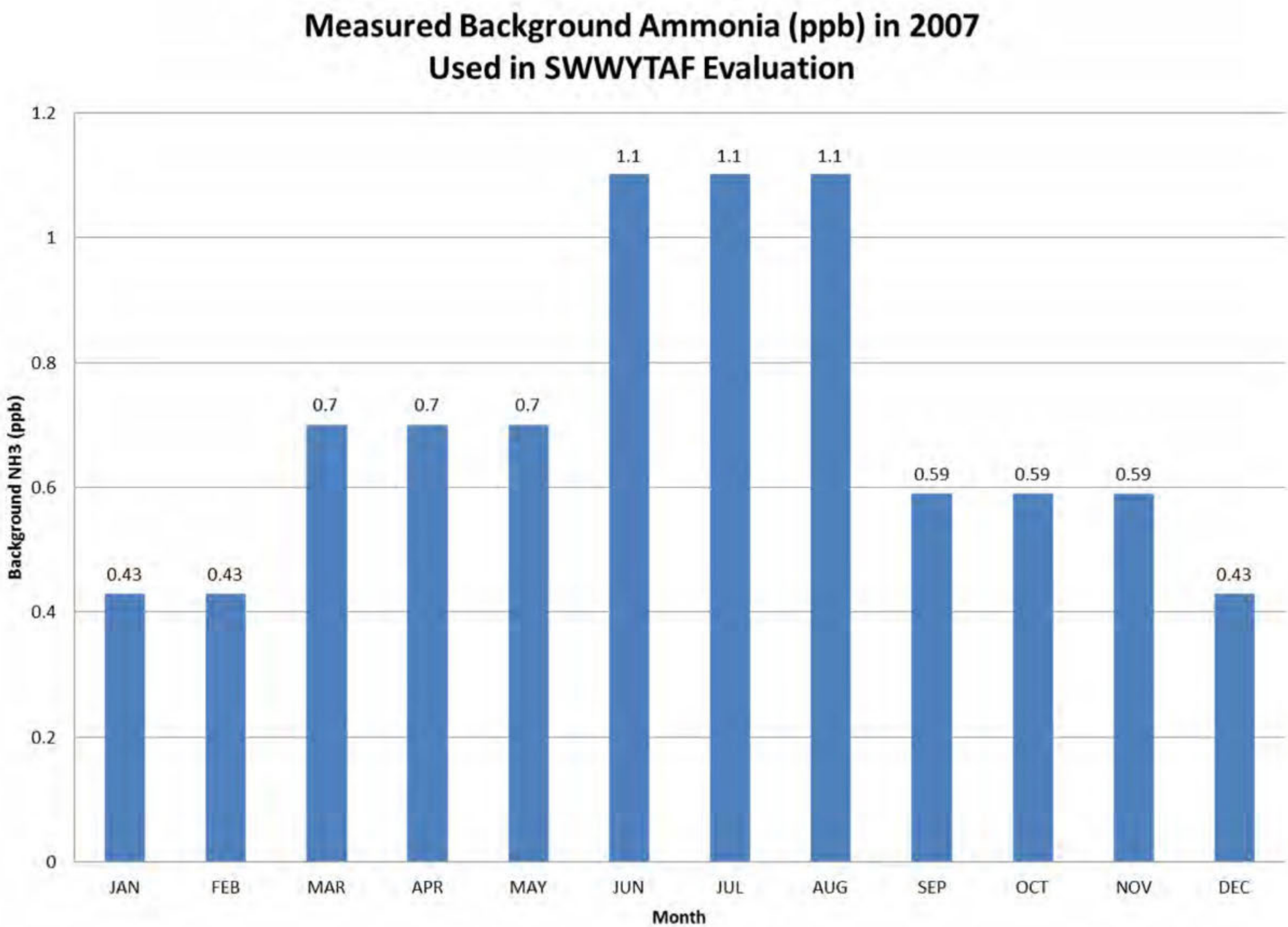
SWWYTAF Scenarios

- **Gas phase chemistry**
  - MESOPUFF II scheme
  - Modified RIVAD (API chemistry)
  - With and without Ammonia Limited Method (ALM) applied in postprocessing step
- **Aerosol chemistry**
  - Original CALPUFF (CHEMEQ) method (Stelson & Seinfeld, 1982)
  - ISORROPIA II (Nenes, Pandis & Pilinis, 1998)
- **Background Ammonia**
  - Constant (1 ppb) background NH_3
  - Seasonally-varying 2007 measured background
- **Wet scavenging/Aqueous phase chemistry**
  - Scavenging coefficient/ No AQ chemistry
  - Aqueous phase chemistry (surrogate and 3D liquid water)

Aqueous-Phase: Cloud Water

- **Cloud Liquid Water Content Option MLWC=0**
  - Surrogate cloud-cover and precipitation data
  - LWC = 0.1 g/kg for non-precipitating clouds
  - LWC = 0.5 g/kg for precipitating clouds
  - In-cloud SO_2 conversion rate apportioned to puff mass by cloud-cover fraction
  - Vertical distribution of cloud water is not addressed
  - Cloud-cover observations are spatially sparse
- **Cloud Liquid Water Content Option MLWC=1**
  - MM5/WRF 3D LWC provides detailed vertical and horizontal resolution
  - CALMET modified to pass 3D LWC data to CALPUFF via CALMET.AUX file
  - CALPUFF uses only LWC that overlaps puff mass distribution



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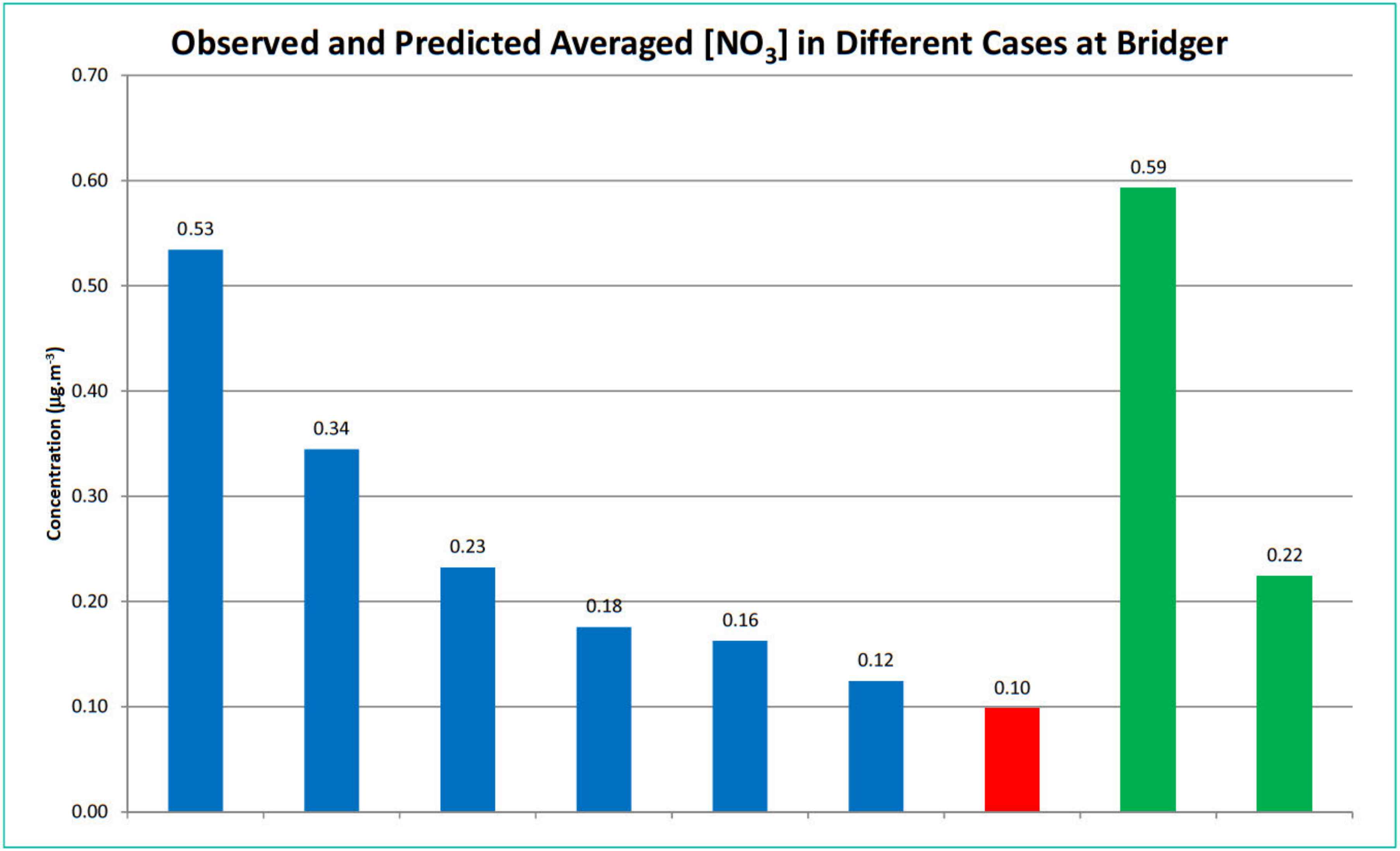

Scenario:	Base	Base + ALM	Run A	Run B	Run C	Run C + ALM	Observed	Base2	Run C2
Chemistry:	MESOPUFF II CHEMEQ	MESOPUFF II CHEMEQ/ALM	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA/ALM		MESOPUFF II CHEMEQ	Modified RIVAD ISORROPIA
Aqueous chem:	No	No	No	Yes	Yes	Yes		No	Yes
Wet dep:	Scav coef.	Scav coef.	Scav coef.	Default LWC	MM5 LWC	MM5 LWC		Scav coef	MM5 LWC
Background NH3	2007 OBS	2007 OBS	2007 OBS	2007 OBS	2007 OBS	2007 OBS		1 ppb	1 ppb

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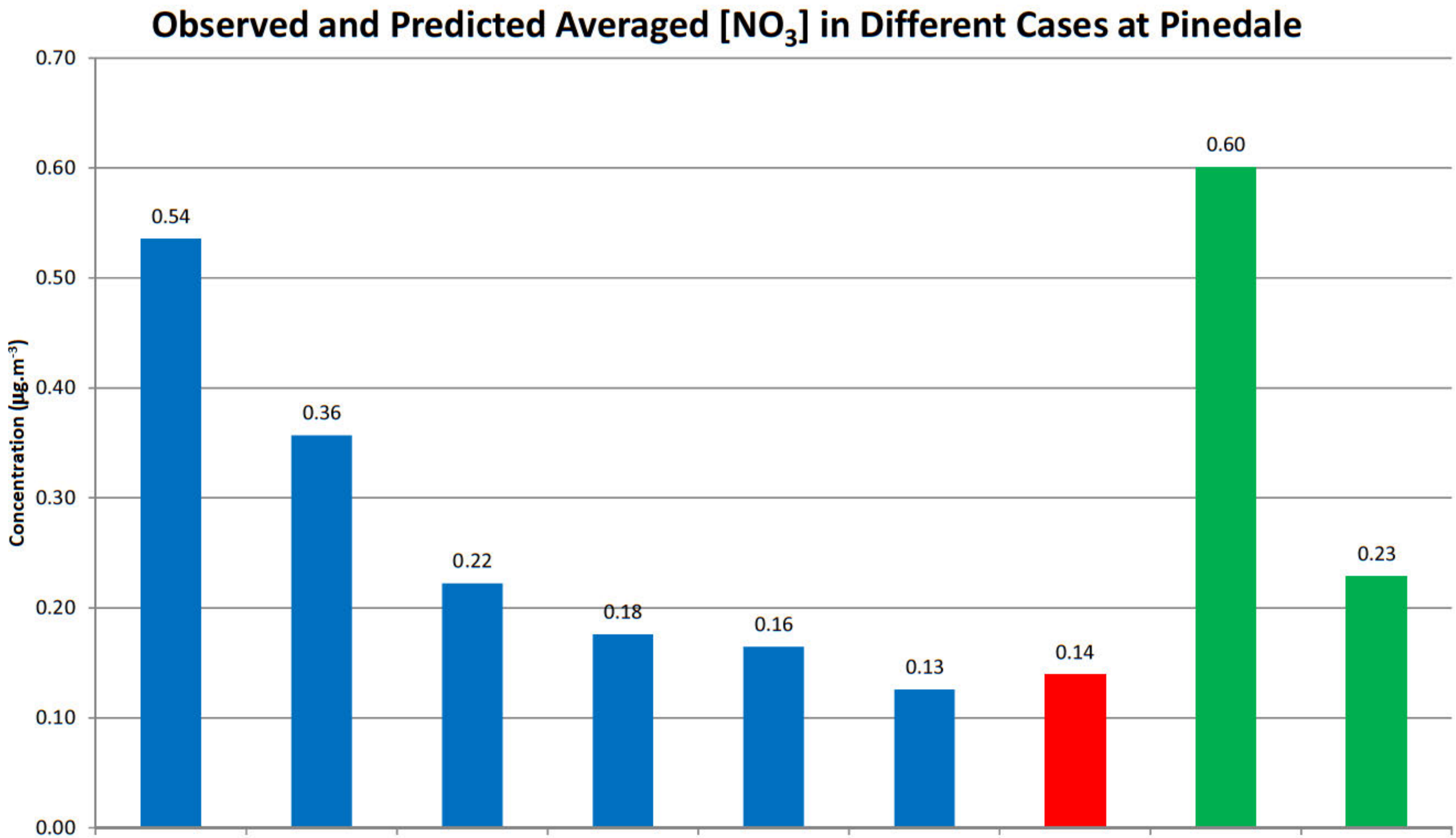


Scenario:	Base	Base + ALM	Run A	Run B	Run C	Run C + ALM	Observed	Base2	Run C2
Chemistry:	MESOPUFF II CHEMEQ	MESOPUFF II CHEMEQ/ALM	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA/ALM		MESOPUFF II CHEMEQ	Modified RIVAD ISORROPIA
Aqueous chem:	No	No	No	Yes	Yes	Yes		No	Yes
Wet dep:	Scav coef.	Scav coef.	Scav coef.	Default LWC	MM5 LWC	MM5 LWC		Scav coef	MM5 LWC
Background NH3	2007 OBS	2007 OBS	2007 OBS	2007 OBS	2007 OBS	2007 OBS		1 ppb	1 ppb

Exhibit PAC/4002
Owen/145

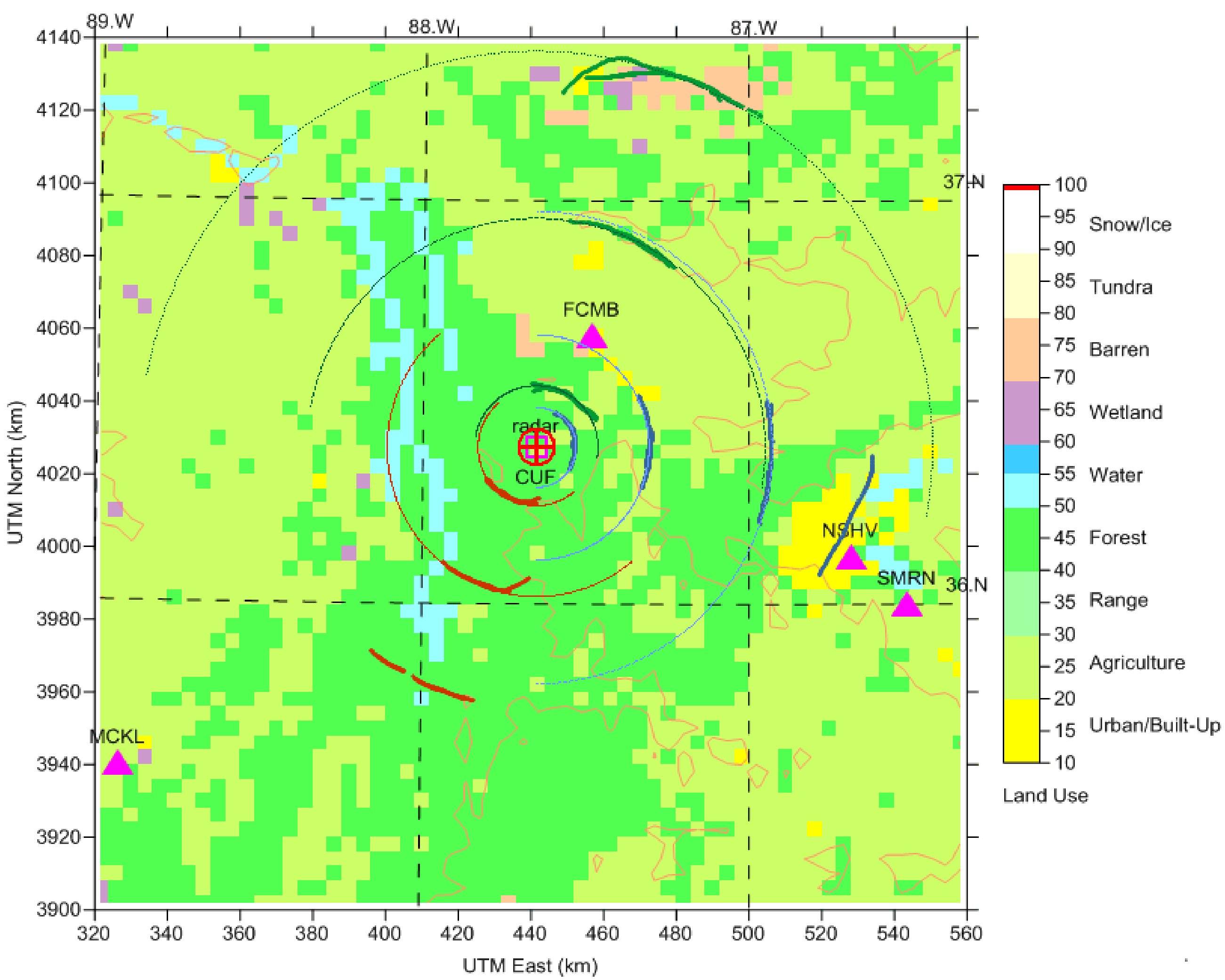
SWWYTAF Summary

- **CALPUFF using constant ammonia with old chemistry overpredicts nitrate by about 4-6x at Bridger and Pinedale, WY**
- **ISORROPIA-v2.1 in CALPUFF-v6.42b substantially improves performance of the model**
- **Use of seasonally-varying ammonia, which shows substantial variability improves performance**
- **Use of aqueous phase chemistry with MM5 3D cloud data produces the overall best results**
- **ALM is important with MESOPUFF II chemistry but results with ISORROPIA are less sensitive to ALM**

July 1999 Cumberland Plume Study

- **Modules Tested**
  - MCHEM=6: Updated RIVAD implementation with ISORROPIA V2.1 gas-particle phase equilibrium
  - MCHEM=3: Original RIVAD implementation with CHEMEQ gas-particle phase equilibrium
  - MCHEM=1: MESOPUFF II transformation with CHEMEQ gas-particle phase equilibrium
- **Data**
  - Plume chemistry measurements (aerial sampling)
  - Hourly emissions (SO_2, SO_4, NO, NO_2)
  - RADAR wind profiles at the source
  - Tabulated hi-vol data from study report (Tanner et al., 2002)
  - Hourly WMO surface met. reports, 2/day Nashville radiosondes

RADAR Wind Profiler at Stack (CUF)
Hourly Surface Meteorology at Triangles, 2/day RAOB Profiles Near NSHV (Nashville)
Aircraft Sampling Locations (blue-grey [E] = July 6; red [SSW] = July 13; green [NNE] = July 15)
High-Resolution CALPUFF Receptors Along Arcs



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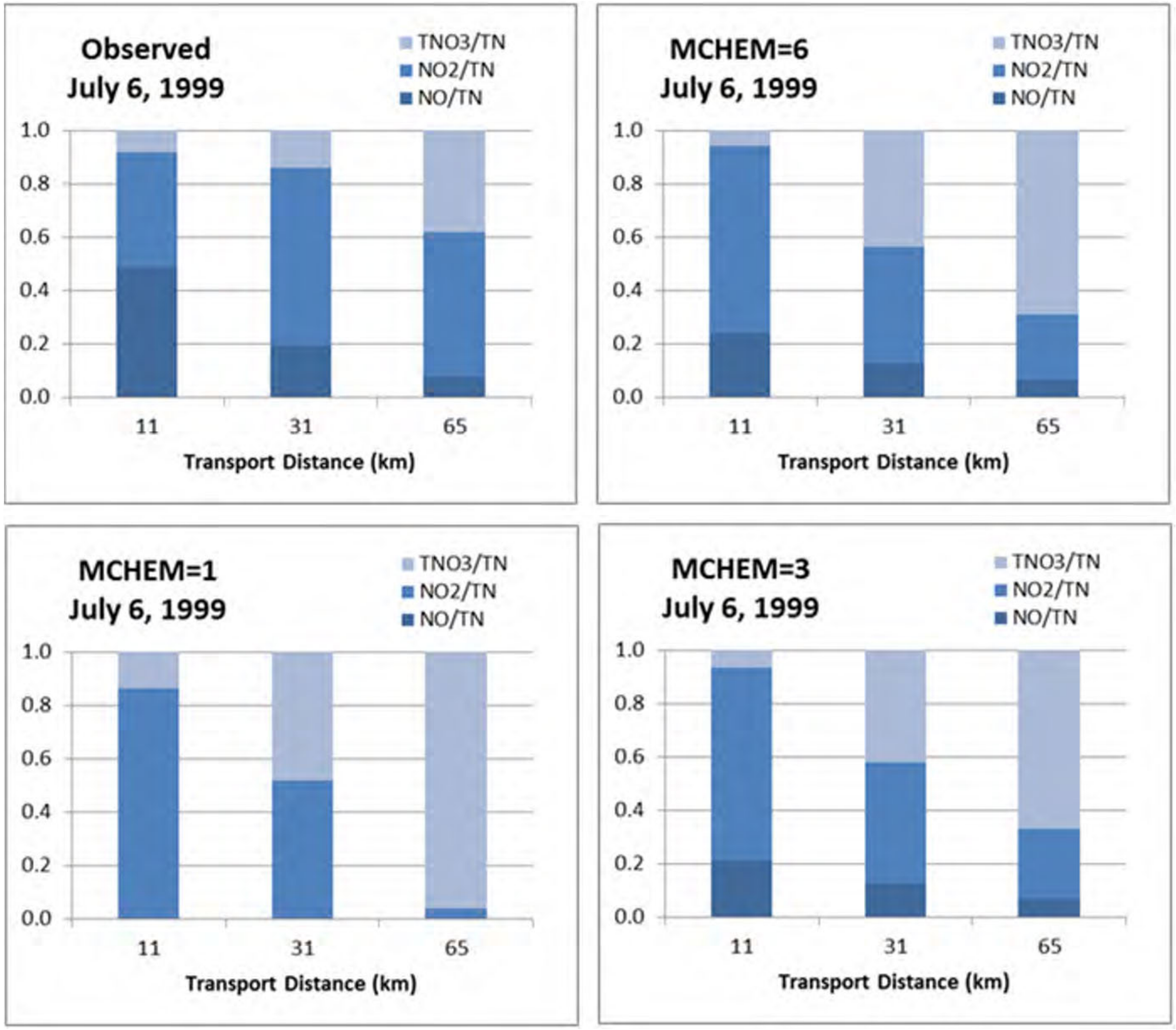
July, 1999 Cumberland Plume Study



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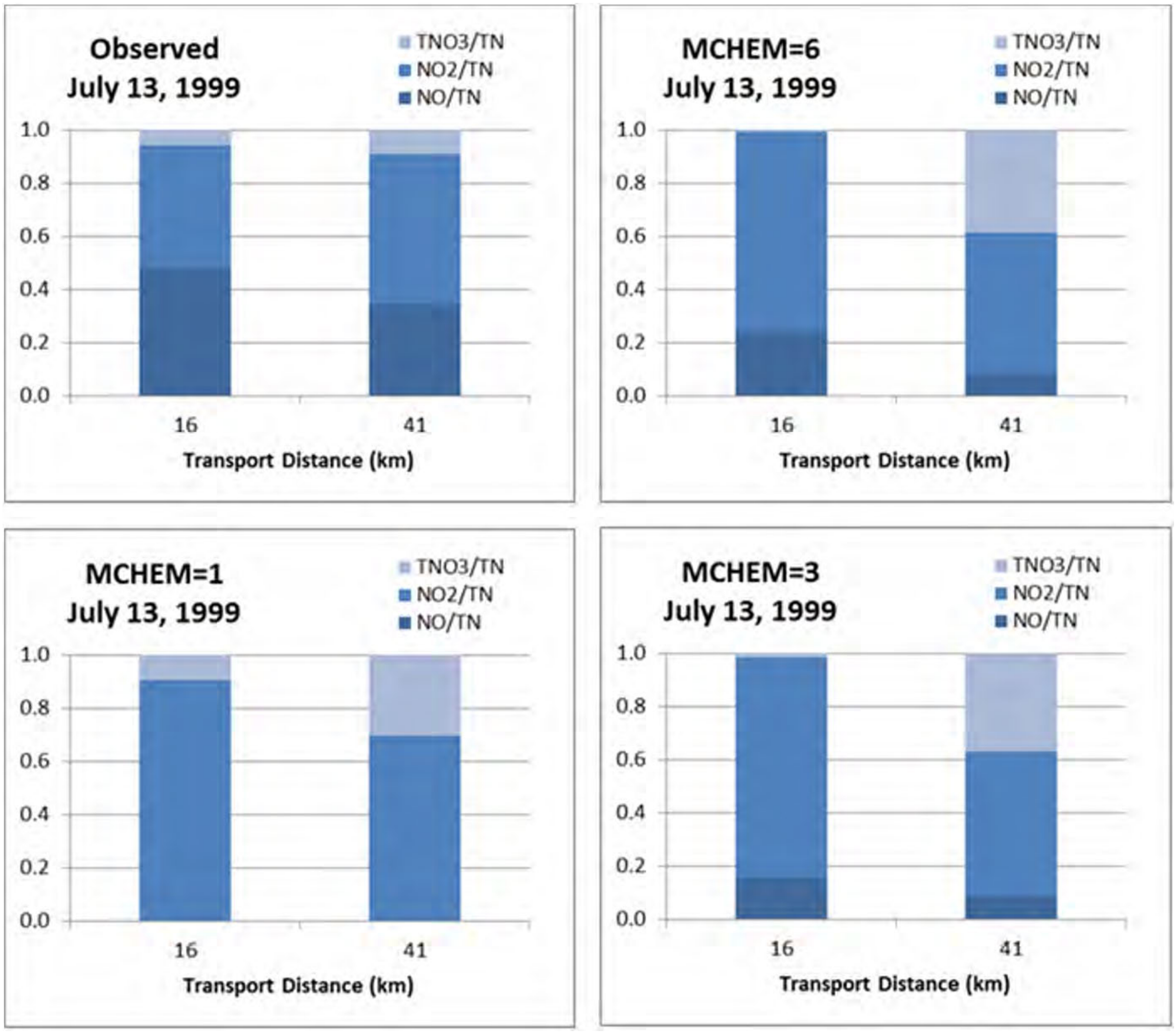
July, 1999 Cumberland Plume Study



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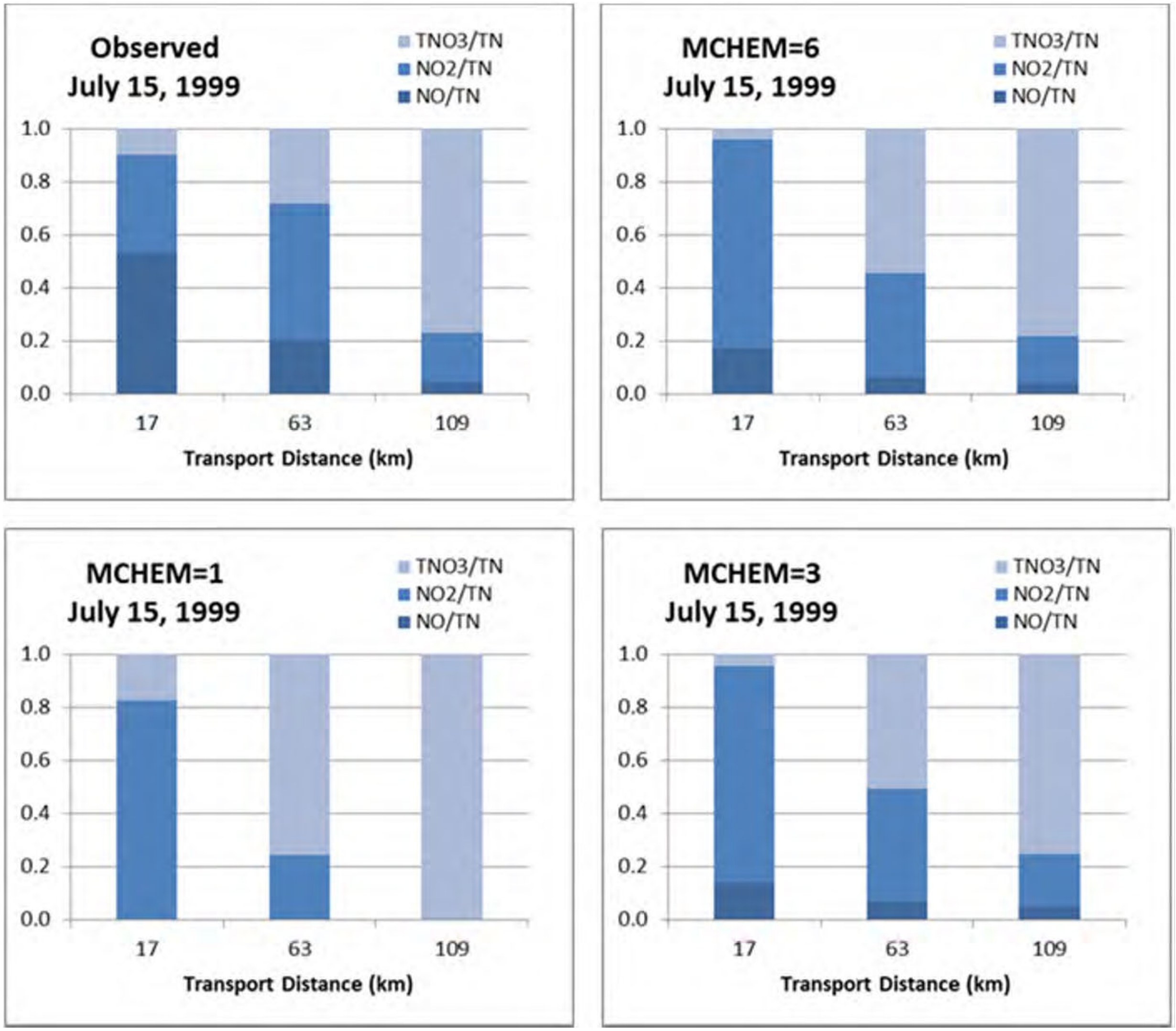

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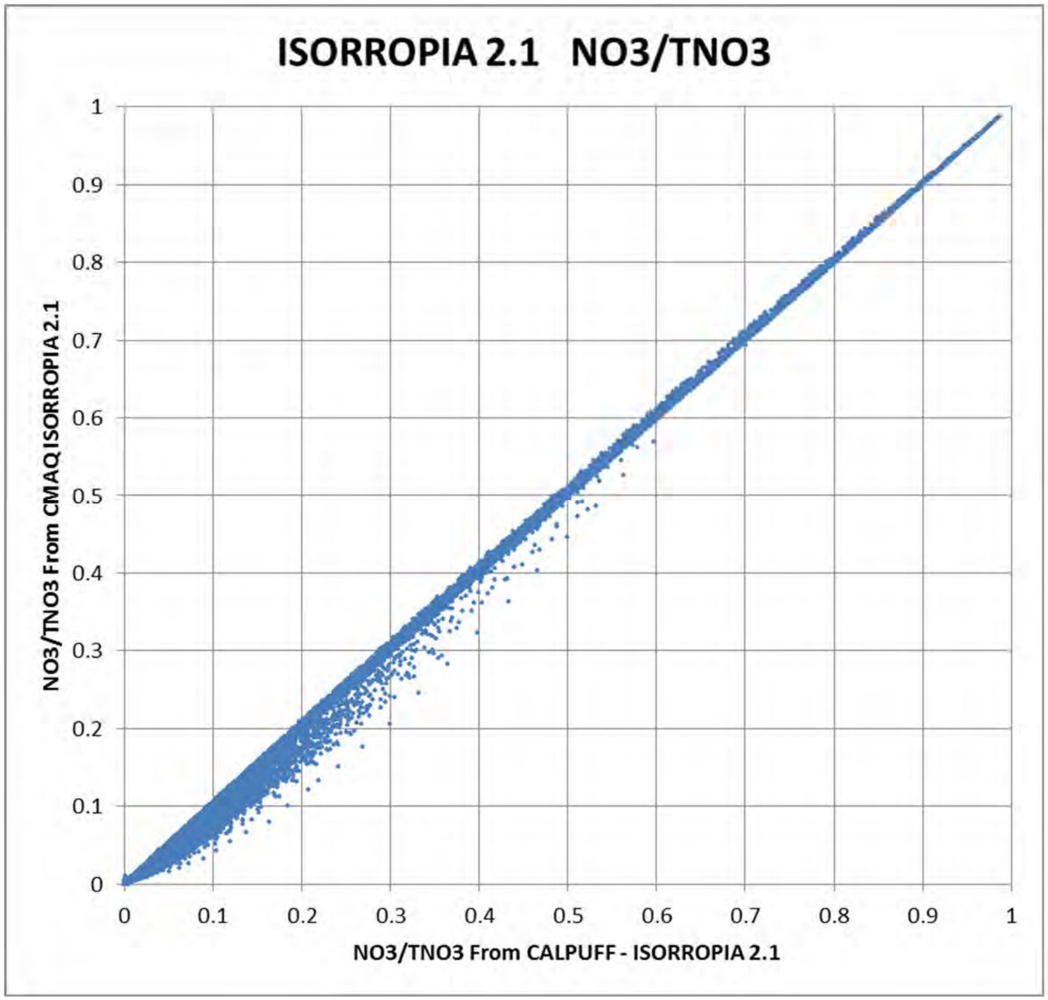
Cumberland Plume Summary

- **Revised and original RIVAD implementations are nearly equivalent in modeling the NO_x transformation data for this plume, and improve model performance relative to MESOPUFF II**
- **Updated RIVAD implementation improves modeled SO_4 Conversion Rate**
  - Upper-bound rate on July 15 at 63 km and 109 km = 3.4%/hr (+/-1.2)
  - RIVAD(updated) = 2.7 to 2.9 %/hr (MCHEM=6)
  - RIVAD = 4.2 to 4.4 %/hr (MCHEM=3)
  - MESOPUFF II = 1.8 to 2.1 %/hr (MCHEM=1)
- **Modeled plume nitrate is nearly all HNO_3, with little particulate NO_3, consistent with the partition expected for the indicated meteorological conditions**

ISORROPIA II in CMAQ v5.0

- **CMAQ v5.0 released February 2012**
- **Subroutines in CALPUFF and CMAQ compared**
  - Bug in array assignment fixed in CMAQ version, and several lines are re-activated
  - New version of ISORROPIA is expected soon
- **Evaluation**
  - Monte Carlo driver compares equilibrium ratio of particulate NO_3 to total nitrate ($TNO_3 = NO_3 + HNO_3$) for range of temperature, relative humidity, and total concentrations of sulfate, nitrate, NH_3
  - Differences in NO_3 / TNO_3 ratios are less than 0.01 in over 99% of the simulations made, and less than 0.1 in all 3 million simulations
  - Compared to CHEMEQ, differences between the two schemes can range up to 100% of the total nitrate, although over 63% of the simulations result in a difference in the NO_3/TNO_3 ratio less than 0.01 and over 84% result in a difference less than 0.10

ISORROPIA II in CMAQ and CALPUFF



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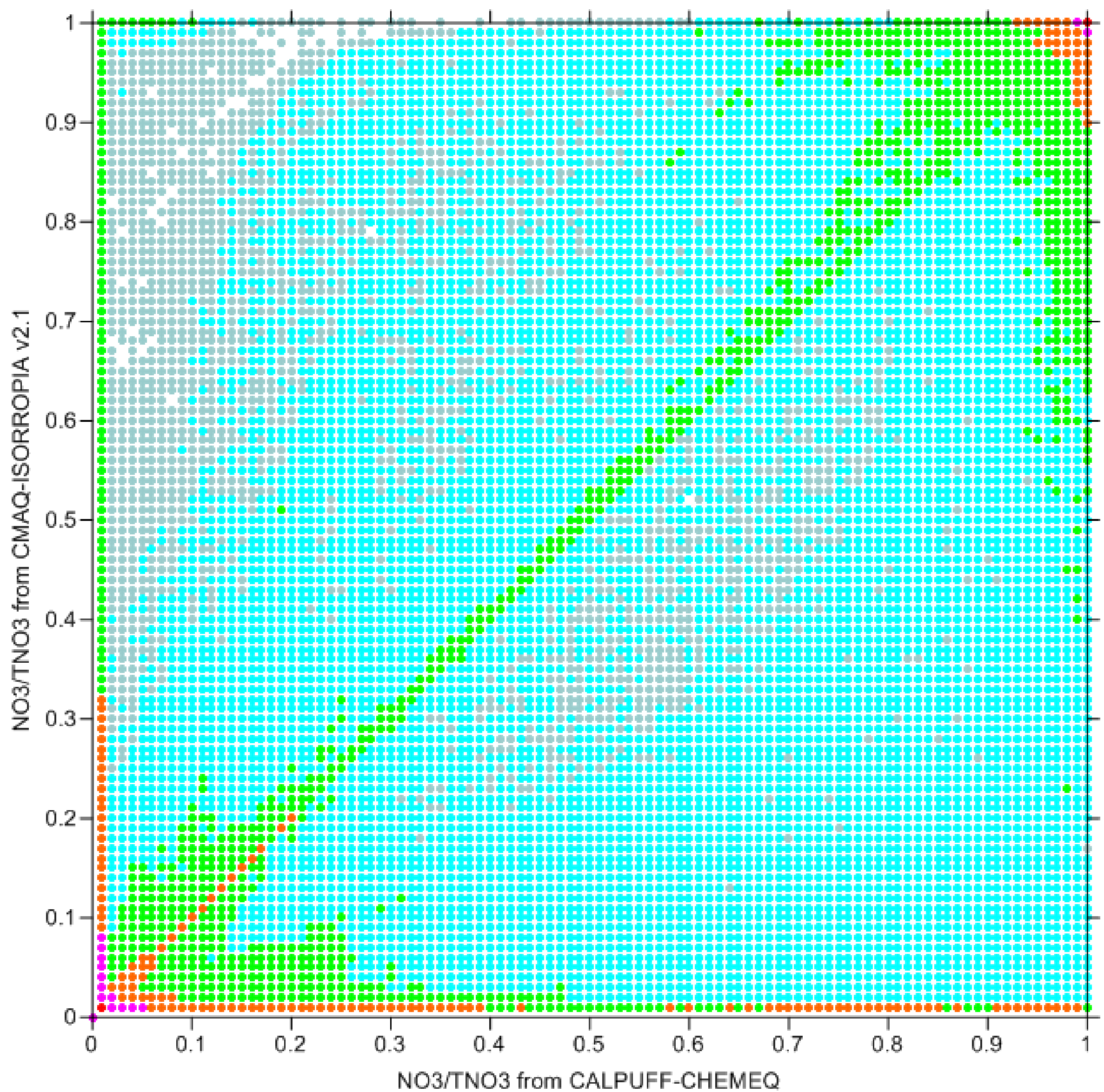
OLD CALPUFF (CHEMEQ) vs CMAQ



Summary - 1

- **CALPUFF v6.42b includes significant improvements in the treatment of chemical reactions**
  - ISORROPIA II model for inorganic gas-particle equilibrium as in CMAQ
  - Revised gas phase chemical transformation module for SO_2 conversion to sulfate and NO_x conversion to nitric acid and nitrate
  - Aqueous phase oxidation and wet scavenging module adapted from the RADM cloud implementation in CMAQ/SCICHEM, with access to 3D cloud water fields from MM5/WRF
  - New option for anthropogenic secondary organic aerosol (SOA) formation based on the CalTech SOA routines implemented in CMAQ-MADRID

Summary – 2

- **SWWYTAF evaluations with enhanced resolution MM5 meteorological data demonstrates significant improvement in performance over the default FLAG (2010) chemistry options**
- **Large overprediction of average observed nitrate concentrations with the older chemistry mechanism is reduced or eliminated with new chemistry**
- **Cumberland plume simulations indicate O_3 depletion improves the modeled sulfate transformation rate, and both RIVAD module options improve modeled NO_x transformation at large distances**

Conclusions

- **New chemistry modules in v6.42b use well-established algorithms referenced in the referred literature and almost universally accepted in the modeling community as better science**
- **CALPUFF v6.42b is backwardly compatible with v5.8 (after bug fixes are introduced into v5.8). CALPUFF should be adopted as a replacement for v5.8 to allow access to 7 years of optional model improvements, including the new chemistry. Because v6.42b is equivalent to v5.8 when run in the same mode, v6.42b is an equivalent model.**
- **New chemistry can and should be accepted under Section 3.2 of Appendix W**
  - Section 3.2 is designed to allow use of important model enhancements in a timely way on a case-by-case basis, without the 3-5 year wait for formal rulemaking
  - BART rule indicates CALPUFF is acceptable but also allows for alternative models
- **EPA should approve v6.42b on case-by-case basis for use in BART applications**

Attachment 11

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
HEADQUARTERS: P.O. BOX 33695 DENVER, COLORADO 80233-0695 303-452-6111

July 2, 2010

Sent via e-mail

Mr. Paul Tourangeau, Director
Air Pollution Control Division
Colorado Department of Public Health and Environment
4300 Cherry Creek Drive South, B Building
Denver, CO 80246-1530

Mr. Doug Lempke
Administrator
Air Quality Control Commission
Colorado Department of Public Health and Environment
4300 Cherry Creek Drive South, EDO-AQCC-A5
Denver, CO 80246-1530

Re: Regional Haze SIP Development Process:
Reopening BART Determinations and Related Modeling

Dear Paul and Doug:

This letter follows up discussions held with Air Pollution Control Division (Division) personnel over the last few months concerning the development of a Regional Haze element of the Colorado State Implementation Plan (SIP). I write today to focus on what we not long ago learned was the Division's intention to ask the Air Quality Control Commission (Commission) to reopen the BART provisions in Regulation 3 concerning the findings the Commission made respecting post-combustion controls for electric generating units (EGUs), and to reopen the BART Determinations that were made in the 2006 – 2008 timeframe. Commission Chair, Barbara Roberts, is copied on this letter because of her invitation to the attendees at the June 17, 2010 Commission meeting. Commissioner Roberts invited stakeholders in the Regional Haze process to provide early comments regarding what should be considered as the Division and the Commission, prepare for the upcoming process concerning the development of the Regional Haze element of the Colorado SIP.

While Tri-State Generation and Transmission Association, Inc. (Tri-State) has significant concerns respecting this reopening of the BART regulations and determinations, those concerns will be addressed separately. This letter is focused solely on the work the Division reports is underway pertaining to the conduct of air quality modeling of BART sources. We assume that Craig Station Units 1 and 2 are included in this modeling exercise. Tri-State requests the

Division's consideration of the request for consultation contained in this letter, and of the attached White Paper prepared by AECOM. Tri-State respectfully requests that any Division modeling be performed consistent with the recommendations in the AECOM White Paper.

We understand the Division intends to use the CALPUFF model to estimate visibility impacts from existing sources, and to run a series of scenarios in which lower levels of emissions are assumed to correspond to the results of the installation of additional controls. Tri-State would note that there is debate about the appropriateness of the use of CALPUFF for purposes of estimating the impacts of an existing source. This is so because CALPUFF is quite conservative in its estimation of impacts. While the use of CALPUFF modeling may make compelling public policy sense in the context of permitting new sources where one wants to be conservative in terms of the potential impacts of new sources, we question the reasonableness of the use of such over-conservatism to estimate not only the impacts of existing sources, but to also estimate the potential benefits of emission reductions from existing sources because the model similarly would overestimate impacts and, thus provide a skewed view of the benefits of emissions reductions. Nevertheless, without compromising or withdrawing these concerns about the appropriateness of using CALPUFF for this purpose, if the Division intends to perform CALPUFF modeling to evaluate existing Tri-State facilities, in the interest of fairness, due process, and transparency, there should be consultation between the Division and Tri-State as to the assumptions to be used in such CALPUFF modeling in order to minimize areas of disagreement.

We mentioned the following set of issues and concerns to Mike Silverstein on June 9, 2010. We raised these issues and asked if the Division would adjust their modeling work to accommodate these concerns. Having not heard back, and given the aggressive schedule we understand the Division to be pursuing, we wanted to provide this letter for the Division's consideration.

1. We learned in mid-May that a modeling protocol, dated April 15, 2010 had been developed indicating it would be used for BART source-related modeling work. The April protocol was not provided for any public comment, much less for comment from the affected sources to be modeled. In all due respect, taking the position that there was no time for public comment or consultation with the affected sources does not remedy the problems presented. Had there been notice and the opportunity for comment and consultation, it could have avoided or reduced the potential for disagreement over the assumptions to be used in, and thus, the results of such modeling exercises.

2. We were concerned that the April protocol contains statements that modeling will be performed using assumptions with regard to background ammonia levels that

are not reasonable for Northwest Colorado. Specifically, on June 9th we suggested that the capabilities of the new version of the CALPUFF model be utilized to improve the exercise by adjustment of background ammonia concentrations on a seasonal basis. This suggestion was made because we understand this adjustment to be relatively simple. We also indicated that our recollection was that the data from the Mt. Zirkel Study, referenced in a general way in the April protocol, indicate that ammonia concentrations in northwest Colorado are low compared to eastern Colorado and that in the fall, winter, and early spring months, ammonia concentrations in northwest Colorado are extremely low. Accordingly, any CALPUFF modeling that is performed should have background ammonia level assumptions seasonally adjusted to reflect the measured data from the Mt. Zirkel Study concerning northwest Colorado.

3. We are also interested in learning what other assumptions are to be used in this CALPUFF modeling. Important examples of what assumptions we seek to consult about include: What "baseline" operating conditions of the source are used: some artificial 24-hour high value or recent 30-day averages reflecting current conditions? What emissions scenarios are being run and to what emission control levels do they relate? And, to what conditions are modeling scenario runs to be compared: a background of annual average conditions, a background of the average of "20% best" days, or some other condition?

We asked AECOM, which has extensive experience in CALPUFF modeling, to research the topic of ammonia background conditions mentioned above and to provide a report on the subject. An AECOM white paper is enclosed for your consideration. It concludes that the statement in the Division's April protocol indicating use of a 1.0 part-per-billion (ppb) background ammonia level for all 12 months of a year should be modified. The AECOM white paper is based on review of ammonia data near Mt. Zirkel and in Wyoming. The following levels of background ammonia should be used.

- 0.1 ppb during months with snow cover (November – March)
- 0.2 ppb during transition months at the beginning and end of the snow season (April and October)
- 1.0 ppb during the remainder of the year.

In summary, we respectfully ask for the following:

A. Any CALPUFF modeling the Division feels it must undertake should utilize assumptions respecting ammonia background levels based on actual data and consistent with the recommendations of AECOM in the attached white paper and summarized above.

B. Tri-State should be provided an opportunity to consult with the Division staff concerning the balance of the assumptions to be utilized in any CALPUFF modeling to be performed, so that any Tri-State comments can be considered by the Division prior to finalizing any modeling report concerning Tri-State facilities.

If you have questions or wish to discuss these comments, please contact Andy Berger or me at (303) 452-6111

Sincerely,

Barbara A Walz

Barbara A. Walz
Vice President
Environmental

Enclosure

cc via email w/enc.: Commissioner Barbara Roberts
Doug Lempke
Mike Silverstein
Kirsten King
Will Allison, Esq.

cc: Jim Sanderson
Andy Berger

AECOM

Environment

Selection of Monthly Background Ammonia Concentrations for CALPUFF Modeling in NW Colorado

Jeff Connors and Bob Paine, AECOM

June 12, 2010

Introduction

The Colorado Department of Public Health and Environment (CDPHE) has issued an update to their Best Available Retrofit Technology (BART) modeling protocol, dated April 15, 2010. The BART modeling protocol recommends that CALPUFF is to be used to determine the visibility improvement relating to emission reductions from sources subject to BART.

One of the input parameters to CALPUFF involves the specification of monthly background levels of ammonia. The ammonia concentrations are used in the model to determine the secondary particulate formation of ammonium nitrate from NO_x emissions. We have found that ammonium nitrate formation is particularly important in cold conditions, when seasonal ammonia levels are usually at their lowest. CALPUFF has been shown to significantly overpredict wintertime nitrate formation (Morris et al., 2005) if it uses wintertime ammonia levels that are too high.

It is noteworthy that the CDPHE BART protocol documents a sensitivity study of ammonium nitrate concentrations as a function of background ammonia concentration, and the protocol states that the nitrate modeling results are very sensitive to ammonia background concentrations between 0.1 and 1 ppb, especially in winter Lower predictions of nitrates occur with lower background ammonia values.

The CDPHE protocol states on page 29 that "an annual background ammonia concentration of about 1 ppb or less is probably more reasonable, based on ammonia measurements from the Mt. Zirkel Visibility Study." The "or less" part of this recommendation is very important, especially during the winter season. The protocol does not provide any further discussion about the seasonality of the ammonia background concentration or further discussion of using ammonia concentration values less than 1 ppb. On page 30, the final guidance is to use 1 ppb for ammonia in northwest Colorado for all months. This is probably because at the time of the Mt. Zirkel Study, CALPUFF only had the capability of handling one year-round value for the ammonia background. In light of widespread evidence of seasonal differences (e.g., see attached paper by Molenar et al., 2008) and CALPUFF's current ability to account for monthly variations, the use of one value for the entire year is not justified. The use of annual average values of ammonia concentrations in winter will lead to overpredictions of nitrate concentrations in winter. Since the use of monthly average ammonia values in CALPUFF is very easy to do, we request that CDPHE adjust their CALPUFF modeling procedures for sources in NW Colorado to include the use of monthly ammonia values as described in this report.

The discussion below provides a review of the Mt. Zirkel Study wintertime ammonia concentrations as well as available ammonia concentrations in an adjacent state (Wyoming) to determine the appropriate monthly background ammonia values for CALPUFF BART modeling for sources in NW Colorado.

Available Ammonia Databases

Mount Zirkel Visibility Study

In 1993, the U.S. Forest Service (USFS) certified that occasions existed during which visibility was significantly impaired in the Mount Zirkel Wilderness Area (MZWA). The Mt. Zirkel Visibility Study was commissioned to obtain more information relevant to this certification.

During certain intensive field study periods, the ambient measurements included ammonia measurements at two sites shown in Figure 1 (VORZ near Hayden and BUFZ at Buffalo Gap). The ammonia concentrations were determined by denuder differences (non-denuded NH_4 versus the denuded NH_4 collected on the citric acid filter). The data taken at the two ammonia measurement sites indicated higher ambient ammonia concentration levels at the Hayden VORZ site as compared to the Buffalo Pass site. This is not surprising because, as noted by Watson (2010), there is grazing in the Yampa Valley except during months of snowfall (mid-October through mid-April; see http://www.wrcc.dri.edu/htmlfiles/co/co.sno.html). During the period of snowfall, the absence of anthropogenic ammonia sources (i.e., grazing cattle) lead to very low ammonia concentrations. This phenomenon has also been noted by other researchers (e.g., Kirschner et al., 1999). The Buffalo Pass concentrations are more representative of a regional value than the VORZ values, according to the Study coordinator, Dr. John Watson (2010), because the Hayden VORZ monitor was located close to local sources of ammonia that are not representative of the overall Yampa Valley environment. Therefore, we have proceeded to use only the Buffalo Gap ammonia values in our recommendations for the input to CALPUFF. These values are plotted in Figure 2.

Figure 1 Mount Zirkel Study Measurement Locations

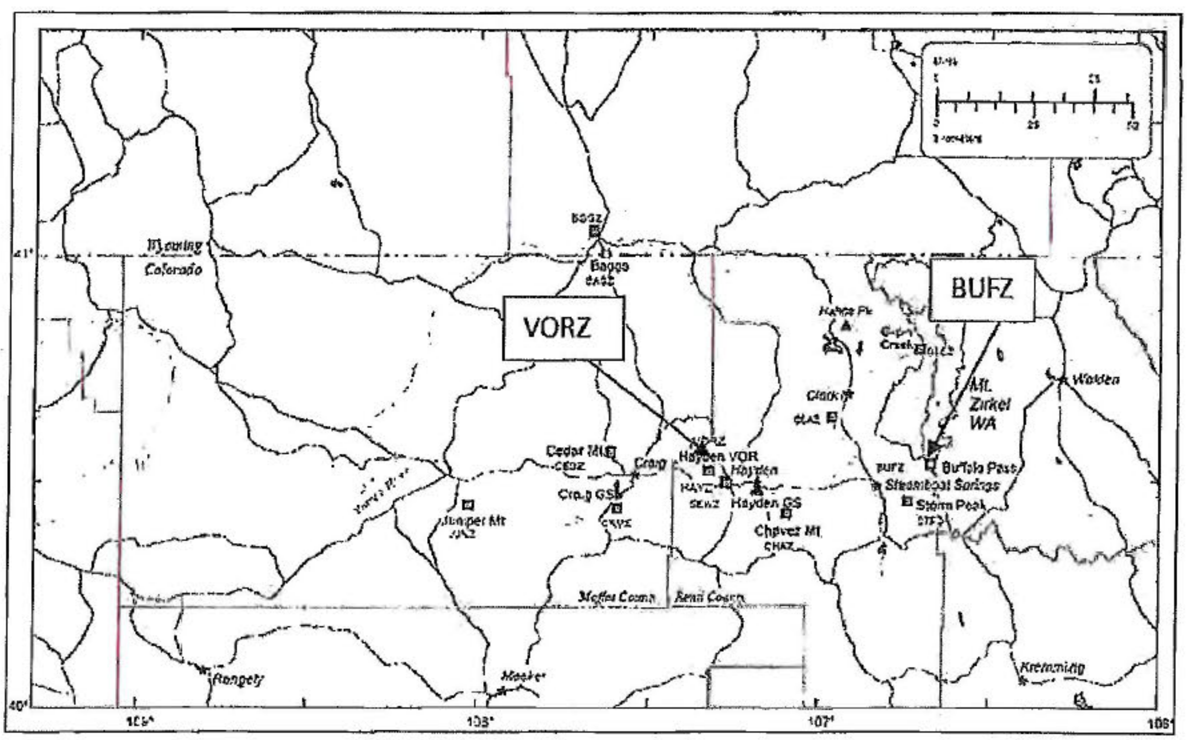
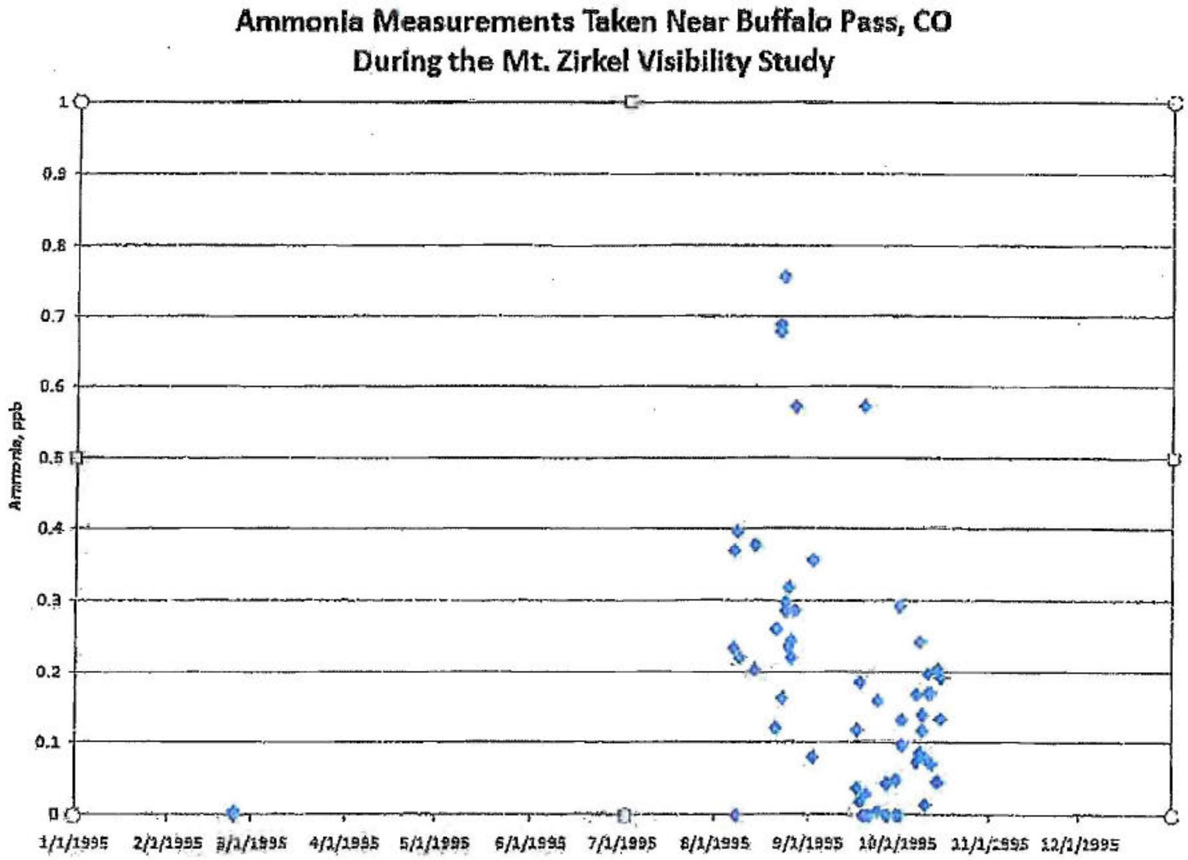


Figure 2 Buffalo Gap Ammonia Concentrations



The Buffalo Gap measurements during the period of snowfall (latter portion of October through mid April) are minimal due to the snow cover, but the concentrations in February indicate very low values (less than or equal to 0.1 ppb). Ammonia concentrations in transition months (April and October) are generally not expected to exceed 0.2 ppb. Ammonia concentrations in the months of May-September can be assigned a value of 1.0 ppb.

Due to the lack of wintertime measurements during the Mt. Zirkel study, another database was reviewed to check on the expected ammonia concentrations during that season.

NH_3 Monitoring in the Upper Green River Basin, Wyoming

A more extensive monitoring program was undertaken in Boulder, WY less than 300 km away from northwestern Colorado (Molenar 2008). Ammonia measurements were taken during this field study every 3 to 4 days using a URG denuder sampler A summary of the ammonia background data over the past three years is provided in Figure 3. The ammonia concentrations observed in Boulder are less than 0.1 ppb during winter, early spring, and late fall. This likely correlated to snow cover which inhibits anthropogenic sources of ammonia such as grazing cattle. The wintertime ammonia values measured in this study are consistent with the choice of 0.1 ppb for the months of November-March for the Yampa Valley sources.

Figure 3 Timeline of Ammonia Concentrations from Boulder, WY (Molenar 2008)

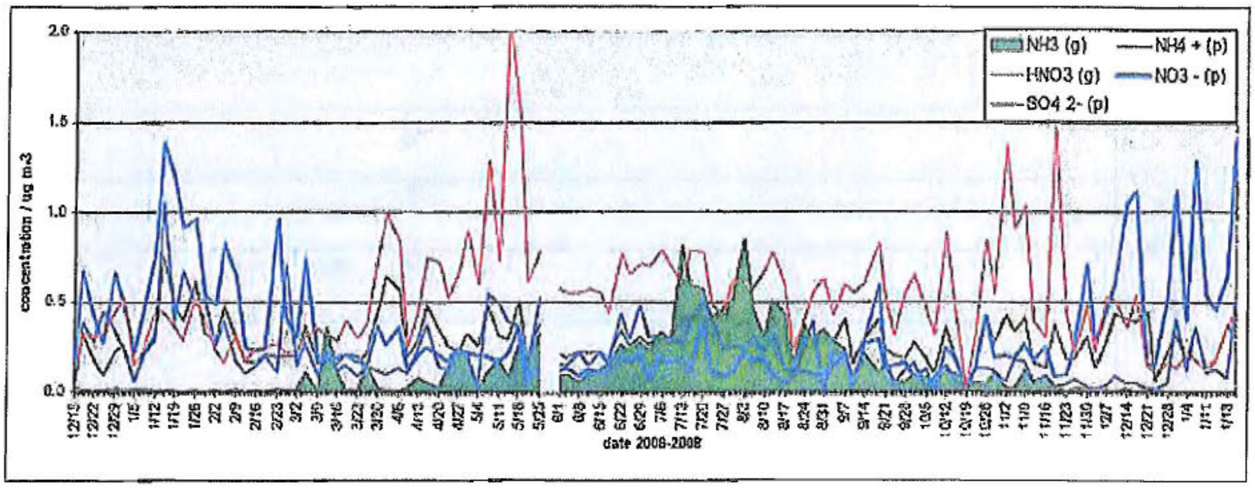
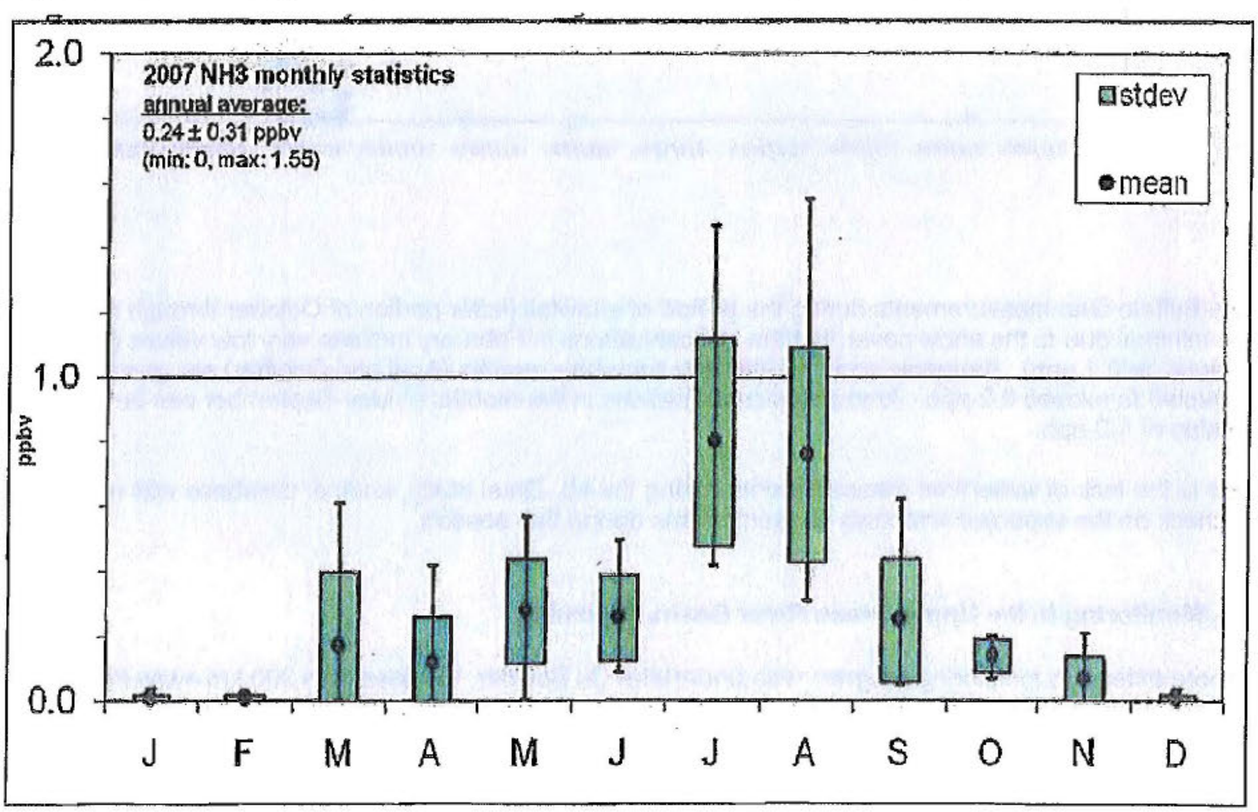


Figure 4 2007 Monthly and Annual NH3 Concentration Data (Molenar 2008)



Conclusions

The ammonia measurements during the Mt. Zirkel study (and confirmed in the Boulder, WY study) which have been plotted in Figures 2-4 suggest a monthly variation of concentrations should be used as input to CALPUFF. The data indicate that the following monthly values would be appropriate:

- 0.1 ppb during months with snow cover (November – March)
- 0.2 ppb during transition months at the beginning and end of the snow season (April and October)
- 1.0 ppb during the remainder of the year

References

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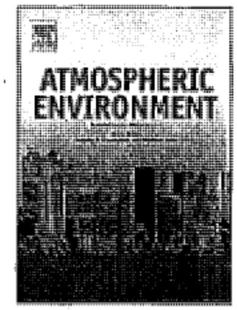
Watson, J.G., D. Blumenthal, J.C. Chow, C.F. Cahill, L.W. Richards, D. Dietrich, R. Morris, J. Houck, R.J. Dickson, S. Andersen (1995). Mt. Zirkel Wilderness Area Reasonable Attribution Stud of Visibility Impairment - Volume II: Results of Data Analysis and Modeling Final Report. July 1, 1996. Prepared for Technical Steering Committee, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, Denver, CO. Available at http://vista.cira.colostate.edu/improve/Studies/ZIRKEL/FinalReport/zirkelfinalreport.htm.

Watson, J. 2010. Personal communication with Mr. Robert Paine

Attachment 12

Exhibit PAC/4002
Owen/170

Accepted Manuscript



Title: Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park

Authors: Jonathan Terhorst, Mark Berkman

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TRI-STATE - RH1
EXHIBIT 7

Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park

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Abstract

The Mohave coal-fired power plant has long been considered a major contributor to visibility impairment in Grand Canyon National Park. The permanent closure of the plant in 2005 provides the opportunity to test this assertion. Although this analysis, based on data from the Interagency Monitoring of Protected Environments (IMPROVE) Aerosol Network, shows that fine sulfate levels in the park dropped following the closure, no statistically significant improvement in visibility resulted. Difference-in-differences estimation was used to control for other influences. This finding has important implications for the methods generally employed to attribute visibility reductions to air pollution sources.

Keywords: Mohave; IMPROVE; Grand Canyon; visibility; CALPUFF

1. Introduction

The Mohave Power Project (MPP) is a large (1,590 MW) coal-fired power plant located 90 miles southeast of Las Vegas in Laughlin, Nevada. Constructed in 1971, the plant was, for some time, the largest emitter of sulfur dioxide in the western United States. In 1998, a group of environmental advocacy organizations sued the plant's owners, alleging that its emissions of sulfur dioxide and particulate matter were in violation of the Clean Air Act. Approximately one year later, the plant was identified as a major cause of visibility impairment in Grand Canyon National Park (GCNP) by the U.S. Environmental Protection Agency (EPA). Upon completion of a multi-year study referred to as Project MOHAVE (Pitchford et al., 1999), the Agency concluded that, although other sources contribute to the visibility reduction, "[because] of the

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quantity of SO_2 emitted from the Mohave Generating Station and its proximity to the Grand Canyon, no other single emissions source is likely to have as great an impact on visibility in the Park."

A few months after this determination, the plant's owners settled the lawsuit and entered into a consent decree which required the plant to reduce SO_2 emissions no later than 2005 (Consent Decree, 1999). Subsequently, the owners estimated that additional emissions controls would cost more than $1 billion and elected to close the plant on December 31, 2005 rather than make such an investment. Over four years have passed since the closure, and we now have the opportunity to determine whether, in the prolonged absence of plant operations, air quality in the Grand Canyon has improved.

2. Literature Review

The link between Mohave emissions and air quality in the Grand Canyon has been studied and debated for over 20 years, resulting in a large body of published research. The most comprehensive study to date, termed Project MOHAVE (Measurement of Haze and Visual Effects) (Pitchford et al., 1999), was performed by the EPA at the request of Congress. This multi-year research effort included two intensive tracer/receptor field experiments, several source emissions simulations and a number of related statistical analyses, all designed to definitively elucidate how MPP operation affected the atmosphere in GCNP.

Despite these considerable efforts, Project MOHAVE's conclusions are ambiguous. Tracer studies revealed that MPP emissions did reach the park, particularly in the summer, when tracer concentrations were recorded above background levels on 90% of the days at the park's western edge. However, there was no evidence linking these elevated concentrations with actual visibility impairment; indeed, "correlation between measured tracer concentration and both particulate sulfur and light extinction were virtually nil" (Pitchford et al., 1999, p. iii). Tracer data also indicated that "primary particles from MPP disperse during transport to GCNP to the extent that though they contribute to visibility impacts they alone would not cause noticeable impairment" (p. v). Overall, the combined results from the tracer studies "strongly suggest[ed] that other sources [than MPP] were primarily responsible for the haze" (p. v).

In contrast to these measurements, pollution transport simulations such as HAZEPUFF

(Latimer, 1993), CALPUFF (Scire et al., 2000), and RAPTD / HOTMAC (Williams et al., 1989) did suggest a negative relationship between MPP emissions and visibility. According to these models, MPP contributed between 8.7% and 42% of measured sulfate on the 90th percentile worst air quality days at the western edge of the Canyon, and 3.1% to 13% of sulfate on the south rim. In terms of visibility, the models showed that MPP increased light extinction by 1.3% to 5.0% at the western edge of the canyon and 0.5% to 2.6% on the south rim. The predicted effect at the 50th percentile was lower in each case, suggesting that MPP impaired visibility most on days when air quality was already quite poor.

Noting the disconnect between the measurements and model predictions, EPA observed that "empirical data (actual field measurements) show poor correlation between the presence of MPP tracer and visibility impairment in the GCNP. Project MOHAVE analysts were unable to find any data to directly corroborate the extreme values calculated by some of the models ..." (Pitchford et al., 1999, p. x). Based on these findings, EPA concluded that MPP was the largest sole contributor to visibility impairment in GCNP. Emissions from large urban areas in California, Arizona and northwestern Mexico were also judged to have contributed significantly (Environmental Protection Agency, 1999).

Subsequent analyses which used CALPUFF to model the transport of MPP emissions to GCNP obtained similar results. A Best Available Retrofit Technology (BART) Assessment[1] conducted for Southern California Edison used CALPUFF to estimate the visibility impact of retrofitting Mohave as a natural gas-fired plant (Paine and Kostrova, 2008). Model results predicted that retrofitting MPP to burn natural gas instead of coal would result in an improvement of approximately 2 deciviews (a standard unit of visibility measure; see below) in the top 2% annual worst air quality days. Additionally, it was estimated that MPP reduced visibility at least .5 dv on approximately 500 days over two years. Another CALPUFF analysis conducted by the State of Nevada found that the 98% percentile improvement would be 2.4 dv and that there would be 186 fewer days annually where the MPP effect would be greater than .5 dv (Nevada Division of Environmental Protection, 2009).

[1] As part of the Regional Haze Rule, EPA requires certain power plants constructed between 1962 and 1977 to install the best-available retrofit technology (BART) in order decrease their emissions of haze-forming pollutants.

Independent reanalyses of the Project MOHAVE tracer data suggest a small or nonexistent Mohave effect. Kuhns et al. (1999) used tracer concentrations during the summer intensive to identify areas which were unaffected by the Mohave plume, and hence only subject to regional changes in sulfate. After controlling for this regional component, they found that MPP was responsible for $7 \mp 3\%$ of the particulate sulfur deposited in the western portion of GCNP; the single largest daily contribution was estimated at $.286 \mp .9\ \mu g/m^3$. Mirabella and Farber (2000) found evidence of a strong regional sulfate component but almost no correlation between local tracer and sulfate concentrations. Eatough et al. (2000) estimated that MPP emissions contributed only 4.3%–5.5% of total sulfate in GCNP; the principal sources of sulfate were surrounding urban areas such as Las Vegas, Los Angeles and the San Joaquin Valley. Later, Eatough et al. (2006) determined that the Los Angeles and Las Vegas urban areas were also the main causes of light extinction in GCNP, and that MPP-associated emissions contributed neglibibly.

Two earlier papers have used a disruption in plant operations to identify MPP's effect on Grand Canyon air quality. First, Murray et al. (1990) examined a seven-month plant closure in 1985 and found no effect on ambient sulfate concentrations in GCNP during the shutdown. They concluded that MPP was responsible for less than 3% of sulfate at the south rim of the canyon. Switzer et al. (1996) expanded on this study by examining monitoring data for the summers of 1985–1987, a period which included both the seven-month shutdown as well as numerous partial shutdowns that occurred when one or both of the plant's two generating units were temporarily offline. By comparing these daily variations in plant operations with simultaneous sulfate measurements taken in GCNP, any link between MPP emissions and GCNP air quality would potentially be cast into greater relief. Despite this added variation, the authors were again unable to detect any statistically significant effect.

There is some evidence that GCNP air quality responded positively to a decrease in emissions from another nearby power plant. Between 1997 and 1999 three scrubbers were installed at the Navajo Generating Station (NGS), a 2,250 MW coal-fired facility located on the eastern edge of GCNP. Analyzing the resulting 90% decrease in emitted SO_2, Green et al. (2005) found that the upper percentiles of the sulfur and light extinction distributions fell following the installation of all three scrubbers. A chi-squared test for independence was used to show that the percentage of winter days exceeding a pre-set threshold for particulate sulfate fell by a statistically significant amount. The authors conclude that reducing NGS emissions decreased winter haze and improved visibility in the park.

3. Model

Since prior research is ambiguous regarding the impact of MPP on GCNP air quality, it is useful reinvestigate this relationship taking advantage of prolonged plant closure and the availability of data to control for weather, background trends in air quality, human activity and other factors which could have affected contemporaneous visibility. A rigorous statistical model is also needed in order to isolate the air quality improvement attributable to emissions reductions.

Consider a two-period model of air quality at a network of regional monitoring sites in the presence of a power plant shutdown. The air quality outcome (light extinction, visibility, pollutant concentration, etc.) at monitoring site $i \in \{1,\ldots,n\}$ in period $t \in \{0,1\}$ is denoted $y_{i,t}$. Air quality at each site and time period is governed by several factors. The first is a regional component R_t which, as the subscript suggests, varies over time but affects all sites equally. Examples of such effects include mesoscale meteorological conditions and pollution transported into the region from large urban areas, as appears to be the case on the Colorado Plateau.

A second component, denoted S_i, captures time-invariant, site-specific effects, which would include elevation and proximity to localized pollution sources whose emissions profiles are relatively constant over time. Finally, emissions from a nearby power plant affect only some of the sites in period 0. Let δ denote this effect, and let $P_{i,0} = 1$ if site i was affected by the plant. The plant closes between the periods 0 and 1, so $P_{i,1} = 0$ for all i. In the treatment effects literature, the group $C := \{i \in \{1,\ldots,n\} : D_{i,0} = 0\}$ is known as the "control" group and $T := \{i \in \{1,\ldots,n\} : D_{i,0} = 1\}$ the "treated" group, and the effect of the plant closure is the treatment effect.

Assuming these components are additive, the air quality outcome at site i in period t is then

$$y_{i,t} = R_t + \delta \cdot P_{i,t} + S_i + v_{i,t}, \tag{1}$$

where $v_{i,t}$ is an error term which is assumed to have zero mean over all i and t. In this model, we only observe $y_{i,t}$ and $P_{i,t}$, and are interested in estimating δ, the effect of the plant operation on the affected sites. Model (1) may be estimated by least squares provided the identifying assumption

$$\mathbb{E}(v_{i,t}|R_t, P_{i,t}, S_i) = 0 \tag{2}$$

holds. In particular, this requires that δ would be zero for the "treated" sites if the closure had not occurred, and that there are no omitted idiosyncratic covariates.

In econometrics, the OLS coefficient $\hat{\delta}$ is known as the difference-in-differences estimator, so-called because the difference in mean outcome between the treated and control groups is computationally identical to the OLS estimator for $\hat{\delta}$ in (1):

$$\hat{\delta} \equiv \overline{\Delta y}_C - \overline{\Delta y}_T, \tag{3}$$

where $\Delta y_i = \Delta R - \delta \cdot P_{i,0} + \Delta v_i$.

This model generalizes to multiple time periods and heterogeneous treatment effects, and additional covariates can (and should) be added to ensure assumption (2) holds. In the air quality arena, this approach has been previously applied to study the effect of pollution regulation on firm location (Millimet and List, 2004; List et al., 2003), particulate matter concentrations on infant mortality (Jayachandran, 2009), air pollution on school absences (Currie et al., 2009), air quality advisories on public transit use (Cutter and Neidell, 2009), and similar policy questions. Previous studies which used spatial or temporal variations in MPP's output as an instrument for GCNP air quality (Murray et al., 1990; Switzer et al., 1996; Kuhns et al., 1999) also employ essentially the same technique, provided the GCNP outcomes are compared with nearby unaffected areas. Conversely, we contend that trend analyses which simply examine air quality over time misidentify the Mohave effect by failing to remove latent regional components and/or control for idiosyncratic effects.

4. Data

We studied the Mohave effect using the above model and a high-frequency, heterogeneous panel of air quality data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) Aerosol Network. The network consists of remote sensing stations located in EPA Class 1 visibility areas, which are primarily national parks and wilderness areas. IMPROVE is EPA's designated data source for measuring air quality under the Regional Haze Rule.[2]

Data are collected every three days, and most of the sites have at least ten years of historical observations available, including three years of data collected after the Mohave closure. The data consist of measurements of sulfate, nitrate, and other aerosol concentrations, as well relative humidity.[3] IMPROVE composites these measurements into a standard index of visibility known as the deciview (dv) (Pitchford and Malm, 1994). The deciview is analogous to the decibel unit of noise measurement; it is approximately linear with respect to perceived changes in visibility, and higher values signify increased degradation. A one-unit decrease in deciviews represents a small but perceptible improvement in visibility. The deciview is the primary metric of the Regional Haze Rule.[4] IMPROVE monitoring sites also include a log which notes maintenance events as well as external anomalies which could perturb the measurements. We used these logs to build an auxiliary panel of anomalous events for control purposes.

Limited censoring was performed on the IMPROVE time series to ensure representativity. We used daily surface wind direction and speed measurements taken at Laughlin/Bullhead City Airport, located 3 miles east of MPP, to isolate days when the wind blew from the south and southwest, directing the Mohave plume towards GCNP. A mid-level wind measurement is preferable to surface wind data when modeling plume transport, but the two should be sufficiently correlated for our purposes. Also, we excluded observations taken on days when the National Weather Service issued warnings concerning dust storm activity in northern Arizona

[2]The Regional Haze Rule (40 CFR 51), promulgated in 1999 by the U.S. EPA to meet Clean Air Act requirements, is designed to improve air quality in general and visibility in particular at 156 national parks and wilderness areas. The Rule obligates the States, in coordination with federal agencies such as the U.S. Forest Service and the National Park Service, to develop and implement plans to improve visibility by 2008.

[3]For lack of a better term, we refer to the IMPROVE data as "daily" even though it is not sampled every day.

[4]In 2006 the IMPROVE Steering Committee adopted a revised algorithm for calculating visibility. The revised estimates were used in this study.

to avoid confounding the visibility measures.

To control for cloudiness and its effect on sulfate formation, daily satellite imagery from NASA's Moderate Resolution Imaging Spectroradiometer (MODIS) program was used to calculate cloud albedo on a $.5 \times .5$-degree (latitude $\times$ longitude) grid. To control for wildfires, a separate MODIS product was used to determine fire activity. This pixel-level data was interpolated over the study area using density estimation to model smoke effects. Finally, we used data on monthly generation at individual power plants in the southwest to examine how regional power generation responded to the Mohave Closure. These data were derived from the U.S. Energy Information Administration's Form EIA-920 database.

5. Analysis

There are three IMPROVE monitoring sites in or near the Grand Canyon. Indian Gardens is 3 km from the south rim at an elevation of 1,166 m, approximately one quarter of the distance from the Colorado River to the upper rim of the canyon. Hance Camp is almost directly above Indian Gardens, on the edge of the south rim at nearly twice the elevation (2,267 m). Meadview overlooks the southern shore of Lake Mead on the western edge of the park. It is 20 km from the mouth of the Grand Canyon and 107 km from MPP.

Project MOHAVE tracer studies suggest areas which were near Mohave but unaffected by its plume Green (1999). Several of these areas have IMPROVE monitoring stations, and they form the basis for comparing air quality outcomes in GCNP. The particular sites used as the control group were Ike's Backbone, Petrified Forest and Queen's Valley. Each site is located on the Colorado Plateau, 100–300 km distant from GCNP. Since these sites are southeast of Mohave, they are unlikely to have been affected by MPP operation, particularly in the summer.

5.1. Descriptive Statistics

Descriptive statistics for the IMPROVE data are shown in Tables 1 (deciviews), 2 (light extinction) and 3 (fine sulfate). The first three rows consider the three GCNP sites, followed by nearby Colorado Plateau sites in rows four through six. The final rows show monitoring data for sites located in Phoenix and east of Southern California (Agua Tibia Wilderness); as transported urban pollution is believed to strongly influence air quality on the plateau, it is wise to examine how these donor areas performed over the same time period. Columns one through four show mean visibility for the entire study period, the pre-closure period 2003–2005, the post-closure period 2006–2008, and the difference in means between the two periods. Comparing the between-group differences in column four is analogous to(3) and hence estimates how the closure altered air quality in GCNP after controlling for other sources of variation.

Average visibility (Table 1) was unchanged at Meadview after the closure; a slight improvement was noted at the upper south rim (Hance Camp); and Indian Gardens worsened slightly. Meanwhile, the control group sites improved by .21–.73 dv. Visibility at sites in Phoenix and Southern California also improved perceptibly post-closure, by 1.22 dv and .69 dv respectively. Similar patterns are seen in light extinction (Table 2). Light extinction fell at every monitoring site in the region compared with before the closure. Large improvements occurred in Phoenix and Southern California, while sites around the Colorado Plateau also improved by lesser amounts. Despite the shutdown, Meadview actually witnessed the least change in light extinction.

Fine sulfate concentrations (Table 3) exhibit a more marked difference between GCNP and surrounding areas. A large drop in SO_4 $\left(-0.11\,\mu g/m^3\right)$ was registered at Meadview, while other sites within the canyon were essentially unchanged. Smaller changes in sulfate concentration were registered elsewhere on the plateau. Finally, sulfate levels in the surrounding urban areas also fell by a significant amount; in particular, the percent improvement in the Southern California region roughly equals that witnessed at Meadview.

Arizona and Southern California are major sources of pollution in the Grand Canyon area. At the same time, they are both distant from and generally downwind of Mohave and hence should not have been affected by the closure. These observations lead us to suspect that visibility improved throughout the region from 2003 to 2008, and that GCNP may have benefited from a drop in transported pollution from surrounding urban areas over that time.

One conclusion of the Project MOHAVE report is that MPP operation was most detrimental to the Grand Canyon on days when air quality was already very poor. If so, the closure effect would be more pronounced at the upper tail of the air quality distribution, for example by decreasing the frequency of days with extremely low visibility. Following Green et al. (2005), Figure 1 shows empirical cumulative distribution plots for fine sulfate at Meadview. For clarity, only the 70th through 99th percentiles are shown. The upper percentiles for fine sulfate at Meadview dropped approximately .2 μg /m^3 following the closure, and extreme events appear to have lessened by varying degrees in each plot. Similar results (not shown) were encountered for Hance Camp and Indian Gardens.

Figure 2 repeats the same plot for the Southern California monitoring station. A similar pattern of improvement emerges even though this site is too far from Mohave to have benefited from the plant closure. This again suggests that regional air quality was improving when the shutdown took place, and underscores the need for a more comprehensive analysis to identify the precise effect of the closure on GCNP.

5.2. Average Effect

Specification (4) is a standard generalization of the two-period difference-in-differences estimator to multiple time periods and sites:

$$y_{i,t} = \beta_0 + \boldsymbol{\beta}_t + \boldsymbol{\beta}_i + \beta_1 \text{FIRE}_{i,t} + \beta_2 \text{CLOUD}_{i,t} + \beta_3 \text{ANOMALY}_{i,t}$$
$$\boldsymbol{\delta} \cdot (\text{SITE}_i \times \text{CLOSURE}_t) + \boldsymbol{\gamma} \cdot (\text{SITE}_i \times \text{CLOSURE}_t \times \text{SUMMER}_t) + \varepsilon_{i,t} \quad (4)$$

The subscripts i and t index monitoring sites and time (days), respectively. The outcome variable $y_{i,t}$ is deciviews, sulfate or light extinction, as measured by IMPROVE. Vectors $\boldsymbol{\beta}_t$ and $\boldsymbol{\beta}_i$ capture site- and time-level fixed effects, GCNP_i and CLOSURE_t are dummy variables for the Grand Canyon monitoring sites and post-closure days. $\text{FIRE}_{i,t}$ is a unit-less parameter derived from the MODIS fire product. $\text{ANOMALY}_{i,t}$ is an indicator variable equal to one if the site's log noted an anomaly on that day. $\text{CLOUD}_{i,t}$ is cloud albedo, as measured by the MODIS daily high-resolution cloud product. $\varepsilon_{i,t}$ is an error term. Vectors $\boldsymbol{\gamma}$ and $\boldsymbol{\delta}$ represent the net effect of the closure on each GCNP monitoring site in the summer and in the remainder of the year, respectively.

We estimated this specification by multiple regression on a balanced panel of daily data spanning six years (2003–2008, inclusive). Estimation results are reported in Table 4. A Durbin-Watson test showed strong evidence of temporal autocorrelation in the error terms, so the reported standard errors are heteroskedasticity and autocorrelation consistent. The three columns of estimates use sulfate, aerosol light extinction and deciviews as the outcome.

Fire is positively associated with degraded visibility but was not found to be significant. Cloud albedo was also not significant. We suggest that this is because the effect of cloudiness on sulfate formation is largely absorbed by the daily dummy variables. The closure induced drops in sulfate concentrations at all three monitoring sites in the summer. The largest decrease was experienced at Meadview, where sulfate dropped .318 μg /m^3 on average. The next-largest decrease occurred at Indian Gardens and measured .256 μg /m^3. Finally, Hance Camp improved by .194 μg /m^3. The ordering of the coefficients is consistent with the notion that MPP pollution enters GCNP over Meadview, is funneled through the canyon towards Indian Gardens, and has the least impact on the upper rim at Hance Camp. No change was detected in the winter months (October–April) at any location.

Turning to the visibility measures, results show that these reductions in sulfate failed to translate into improved visibility in GCNP. The only statistically significant change in visibility was a 3.346 Mm^{-1} decrease in light extinction at Hance Camp. There was no change in deciviews in the summer or winter at any of the three sites. To see if an increase in some other component could have masked the potential improvement resulting from the closure, we estimated specification (4) for every air quality component used to calculate light extinction and deciviews. We found statistically significant alterations in two components, nitrate and coarse mass. Summer nitrate concentrations fell by approximately .12 μg /m^3 at Indian Gardens and Hance Camp; no change was detected at Meadview. Coarse mass increased by approximately 2.1 μg /m^3 at all three sites after the closure.

5.3. Distributional Effect

Discussion of MPP's effect on GCNP is often couched in terms of its effect on the given quantiles of the air quality distribution. The above regressions suggest this effect by isolating periods when wind and season favor poor air quality, but it is also useful to estimate it directly using a quantile regression (Koenker, 2005). Unfortunately, large cross-sectional models such as ours pose theoretical and computational challenges for existing quantile regression techniques Koenker (2004). To alleviate these problems, we estimated a simpler version of specification (4). We used only summer data, and the GCNP sites were pooled into a single treatment group. Month fixed effects were used instead of day fixed effects. The two-step estimator suggested by Canay (2010) was employed to allow for quantile-invariant individual fixed effects.

Regression results are reported in Table 5. The MPP closure resulted in median sulfate levels in GCNP falling by .103 μg /m^3. At the 90th percentile, the change increased to .144 μg /m^3. We found that median light extinction increased by 2.6 Mm^{-1} after the closure, but were unchanged at the 90th percentile. Similarly, overall visibility worsened by .52 dv at the median, but was unchanged at the 90th percentile. Fire had a large, negative effect in air quality in several of the regressions, as did the anomaly indicator variable.

6. Discussion

The Mohave closure decreased fine sulfate concentrations in GCNP. Several different estimations found a statistically significant reduction when compared with nearby sites which not exposed to MPP emissions. The range of our estimates–.10 to .32 μg /m^3 in the summer–corresponds to approximately a 3–10% drop in sulfate, which is in line with Project MOHAVE predictions and earlier estimates of the Mohave sulfate component.

However, we found no corresponding improvement in deciviews or light extinction. This is partially explained by fluctuation in other aerosols masking the drop in sulfate. It is also possible that the sulfate change is too small relative to natural daily variation in visibility conditions to have a significant impact. In the hypothetical case that every component except sulfate remained constant after the closure, analysis of the underlying equations provides some sense of how visibility would have responded. The IMPROVE aerosol light extinction equation is (Pitchford et al., 2007):

$$b_{ext} = f_S(RH)\left(2.2\times SO_4^S + 2.4\times NO_3^S\right) + f_L(RH)\left(4.8\times SO_4^L + 5.1\times NO_3^L\right) + \\ 2.8\times OM^S + 6.1\times POM + 10\times EC + Soil + 1.7\times f_{SS}(RH)\times SeaSalt + \\ 0.6\times CM + RS + 0.33\times NO_2, \quad (5)$$

where $f(RH)$ is a relative-humidity correction factor, POM measures particulate organic material concentration, EC measures light-absorbing carbon, $Soil$ measures fine soil, CM measures coarse mass, and SO_4 and NO_x measure the relevant oxides. The S and L sub/superscripts denote small- and large-particle concentrations, which for SO_4 are given by $SO_4^L = (SO_4)^2/20$ and $SO_4^S = SO_4 - SO_4^L$. Combining these identities and equation (5) gives

$$\frac{\partial b_{ext}}{\partial SO_4} = 2.2 \cdot f_S(RH) \cdot \left(1 - \frac{SO_4}{10}\right) + 4.8 \cdot f_L(RH) \cdot \frac{SO_4}{10}.$$

With average summer values for Meadview ($f_S(RH) = 1.385; f_L(RH) = 1.267; SO_4 = 1.633$), we have that a $-0.20\ \mu$g/m^3 change in sulfate results in a -0.71 Mm^{-1} change in light extinction. Using the deciviews formula

$$dv = 10 \times \ln\left(\frac{b_{ext}}{10} + S_R\right), \tag{6}$$

with site-specific Rayleigh scattering constant $S_R = 10$ Mm^{-1} for Meadview, this translates to an improvement of roughly .40 dv at an average light extinction level (28.22 Mm^{-1}). Assuming a $-0.7\ \mu$g/m^3 change–much higher than suggested by previous studies, and over twice as large as the greatest change we encountered–gives an expected change of -1.0 dv. Hence, conservatively speaking, we believe it is unlikely that the Mohave closure would have resulted in an visibility improvement in excess of 1 dv (other factors unchanged.)

It is prudent to ask whether any GCNP-specific exogenous change in sulfur could have occurred after the closure; if so, our estimates would be downward-biased. One potential source of SO_2, fire, is controlled for in the model. Another source is power generation. Did a nearby power plant (for example, NGS) increase generation to compensate for the Mohave closure? We examined federal regulatory records of monthly power generation for other plants within 300km of the Grand Canyon before and after the closure and found no indication of such a surge. After taking seasonality into account, regional power generation (excepting Mohave) peaked in 2005, and trended slightly downwards for the remainder of the study period. Additionally, a followup EPA study of the Mohave closure noted that "[most] of the electricity production lost due to the closure of the Mohave Generation Station has been replaced by new natural gas-fired generation, particularly in Nevada" (U.S. Energy Information Administration (EIA), 2009). As the combustion of natural gas releases approximately 1% of the SO_2 of a comparable coal-fired plant (on a MWH basis), there is little possibility that this could have offset the effect of the closure.

Tourism in GCNP is another potential idiosyncratic source of pollution, but again the data do not indicate a countervailing effect. Monthly attendance figures from the National Park Service show that seasonally-adjusted attendance in GCNP was relatively stable from 2003 through 2008. There is no evidence that visits spiked in the years following the MPP closure, as would be required to bias the estimators.

Our results indicate that other components of visibility, in particular coarse mass and nitrate, changed in GCNP after the closure. Soil is known to be the main component of coarse mass in the Grand Canyon (Malm et al., 2007), leading us to hypothesize that dust anomalies in and around GCNP in the years following the closure might caused visibility to worsen. To the extent that these are ignored by the controls we introduced, this constitutes an omitted variable in our model. The creation of a high resolution dust measurement data source would advance our ability to study air quality changes over time in the southwest. Since dust is also a byproduct of driving, specific data on regional vehicle activity is also desirable.

These difficulties are indicative of a larger problem encountered when attempting to conduct inference on a calculated parameter (like deciviews) which it itself a function of many stochastic processes, each governed by a unique set of anthropogenic and natural factors. Achieving identification (in the sense of assumption 2) will generally be much harder than when considering any one parameter in isolation. To the extent that the MPP shutdown mainly affected a single aerosol (SO_4) which has a strong regional component and is relatively stable over time, we are most confident that the sulfate effect is correctly identified.

7. Conclusion

In this paper we studied how operation of the Mohave Power Plant affected air quality in the Grand Canyon. We compared pre- and post-closure visibility in the Canyon and at nearby unaffected sites in order to identify the level of degradation attributable solely to MPP. Net of the prevailing environmental and anthropogenic factors in the region, we found virtually no evidence that the MPP closure improved visibility in the Grand Canyon; or, equivalently, that the plant's operation degraded it. Mean visibility (deciviews) and light extinction in GCNP did not respond to the closure in a statistically significant fashion. Sulfate levels did drop throughout the park, but not by an amount sufficient to induce a perceptible improvement in visibility.

We are thus unable to conclude that the closure improved visibility in the Grand Canyon. Our findings are consistent with, and indeed were predicted by, the results of tracer/receptor analyses performed over the past two decades, which consistently noted low correlation between MPP emissions and GCNP visibility. They stand in contrast to the various atmospheric transport models employed by Project MOHAVE, which predicted that visibility would have improved by 5% or more after the closure.

Since recent applications of CALPUFF (Nevada Division of Environmental Protection, 2009; Paine and Kostrova, 2008) continue to predict that retrofitting MPP will improve visibility in the Grand Canyon, our results raise questions about the reliability of CALPUFF. These concerns are especially pertinent in light of EPA's designation of CALPUFF as the preferred model for assessing the effects of long-range pollution transport on air quality in Class I visibility areas under the Regional Haze Rule.

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Outcome: dv	2003–2008 (1)	2003–2005 (2)	2006–2008 (3)	Δ (4)	SD (5)	N (6)	Missing (7)
Meadview	8.24	8.23	8.24	0.00	3.06	659	68
Indian Gardens	8.92	8.86	8.96	0.10	3.66	614	113
Hance Camp	6.54	6.61	6.47	−0.14	3.58	695	32
Sycamore Cyn.	10.09	10.22	9.96	−0.26	3.65	675	52
Ike's Backbone	9.36	9.46	9.26	−0.21	3.14	698	29
Phoenix	18.04	18.61	17.40	−1.22	4.39	618	109
So. Cal.	15.90	16.25	15.55	−0.69	5.01	592	135

Table 1: *Descriptive statistics for daily visibility, 2003–2008.*

Outcome: b_{ext}	2003–2008 (1)	2003–2005 (2)	2006–2008 (3)	Δ (4)	SD (5)	N (6)	Missing (7)
Meadview	13.93	13.94	13.93	−0.02	8.18	659	68
Indian Gardens	16.41	16.69	16.18	−0.50	14.20	614	113
Hance Camp	11.77	12.38	11.13	−1.25	11.20	695	32
Sycamore Cyn.	20.39	20.97	19.80	−1.17	11.85	675	52
Ike's Backbone	16.86	17.36	16.39	−0.97	9.63	698	29
Phoenix	56.70	61.32	51.47	−9.85	36.80	618	109
So. Cal.	44.24	46.56	41.97	−4.59	27.29	592	135

Table 2: *Descriptive statistics for daily aerosol light extinction, 2003–2008.*

Outcome: SO_4	2003–2008 (1)	2003–2005 (2)	2006–2008 (3)	Δ (4)	SD (5)	N (6)	Missing (7)
Meadview	1.17	1.22	1.11	−0.11	0.75	659	68
Indian Gardens	1.02	1.02	1.01	−0.00	0.63	614	113
Hance Camp	0.86	0.87	0.85	−0.01	0.55	695	32
Sycamore Cyn.	0.95	0.97	0.93	−0.04	0.60	675	52
Ike's Backbone	1.14	1.12	1.16	0.04	0.70	698	29
Phoenix	1.59	1.63	1.54	−0.09	0.80	618	109
So. Cal.	2.49	2.60	2.38	−0.22	1.79	592	135

Table 3: *Descriptive statistics for daily fine sulfate, 2003–2008.*

	SO_4	b_{ext}	dv
(Intercept)	1.512***	21.717***	11.073***
	(0.176)	(4.086)	(1.023)
Fire	0.001	0.090	0.014
	(0.002)	(0.069)	(0.012)
Anomaly	−0.173*	13.673	3.313
	(0.087)	(9.975)	(1.897)
Cloud Albedo	−0.001*	0.003	0.001
	(0.000)	(0.006)	(0.002)
Meadview × Closure	−0.004	0.211	0.120
	(0.068)	(0.935)	(0.359)
Meadview × Closure × Summer	−0.318**	0.484	0.118
	(0.116)	(1.566)	(0.490)
Hance Camp × Closure	0.071	0.786	0.458
	(0.046)	(0.865)	(0.351)
Hance Camp × Closure × Summer	−0.194**	−3.346*	−0.918
	(0.073)	(1.675)	(0.489)
Indian Gardens × Closure	0.112**	1.839	0.672*
	(0.042)	(0.975)	(0.339)
Indian Gardens × Closure × Summer	−0.256***	−4.539	−0.939
	(0.074)	(2.871)	(0.530)
adj. R^2	0.790	0.476	0.679
F	21.096	5.719	11.978
$P(>\|F\|)$	0.000	0.000	0.000
N	1601	1556	1556

Significance levels: ***=0.001 **=0.01 *=0.05

Table 4: *Difference-in-differences estimate of the effect of Mohave operation on Grand Canyon air quality.*

Outcome:	SO_4		b_{ext}		dv	
τ	50%	90%	50%	90%	50%	90%
(Intercept)	−0.064	0.894***	−1.991	19.121**	0.243	4.760***
	(0.142)	(0.139)	(1.850)	(7.300)	(0.520)	(0.915)
Fire	0.002	0.004*	0.379***	0.407	0.075***	0.096
	(0.007)	(0.002)	(0.079)	(0.485)	(0.010)	(0.128)
Anomaly	−0.002	−0.324*	3.334	15.452*	1.104	3.335
	(0.177)	(0.163)	(2.494)	(7.438)	(0.884)	(2.492)
Cloud Albedo	0.001***	0.000	0.004	−0.011	0.002	−0.001
	(0.000)	(0.001)	(0.004)	(0.007)	(0.001)	(0.002)
GCNP × Closure	−0.103*	−0.144*	2.597***	0.690	0.519*	0.034
	(0.045)	(0.069)	(0.555)	(1.084)	(0.209)	(0.307)
N	1683	1683	1631	1631	1631	1631

Significance levels: ***=0.001 **=0.01 *=0.05

Table 5: *Difference-in-differences estimate of the effect of Mohave operation on median and 90th percentile air quality in Grand Canyon.*

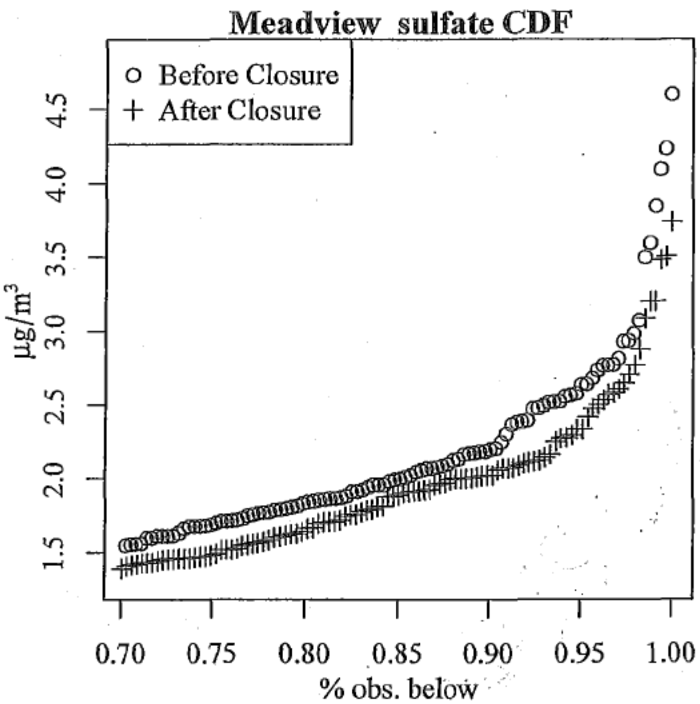

Figure 1: *Empirical cumulative distribution of fine sulfate at Meadview. Plots is of the upper 30 percentiles only.*

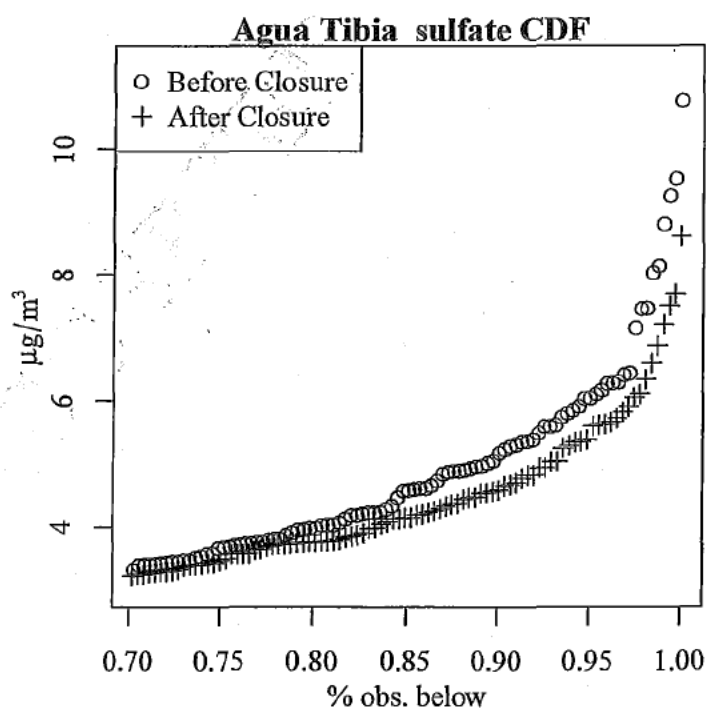

Figure 2: *Empirical cumulative distribution of fine sulfur at Agua Tibia wilderness area. Plot is of the upper 30 percentiles only.*

Attachment 13

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

July 12, 2012 Submitted electronically to www.regulations.gov

Mr. Carl Daly
Director, Air Programs
Environmental Protection Agency Region 8
Mailcode: 8P-AR
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Docket ID No. EPA-R08-OAR-2012-0026
Initial Information Submittal by PacifiCorp

Dear Mr. Daly:

PacifiCorp is providing this initial information[1] in response to EPA's request regarding comments on its ―Proposals in the Alternative" for PacifiCorp's Jim Bridger Units 1, 2, 3, and 4 NO_x BART, published in the Federal Register on June 4, 2012. 77 Fed. Reg. 33022, 33053. Specifically, EPA has requested more information regarding what EPA calls the first, second and third proposed approaches in light of the impacts expected as a result of EPA's Federal Implementation Plan (―FIP") on PacifiCorp's customers and on the reliability of PacifiCorp's generating system as a whole. In submitting this initial information, it is important to note that PacifiCorp firmly believes the issues of customer impacts and system reliability are not limited to the proposed NO_x BART alternatives for Jim Bridger Units 1, 2, 3 and 4; rather, PacifiCorp believes that in making any determination on a large, multi-jurisdictional system such as PacifiCorp's, the regulating agency must consider the broad scope of the impacts of its decisions on customers and generating system reliability as a whole. This is precisely what the state of Wyoming properly did in establishing its State Implementation Plan (―SIP") in this regard. In support of its position, and without waiving any arguments addressing EPA's approach, PacifiCorp provides the following initial information to support EPA's ―Third Proposed Approach," as outlined in the June 4, 2012, EPA action, to address the timing of controls at the Jim Bridger units. PacifiCorp believes that the issues raised herein are applicable to the timing of all BART or reasonable progress controls on PacifiCorp's units, whether in Utah, Wyoming, Arizona or Colorado, required to be installed under the Regional Haze program.

[1] PacifiCorp intends to file additional, extensive comments on the EPA's proposed action at a later date.

Because of the Size and Multi-State Nature of its Generation Fleet, PacifiCorp and its Customers are Unreasonably Impacted by the Regional Haze Rules

PacifiCorp provides regulated electric service to more than 1.7 million customers in California, Idaho, Oregon, Utah, Washington and Wyoming with a net system capacity of 10,597 megawatts, operating 75 generating units across the Western U.S. PacifiCorp's diverse generation portfolio includes coal (58% of total owned capacity), natural gas (21% of total capacity), hydroelectric (11% of total capacity), and wind and other resources (10% of total capacity). PacifiCorp is one of the largest owners of rate-regulated renewable generation in the United States (second only to its sister company, MidAmerican Energy Company) with 21% percent of its generation capacity being renewable. PacifiCorp owns and operates 19 coal-fueled generating units in Utah and Wyoming, and owns 100% of Cholla Unit 4, a coal-fueled generating unit in Arizona. In addition, PacifiCorp has an ownership interest in Craig Units 1 and 2 and Hayden Units 1 and 2 in Colorado.

Importantly, for purposes of evaluating EPA's Proposals in the Alternative, more than 80% of PacifiCorp's 6,157 total owned megawatts of coal-fueled generating capacity are BART-eligible. Even without considering the ultimate outcome of EPA's recently proposed action to partially disapprove the Utah Regional Haze SIP, approximately half (more than 3,000 megawatts) of PacifiCorp's coal-fueled generating capacity will be subject to the installation of controls within the next five years. This conclusion is based on EPA's proposed actions to partially approve and partially disapprove Wyoming and Arizona's SIPs and to approve Colorado's SIP. If EPA ultimately attempts to require four additional SCR on PacifiCorp's Utah units as BART controls, which is beyond the NO_x controls already installed or planned for those units under the existing Utah SIP, then the impact on PacifiCorp, its customers, and system reliability will be even more severe.

When considering PacifiCorp's diversified generation portfolio on an energy (as opposed to capacity) basis[2], PacifiCorp's coal-fueled generation fleet serves as the backbone of the system with 66% of the electricity serving customers being coal-fueled. PacifiCorp cannot simply shut these coal units down or replace all of the energy; it is subject to state and federal requirements to provide reliable generation and transmission service on demand. As a result, additional and accelerated costs imposed on coal-fueled plants have a greater cost impact on customers.

[2] The word ―energy" as used here is intended to mean the amount of electricity actually produced in any given period as opposed to the total ability to produce electricity in that same period. In other words, although a unit may have a rated capacity to produce 100 megawatts of electricity (its capacity), it may only produce 50 megawatts of electricity in a given period (its energy).

EPA's Primary Regional Haze Proposal is Simply Too Much, Too Fast

As evidenced by the emission reduction projects which PacifiCorp has already installed in accordance with the Utah and Wyoming Regional Haze SIPs, PacifiCorp is not opposed to making emission reductions that are cost effective for its customers and that achieve environmental benefits, as required by law. PacifiCorp has undertaken projects to comply with the Utah and Wyoming SIPs at a cost of approximately $1.3 billion (PacifiCorp's share of $1.4 billion of total project costs) between 2005 and 2011. Those projects, in conjunction with projects completed through 2012, have reduced emissions of SO_2 by approximately 58% and emissions of NO_x by approximately 46%, with associated visibility benefits.

Just as modeled visibility improvements associated with PacifiCorp's emission reduction projects do not stop artificially at a state border, EPA's analysis of the impacts of its proposed FIP for a large, multi-state system like PacifiCorp's should not be limited to only those facilities and customers located within Wyoming's borders. EPA's actions impacting large, multi-state systems in one state must also consider the cumulative impacts of all of its actions in all other states that affect the same system. In connection with its proposed FIP in Wyoming, EPA should also consider its proposed partial disapproval of the Utah SIP and the resulting impact on PacifiCorp's four BART-eligible Utah facilities. In addition, EPA Region 8 has already approved the Colorado SIP, which includes major emissions control retrofit requirements for selective catalytic reduction (―SCR") and selective non-catalytic reduction (―SNCR") and their associated costs at the Craig and Hayden facilities in Colorado. Further, EPA Region 9 recently released a proposed Federal Implementation Plan (―FIP") requiring installation of SCR at Cholla Unit 4 within the next five years. In each case, the costs of these incremental environmental controls will be borne by PacifiCorp and its customers, as PacifiCorp's generation fleet costs are allocated on a system-wide basis to customers across all states where it provides retail service. Likewise, in each case, installation of controls on all of these facilities within the prescribed or proposed timeframes takes generation out of PacifiCorp's system for prolonged periods of time to effectuate the construction and tie-in of these controls.

To illustrate the magnitude of the impacts on PacifiCorp's generating system, Table 1 below identifies the units owned (along with ownership share) and operated by PacifiCorp that are impacted by the state SIPs and proposed FIPs. Table 2 includes units in which PacifiCorp has an ownership share but for which it is not the operator, and, therefore, has a financial obligation for controls required by Regional Haze-related requirements.

[Table 1 on next page]

Table 1
Summary of EPA Proposed Incremental NO_x Actions
PacifiCorp Owned and Operated Units

State	Unit	MW	Ownership Share	Proposed NO_x Controls	Installation Requirements
WY	Dave Johnston 1[3]	106	100%	LNB/OFA	SIP – Not required *FIP – July 31, 2018*
WY	Dave Johnston 2[2]	106	100%	LNB/OFA	SIP – Not required *FIP – July 31, 2018*
WY	Dave Johnston 3	220	100%	SNCR	SIP – Not required *FIP – Within 5 years; 2017*
WY	Jim Bridger 1	531	66.66%	SCR	SIP – December 31, 2022 *FIP – 2017 (first proposed approach)* *FIP – 2022 (third proposed approach)*
WY	Jim Bridger 2	527	66.66%	SCR	SIP – December 31, 2021 *FIP – 2017 (first proposed approach)* *FIP – 2021 (third proposed approach)*
WY	Jim Bridger 3	523	66.66%	SCR	SIP – December 31, 2015 *FIP – 2015 (first proposed approach)* *FIP – 2017 (second proposed approach)*
WY	Jim Bridger 4	530	66.66%	SCR	SIP – December 31, 2016 *FIP – 2016 (first proposed approach)* *FIP – 2017 (second proposed approach)*
WY	Naughton Unit 3[4]	330	100%	SCR	SIP – December 31, 2014 *FIP – 2014*

[3] EPA's proposed action on the Wyoming SIP reaches beyond PacifiCorp's BART-eligible units in that state to non-BART-eligible Dave Johnston Units 1 and 2.

[4] While both the Wyoming SIP and the EPA's proposed FIP require installation of SCR and a baghouse at Naughton Unit 3 by the end of 2014, PacifiCorp's economic modeling suggests that it is not cost effective to install the required controls and that a lower cost alternative is conversion of Naughton Unit 3 to natural gas. As a result, PacifiCorp has withdrawn its application for a certificate of public convenience and necessity filed with the Wyoming Public Service Commission and plans to file for the necessary approvals to complete a gas conversion. Significant reductions in emissions of SO_2, NO_x and particulate matter are expected to be achieved as a result of this action.

WY	Wyodak	335	80%	SNCR	SIP – Not required *FIP – Within 5 years; 2017*
UT	Hunter Unit 1	446	94%	TBD	SIP – Not required EPA Action – TBD
UT	Hunter Unit 2	446	60%	TBD	SIP – Not required EPA Action – TBD
UT	Huntington Unit 1	457	100%	TBD	SIP – Not required EPA Action – TBD
UT	Huntington Unit 2	450	100%	TBD	SIP – Not required EPA Action – TBD
	Total impacted megawatts in Utah and Wyoming	5,007			

Table 2
Summary of EPA Proposed Incremental NOx Actions
PacifiCorp Partner Operated Units

State	Unit	MW	Ownership Share	Proposed NO_x Controls	Installation requirements
AZ	Cholla Unit 4	395	100%	SCR	SIP – Not required *FIP – Within 5 years; 2017*
CO	Hayden Unit 1	184	24.46%	SCR	SIP – 2015 EPA Approved
CO	Hayden Unit 2	262	12.60%	SCR	SIP – 2016 EPA Approved
CO	Craig Unit 1	435	19.28%	SNCR	SIP – 2017 EPA Approved
CO	Craig Unit 2	428	19.28%	SCR	SIP – 2016 EPA Approved
	Additional megawatts impacted	1,704			

Accelerated and Incremental Costs Are Significant and Unnecessary To Address Regional Haze

In addition to the expenditures already made between 2005 and 2011 to comply with state-imposed Regional Haze requirements, PacifiCorp also plans to spend approximately $800 million from 2012 through 2022 on emissions reduction projects to meet the emission reduction requirements reflected in the Wyoming and Utah Regional

Haze SIPs. Under either EPA's first or second proposed approaches, PacifiCorp would need to accelerate approximately $260 million of that planned capital expenditures in Wyoming alone and would add approximately $40 million in new capital compliance projects (also in Wyoming). Moreover, all of these accelerated and new costs would be pushed into the pre-2018 timeframe and would result in minimal visibility improvement (as will be explained in detail in PacifiCorp's later comments). Along with the capital costs of these new and accelerated projects will come the costs of operating and maintaining the equipment of approximately $7 million to $10 million annually, as well as ongoing capital expenditures of $4 million to $5 million annually for catalyst replacement projects.

In addition, preliminary estimates of the cost of EPA's recently proposed FIP in Arizona for Cholla Unit 4 is approximately $200 million of incremental capital, along with approximately $2 million to $4 million in levelized annual operating and maintenance and catalyst replacement costs.

Piling on to these costs, the EPA-approved SIP in Colorado results in more than $70 million of incremental capital costs to PacifiCorp, along with approximately $3 million to $5 million in levelized annual operating and maintenance and catalyst replacement costs. Notably, none of the costs quoted above include any added costs of EPA's action in response to the Utah SIP, which according to EPA may involve requirements for retrofits of more units owned by PacifiCorp in that state.

Given the number of facilities operated by PacifiCorp and the facilities in which the company has an ownership interest in and is required to pay costs for the installation of Regional Haze-related controls, accelerated and additional controls under the proposed FIP result in approximately $500 million of additional capital expenditures plus an incremental annual cost of $16-24 million to operate those controls in the next five years. In addition, an EPA proposal for stringent control requirements in Utah (i.e., SCR) within five years would add approximately $750 million in capital expenditures plus approximately $7 million to $9 million annually in operating costs and approximately $4 million annually for catalyst replacement projects. All of these costs will be put on the backs of PacifiCorp and its customers in an extremely short time frame, ironically for a program that was designed to gradually achieve reasonable progress towards the goal of natural visibility conditions by 2064 – 52 years from now. Moreover, EPA's proposed actions in Utah and Wyoming are devoid of the recognition of the significant reductions in emissions already achieved under the Wyoming and Utah Regional Haze SIPs and the significant investment made to obtain those emission reductions.

Compliance with the MATS Adds Incremental Costs and Impacts Available Generation

In addition to the Regional Haze requirements, PacifiCorp's coal-fueled generating fleet, including the BART-eligible units, must accommodate controls for compliance with the

Mercury and Air Toxics Standards (―MATS") during the same timeframe. While the scrubbers and baghouses already installed at many of the PacifiCorp facilities pursuant to the Utah and Wyoming Regional Haze SIPs position the company well to comply with the acid gas and non-mercury metals limits under the MATS requirements, additional work will be necessary, particularly at PacifiCorp's Wyoming facilities, to comply with the mercury emission limits by April 2015. Further, PacifiCorp has not yet identified a viable control suite that will allow it to comply with the MATS provisions at the Carbon plant in Utah. As a result, while not finally determined, it is anticipated that Carbon Units 1 and 2 will be required to be shut down in the 2015 timeframe, resulting in the loss[5] of 172 megawatts of generation from PacifiCorp's system. The anticipated loss of this generating resource places additional strain on PacifiCorp's remaining baseload generation and will likely require transmission system modifications to address the resulting lack of generation in that area. Closure of the Carbon plant would also result in an increase in costs to PacifiCorp's customers for removal costs and recovery of plant costs.

<u>PacifiCorp's Customers Cannot Absorb Increasing Environmental Costs, Particularly When Implemented in a Short Period of Time Period</u>

To accommodate, among other cost increases, the costs of the environmental controls already installed on PacifiCorp's coal-fueled generating facilities, PacifiCorp has filed with its utility regulatory authorities annual cases to increase customer rates. PacifiCorp's customers and AARP (among others) have consistently participated in these cases to express concerns regarding increases in electric rates. While EPA may view its proposal to accelerate the installation of controls and require additional controls at PacifiCorp's facilities as just another utility complaining to avoid the consequences of large investments in controls, EPA's proposal has a very real impact on customers.

As Paul Anderson of Mountain Cement Company, a member of the Wyoming Industrial Energy Consumers, testified at the public hearing in Cheyenne on June 26, 2012:

> Our power costs are a significant component of our manufacturing costs. So we're very sensitive to impacts on rates of – of capital investments that are required and other things. This proposal that would speed up the required capital investment is going to have a significant impact on the capital requirements of the utility companies, which then, as a regulated utility, they have the ability to pass on those rates to the rate payers. This will impact every person in the state of Wyoming, from the residential people to the small business operators to the industrial users.[6]

[5] In addition, if the Carbon units are taken out of service and the resulting emissions are eliminated, the state of Utah and EPA should take that into account in determining reasonable progress under the Regional Haze program.

[6] See Transcript of Public Hearing Proceedings from June 26, 2012, available at: http://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2012-0026-0035, pages 34-35.

Testimony by the Citizens Utility Board in Oregon has been very pointed on the issue of increasing rates:

> [R]ates for Oregon customers have gone through the roof. . .[t]he primary driver of higher rates has been capital investments. . .It would be helpful if the Company saw capital investments as costs that can be avoided. . .[7]

Additional position statements by the Citizens' Utility Board of Oregon indicate that:

> The double-digit increase that went into effect on January 1 of this year is already proving to be too much for customers to handle. This fact is most easily demonstrated through a review of the number of disconnection notices issued yearly for the last few years. The average number of disconnection notices in 2011 has increased by over 10 percent from previous years on a month-to-month basis. In addition, the average amount of arrearage from residential customers, i.e., the total amount that customers are behind on their bills, has also increased by nearly 25% on a month-to-month basis over previous years.
>
> The primary cause of these rate increases is the massive capital investment MEHC is injecting into PacifiCorp. PacifiCorp's capital investment in coal clean air projects, new wind generation, new transmission lines, and new combined cycle combustion turbines is expected to be in the billions of dollars. . . customers cannot afford this level of investment.[8]

In recent Wyoming Public Service Commission rate proceedings, the AARP expressed the concerns of their 95,000 members in Wyoming about rate hikes:

> This is hardship, unbelievable. [An e-mail] from Mrs. Mary Brandt in Pinedale says. . .this is not the time to raise prices on basics, such as utilities. . .this hike would be just another hardship and discouragement to employers who would be forced to pass this cost on to their customers, many of which are also struggling. . . The point is that the people of

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[7] See Oregon Docket UE 246, CUB/100/Jenks-Feighner/pages 12-15, available at: http://edocs.puc.state.or.us/efdocs/HTB/ue246htb152816.pdf

[8] See Opening Comments of the Citizens' Utility Board of Oregon before the Public Utility Commission of Oregon, LC 52, In the Matter of PacifiCorp dba Pacific Power 2011 Integrated Resource Plan, pages 1-2, available at: http://edocs.puc.state.or.us/efdocs/HAC/lc52hac132518.pdf

> Wyoming, and particularly AARP members who are on fixed incomes, and many of them are, simply can't afford to have further rate hikes.[9]

As demonstrated by these groups and individuals, PacifiCorp's customers have already felt the burden of installing emission controls to address Regional Haze; they should not be further burdened by EPA's proposed acceleration of costs, particularly when Wyoming has developed a SIP that takes into consideration the Regional Haze requirements <u>and</u> their impact on electricity consumers.

The very first of the five BART factors stated in the Clean Air Act is “the costs of compliance.” CAA §169A(g)(2). Surely the rate burden placed on electricity customers of a multi-state system like PacifiCorp's as a result of varied actions by EPA in separate states is among the “costs of compliance” Congress intended EPA to consider in the Regional Haze program.

<u>EPA's Primary Proposal Increases Risk to PacifiCorp's System</u>

As a regulated utility, PacifiCorp has a legal obligation to supply reliable electric service at reasonable rates as set by state utility commissions; it also has a legal requirement to supply its customers as much electricity as they want, when they want it. While the installation of emissions controls on multiple units in a short period of time creates substantial challenges from a project management perspective, these challenges are exacerbated by increased risk factors that jeopardize PacifiCorp's ability to meet its underlying utility obligations:

1. <u>Additional Exposure to Market Power Purchases</u> - The compressed tie-in outage schedule proposed by the EPA under the first and second alternatives for the Jim Bridger plant will increase the risk and cost to PacifiCorp's operations and customers by requiring the purchase of substitute power in the electricity markets. Typically, generation owners, including PacifiCorp, conduct periodic maintenance and repairs during long planned outages in the spring and fall “shoulder months.” This is the time when daily loads decline from their summer and winter peaks and substantial amounts of capacity can be removed from service (for maintenance, retrofits, etc.) without degrading system reliability. Environmental retrofit “tie-ins” planned long enough in advance can be incorporated into existing outage schedules (which are also planned long in advance) in order to minimize the time that such generation is not available, particularly because a substantial amount of major environmental retrofit project construction work occurs on site while the unit is in service. However, the “tie-in” outage generally is longer than a typically scheduled maintenance outage, and therefore such outages generally need to be extended by several weeks in order to place the

[9] See In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in its Retail Electrical Service Rates in Wyoming of $62.8 Million Per Year or 10.4 Percent, Docket No. 2000-405-ER-11 (Record No. 13034), Transcript of Hearing Proceedings before the Public Service Commission of the State of Wyoming.

environmental control equipment into service. When multiple major retrofits occur at many units during a short time frame across a regional system, such outage extensions can materially affect the balance between loads (i.e., electricity demand) and available resources (i.e., electricity supply).

When an imbalance between load and available resources exists, utilities are forced to purchase electricity in the market, if it is available. A multitude of factors can impact electricity market prices, including planned or forced outages, fuel prices, and availability of intermittent resources (i.e., renewables), as well as natural conditions over which entities have no control, such as seasonal temperature variations, wildfires (which, of course, are themselves unexpected and significant contributors to Regional Haze) that may impact transmission facilities, etc. As PacifiCorp is required to take facilities out of service for retrofit equipment tie-ins, it will be forced to make up any load and resource imbalances with power purchases, which have the potential to significantly increase its costs to customers of generation.

2. Management of Planned Outages - The management of planned outages over time also affects the timing of retrofit construction. Generation owners, including PacifiCorp, often find it necessary and advantageous to begin construction sufficiently in advance of a compliance deadline in order to time the retrofit "tie-in" outage to coincide with a lengthy planned outage, thus minimizing the amount of additional time the unit is out of service to complete the retrofit. This approach affords generation owners limited flexibility to manage availability of generating units. This limited flexibility, however, is subject to practical limitations of not expending funds too far ahead of compliance deadlines, the required maintenance on individual units, and market drivers such as labor and equipment availability—all while balancing overall outage schedules with market power costs and system reliability considerations. When major control projects are not coordinated with existing outage schedules (such as when EPA unilaterally announces in a FIP a date by which controls must be installed), a unit will be required to either have a second outage to tie-in control equipment, or accelerate or defer the normal planned maintenance schedule. Both of these scenarios increase risk for the unit in question – these risks include added costs, decreased availability potentially during high demand for electricity, and decreased reliability. This is especially true where, as in PacifiCorp's case, a large number of units with multiple control projects must be managed within relatively short periods of time.

Additionally, the joint ownership of many units in the Western U.S. creates an added dynamic whereby changes in planned outages for the tie-in of controls may significantly impact a joint owner's ability to serve its underlying load.

3. Enhanced Risk Associated with Resource Availability - In the Western U.S., the prevalence of hydropower and its typical seasonal output profile means that much more planned outage time occurs in the spring than in the fall. In fact, PacifiCorp historically conducts approximately 90% of its planned outages (measured in MW-days out of service) for fossil units during the spring, when hydropower typically is abundant and

can be relied upon as a firm resource to meet customer demands. While hydropower affords a resource adequacy cushion in average years, drought conditions can reduce this cushion significantly. Not only does hydropower availability influence the resource adequacy cushion, PacifiCorp's analysis of the system impacts associated with past dry years show they can reduce the availability of system resources by as much as 400 available megawatts. In terms of planning for multiple control projects on multiple units required under a FIP in an extremely short time frame, the chance of an inadequate ―cushion" from hydropower resources (for reasons outside of PacifiCorp's control) only adds to the risk of PacifiCorp being unable to meet its electricity supply obligations or being able to do so at an unfair cost to its customers.

4. Planning for Adequate Generation and Reasonable Costs - PacifiCorp performs load and resource assessments as part of its biennial Integrated Resource Plan (―IRP"). These assessments focus on load and resource conditions forecasted during the summer peak. Recognizing that the impact of major emission controls retrofit project ―tie-in" outages would be felt primarily in the Spring months, the IRP Load & Resource balance framework has been extended to those months to provide additional information pertaining to PacifiCorp's planning considerations.

Resource planning requires forecasts of peak hour loads and available resources to meet those loads. The supply/demand balance methodology used in PacifiCorp's IRPs compares peak load (plus a planning reserve margin) against owned and firm resources, including thermal capacity, hydroelectric capacity, renewables and qualifying facilities, demand-side management resources (DSM), and net firm purchases. Although the IRP focuses on July system peak conditions, monthly load and resource projections through 2022 can be constructed using other data that PacifiCorp utilizes for 10-year modeling outlooks.

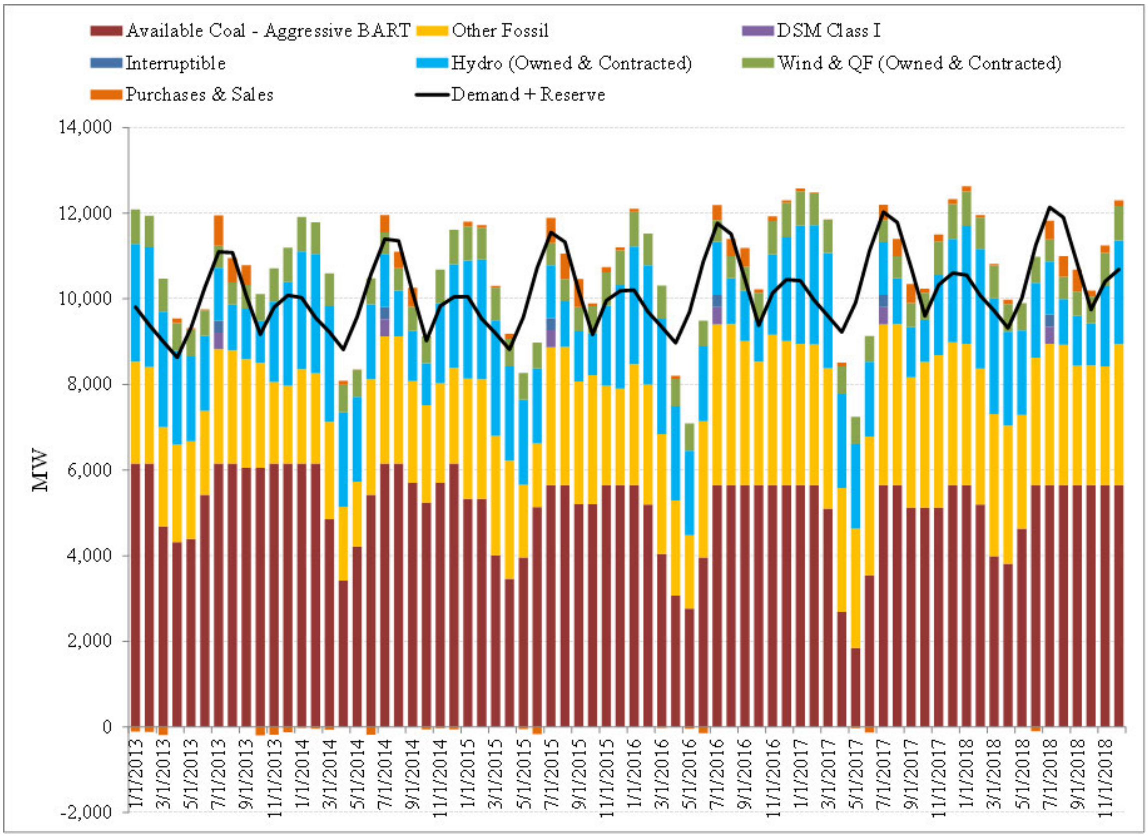
PacifiCorp has examined two scenarios to evaluate the implications of complying with EPA's proposed and prospective actions on Regional Haze proposals throughout the Western U.S., particularly those regions impacting PacifiCorp operations. The scenarios include:

A. A ―SIP Scenario" that reflects retrofit plans and compliance dates under currently proposed State Implementation Plans in Wyoming, Utah, and Arizona, as well as the approved plan in Colorado; and,

B. An ―EPA Aggressive BART Scenario" that depicts EPA's proposed FIP in Wyoming, EPA's proposed FIP in Arizona, a FIP in Utah that would require installation of SCR at PacifiCorp's units within five years, and Colorado's approved SIP.

Figure 1 below shows the monthly load and resource balance between 2012 and 2018 for an EPA Aggressive BART Scenario, incorporating the impact of potential emission control retrofit “tie-in” outage schedules that could reasonably be anticipated to result from EPA’s ongoing SIP reviews based on past EPA actions across the country. [10]

Figure 1
PacifiCorp System Load and Demand versus Available Resources
EPA Aggressive BART Scenario - Forecasted 2013 through 2018



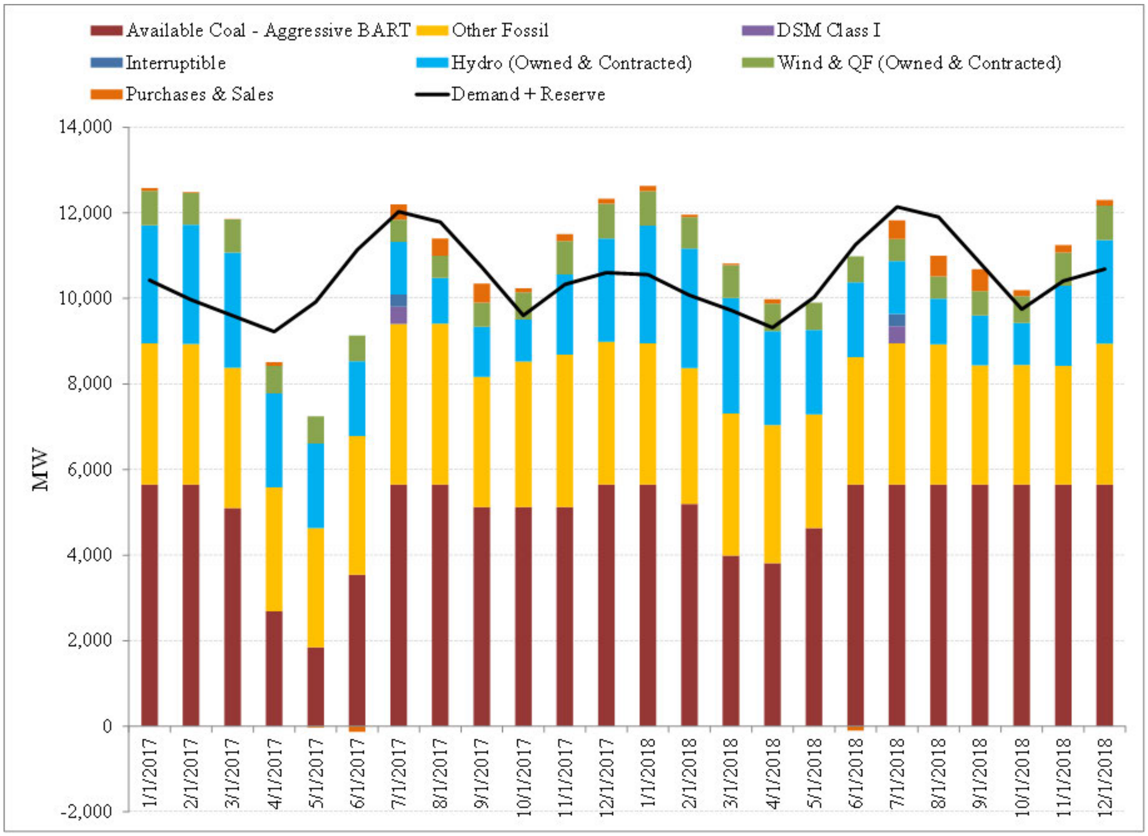
Note: Negative figures correspond to net firm contract sales.

Figure 1 above clearly shows the reduction in coal capacity that occurs each Spring under the planned outage schedules that generally coincide with lower Spring demand. Notably, in the Spring of 2017, primarily as a result of the additional outages required to tie in the SCRs potentially required under the EPA Aggressive BART scenario, demand significantly outstrips supply. Figure 2 below magnifies 2017 and 2018 to more closely examine these years.

[Figure 2 on next page]

[10] Details regarding the requirements and timing under the Aggressive BART Scenario is provided in the next section.

Figure 2
PacifiCorp System Load and Demand versus Available Resources
EPA Aggressive BART Scenario - Forecasted 2017 through 2018

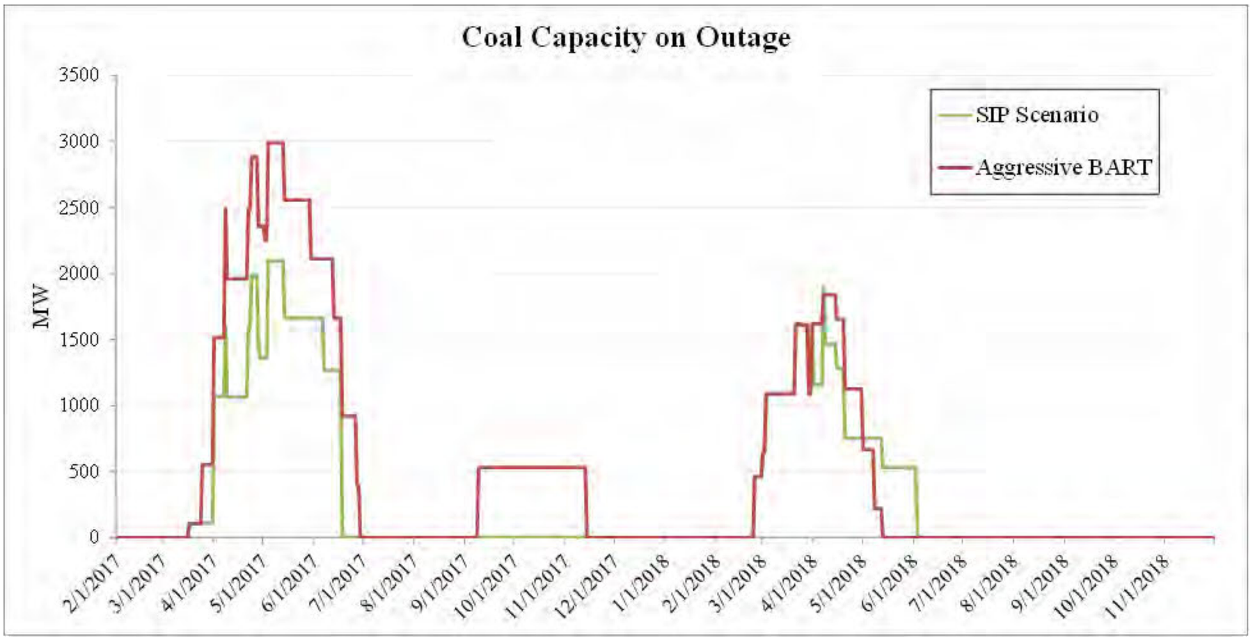


Note: Negative figures correspond to net firm contract sales.

In order to see how the additional EPA Aggressive BART outage time could impact the PacifiCorp system, a more granular picture is helpful. The outage schedule is optimized (and as forecast conditions change, re-optimized) to (1) fit as much planned outage time as necessary to maintain the coal units properly while minimizing the impact on reliability and (2) to rationalize the deployment of labor and equipment resources across the fossil fleet. Additional planned outage days necessary to complete emission control retrofits are accommodated using the same criteria – namely to minimize the overall peak (combined MW) outage impact while scheduling the extended outages to ―fit" into the low-load Spring season without unduly extending the overall outage season back into the winter months or forward into the summer months. Figure 3 below shows two (optimized) planned outage schedules through the 2017 and 2018 outage planning window, under the SIP Scenario and the EPA Aggressive BART scenario.

[Figure 3 on next page]

Figure 3
PacifiCorp Coal Capacity on Planned Outage
Current SIP Obligations versus EPA Aggressive BART Scenario
Forecasted 2017 through 2018



As shown in Figure 3 above, the outage season in the Spring of 2017 would begin identically during the third week of March, but the EPA Aggressive BART scenario outages would exceed the SIP Scenario outages about a week after, and remain higher for the duration of the outage season, which would be extended through the end of June in the EPA Aggressive BART Scenario. For most of April and May, the difference between the two scenarios is over 900 MW of additional coal capacity that will be out of production due to the emissions control retrofit ―tie-in" outage extensions.

The outage season in the Fall of 2017 would result in approximately 500 MW of previously available coal capacity being out of production for a period of time, and the Spring 2018 outage would begin identically at the end of February with an extended peak outage duration under the EPA Aggressive BART scenario.

Since available replacement power is likely to cost more than PacifiCorp coal generation, those additional costs should be ascribed to complying with the Regional Haze Program, should the EPA Aggressive BART Scenario become required. While there would be some additional resource adequacy risk involved, quantifying that risk in terms of the increased probability of failing to meet load requires a much more complex analysis. However, the figure does depict the challenges that PacifiCorp would face in maintaining reliability under a more stringent program to curb Regional Haze, particularly in 2017.

The additional outage time required for retrofits in the 2017 through 2018 period under the EPA Aggressive BART scenario poses challenges and risks for PacifiCorp. Meeting those challenges would require procuring additional resources during the outage months beyond those currently envisioned in the IRP, which may or may not be readily obtainable in the market (depending on prevailing conditions at the time) and at unknown costs.

5. Planning for Grid Reliability

Similar to the potential system resource adequacy risk discussed above, quantifying the reliability risks that PacifiCorp's transmission system may face under the EPA Aggressive BART scenario requires a much more complex analysis than can reasonably be completed in the timeframe requested by the EPA for this preliminary assessment. However, the incremental localized reduction in available coal capacity underlying the EPA Aggressive BART outage planning scenario depicted in Figure 3 above would be expected to pose operational challenges and risks for PacifiCorp. These challenges unnecessarily pose increased risks and cost to customers that EPA's third proposed alternative would minimize.

Unprecedented Level of Retrofit Activity

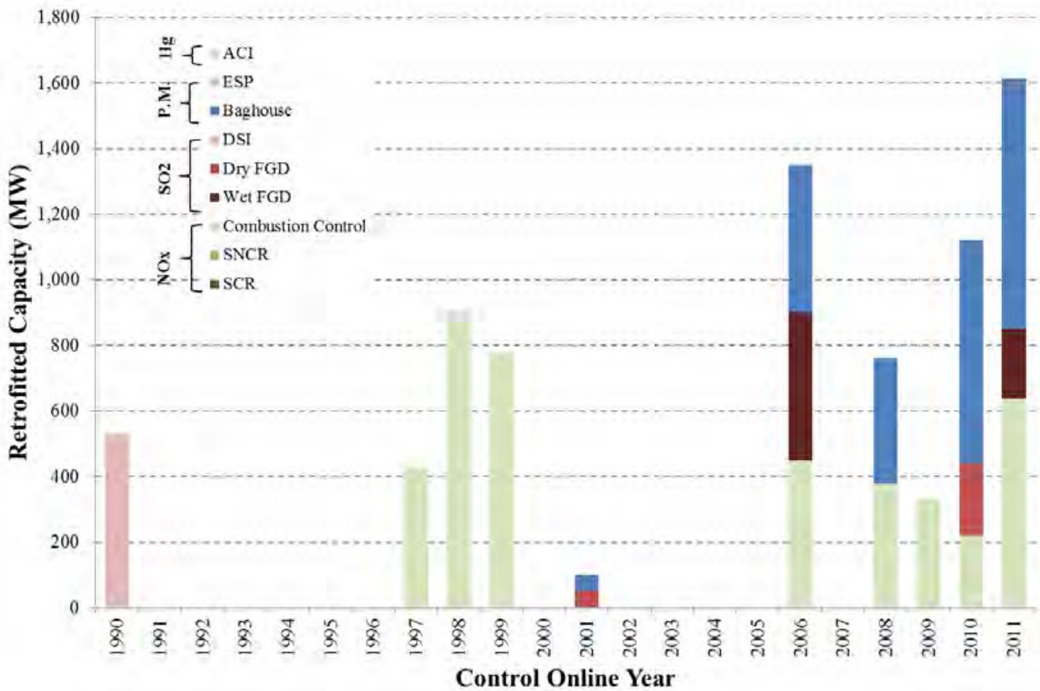
The EPA's FIP would result in an unprecedented level of retrofit activity on PacifiCorp's system, creating significant new issues not previously experienced, including those described below:

Historic Retrofit Activity

For historical perspective, a view of the environmental retrofits completed at power plants in the PacifiCorp region over the past two decades is detailed below in Figure 4 by in-service year and technology type.

[Figure 4 on next page]

Figure 4
Historical Quantities of Retrofits in PacifiCorp Region



Notes:
All generation fuel types are represented; individual units may be represented more than once if subject to multiple retrofits.

As shown in Figure 4 above, the pace of retrofitting environmental controls has accelerated substantially in the past six years, with significant capacity retrofitted with enhanced controls for NO_x, SO_2, and PM, with some units receiving controls for all three pollutants. Note that while Figure 4 is a plot of the equipment online date, construction of the individual retrofits may be presumed to occur before the in-service year.

Because implementation and retrofit of these controls vary significantly in capital costs and project complexity, in order to normalize the data set, all types of major environmental retrofit projects are converted into their wet FGD equivalent MW according to the conversion rates in Table 3 below. Following the convention used by the EPA in a recent study, this conversion is based on the capital costs of each type of control upgrade as listed.[11] Using these conversions, one MW of upgrades from any type of control technology would be normalized to have the same capital cost and approximate supply chain implications.

[Table 3 on next page]

[11] *An Assessment of the Feasibility of Retrofits for the Mercury and Air Toxics Standards Rule*. December 16, 2011. Retrieved from http://www.epa.gov/ttn/atw/utility/revised_retrofit_feasibility_tsd_121611.pdf

Table 3
Wet FGD Equivalence of Retrofit Technologies

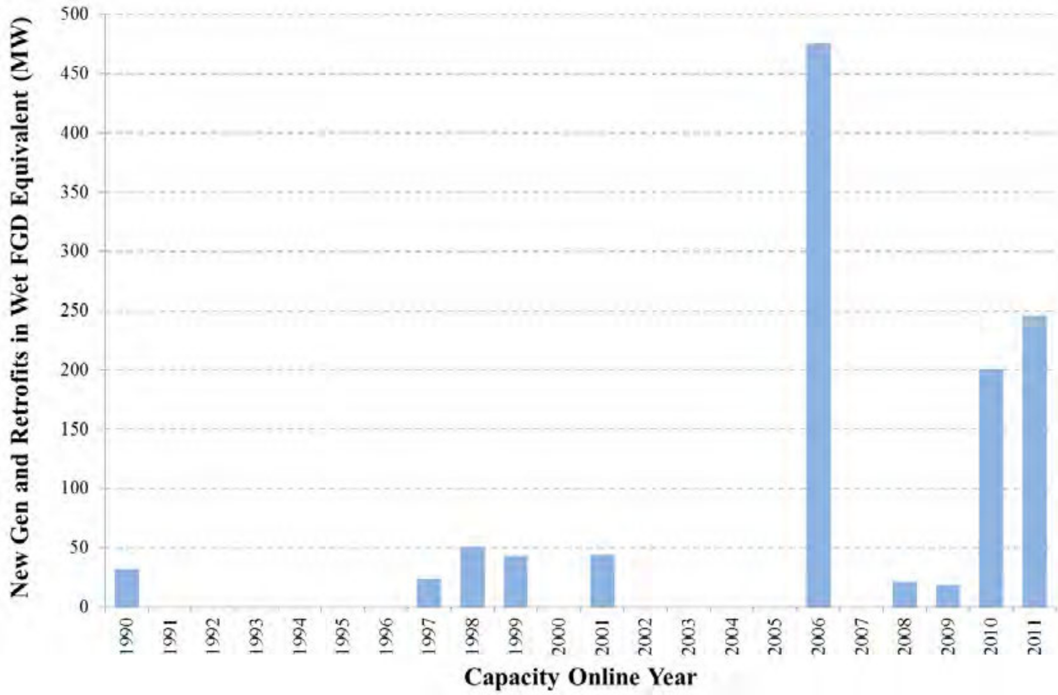
Retrofit Equipment	Capital Cost *(2011$/kW)*	Wet FGD Equivalent *(MW)*
Coal		
SCR	$223	0.33
SNCR	$51	0.07
Dry FGD	$585	0.86
Wet FGD	**$683**	**1.00**
DSI	$41	0.06
Baghouse	$353	0.52
ESP	$70	0.10
ACI	$26	0.04
Combustion Controls	$41	0.06
Wet FGD Upgrades	--	0.20
Dry FGD Upgrades	--	0.20
ESP Upgrades	--	0.10
Oil/Gas		
Coal SCR		--
Coal SNCR		--
SCR	$64	0.09
SNCR	$13	0.02

Sources and Notes:
Capital costs of retrofit on coal plants from EPA: *IPM Base Case v.4.10.* Chapter 5. August 2010 and EEI: *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet. Final Report.* January 2011.
Oil/gas costs from year 2004 estimate inflated by ratio of coal SCR and SNCR cost inflation between 2004 and 2011 from the same sources.

The total control retrofits reported in Figure 4 above can be converted into their wet FGD equivalent values as shown below in Figure 5.

[Figure 5 on next page]

Figure 5
Historical Retrofits in PacifiCorp Region on a Wet FGD Equivalent Basis



Notes:
Retrofit and new construction MW converted into Wet FGD equivalent basis from Table 1.

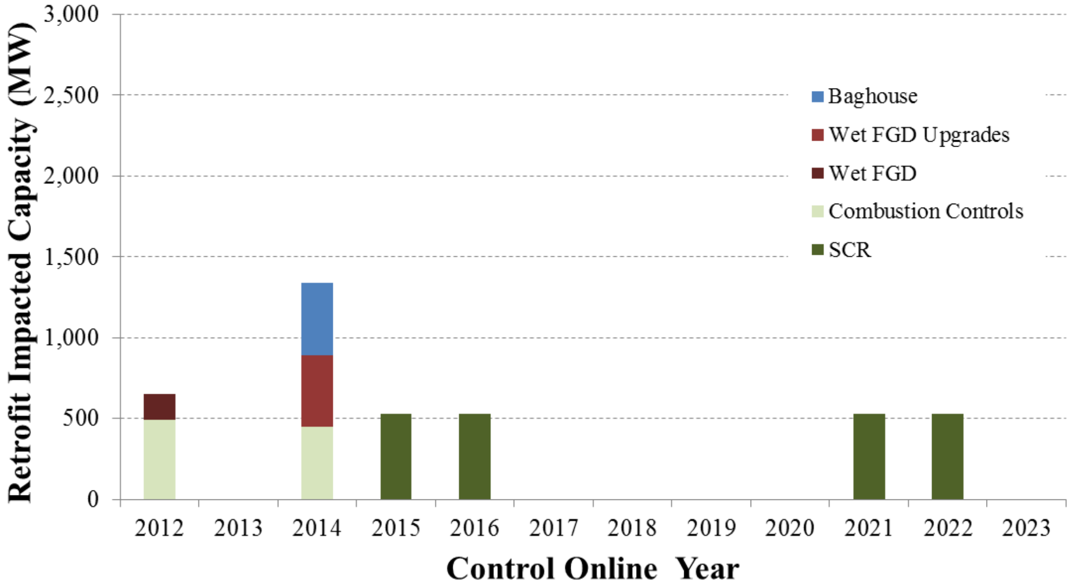
As seen on Figure 5 above, 2006 represented the year when PacifiCorp placed into service the greatest amount of retrofit equipment – about 475 MW on a wet FGD basis. The next highest years – 2011 (246 MW) and 2010 (201 MW) are only about half that level.

Potential Regional Haze Program Retrofit Activity

Two scenarios have been analyzed under two different retrofit compliance assumptions. The ―SIP Scenario" reflects the retrofits and compliance dates under the currently proposed State Implementation Plans and the ―EPA Aggressive BART" depicts proposed and prospective actions by the EPA requiring more stringent application of the Regional Haze program beyond the levels proposed by the respective States. For each scenario, the impacted capacity for various types of retrofit equipment by the retrofit online date is summarized.

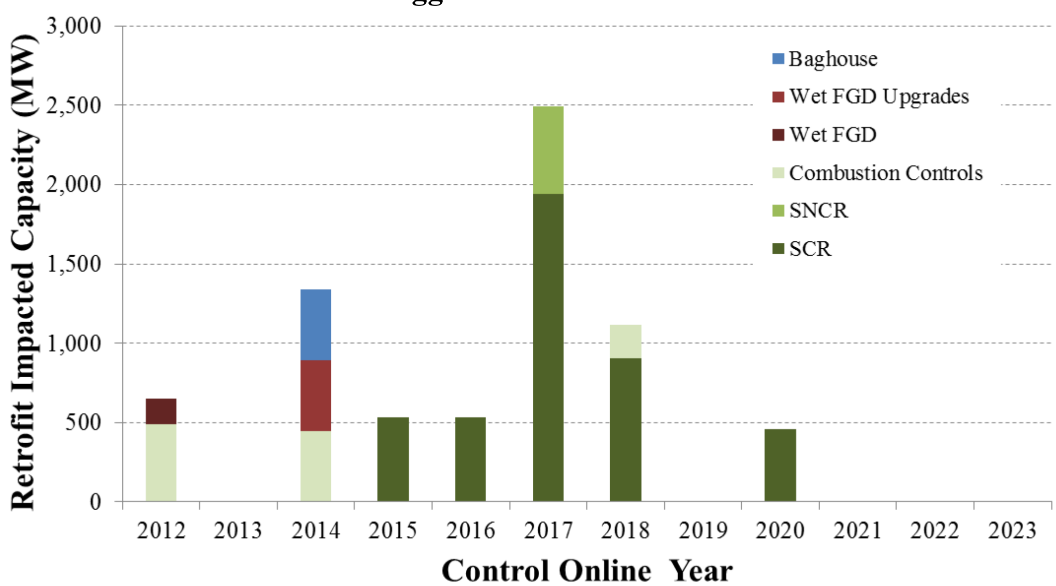
[Figure 6 on next page]

Figure 6
Projected Retrofits in PacifiCorp System
SIP Scenario



The retrofit equipment online schedules under the SIP assumptions are plotted in Figure 6, and similarly, Figure 7 depicts the online schedules for the retrofits under EPA Aggressive BART assumptions.

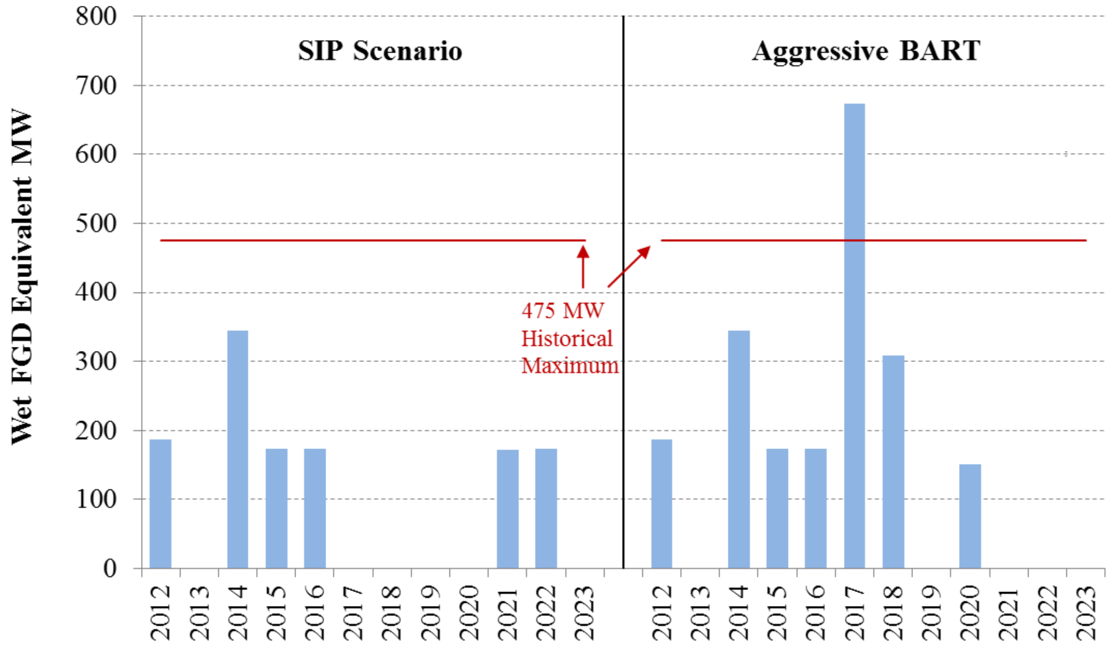
Figure 7
Projected Retrofit in PacifiCorp System
EPA Aggressive BART Scenario



In order to compare with historic levels of retrofit activity, retrofit impacted capacities under the SIP and EPA Aggressive BART scenarios were converted into Wet FGD equivalents in Figure 8, along with the historic annual benchmark of 475 MW.

The differences between the SIP Scenario and the Aggressive BART Scenario are fairly substantial on an equivalent Wet FGD basis. In the SIP Scenario, only one year exceeds the 2010-2011 levels of retrofit investment (of about 225 MW/year), while retrofits placed in service in 2017 (675 MW) substantially exceed the previous historic maximum of 475 MW by 200 MW and two years are above the 2010-2011 level. The control installation requirements under the EPA Aggressive BART Scenario would result in more work, less time, and increased costs.

Figure 8
Projected Retrofit in PacifiCorp System Relative to Historical Maximum



Notes:
Historical maximum from Figure 5 above.
Conversions to Wet FGD equivalent from Table 3 above.

Supply Chain and Labor Considerations

When considered independently from other environmental requirements, the retrofits required under either Regional Haze compliance scenario are not anticipated to impose undue stress on the national supply chain for specialized labor, materials and equipment. However, analyses of compliance with the Mercury and Air Toxics Standard (MATS) have raised concerns that requiring much of the U.S. coal fleet to retrofit or retire in a 3 to 5 year time frame (partially overlapping the compliance time period under the Regional Haze Program) will challenge the equipment construction industry. A study performed for the Midwest Independent Transmission System Operator (MISO) analyzed compliance with MATS by 2015-2016 and identified potential bottlenecks in labor and equipment that might accompany the retrofit and capacity replacement activities in that region.[12] PacifiCorp is not aware of any study that has assessed the potential interaction between the Regional Haze Program requirements and other environmental requirements such as the investments implied by MATS. In addition to the MATS requirements, additional pressure will be placed on labor and equipment from the Cross-State Air Pollution Rule (―CSAPR") or its successor, as utilities in the Eastern U.S. install scrubbers and SCR or SNCR to meet their obligations under a Transport Rule. To the extent that MATS and CSAPR or other environmental requirements create pressure on labor and equipment supplies, that pressure will be increased by the Regional Haze requirements for installation of controls within a five year period as is being proposed and/or adopted by EPA in the Western U.S.

Figure 8 shows that over half of the PacifiCorp retrofit activity in the SIP Scenario occurs in the 2014-2016 timeframe, during which coal units across the U.S. will likely comply with MATS and compete for many of the same resources. This raises the prospect of higher costs and delays associated with completing retrofit projects in this timeframe, assuming that MATS compliance stays on its current schedule. Moreover, while the MATS compliance schedule will not accelerate, there remains a possibility that the MATS compliance deadlines could be delayed as a result of legislative or other action at the national level. If this were to happen, some of the stress on supply chains would be alleviated under the SIP Scenario. However, any delayed compliance with MATS would then coincide with the retrofits necessary to comply with the EPA Aggressive BART scenario. There is also some overlap between the labor and equipment markets for environmental retrofits and new capacity construction, both regionally and nationally, which may affect the accessibility and cost of these resources during a period of aggressive Regional Haze Program retrofits.

Wyoming and EPA are Legally Required to Consider the Economic and System Impacts on PacifiCorp and Its Customers

EPA must include the information provided herein as part of its analysis of Wyoming's Regional Haze SIP and EPA's proposed Regional Haze FIP. As EPA's Regional Haze guidance, Appendix Y, explains:

> There may be unusual circumstances that justify taking into consideration the . . . economic effects of requiring the use of a given control technology. These effects would include effects on product prices. . .

[12] See *Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS* by The Brattle Group, May 2012. This report also surveyed other supply chain studies, providing a range of potential effects from MATS compliance.

> Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail, for public review, the specific economic effects, parameters, and reasoning.

Appendix Y, IV.E.3. Given the large number of BART impacted units owned by PacifiCorp in different states, these ―unusual circumstances" justify Wyoming's BART actions on PacifiCorp's facilities and PacifiCorp's customers.

Regional Haze is Primarily a State Issue and the Wyoming SIP Schedule Should be Maintained

The Clean Air Act and EPA's own rules require Regional Haze requirements to be determined and implemented at the state level. In Wyoming, however, EPA has elected to reject part of Wyoming's carefully-crafted SIP and replace it with its own. This is not how the Regional Haze program is supposed to work. PacifiCorp believes that EPA's proposal fails to give proper deference to the State of Wyoming's Regional Haze determinations as required by the Clean Air Act.

The Wyoming Department of Environmental Quality conducted a robust BART analysis. In doing so, it exercised the very discretion contemplated by the Clean Air Act in applying the relevant factors to its BART determinations. These factors, found in EPA's own requirements, included consideration of issues such as those identified herein. The EPA should not substitute its judgment for that of Wyoming, particularly when Wyoming has taken into consideration the issues that are important to the State of Wyoming, its citizens, PacifiCorp and our customers, such as grid reliability, costs and the complexity of PacifiCorp's integrated electricity system and resources.

PacifiCorp urges EPA to adopt the third proposed approach, providing additional time for PacifiCorp to manage the system impacts of controls and costs. The emission reductions achieved by accelerating the SCR at the Jim Bridger facility by four to five years pale in comparison to the emission reductions already achieved under the Wyoming Regional Haze SIP. PacifiCorp's later comments will address this issue in more detail. Moreover, nothing in this submission should be interpreted as PacifiCorp's agreement with any of EPA's proposed Regional Haze FIP. As PacifiCorp will explain in its later comments, PacifiCorp completely disagrees with EPA's proposed Regional Haze FIP.

PacifiCorp appreciates the opportunity to provide comments on the EPA alternative proposals for PacifiCorp's Jim Bridger Units 1, 2, 3, and 4 NO_x BART. Additional, extensive comments on the balance of EPA's proposed action will follow.

Respectfully submitted,

Micheal G. Dunn
President and Chief Executive Officer
PacifiCorp Energy
1407 West North Temple
Salt Lake City, UT 84116
(801) 220-4893

Attachment 14

Steve Dietrich, Wyoming's Air Quality Administrator, testified in a public hearing in Cheyenne, Wyoming on June 26, 2012 regarding regional haze issues. As part of his testimony, he explained how the timing of the regional haze program, and why EPA should not force controls into the first planning period.

> The Regional Haze Rule is a unique federal rule in many ways, but the most unusual aspect of the rule is the time frame that it attempts to cover. The rule looks forward 60 years with the goal of returning visibility to natural conditions by 2064. Many of us that are currently working on this problem will not be alive when the goals of this program are attained. . .
>
> EPA recognized that as a long-term program the states would need to address overall goals in smaller pieces. In 40 CFR 51.308(f), EPA placed a requirement to 20 submit comprehensive state implementation revisions in 2018 and every 10 years thereafter, which means SIP revisions in the year 2018, 2028, 2038, 2048, and 2058. So states will be doing five more comprehensive regional haze SIPs before the year 2064. In addition to the comprehensive SIP revisions, states are also required under 40 CFR 51.308(g) to submit progress reports in the form of a SIP revision every five years. With the first revision due in 2013 and every five years thereafter, the State will be doing 11 progress reports and SIP revisions. Between the comprehensive SIP revisions and the not so comprehensive SIP revisions, the states will be submitting at a minimum 16 more SIP revisions to address regional haze. It is very possible that the number could be higher than 16 SIP revisions because the State of Wyoming has already submitted four regional haze SIP revisions for the first planning period alone. This was not the State's choice, but intervening lawsuits and changes to the Regional Haze Rule required changing the plan multiple times.
>
> Our point in outlining all of this-- all the increments in the long-range plan is to underscore EPA's intention to give states some time to get the job done. EPA never intended for states to attain all of the reductions in the first planning period. There are no requirements in the rule to hit certain emissions reductions by a certain period of time. In fact, EPA recognizes in the preamble that many things will change over time and that it may be possible to get emissions reductions in the future that cannot be procured at an earlier time. On page 35732 of the July 1st, 1999 Regional Haze preamble, EPA says, "In the longer term, it can be expected that continued progress in visibility impairment will be possible as industrial facilities built in the latter half of the 20th century reach the end of their useful lives and are retired and/or placed by – replaced by cleaner, more fuel-efficient facilities. Significant improvements in pollution prevention techniques, emission control technologies, and renewable energy have been made over the last -- past 30 years and continue to be made. History strongly suggests that further innovations in control technologies are likely to continue in future decades, leading to the ability of the new plants to meet lower emission rates.

Pages 46 through 48 of the Transcript from the Public Hearing, available at: http://www.regulations.gov/#!searchResults;dct=PS;rpp=25;po=0;s=EPA-R08-OAR-2012-0026.

Attachment 15

Future Clean Air and CCR Project Cash Flow Template

Project Name:	SNCR System
Plant:	Dave Johnston
Unit:	3
Implementation APR Number:	(Later)
Plant Project Coordinator:	(Later)
ResD Project Manager:	(Later)
In-Service Year:	2018
In-Service Month:	November, 2018
Version Date:	8/23/2013
Development APR # (if applicable)	(Later)

YELLOW CELLS SHOULD BE COMPLETED

These year fields will update based on In-Service Year >

Annual Capacity Factor (%), From 10-Yr Plan

Annual Generation (MWhs), From 10-Yr Plan

Capital Project Implementation Costs (without AFUDC)

Development	$ -	Total Costs All Years for Development
Implementation (Project Execution)	$ 8 996	Total Costs All Years for Implementation

Operations and Maintenance Costs (current year dollars only)

These year fields will update based on In-Service Year >

Chemicals	Cost Per Unit $/Unit)	Units (Tons, lbs, gals, ?)	Use Rate (Units/hr)	Data Owner/Source
Reagent A (Urea, 50% Solution; 85% annual capacity factor)	$ 400	Tons	0.304	SL, ResD; 1308
Reagent B (__________)				
Reagent C (__________)				

Operations and Maintenance (Non-Chemicals)	$/Year ($000)	Data Owner/Source
Incremental plant labor (including OT) attributable to project	$ 235	SL, ResD
Incremental parts, materials, contracts, fees, royalties	$ 58	SL, ResD
Demineralized water, (for urea solution dilution)	$ 43	SL, ResD
Other Consumables (solvents, lubricants, greases)		

Ongoing Capital (Current year dollars)

	Cost ($000S)	Frequency (once every X? years)	Data Owner/Source
Periodic Major Replacments (i.e. catalyst replacement) - Type 1			
Periodic Major Replacments (i.e. catalyst replacement) - Type 2			
Ongoing blanket replacements (i.e. pumps, motors)			

Cash flow ($000s), 2013–2025 (In Service Year 1 = 2018):

	2013	2014	2015	2016	2017	2018 (1)	2019 (2)	2020 (3)	2021 (4)	2022 (5)	2023 (6)	2024 (7)	2025 (8)
Development													
Implementation (Project Execution)		$ 217	$ 867	$ 2,168	$ 2,168	$ 3,576							
TOTAL IMPLEMENTATION CAPITAL	$ -	$ 217	$ 867	$ 2,168	$ 2,168	$ 3,576	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reagent A						$ 151	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905
Reagent B													
Reagent C													
Sub-Total, Chemicals	$ -	$ -	$ -	$ -	$ -	$ 151	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905
Incremental plant labor						$ 39	$ 235	$ 235	$ 235	$ 235	$ 235	$ 235	$ 235
Incremental parts, materials, contracts, fees, royalties						$ 10	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58
Demineralized water						$ 7	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43
Other Consumables													
Sub-Total, Non-Chemical O&M	$ -	$ -	$ -	$ -	$ -	$ 49	$ 293	$ 293	$ 293	$ 293	$ 293	$ 293	$ 293
TOTAL OMAG	$ -	$ -	$ -	$ -	$ -	$ 200	$ 1,198	$ 1,198	$ 1,198	$ 1,198	$ 1,198	$ 1,198	$ 1,198
Periodic Major Replacments - Type 1													
Periodic Major Replacments - Type 2													
Ongoing blanket replacements													
TOTAL ONGOING CAPITAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Cash flow ($000s), 2026–2038:

	2026 (9)	2027 (10)	2028 (11)	2029 (12)	2030 (13)	2031 (14)	2032 (15)	2033 (16)	2034 (17)	2035 (18)	2036 (19)	2037 (20)	2038 (21)
Development													
Implementation (Project Execution)													
TOTAL IMPLEMENTATION CAPITAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reagent A	$ 905	$ 905											
Reagent B													
Reagent C													
Sub-Total, Chemicals	$ 905	$ 905	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental plant labor	$ 235	$ 235											
Incremental parts, materials, contracts, fees, royalties	$ 58	$ 58											
Demineralized water	$ 43	$ 43											
Other Consumables													
Sub-Total, Non-Chemical O&M	$ 293	$ 293	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL OMAG	$ 1,198	$ 1,198	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Periodic Major Replacments - Type 1													
Periodic Major Replacments - Type 2													
Ongoing blanket replacements													
TOTAL ONGOING CAPITAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Other (Performance Impacts)

	Change	Data Owner/Source	
Change in Aux Power (in kilowatts, + = increase in Aux. Power)	-50	SL ResD	(Net consumption increase)
Change in Minimum Load (Yes/No?)	No	SL, ResD	
New Minimum Load (if applicable, in MW)	NA	SL, ResD	

Purpose:

1. Identify the major assumptions for long term ownership of the project (capital, ongoing capex and omag for 20 years following the inservice date of the project.
2. Provide a common database for project APR and plant budgets
3. Identifies the "owners" or originators of the major data assumptions
4. This is intended as a summary level roll up document; it may not include all of detailed calculations required to provide the summary information.

Assumptions:

1. 100% share
2. Costs do not include AFUDC.
3. All current year cost basis (i.e. no escalation), 2013 dollars.
4. December 31, 2027 is end of depreciable life.
5. Capacity factor equals 85%
6. Urea solution utilization rate used was 12%
7. Baseline (inlet) NOx concentration was 0.22 lb/mmBtu (average basis)
8. NOx permit limit assumed was 0.21 lb/mmBtu, 30 boiler operating day rolling average; controlled to 0.19 lb/mmBtu.

Notes:

Reagent costs based on costs delivered to plant including freight and taxes

Development costs will be project specific (not all projects will have a development APR)

Attachment 16

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Matthew H. Mead, Governor

Todd Parfitt, Director

July 5, 2013

Mr. William K. Lawson
Environmental Manager
PacifiCorp Energy
1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

CERTIFIED – RETURN RECEIPT REQUESTED

Re: Air Quality Permit No. MD-14506

Dear Mr. Lawson:

The Division of Air Quality of the Wyoming Department of Environmental Quality has completed final review of PacifiCorp Energy's application to modify the Naughton Power Plant by reducing permitted emissions from Unit 3 and ultimately converting the unit from a coal-fired electric generating unit to a natural gas-fired unit in 2018. The Naughton Plant is located in sections 32 and 33, T21N, R116W, approximately four (4) miles southwest of Kemmerer, in Lincoln County, Wyoming. Comments were received from PacifiCorp Energy on June 14, 2013; and on June 17, 2013 from the United Mine Workers of America Local 1307; from Westmoreland Kemmerer, Incorporated; and from the Lincoln Conversation District. All comments were considered in the final permit and are addressed below.

Comments from the United Mine Workers of America Local 1307; Westmoreland Kemmerer, Incorporated; and the Lincoln Conservation District

Comments: The United Mine Workers of America Local 1307 and Westmoreland Kemmerer, Incorporated oppose the permitting action that would allow the conversion of Naughton Unit 3 to a natural gas-fired unit. Both commenters state that controls could be used on the existing unit to achieve compliance with EPA standards. Both commenters also cite the potential reduction in the workforce at the Kemmerer Mine, reduction in tax revenue, and a potential loss of school district funding as the reasons for their opposition. The Lincoln Conservation District commented that the price of natural gas could rise in the future, which could increase rates for electricity from gas-fired units. They also cite the potential loss of tax revenue and impact to local budget cuts, and concur that pollution controls could be used on the existing coal-fired unit to achieve compliance with EPA standards.

Responses: The Division grants air quality permits for the construction or modification of air pollution sources based on compliance with the Wyoming Air Quality Standards and Regulations. The Division does not dictate fundamental design of the applicant's facility or the applicant's choice of fuels or the cost of those fuels. We do not have the authority to deny an air quality permit for a proposed project because of a project's impact on tax revenue or the local economy. We do consider the costs of the air pollution control equipment that is proposed for the facility, but only to ensure that Best Available Control Technology (BACT) is being applied in accordance with the WAQSR.

Air Quality Permit MD-14506
Response to Comments
Page 2

PacifiCorp Energy's Comments

Comment: Permit Conditions 6.ii.4 and 10 – PacifiCorp stated that it intends to implement the requirements imposed by Condition 6.ii beginning April 1, 2015, and requests that Conditions 6.ii.4 and 10 be revised to require that initial performance testing be completed within 30 boiler operating days from April 1, 2015. PacifiCorp also notes that Condition 10 refers to limits contained in Condition 5.ii that are actually stated in 6.ii.

Response: The Division will retain the effective date of the emission limits shown in 6.ii.4, but will revised the timeframe for initial performance testing from April 1, 2015 to within 30 boiler operating days from April 1, 2015 in accordance with Chapter 6, Section 2(j) of the Wyoming Air Quality Standards and Regulations (WAQSR). Condition 10 will be revised to correctly refer to the limits in Condition 6.ii rather than 5.ii.

Comment: Permit Conditions 6.iii.4 and 11 – PacifiCorp intends to complete the conversion of Unit 3 and place the unit in service as a natural gas unit prior to June 30, 2018. Therefore, the requirement that initial performance testing for limits under 6.iii.4 be complete by December 31, 2017 cannot be met. PacifiCorp also notes that Condition 11 refers to limits contained in Condition 5.iii that are actually stated in 6.iii.

Response: The Division's intent in requiring testing under Condition 6.iii.4 by December 31, 2017 was to ensure that Unit 3 would not be fueled by coal beyond that date, as represented in the application. To allow PacifiCorp the time needed to make the conversion of Unit 3 to a natural gas-fired unit, the Division will extend the initial performance testing requirement to 90 calendar days following startup of the unit on natural gas. The Division will require that the coal pulverizers for Unit 3 be removed from service no later than January 1, 2018, in accordance with PacifiCorp Energy's comment, to ensure that Unit 3 does not operate on coal during the conversion to a natural gas-fired unit. Condition 11 will be revised to correctly refer to the limits specified in Condition 6.iii rather than 5.iii.

Comment: Permit Conditions 6.iii.2 and 11.i.2 - PacifiCorp requests that the 2-hour rolling average limit and the 3-hour block average limit for SO_2 be removed. PacifiCorp also requests that the requirement to determine SO_2 emissions using a continuous emissions monitoring system (CEMS) be replaced with a method using gas flow and an emissions factor from 40 CFR part 75.

Response: The Division will not grant these requests without a demonstration on the part of the applicant that the remaining emissions limits for SO_2 will allow for the same level of air quality protection as the limits that are requested for removal. The SO_2 limits for Naughton Unit 3 will remain as proposed. If PacifiCorp Energy provides a demonstration to revise the SO_2 limits, then the Division will consider revising the applicable monitoring requirements based on the averaging period of the determined limits.

Comment: Permit Conditions 13.i.1 and 13.i.3 - PacifiCorp requests that the 30-day and 12-month rolling average emission limits be based on the summation of hourly emissions divided by the summation of hourly heat input for the same time period.

Response: The Division will retain the methods specified in Conditions 13.i.1 and 13.i.3 to define exceedances of the emission limits as they are consistent with existing methods specified in other air quality permits for the Naughton Plant. The Division does not anticipate that the requested methods would yield results appreciably different from those produced by the methods required in the draft permit.

Comment: Permit Condition 20 - PacifiCorp intends to complete the conversion of Unit 3 and place the unit in service as a natural gas unit prior to June 30, 2018, therefore they request that Condition 20 be modified to reflect that the conversion must be completed prior to June 30, 2018, and that initial performance tests be completed within 90 days of initial startup on natural gas.

Response: The Division's intent in requiring the conversion of Unit 3 and initial testing by December 31, 2017 was to ensure that Unit 3 would not be fueled by coal beyond that date, as represented in the application. To allow PacifiCorp the time needed to make the conversion of Unit 3 to a natural gas-fired unit, the Division will extend the initial performance testing requirement to 90 calendar days following the startup of the unit on natural gas. The Division will require that the coal pulverizers for Unit 3 be removed from service no later than January 1, 2018 to ensure that Unit 3 cannot operate on coal during the conversion to a natural gas-fired unit.

If we may be of further assistance to you, please feel free to contact this office.

Sincerely,

Steven A. Dietrich

Steven A. Dietrich
Administrator
Air Quality Division

cc: Greg Meeker

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Matthew H. Mead, Governor

Todd Parfitt, Director

July 5, 2013

Mr. William K. Lawson
Environmental Manager
PacifiCorp Energy
1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

Permit No. **MD-14506**

Dear Mr. Lawson:

The Division of Air Quality of the Wyoming Department of Environmental Quality has completed final review of PacifiCorp Energy's application to modify the Naughton Power Plant by reducing permitted emissions from Unit 3 and ultimately converting the unit from a coal-fired electric generating unit to a natural gas-fired unit in 2018. The Naughton Plant is located in sections 32 and 33, T21N, R116W, approximately four (4) miles southwest of Kemmerer, in Lincoln County, Wyoming.

Following this agency's proposed approval of the request as published May 16, 2013 and in accordance with Chapter 6, Section 2(m) of the Wyoming Air Quality Standards and Regulations, the public was afforded a 30-day period in which to submit comments concerning the proposed modification, and an opportunity for a public hearing. Comments were received and considered in the issuance of the final permit. Therefore, on the basis of the information provided to us, approval to modify the Naughton Power Plant as described in the application is hereby granted pursuant to Chapter 6, Section 2 of the regulations with the following conditions:

1. That authorized representatives of the Division of Air Quality be given permission to enter and inspect any property, premise or place on or at which an air pollution source is located or is being constructed or installed for the purpose of investigating actual or potential sources of air pollution and for determining compliance or non-compliance with any rules, standards, permits or orders.

2. That all substantive commitments and descriptions set forth in the application for this permit, unless superseded by a specific condition of this permit, are incorporated herein by this reference and are enforceable as conditions of this permit.

3. PacifiCorp Energy shall file a complete application to modify their Operating Permit within twelve (12) months of commencing operation, in accordance with Chapter 6, Section 3(c)(i)(B) of the WAQSR.

4. All notifications, reports and correspondence associated with this permit shall be submitted to the Stationary Source Compliance Program Manager, Air Quality Division, 122 West 25th Street, Cheyenne, WY 82002 and a copy shall be submitted to the District Engineer, Air Quality Division, 510 Meadowview Drive, Lander, WY 82520.

5. For the conversion of Naughton Unit 3 to natural gas, the owner or operator shall furnish the Administrator written notification of: (i) the anticipated date of initial startup not more than 60 days or less than 30 days prior to such date, and; (ii) the actual date of initial start-up within 15 days after such date in accordance with Chapter 6, Section 2(i) of the WAQSR.

6. This condition shall supersede portions of Condition 5 of Air Quality Permit MD-11725 as it pertains to Naughton Unit 3. Condition 5, Unit 3, Condition i. of MD-11725 shall remain in effect. Emissions from Naughton Unit 3 shall not exceed the levels below:

Unit 3

ii. Effective April 1, 2015:
   1. NO_x: 0.75 lb/MMBtu; 3-hour rolling average
      0.40 lb/MMBtu; 30-day rolling average
      1,258.0 lb/hr; 30-day rolling average
      4,700 tons per calendar year
      a. Limits shall apply during all operating periods.
   2. SO_2: 0.5 lb/MMBtu; 2-hour rolling average
      0.20 lb/MMBtu; 30-day rolling average
      1,850 lb/hr; 3-hour block average
      629.0 lb/hr; 30-day rolling average
      2,350 tons per calendar year
      a. Limits shall apply during all operating periods.
   3. PM: 0.035 lb/MMBtu
      110.0 lb/hr
      434.0 tons per calendar year
      a. Filterable PM/PM_{10}
      b. lb/hr limit shall apply during all operating periods.
      c. lb/MMBtu shall apply during all operating periods, except startup.
         i. Startup begins with the introduction of natural gas into the boiler and ends no later than the point in time when the ESP reaches a temperature of 225°F.
   4. Limits in (ii.) above supersede limits in MD-11725, Condition 5(i.) for Unit 3 on and after April 1, 2015. Initial performance tests required by Condition 10 of this permit shall be completed within 30 boiler operating days of April 1, 2015.

iii. Effective upon conversion to natural gas:
   1. NO_x: 0.75 lb/MMBtu; 3-hour rolling average
      0.08 lb/MMBtu; 30-day rolling average
      250.0 lb/hr; 30-day rolling average
      519.0 tons per calendar year
      a. Limits shall apply during all operating periods.
   2. SO_2: 0.5 lb/MMBtu; 2-hour rolling average
      0.0006 lb/MMBtu; 30-day rolling average
      1,850 lb/hr; 3-hour block average
      2.0 lb/hr; 30-day rolling average
      4.0 tons per calendar year
      a. Limits shall apply during all operating periods.

3. PM: 0.008 lb/MMBtu
   30.0 lb/hr
   52.0 tons per calendar year
   a. Total PM/PM_{10}
   b. Limits shall apply during all operating periods.
4. Limits in (iii.) above supersede limits in (ii.) of this condition for Unit 3 on and after January 1, 2018. Initial performance tests required by Condition 11 of this permit shall be completed within 90 calendar days of startup after conversion to natural gas.

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7. Effective upon permit issuance, this condition shall supersede Condition 6(i) of Air Quality Permit MD-11725. Opacity shall be limited as follows:

   i. Units 1-2:
      1. No greater than forty percent (40%) opacity of visible emissions.
         a. Limit shall apply during all operating periods.

      Unit 3:
      1. No greater than twenty percent (20%) opacity for visible emissions.
         a. Limit shall apply during all operating periods.
         b. Limit shall become effective upon startup of Unit 3 after natural gas conversion and completion of initial performance tests required by Condition 11 of this permit.

8. Effective upon permit issuance, this condition shall supersede Condition 10 in MD-9861.

   i. Authorization for SO_3 injection on Unit 3 shall remain in effect until start-up of Unit 3 after natural gas conversion and completion of the initial performance tests required by Condition 11 of this permit.

9. Effective upon permit issuance, this condition shall supersede Condition 17 in MD-5156. PacifiCorp Energy shall not be required under MD-5156 to install, calibrate, operate, and maintain a PM continuous emissions monitoring system (CEMS) on Unit 3.

10. Within 30 boiler operating days of April 1, 2015, performance tests shall be conducted on Unit 3 to demonstrate compliance with the limits in Condition 6.ii. and a written report of the results shall be submitted. If the maximum allowable heat input rate established in Condition 15 is not achieved during the performance tests, the Administrator may require testing be done at the rate achieved and again when the maximum allowable rate is achieved. Performance tests shall consist of the following:

    i. Unit 3:

       1. <u>NO_x Emissions</u> – Compliance with the NO_x 3-hour and 30-day rolling averages shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

2. SO_2 Emissions – Compliance with the SO_2 2-hour and 30-day rolling averages and 3-hour block average shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

3. PM/PM_{10} Emissions – Testing shall follow EPA Reference Test Methods 1-4 and 5, or an equivalent EPA Reference Method.

Testing required by the Chapter 6, Section 3, Operating Permit or required by 40 CFR part 63, subpart UUUUU may be submitted to satisfy the testing required by this condition.

11. Effective upon permit issuance, the applicable requirements of this condition shall supersede Condition 11.ii.2.(Unit 3) of MD-5156. Within 90 calendar days of conversion of Unit 3 to natural gas performance tests shall be conducted on Unit 3 to demonstrate compliance with the limits in Condition 6.iii. of this permit and a written report of the results shall be submitted. If the maximum allowable heat input rate established in Condition 15 of this permit is not achieved during the performance tests, the Administrator may require testing be done at the rate achieved and again when the maximum allowable rate is achieved. Performance tests shall consist of the following:

i. Unit 3:

1. NO_x Emissions – Compliance with the NO_x 3-hour and 30-day rolling averages shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

2. SO_2 Emissions – Compliance with the SO_2 2-hour and 30-day rolling averages and 3-hour block average shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

3. PM/PM_{10} Emissions – Testing shall follow EPA Reference Test Methods 1-5 and 202, or an equivalent EPA Reference Method.
4. CO Emissions - Testing shall follow EPA Reference Test Methods 1-4 and 10 or an equivalent EPA Reference Method.

Testing required by the Chapter 6, Section 3, Operating Permit or required by 40 CFR part 63, subpart UUUUU may be submitted to satisfy the testing required by this condition.

12. Prior to any testing required by this permit, a test protocol shall be submitted to the Division for approval, at least 30 days prior to testing. Notification should be provided to the Division at least 15 days prior to any testing. Results of the tests shall be submitted to this office within 45 days of completing the tests.

13. This condition shall supersede Condition 8 of Air Quality Permit MD-11725 as it applies to Naughton Unit 3. Compliance with the NO_x and SO_2 limits for Naughton Unit 3 set forth in Condition 5(i.) of MD-11725 and Condition 5 of this permit shall be determined with data from the NO_x and SO_2 continuous monitoring systems required by 40 CFR Part 75 as follows:

    i. Exceedances of the limits shall be defined as follows:

        1. Any 12-month rolling average which exceeds the lb/MMBtu NO_x limits as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n}(C)_h}{n}$$

Where:

E_{avg} = Weighted 12-month rolling average emission rate (lb/MMBtu).

C = 1-hour average SO_2 or NO_x emission rate (lb/MMBtu) for hour "h" calculated using valid data from the CEM equipment certified and operated in accordance with Part 75 and the procedures in 40 CFR part 60, appendix A, Method 19. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours monitored during a boiler operating day in the last twelve (12) successive calendar months with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

        2. Any 12-month rolling average which exceeds the lb/hr NO_x limit as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n}(C)_h}{n}$$

Where:

E_{avg} = Weighted 12-month rolling average emission rate (lb/hr).

C = 1-hour average emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment certified and operated in accordance with Part 75. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours monitored during a boiler operating day in the last twelve (12) successive calendar months with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

3. Any 30-day rolling average which exceeds the lb/MMBtu SO_2 or NO_x limit as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n} (C)_h}{n}$$

Where:

E_{avg} = Weighted 30-day rolling average emission rate (lb/MMBtu).

C = 1-hour average emission rate (lb/MMBtu) for hour "h" calculated using valid data from the CEM equipment certified and operated in accordance with Part 75 and the procedures in 40 CFR part 60, appendix A, Method 19. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours in the last thirty (30) successive boiler operating days with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

4. Any 30-day rolling average which exceeds the lb/hr SO_2 or NO_x limits as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n}(C)_h}{n}$$

Where:

E_{avg} = Weighted 30-day rolling average emission rate (lb/hr).

C = 1-hour average emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment certified and operated in accordance with Part 75. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours in the last thirty (30) successive boiler operating days with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

5. Any 3-hour rolling average of NO_x emissions calculated using data from the CEM equipment required by 40 CFR part 75 which exceeds the lb/MMBtu limit established in this permit using valid data. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 3-hour average emission rate shall be calculated as the arithmetic average of the previous three (3) operating hours.

6. Any 2-hour rolling average of SO_2 emissions calculated using data from the CEM equipment required by 40 CFR part 75 which exceeds the lb/MMBtu limit established in this permit using valid data. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 2-hour average emission rate shall be calculated as the arithmetic average of the previous two (2) operating hours.

7. Any 3-hour block average of SO_2 emissions calculated using data from the CEM equipment required by 40 CFR part 75 which exceeds the lb/hr limit established in this permit using valid data. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 3-hour average emission rate shall be calculated at the end of each 3-hour operating block as the arithmetic average of hourly emissions with valid data during the previous three (3) operating hours.

ii. PacifiCorp will comply with all reporting and record keeping requirements as specified in WAQSR, Chapter 5, Section 2(g).

iii. Exclusion of startup, shutdown, and malfunction emissions only applies to federal standard(s) as authorized in the respective subpart and as authorized in this permit.

14. Effective April 1, 2015, Naughton Unit 3's hourly heat input shall be limited to 3,145 MMBtu/hr, based on a 24-hour block average defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit. Compliance with the heat input limit will be determined using a 40 CFR Part 75 certified CEMS and the procedures for determining heat input per 40 CFR Part 75.

15. Effective January 1, 2018, Naughton Unit 3's heat input shall be limited to 12,964,800 MMBtu based on 12-month rolling average of hourly heat input values. Compliance with the heat input limited will be determined using a 40 CFR Part 75 certified CEMS and the procedures for determining heat input per 40 CFR Part 75.

16. Effective upon permit issuance, this condition shall supersede Condition 5.ii of Air Quality Permit MD-11754.

ii. PAL limits effective upon completion of initial performance tests required by Condition 11.

1. NO_x: 5,402.4 tons per year
   a. Limit is based on a 12-month rolling total.
   b. Initial compliance shall be determined 12 months after the effective date of the PAL. The effective date is the first day of the next month following completion of the initial performance tests required after the completion of natural gas conversion and startup of Unit 3. PacifiCorp Energy shall continue to demonstrate compliance with the NO_x PAL of 11,112.8 tons per year until the initial compliance date for the modified NO_x PAL is triggered.

2. SO_2: 2,862.2 tons per year
   a. Limit is based on a 12-month rolling total.
   b. Initial compliance shall be determined 12 months after the effective date of the PAL. The effective date is the first day of the next month following completion of the initial performance tests required after the completion of natural gas conversion and startup of Unit 3 and. PacifiCorp Energy shall continue to demonstrate compliance with the SO_2 PAL of 8,789.8 tons per year until the initial compliance date for the modified SO_2 PAL is triggered.

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17. Unit 3 shall be equipped with in-stack continuous emission monitoring (CEM) equipment to monitor CO emissions:

i. CO CEM shall be installed and certified within ninety (90) days of permit issuance.

ii. PacifiCorp Energy shall install, calibrate, operate, and maintain a monitoring system, and record the output, for measuring CO emissions discharged to the atmosphere in units of ppm_v, lb/MMBtu, and lb/hr. The CO monitoring system shall consist of the following:

   1. A continuous emission CO monitor located in the stack of Unit 3.

   2. A continuous flow monitoring system for measuring the flow of exhaust gases discharged into the atmosphere.

   3. An in-stack oxygen or carbon dioxide monitor for measuring oxygen or carbon dioxide content of the flue gas at the location CO emissions are monitored.

iii. Each continuous monitor system listed in this condition shall comply with the following:

   1. Monitoring requirements of WAQSR, Chapter 5, Section 2(j) including the following:

      a. 40 CFR part 60, appendix B, Performance Specification 4 or 4a for carbon monoxide. The monitoring systems must demonstrate linearity using 40 CFR part 60, appendix F, and be certified in concentration (ppm_v) and units of lb/MMBtu and lb/hr.

      b. Quality Assurance requirements of 40 CFR part 60, appendix F.

      c. PacifiCorp Energy shall develop and submit for the Division's approval a Quality Assurance plan for each monitoring system listed in this condition. Quality Assurance plans shall be submitted within 180 days from startup of each unit after new low NO_x burners have been installed.

iv. The CO monitor may be removed after December 31, 2017, upon Division approval.

18. Annually, as otherwise specified by the Administrator, Unit 3 shall be tested to verify compliance with the PM limits set forth in Condition 6. The first annual test is required the following calendar year after completion of the initial performance test required by Condition 10. Testing for PM shall be conducted in accordance with EPA Reference Methods 1-5 and 202, or an equivalent EPA Reference Method. A test protocol shall be submitted to this office for review and approval prior to testing. Notification of the test date shall be provided to the Division fifteen (15) days prior to testing. Results of the tests shall be submitted to the Division within forty-five (45) days of completing the tests.

19. Records required by this permit shall be maintained for a period of at least five (5) years and shall be made available to the Division upon request.

20. PacifiCorp Energy shall remove the coal pulverizers on Unit 3 from service no later than January 1, 2018. PacifiCorp Energy shall provide written notification to the Division of the actual date of pulverizer removal within 30 days of such date.

21. PacifiCorp Energy shall complete the conversion of Naughton Unit 3 to natural gas prior to June 30, 2018, and conduct the initial performance tests required in Condition 11 of this permit no later than 90 calendar days after initial startup of Unit 3 after natural gas conversion.

22. This condition shall become effective upon start-up of Naughton Unit 3 after conversion to natural gas, as reported in accordance with Condition 5 of this permit, and shall supersede Air Quality Permit MD-11894 for the Naughton Plant.

23. All conditions from previously issued Air Quality Permits MD-5156, MD-9861, and MD-11725 shall remain in effect unless specifically superseded by a condition of this permit.

It must be noted that this approval does not relieve you of your obligation to comply with all applicable county, state, and federal standards, regulations or ordinances. Special attention must be given to Chapter 6, Section 2 of the Wyoming Air Quality Standards and Regulations, which details the requirements for compliance with Conditions 5, 10 and 11. Attention must be given to Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations, which details the requirements for compliance with Condition 3. Any appeal of this permit as a final action of the Department must be made to the Environmental Quality Council within sixty (60) days of permit issuance per Section 16, Chapter I, General Rules of Practice and Procedure, Department of Environmental Quality.

If we may be of further assistance to you, please feel free to contact this office.

Sincerely,

Steven A. Dietrich

Steven A. Dietrich
Administrator
Air Quality Division

Todd Parfitt
Director
Dept. of Environmental Quality

cc: Greg Meeker

Docket No. UE 374
Exhibit PAC/4003
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of James Owen

PacifiCorp's Jim Bridger Power Plant Regional Haze Reasonable Progress Determination to Support PacifiCorp's Reasonable Progress Reassessment

August 2020

1407 W. North Temple, STE 210
Salt Lake City, UT 84116

February 5, 2019

Nancy Vehr
Administrator
Wyoming Department of Environmental Quality, Air Quality Division
200 West 17th Street
Cheyenne, WY 82002

Subject: Jim Bridger Regional Haze Reassessment Permit Application

Dear Ms. Vehr:

On December 21, 2017, PacifiCorp submitted an application to the Wyoming Air Quality Division to permit the installation of selective catalytic reduction (SCR) equipment on Jim Bridger plant Units 1 and 2. The December 2017 application was provided to the Wyoming Air Quality Division to meet requirements included in the November 3, 2010 BART Appeal Settlement Agreement.

As discussed in the December 21, 2017 permit application, PacifiCorp continues to assess the costs and benefits of installing SCR on Units 1 and 2. PacifiCorp's assessments to date are driving PacifiCorp to pursue an alternative strategy for regional haze compliance at the Jim Bridger power plant on behalf of our customers (that strategy, the "Regional Haze Reassessment"). The Regional Haze Reassessment that PacifiCorp has completed and is proposing as part of this application is more cost effective, results in less overall environmental impacts, and leads to better modeled visibility than SCR installation on Units 1 and 2. With this submittal, PacifiCorp hereby requests that the December 21, 2017 Jim Bridger Unit 1 and Unit 2 SCR Permit Application be rescinded and replaced with this Jim Bridger Unit 1 and Unit 2 Regional Haze Reassessment Permit Application.

In addition to this Regional Haze Reassessment Permit Application, PacifiCorp is also submitting a Reasonable Progress Determination, which provides all necessary evaluation and analysis in support of the Regional Haze Reassessment. This submittal also includes PacifiCorp's recommendations for revisions to be made to Wyoming's 309 and 309(g) Regional Haze State Implementation Plans (SIPs). Included in a separate but concurrent and confidential submittal are PacifiCorp's proposed amendments to the corresponding November 3, 2010 BART Appeal Settlement Agreement.

Through this application PacifiCorp requests that plant-wide variable average monthly-block pound-per-hour NO_X and SO_2 emission limits be imposed in a Regional Haze Reassessment Permit on all four Jim Bridger boilers (Units 1, 2, 3 and 4), as identified in Table 1 below.

Table 1: Proposed Jim Bridger Units 1-4 Monthly Average NO_X and SO_2 Emission Limits

Month	Total Units 1-4 NO_X Emission Limit (monthly average basis)	Total Units 1-4 SO_2 Emission Limit (monthly average basis)
January	2,050 lb/hour	2,100 lb/hour
February	2,050 lb/hour	2,100 lb/hour

March	2,050 lb/hour	2,100 lb/hour
April	2,050 lb/hour	2,100 lb/hour
May	2,200 lb/hour	2,100 lb/hour
June	2,500 lb/hour	2,100 lb/hour
July	2,500 lb/hour	2,100 lb/hour
August	2,500 lb/hour	2,100 lb/hour
September	2,500 lb/hour	2,100 lb/hour
October	2,300 lb/hour	2,100 lb/hour
November	2,030 lb/hour	2,100 lb/hour
December	2,050 lb/hour	2,100 lb/hour

In addition to the monthly average NO_X and SO_2 emission limits included in Table 1, PacifiCorp's Regional Haze Reassessment also proposes a plant-wide permit limit with a 12-month rolling total NO_X and SO_2 emission limit of 17,500 tons/year be established for the Jim Bridger Units 1-4 boilers. PacifiCorp requests that these permit limits be implemented and enforced in lieu of the requirement to install SCR on Jim Bridger Units 1 and 2.

The emission limits in this application mirror what is analyzed in the Reasonable Progress Determination, and what is proposed in revisions to the 309(g) Regional Haze SIP. PacifiCorp hereby requests that these proposed emission limits become effective January 1, 2022, commensurate with the compliance requirement to install the earlier of the two remaining SCR systems on Jim Bridger Units 1 and 2.

As the Regional Haze Reassessment will not increase the potential unit heat input, this application does not address any other regulated criteria pollutant beyond those listed above. PacifiCorp anticipates providing a subsequent permit application to address potential wet-stack conversions and opacity monitor relocations for specific Jim Bridger units, if PacifiCorp determines such changes become necessary to maintain compliance with the emission limits proposed herein.

Please contact me at (801) 220-4581 or Megan Withroder at (801) 220-4707 if you have questions regarding this Regional Haze Reassessment Permit Application.

Sincerely,

James Owen
Director, Environmental Services
PacifiCorp

cc: Chad Teply
Dana Ralston
Megan Withroder
Rick Tripp
Paul Fahlsing
Jim Doak
Jenny McIvor

JIM BRIDGER POWER PLANT

REASONABLE PROGRESS DETERMINATION

To Support PacifiCorp's Reasonable Progress Reassessment

FEBRUARY 2019

A BERKSHIRE HATHAWAY ENERGY COMPANY

1407 W North Temple, STE 210
Salt Lake City, UT 84116

TABLE OF CONTENTS

I. History and Purpose

On December 29, 2003 Wyoming submitted a visibility State Implementation Plan (“SIP”) to meet the requirements of 40 C.F.R. § 51.309. The 2003 Section 309 SIP and subsequent revisions (submitted November 21, 2008, and January 12, 2011) were each submitted to EPA as separate Section 309 and Section 309(g) plans. The Section 309 SIP addressed the first phase of requirements as they pertained to stationary source sulfur dioxide (SO2) emission reductions, whereas the Section 309(g) SIP addressed first phase requirements focusing on stationary source nitrogen oxide (NOx) and particulate matter (PM) emission reductions.

On January 30, 2014, EPA published a final regional haze rule (79 FR 5032) that approved the provisions of the Section 309(g) SIP establishing stringent controls of NOx emissions from the four units at the Jim Bridger power plant, located near Point of Rocks, Wyoming. For NOx controls, EPA determined that Wyoming’s selection of the NOx controls of low-NOx burners (“LNB”) and separated overfire air (“SOFA”) qualified for Best Available Retrofit Technology (“BART”) controls. Additionally, EPA approved Wyoming’s requirement that LNB/SOFA plus selective catalytic reduction technology (“SCR”) be installed at Jim Bridger Units 1-4 as part of the State’s Reasonable Progress / Long-Term Strategy (“RP”/”LTS”). The resulting Wyoming SIP required, as part of its RP/LTS, installation of SCR controls for NOx (30-day rolling average emission rate of 0.07 lb/MMBtu) on Jim Bridger units in a phased approach:

- December 31, 2022 for Unit 1
- December 31, 2021 for Unit 2
- December 31, 2015 for Unit 3
- December 31, 2016 for Unit 4

The installations of SCR controls on Jim Bridger Units 3 and 4 have been completed as stated above. Considering the significant costs of installing SCR on Units 1 and 2, and the potential impact of those costs to PacifiCorp’s customers under current market conditions and anticipated remaining life of facilities, PacifiCorp reassessed its compliance with the Regional Haze Rule and developed an alternative regional haze compliance strategy for those units which is more cost effective, has less environmental impacts, and results in better modeled visibility than SCR installation. PacifiCorp is now proposing that alternative regional haze compliance strategy (the “Reasonable Progress Reassessment” or “RP Reassessment”) for the Jim Bridger Power Plant and recommends that the RP Reassessment (in lieu of SCRs on Units 1 and 2) be adopted as part of the reasonable progress determination and long term strategy for the Jim Bridger power plant.

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EPA has approved changes, or reassessments, of other states' reasonable progress determinations.[1] This reasonable progress determination contains all of the plan elements and documentation required for the RP Reassessment for the Jim Bridger power plant.

a. Description of Reasonable Progress Reassessment

The RP Reassessment includes new, lower plant-wide month-by-month, emissions limits for the two principal haze-causing pollutants, NOx and SO2 ("Operational Limits"). These month-by-month Operational Limits are identified in Table 1 below, and would become effective January 1, 2022.

TABLE 1: PROPOSED JIM BRIDGER UNITS 1-4 MONTHLY AVERAGE NOX AND SO2 EMISSION LIMITS

Month	Total Units 1-4 NOx Emission Limit (monthly average basis)	Total Units 1-4 SO_2 Emission Limit (monthly average basis)
January	2,050 lb/hour	2,100 lb/hour
February	2,050 lb/hour	2,100 lb/hour
March	2,050 lb/hour	2,100 lb/hour
April	2,050 lb/hour	2,100 lb/hour
May	2,200 lb/hour	2,100 lb/hour
June	2,500 lb/hour	2,100 lb/hour
July	2,500 lb/hour	2,100 lb/hour
August	2,500 lb/hour	2,100 lb/hour
September	2,500 lb/hour	2,100 lb/hour
October	2,300 lb/hour	2,100 lb/hour
November	2,030 lb/hour	2,100 lb/hour
December	2,050 lb/hour	2,100 lb/hour

In addition to the monthly average NOx and SO_2 emission limits included in Table 1, the RP Reassessment will also establish a plant-wide 12-month rolling total emissions cap of 17,500 tons/year for total NOx and SO2 on the Jim Bridger Units 1-4 boilers. This combined set of lb/hour and tons/year limits would be enforced in lieu of installation of SCR on Jim Bridger Units 1 and 2, and will effectively decrease the operating capacity of the plant, thereby reducing its emission of haze-causing pollutants.

[1] See 83 FR 31332 (July 5, 2018)(Nucla Station, Colorado); 82 FR 42738 (Sep. 12, 2017)(Blaine County Compressor Station, Montana). In fact, EPA has approved changes to a Reasonable Progress Determination that were issued in a FIP. See 83 FR 5927, 5934-35 (Arkansas)("We believe Arkansas is within its discretion to take a different approach than we did in the Arkansas FIP, and that the approach Arkansas has taken to determine whether additional NOX controls are necessary under reasonable progress is reasonable and therefore, approvable.")

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II. Reasonable Progress Analysis

The current SCR installation requirements for Jim Bridger's Units 1 and 2 arise as "part of" the state's long-term strategy for making "reasonable progress," as required by the Regional Haze Program. The statutory reasonable progress factors are: (1) the costs of compliance[2]; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of the existing source. 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(d)(1)(i)(A). Therefore, to demonstrate that the revised plan makes greater reasonable progress than the original plan, each reasonable progress factor is analyzed on a comparative basis for the RP Reassessment, the current SIP (installation of SCR on Units 1 and 2), as well as an analysis of the installation of another possible NOx pollution control device, Selective Non-Catalytic Reduction ("SNCR"), on Units 1 and 2.[3] As shown below, the RP Reassessment makes greater reasonable progress than either the installation of SCR or SNCR, when considering each reasonable progress factor, as well as visibility benefits.

Notably, visibility is not a specific statutory factor, but should be considered as part of a "reasonable progress" determination process. *See* 81 FR 296, 310-311 (Jan. 5, 2016)(Texas and Oklahoma)(" we believe that states are permitted, but not required, to consider visibility improvement alongside the four statutory factors when making their reasonable progress determinations, with the important caveat that they must do so in a reasonable fashion. . . . [T]he national goal of achieving natural visibility conditions is central to the notion of reasonable progress, so Congress had no need to include language regarding visibility improvement in CAA section 169A(g)(1).") ("While visibility is not explicitly listed as a factor … it is appropriate to consider the projected visibility benefits of the controls when determining if the controls are needed to make reasonable progress.") *Id.* at 304.

PacifiCorp considered and relied upon visibility modeling results that compare the visibility impacts of new proposed RP Reassessment with Operational Limits to the visibility impacts of the existing Section 309(g) SIP SCR requirements for Bridger Units 1 and 2, and to a SNCR

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[2] The "costs of compliance" factor for a Reasonable Progress Determination requires an analysis similar to the cost analysis for Best Available Control Technology ("BART"). To analyze this factor for an individual source, EPA's 2007 Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program suggests using "established control cost analysis techniques," and identifies the "BART Guidelines" as a helpful source. The Appendix Y BART Guidelines describe a methodology that could be used to determine control system costs and to calculate control system cost-effectiveness. The 2007 Reasonable Progress Guidance and BART Guidelines state that in order "to maintain and improve consistency," the "cost estimates should be based on the Control Cost Manual, where possible", *see* 70 FR 39166, referencing EPA's Control Cost Manual, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[3] Low-NOx Burners ("LNB") were not evaluated as part of this reasonable progress determination because all Units, 1-4 at the Jim Bridger power plant currently have LNB that utilize the latest proven LNB technology.

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option. Table 2 below summarizes the results of the four factor "reasonable progress" analysis for the three options[4]:

TABLE 2: COMPARISON OF REASONABLE PROGRESS FACTORS FOR REGIONAL HAZE COMPLIANCE

Units 1 and 2 with Selective Catalytic Reduction Technology SCR	Units 1 and 2 with Selective Non-Catalytic Reduction Technology SNCR	Reasonable Progress Reassessment with Operational Limits RP Reassessment
Cost – Remaining Life (2037) • **$280,856,000-capital** • **$5,959 / ton** **Cost – 20 Year Life** • **$280,856,000-capital** • **$5,407 / ton** **Cost – 30 Year Life** • **$280,856,000-capital** • **$4,744 / ton**	**Cost – Remaining Life(2037)** • **$31,076,000-capital** • **$5,685 / ton** **Cost – 20 Year Life** • **$31,076,000-capital** • **$5,469 / ton** **Cost – 30 Year Life** • **$31,076,000-capital** • **$5,209 / ton**	**Cost – Remaining Life (2037)** • **$4,659,000-capital** • **$349 / ton** **Cost – 20 Year Life** • **$4,659,000-capital** • **$341 / ton** **Cost – 30 Year Life** • **$4,659,000-capital** • **$330 / ton**
Time for compliance • **End of 2021, 2022**	**Time for Compliance** • **End of 2021, 2022**	**Time for Compliance** • **January 1, 2022**
Energy and non-air quality environmental impacts • **Increased ammonia use** • **Increased CCR production** • **Higher GHG emissions** • **Higher SO2 emissions** • **Lower NOx emissions**	**Energy and non-air quality environmental impacts** • **Increased ammonia use** • **Increased CCR production** • **Higher GHG emissions** • **Higher SO2 emissions** • **Lower NOx emissions**	**Energy and non-air quality environmental impacts** • **Lower ammonia use** • **Lower CCR production** • **Lower GHG emissions** • **Lower SO2 emissions** • **Higher NOx emissions**
Remaining Useful life • **2037**	**Remaining Useful Life** • **2037**	**Remaining Useful Life** • **2037**

[4] The energy and non-air quality environmental impacts section of Table 2 compares: SCR against the RP Reassessment in the 'SCR' column; SNCR against the RP Reassessment in the 'SNCR' column; and the RP Reassessment against both SCR and SNCR in the 'RP Reassessment' column.

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Visibility impacts **Avg. 98th % Impact (dv)** • **0.760 (common stack)** • **0.735 (individual)** **Total Days Above 0.5 Δ-dv** • **475 (common stack)** • **459 (individual)** **Total Days Above 1.0 Δ-dv** • **127 (common stack)** • **123 (individual)** **Overall worse visibility than RP Reassessment, but better visibility than SNCR**	**Visibility Impacts-** **Avg. 98th % Impact (dv)** • **0.930 (common stack)** **Total Days Above 0.5 Δ-dv** • **597 (common stack)** **Total Days Above 1.0 Δ -dv** • **195 (common stack)** **Overall worse visibility than RP Reassessment, and worse visibility than SCR**	**Visibility impacts[5]** **Avg. 98th % Impact (dv)** • **0.653 (common stack)** **Total Days Above 0.5 Δ-dv** • **371 (common stack)** **Total Days Above 1.0 Δ -dv** • **108 (common stack)** **Overall better visibility than SCR, and better visibility than SNCR**

a. Costs of Compliance

Under EPA's 2007 Guidance for Setting Reasonable Progress Goals ("2007 RPG Guidance"), a pollution control's cost-effectiveness should be evaluated when making a reasonable progress determination.[6] PacifiCorp commissioned Sargent & Lundy (S&L) to provide a Cost and Emissions Analysis for all three potential compliance strategies, using 20 and 30 year amortization periods,[7] as well as an amortization period ending with the currently expected end of the Jim Bridger plant's expected remaining Useful Life (ending in the year 2037[8]). *See* Jim Bridger Power Plant RP Reassessment Cost and Emissions Analysis attached as Attachment 1.

[5] Only SO2 reductions attributable to the operational limits that are over and above the reductions attributable to the 309 Backstop Trading Program were considered in visibility modeling for the Reasonable Progress Reassessment.

[6] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, U.S. Environmental Protection Agency, June 1 2007, p. 5-2.

[7] The EPA finalized revisions to the Air Pollution Control Cost Manual in May of 2016, which changed the amortization period for SCR from 20 years to 30 years; the amortization period for SNCR remains at 20 years. *See* Air Pollution Control Cost Manual, Chapters 1 and 2, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[8] *See* 2019 Integrated Resource Plan (IRP) Public Input Meeting, July 26-27, 2018; http://www.pacificorp.com/es/irp/pip.html

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Based on the S&L analysis, and as can be seen in Table 2 above, the cost-effectiveness of installing SCR on Jim Bridger Units 1 and 2 (over 30-years) is $4,744 per ton of NOx (the only haze-causing pollutant addressed in the Section 309(g) SIP for Units 1 and 2). The cost-effectiveness of installing SNCR on Jim Bridger Units 1 and 2 (over 20 years) is $5,469 per ton of NOx (the only haze-causing pollutant addressed in the Section 309(g) SIP for Units 1 and 2). The RP Reassessment with Operational Limits (over Remaining Useful Life[9]) would cost $349 per ton of NOx+SO2 (combined for both haze-causing pollutants).[10]

Section 7.3.1 of Wyoming's 309(g) SIP acknowledges that it's appropriate to evaluate and compare costs over different amortization periods when the expected life of the source is less than the expected life of the emission control device. For this evaluation, the expected life of the source is to the end of remaining useful life (year 2037); while the expected life for SNCR is 20 years, and the expected life of SNCR is 30 years. The cost effectiveness estimates in Table 2 appropriately reflect these varying life expectancies. Furthermore, using a shorter amortization period for the RP Reassessment, and longer amortization periods for SNCR and SCR provides a conservative comparison, as it provides a highest-cost estimate for the RP Reassessment, and the lowest-cost estimates for SNCR and SCR. To further provide conservative cost estimates, the amortization periods for SNCR and SCR were assumed to begin at the end of year 2021, despite the Bridger Unit 1 installation requirement date of 2022. This approach provides a highest-cost estimate for the Operational Limits, and the lowest-cost estimates for SNCR and SCR.

The estimated capital costs of installing SCR, installing SNCR, and implementing the RP Reassessment are: $280,856,000; $31,076,000; and $4,659,000, respectively. To accurately compare the cost of one control technology – Operational Limits – to another control technology – SCR or SNCR – it is necessary to determine the total tons of reductions of haze-causing pollutants attributable to each particular technology. Operational Limits as a control measure reduces both SO2 and NOx. SCR and SNCR as control technologies only reduce NOx.

Given EPA's recognition of sulfur dioxide as "the predominant cause of regional haze on the Colorado Plateau in the western US" (79 FR 5032, 5097),[11] and more specifically, since SO2 emissions were modeled together with NOx emissions to determine the RP Reassessment's

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[9] This is the highest and most conservative cost for the Reasonable Progress Reassessment, as the End of Remaining Useful life represents a shorter amortization period than either the 20 or 30 year scenarios.

[10] These average cost effectiveness estimates account for previous installation of haze-control technology at the Jim Bridger Plant. The Jim Bridger Power Plant RP Reassessment Cost and Emissions Analysis in Attachment 1 includes Cost Effectiveness Calculation Worksheets for each evaluated control technology over various amortization periods.

[11] The Western Regional Air Partnership ("WRAP") has also determined that SO[2] emissions have the greatest impact on visibility in the West. "Recommendations for Improving Western Vistas," authored by the Grand Canyon Visibility Transport Commission, (June 10, 1996) at page 32 (identifying sulfates as "the most significant contributor to visibility impairment" from stationary sources).

impacts on visibility at the Class I Areas potentially affected by the Jim Bridger power plant (discussed in Section II(e) of this reasonable progress determination), it is conservative and reasonable to treat the two pollutants as interchangeable for purposes of regional haze controls and reasonable progress determinations, both in cost calculations and in modeling visibility impacts.[12] Therefore, PacifiCorp's analysis compares total SO2 and NOx reductions attributable to the Operational Limits on a cost per ton basis to the NOx reductions attributable to each SCR and SNCR on a cost per ton basis so that costs per ton of haze-causing pollutants can be accurately estimated and compared. Furthermore, because the Jim Bridger Plant has already installed NOx emission controls (LNB & SOFA on Units 1-4 and SCR on Units 3-4), and because the RP Reassessment includes restriction on all 4 Units, the ton reductions provided in the cost effectiveness estimates in Table 2 reflect reductions from current operating potential. Evaluating reductions from current operating potential provides a true-cost comparison of the cost and tonnage reduction of each technology. It should be noted that even if all three control technologies are compared on a NOx-only basis, the RP Alternative is still the lowest cost option, by significant margins. *See* Cost Effectiveness Calculation Worksheets in Attachments 3A, 3B, and 3C of Attachment 1.

Considering the interchangeable nature of the two haze-causing pollutants in the analysis, the average cost effectiveness for the proposed RP Reassessment is 13.6 times lower than the cost of SCR and over 15.6 times lower than SNCR. If only NOx is considered, the RP Reassessment shows a capital cost savings when compared to SCR or SNCR, as the capital expenditures associated with the RP Reassessment are for SO2 reduction. The "costs of compliance" reasonable progress factor strongly favors the use of the RP Reassessment as a control measure because the same or better visibility benefits can be achieved at a much lower cost by lowering both SO2 and NOx. Further, as EPA states in its 2007 Reasonable Progress Guidance, it is important to account for the differing impacts on visibility caused by different pollutants.[13] Here, the RP Reassessment and its enforceable Operational Limits will provide greater reductions in SO2 than SCR or SNCR, and will provide greater overall visibility improvements than SCR or SNCR.[14] Proper analysis of this factor favors the RP Reassessment.

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[12] EPA has allowed the use of multi-pollutant regional haze approaches in other states. *See, e.g.*, 80 Fed Reg. 19220, 19221 (Feb. 27, 2015) ("the Alternative would result in greater NOX emissions, but lower emissions of SO2 and PM10")(Arizona); 80 Fed. Reg. 79261, 79264 (Illinois); 81 Fed. Reg. 19519, 19524 (North Carolina) (considering evidence beyond restrictive visibility-only test, including benefits of substituting SO2 for NOx reductions). As explained in both the CALPUFF Modeling Protocol and CALPUFF Modeling Report, generally speaking SO2 emissions have a greater impact year around than NOX. *See* Section II (e); *see also* Attachment 3- Reasonable Progress Reassessment Visibility Improvement Modeling Report for Jim Bridger power plant.

[13] *Supra* Note 6 at p. 5-2.

[14] Only SO2 reductions attributable to the Operational Limits that are over and above the reductions attributable to the Section 309 Backstop Trading Program were considered in the cost per ton estimates for the Operational Limits.

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b. Time Necessary for Compliance

The 2007 Reasonable Progress Guidance states that this factor may be used to adjust the reasonable progress goal to reflect the degree of visibility improvement achievable within the first regional haze planning period if the time needed for implementation of a control measure will be extended beyond 2018.[15] However, in this case, the Section 309(g) SIP requirements to install SCR on Jim Bridger Unit 1 and Unit 2 are 2022 and 2021, respectively – which occurs in the second regional haze planning period but is nonetheless a requirement from the first planning period. Replacing SCR with the RP Reassessment, or choosing the RP Reassessment instead of SNCR, does not impact Wyoming's reasonable progress goals for the first planning period because they can be implemented within the same timeframe as SCR or SNCR, or sooner if necessary. Proper analysis of this factor favors the RP Reassessment.

c. Energy and Non-Air Quality Impacts

Section 5.3 of the 2007 RPG Guidance explains that when analyzing "energy" impacts, a State may "want to consider whether the energy requirements associated with the control technology result in energy penalties." The following provides analysis for: energy impacts; environmental impacts; consumption of natural resources; greenhouse gas ("GHG") emissions; coal combustion residuals ("CCR") impacts (including fly ash and bottom ash disposal); and additional benefits. Support calculations for these analyses are attached as Attachment 2 - Energy and Non-Air Quality Related Impacts Support Calculations.

i. Energy Impacts

The SCR installed on Jim Bridger Units 3 and 4 require significant electrical energy to operate, with each SCR having an electric power requirement of approximately 5.2 MW.[16] The energy demand for Units 1 and 2 would be similar. Adoption of the Regional Haze Reassessment will reduce the Jim Bridger plant's auxiliary load demand as compared to the SCR-based reasonable progress requirements by approximately 10.4 MW, allowing the electrical energy which would have been required by the Units 1 and 2 SCRs to instead be directed to the power grid which is enough energy to power approximately 8,761 average homes.[17] The energy demand for SNCR on Units 1 and 2 would be similar to current operations as SNCR would not require significant auxiliary electrical power as does SCR. *See* Attachment 2, page 1.

ii. Environmental Impacts

[15] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, U.S. Environmental Protection Agency, June 1 2007, p. 5-2.

[16] *See* PacifiCorp's Jim Bridger Units 1 and 2 SCR design data.

[17] In 2017, the U.S. Energy Information Administration estimated an average annual electricity consumption for a U.S. residential utility customer of 10,399 kWh., https://www.eia.gov/tools/faqs/faq.php?id=97&t=3

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Additionally, the RP Reassessment will have much less of an environmental impact than would the installation of SCR or SNCR at Units 1 and 2. Section 5.3 of the 2007 RPG Guidance suggests that some of the "non-air environmental impacts" that States may consider are "the waste stream that may be generated by a particular control technology, and/or other resource consumptions rates such as water, water supply, and waste water disposal." The installation of SCR at Units 1 and 2 would result in the additional storage and use of ammonia (a hazardous substance), and would create more CCR than does the RP Reassessment. *See* Attachment 2, pages 2-4. Likewise, the installation of SNCR on Units 1 and 2 would require the storage and use of urea and would create more CCR than does the RP Reassessment. Additionally, the RP Reassessment will result in the Jim Bridger plant producing fewer GHG than would the installation of SCR or SNCR at Units 1 and 2. *See* Attachment 2, page 2.

Under the original reasonable progress requirement to install SCR on Units 1 and 2, the Jim Bridger plant is not restricted on capacity factor – essentially annual heat input – and could conduct operations under its most restrictive permit – a maximum permitted annual coal consumption of 9,500,000 tons per year. Under the proposed monthly block NO_X and SO_2 emission limits, along with the annual ton per year limit (*see* Section I(a) above) the Jim Bridger plant will be prevented from operating at an unrestricted capacity factor and will effectively be limited to a maximum average annual capacity factor of approximately 76.3 percent, which effectively limits total annual heat input[18].

Because adoption of the RP Reassessment will effectively limit annual boiler heat input, it will therefore provide a reduction in the consumption of natural resources; a reduction in the generation and associated disposal of coal combustion byproducts; and a reduction of air pollutants.

a. Consumption of Natural Resources

Under the current requirement to install SCR on Units 1 and 2, the Jim Bridger plant has a potential to combust 11,303,226 tons of coal per year based on maximum boiler heat input and coal heating value; however, Jim Bridger has a permitted maximum annual coal combustion limit of 9,500,000 tons/year.[19] Under the RP Reassessment with its average annual 76.3 percent capacity factor restriction, the Jim Bridger plant would have the potential to combust a maximum of 8,624,361 tons of coal per year, providing a potential coal combustion decrease of 875,639 tons per year.[20] *See* Attachment 2, page 1.

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[18] PacifiCorp is not proposing any capacity factor limit or heat input limit as part of the RP Reassessment. The capacity factor estimate is provided to demonstrate the estimated effective impact of the NOx and SO2 emissions limits that are being proposed as part of the RP Reassessment.

[19] The Jim Bridger plant is limited to a maximum annual coal consumption of 9,500,000 tons/year under permit OP-267.

[20] The installation of SNCR on Units 1 and 2 is not expected to affect the coal combustion requirements of the two units as compared to SCR.

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The Jim Bridger plant utilizes raw water supplied by the Green River in its plant processes. This water is primarily used for equipment cooling as well as to provide make-up for losses through evaporative cooling and the wet scrubbing process. As a steam-electric power plant utilizing forced draft cooling towers, Jim Bridger's water usage is significant with each of the four cooling towers having a design make-up water requirement of 4,700 gallons per minute.[21] If operated at the coal throughput limit of 9,500,000 tons/year, the Jim Bridger plant has a potential annual make-up water demand of 8,367,362,098 gallons per year (25,678 acre-feet/year). Under the capacity factor restrictions resulting from the RP Reassessment, the Jim Bridger plant's potential annual cooling tower make-up water demand is 7,539,416,640 gallons per year (23,138 acre-feet/year).[22] Thus, the RP Reassessment provides a potential water consumption decrease of 827,945,458 gallons/year (2,540 acre-feet/year) as compared to design cooling tower make-up water requirements under either SCR or SNCR operation on Units 1 and 2. *See* Attachment 2, page 2.

b. Greenhouse Gas Emissions

A byproduct of the coal combustion process is the generation of carbon dioxide (CO_2) which is a greenhouse gas. The Jim Bridger plant coal combustion CO_2 emission rate is 209.76 lb/MMBtu which provides potential annual CO_2 emissions of 18,532,296 tons/year under the current most restrictive permit limits, with a similar potential CO2 emission rate under operating scenarios with SCR or SNCR installed on Units 1 and 2. Under the RP Reassessment, the Jim Bridger plant's potential annual CO_2 emissions would be 16,824,128 tons/year, providing a potential CO_2 emissions decrease of 1,708,168 tons/year as compared to operation under the most restrictive permit limits, or operation with SCR or SNCR installed on Units 1 and 2. *See* Attachment 2, page 2.

c. CCR Impacts

As a coal fired power plant with electrostatic precipitator (ESP) and wet scrubber pollution control equipment, the Jim Bridger plant coal combustion process and pollution control equipment generate waste materials which the EPA has classified as CCR. At the Jim Bridger plant, CCR consists of fly ash, bottom ash and spent scrubber reagent (waste liquor). Fly ash and bottom ash are coal combustion byproducts which are collected in the Jim Bridger boilers and ESPs and disposed in the Jim Bridger plant's landfill (bottom ash); used as a cement admixture or disposed in the landfill (fly ash); or disposed in an on-site waste water evaporation pond (spent liquor). *See* Attachment 2, pages 2-3.

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[21] From The Jim Bridger plant Data Book, Volume 1-2, Section 9, Water Treatment System.

[22] Assumes that cooling tower make-up water demand is a linear relationship with capacity factor; that 4,700 gpm equates to 100% CF with 76.3% CF providing a 3,586 gpm make-up water demand for each cooling tower.

Under the RP Reassessment, due to reduced coal combustion and the resultant manufacture of CCR waste materials, the generation of CCR would be reduced as compared to operation under the most restrictive permit limits, or operation with SCR or SNCR installed on Units 1 and 2.[23] *See* Attachment 2, pages 2-3.

A byproduct of the Jim Bridger plant's coal combustion process is the generation of ash. At Jim Bridger coal ash is presented as fly ash (approximately 75 percent of total ash production) and bottom ash (approximately 25 percent of total ash production). Jim Bridger's current and projected coal ash content is 11.0 percent. Under current operations with a maximum permitted annual coal consumption of 9,500,000 tons per year, the Jim Bridger plant has a potential annual ash production of 1,045,000 tons/year. Under the RP Reassessment with the projected 11.0 percent ash concentration, the Jim Bridger plant has a potential annual ash production of 948,680 tons/year. *See* Attachment 2, pages 2-3.

Currently, the majority of the Jim Bridger plant's generated fly ash is sold for beneficial use as a cement admixture. The installation of SNCR on Units 1 and 2 and resultant ammonia slip has a potential to denigrate the quality of the fly ash such that it would not meet required specifications, making it unsuitable for beneficial use.

All plant-generated bottom ash, and fly ash which is not utilized for beneficial use as a cement admixture, is transported to the Jim Bridger plant's CCR landfill via large dump trucks for final disposal. Upon delivery to the landfill the ash byproducts are placed into a designated, active area of the landfill with the ash distributed and compacted utilizing heavy equipment such as scrapers and bulldozers. Effectively reducing the facility's capacity factor under the RP Reassessment results in a proportional reduction in boiler heat input (coal combustion) and an equivalent proportional reduction in the generation of CCR fly ash and bottom ash as compared to operations at a capacity factor restricted only by other permit limits, or operation with SCR or SNCR installed on Units 1 and 2.

Adoption of the RP Reassessment will provide the following potential CCR-related benefits:

- A reduction in the amount of coal combusted in the Jim Bridger plant boilers
- A commensurate reduction of the volume of fly ash and bottom ash generated at the Jim Bridger plant;
- A reduction of ash transported[24] to and disposed in the industrial landfill;
- A reduction in the use of heavy equipment and its associated air emissions from the transportation of fly ash and bottom ash to the landfill, and the distribution, compaction, contouring and reclamation of CCR solid waste disposed in the landfill,
- A potential increase in the operational life of the Jim Bridger plant's CCR landfill, lessening the future need for another landfill, and;

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[23] It is expected that the quantity of CCR generated with SCR or SNCR installed on Units 1 and 2 would be essentially equivalent to current operations, under the most restrictive permit limits.

[24] A complete analysis of all associated upstream and downstream transportation costs is not provided, but would represent additional reductions of environmental impacts beyond what is included in this reasonable progress determination.

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- A reduced coal demand and a corresponding reduction of coal mining activities, raw material usage, and transportation requirements as compared to current operation or operation with SCR or SNCR installed on Units 1 and 2.

iii. Additional Benefits

In addition to the benefits described above, a reduction of the Jim Bridger plant's capacity factor provided by the RP Reassessment as compared to operation under the most restrictive permits, or operation with SCR or SNCR installed on Units 1 and 2 also provides a commensurate reduction of all consumables and waste products associated with the coal combustion process. *See* Attachment 2, pages 3-5. This includes a potential reduction in the consumption of the following materials:

- Boiler and circulating water treatment chemicals
- Water treatment acids and bases
- SCR anhydrous ammonia reagent
- SNCR urea reagent
- Mercury control system reagent (powdered activated carbon and halogenated compounds)
- Diesel fuel consumed in heavy equipment used to manage the Jim Bridger coal inventory

Lastly, the installation of SCR on Jim Bridger Units 1 and 2 will adversely affect unit heat rate – essentially the thermal efficiency of the two units – due to increased boiler draft restrictions created by the installation of SCR equipment in the boiler flue gas streams. *See* Attachment 2, pages 3-5.

Table 3 below summarizes relevant annual potential benefits provided by implementation of the RP Reassessment as compared to installation of SCR or SNCR on Units 1 and 2[25]. Overall, proper analysis of this factor favors the RP Reassessment.

TABLE 3: COMPARISON OF ENERGY AND NON-AIR QUALITY IMPACTS – ANNUAL POTENTIAL

Energy and Non-Air Quality Related Impacts	Units 1 and 2 with Selective Catalytic Reduction Technology SCR	Units 1 and 2 with Selective Non-Catalytic Reduction Technology SNCR	Reasonable Progress Reassessment with Operational Limits RP Reassessment
Hg (lb/year)[26]	212	212	192

[25] The estimates in Table 3 assume operations under the maximum permitted annual coal consumption of 9,500,000 tons per year.

[26] Units 1-4 mercury limit of 1.2 lb/TBtu per 40 CFR 63 Subpart UUUUU.

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CO (tons/year)[27]	17,670	17,670	16,041
CO_2 (tons/year)[28]	18,532,296	18,532,296	16,824,128
PM (tons/year)[29]	2651	2651	2,406
H_2SO_4 (tons/year)[30]	353	353	321
Potential Coal Consumption (tons/year)[31]	9,500,000	9,500,000	8,624,361
Fly Ash Production (tons/year)[32]	783,750	783,750	711,510
Bottom Ash Production (tons/year)[33]	261,250	261,250	237,170
Raw Water Consumption (acre-feet/year)[34]	25,678	25,678	23,138

d. Remaining Useful Life

The remaining useful life of Jim Bridger Units 1 and 2 is currently expected by PacifiCorp to be 2037. Under the EPA's reasonable progress guidelines, a source may use the expected remaining useful life as an element of its cost analysis. Considering the expected remaining useful life of the Jim Bridger plant, neither Jim Bridger Unit 1 nor Unit 2 is expected to operate long enough to justify SCR or SNCR installation. Using the 2037 end-of-life, the total annual costs of SCR, SNCR, and the RP Reassessment are $34,849,000 /year, $9,402,000 /year, and $2,115,000/year, respectively. Using a 20- year amortization period the total annual costs of SCR, SNCR, and the RP Reassessment are $31,619,000/year, $9,046,000/year, and $2,062,000/year, respectively. Using a 30- year amortization period the total annual costs of SCR, SNCR, and the RP Reassessment are $27,743,000/year, $8,616,000/year, and $1,998,000/year, respectively. *See* Attachment 1 – Cost & Emissions Analysis – Cost Effectiveness Calculation Worksheets.

Under any scenario, the RP Reassessment prevails as the preferred option because they can be utilized immediately, at a substantially lower cost. The Operational Limits of the RP

[27] Units 1-4 CO limit of 0.2 lb/MMBtu per permit MD-12186.

[28] Units 1-4 CO_2 emission factor of 209.76 lb/MMBtu applied on an annual coal burn heat input basis.

[29] Units 1-4 PM limit of 0.030 lb/MMBtu per permit MD-6042A.

[30] Units 1-4 sulfuric acid emission limit of 0.004 lb/MMBtu per permit MD-1552A.

[31] Based on projected average annual coal heating value of 9,300 Btu/lb.

[32] Based on coal heating value of 9,300 Btu/lb, ash concentration of 11.0% and 75% of generated ash presented as fly ash.

[33] Based on coal heating value of 9,300 Btu/lb, ash concentration of 11.0% and 25% of generated ash presented as bottom ash.

[34] Based on design cooling tower make-up water requirement of 4,700 gpm per unit at full load

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Reassessment provide greater reasonable progress than SCR or SNCR by achieving better visibility benefits through the expected remaining useful life of the Units without large increases in capital and operating costs, and with less environmental impacts. Proper analysis of this factor favors the RP Reassessment.

e. Visibility Impacts

Although visibility is not a specific statutory factor, EPA has stated it should be considered as part of a "reasonable progress" determination process. *See* 81 FR 296, 310-311 (Jan. 5, 2016)(Texas and Oklahoma)(" we believe that states are permitted, but not required, to consider visibility improvement alongside the four statutory factors when making their **reasonable progress determinations**, with the important caveat that they must do so in a reasonable fashion."). In fact, EPA has analyzed visibility improvement as part of its reasonable progress determinations in Wyoming before. *See* 79 FR 5032, 5051 ("In evaluating the four reasonable progress factors and the visibility improvement associated with potential controls, we found that the average and incremental cost-effectiveness . . . , while reasonable if viewed in isolation, was not necessarily justified this planning period in light of the relatively modest visibility improvement predicted by the revised modeling.") To determine the visibility improvement associated with the RP Reassessment, and how it compared to the SCR installation, SNCR installation, and baseline emissions, PacifiCorp retained AECOM to perform updated CALPUFF visibility modeling (relying as closely as possible to previous CALPUFF modeling). To provide for consistency with previous analyses, the CALPUFF visibility model was chosen because it was the same model used to analyze the existing RP/LTS (SCR) requirements. *See* 79 FR 5032.

AECOM created a CALPUFF modeling protocol, and PacifiCorp received feedback from the State of Wyoming and EPA regarding that protocol. *See* Reasonable Progress Reassessment Visibility Improvement Modeling Protocol for Jim Bridger Power Plant, attached as Appendix A of Attachment 3. After considering that feedback and incorporating the information into the protocol, AECOM conducted CALPUFF modeling for the baseline emissions scenario, the existing RP/LTS requirements (SCR), a SNCR scenario, and the RP Reassessment.[35] This method is similar to visibility analyses EPA has approved in the past. *See* 79 FR at 5207 ("we think it appropriate to consider visibility improvement when assessing control options for reasonable progress, especially when taking into account the purposes of the RHR. In comparing control options and selecting one, it is appropriate to compare the visibility improvement (that is, to compute the incremental visibility improvement) for each option."). The AECOM CALPUFF modeling results report is attached as Attachment 3 – RP Reassessment Visibility Improvement Modeling Report for Jim Bridger Power Plant.

The AECOM CALPUFF modeling report uses three metrics to evaluate the CALPUFF modeling results:

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[35] AECOM conducted the CALPUFF modeling assuming a common stack (all emissions from one location) and individual stacks (emissions from each of the stacks for the units).

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1) the 98th percentile modeled delta-dv, averaged over the 3 years modeled, applied to each Class I area individually;[36]

2) the number of modeled days (summed over the 3 years modeled) with a plant impact above 0.5 delta-dv, applied to each Class I area individually;[37] and

3) the number of modeled days (summed over the 3 years modeled) with a plant impact above 1.0 delta-dv, applied to each Class I area individually.

The RP Reassessment, regardless of whether the common-stack or individual stack approach was used, demonstrated greater visibility improvement than the existing RP/LTS (SCR) or the SNCR scenario under all three metrics.

Regarding the 98th percentile metrics, Chart 1 below shows the RP Reassessment achieves greater visibility improvement than the other modeled control options. Specifically, when modeled as a combined stack, the average visibility impacts for the Bridger power plant under the SCR,[38] SNCR, and the RP Reassessment scenarios are 0.760, 0.930, and 0.653 deciviews, respectively. Thus, under any scenario using this metric, the RP Reassessment demonstrates the least impacts to visibility at Class I Areas. The RP Reassessment is represented by the red column in Chart 1 below, indicating the RP Reassessment results in a lower (better) visibility impact at almost every Class I Area modeled as compared to the SCR and SNCR options.

[36] This metric was used in the EPA's previous analyses of reasonable progress determinations in the Wyoming SIP. 79 FR at 5051 and 5207.

[37] The EPA also has considered "modeling results comparing the number of days with significant visibility *impairment* relative to natural visibility under the BART Alternative scenario to the number of days under the BART Benchmark." *See* 81 FR 43894, 43988. In that instance, like here, the State "presented this information for two different thresholds of visibility impairment: 1.0 dv of impairment compared to natural visibility, and 0.5 dv of impairment." *Id.* EPA explained that this metric was appropriate for a regional haze analysis because the "the improvement in the number of days with significant visibility impairment relates to assessing the frequency and duration of visibility impacts. It is relevant to look at the results for the Class I areas individually because visibility impacts are location specific." *Id.*

[38] When modeling as individual stacks, the SCR scenario has a visibility impact of 0.735 deciviews according to the 98th percentile metric.

CHART 1: 98[TH] PERCENTILE VISIBILITY IMPACT AVERAGED OVER 3 YEARS MODELED.

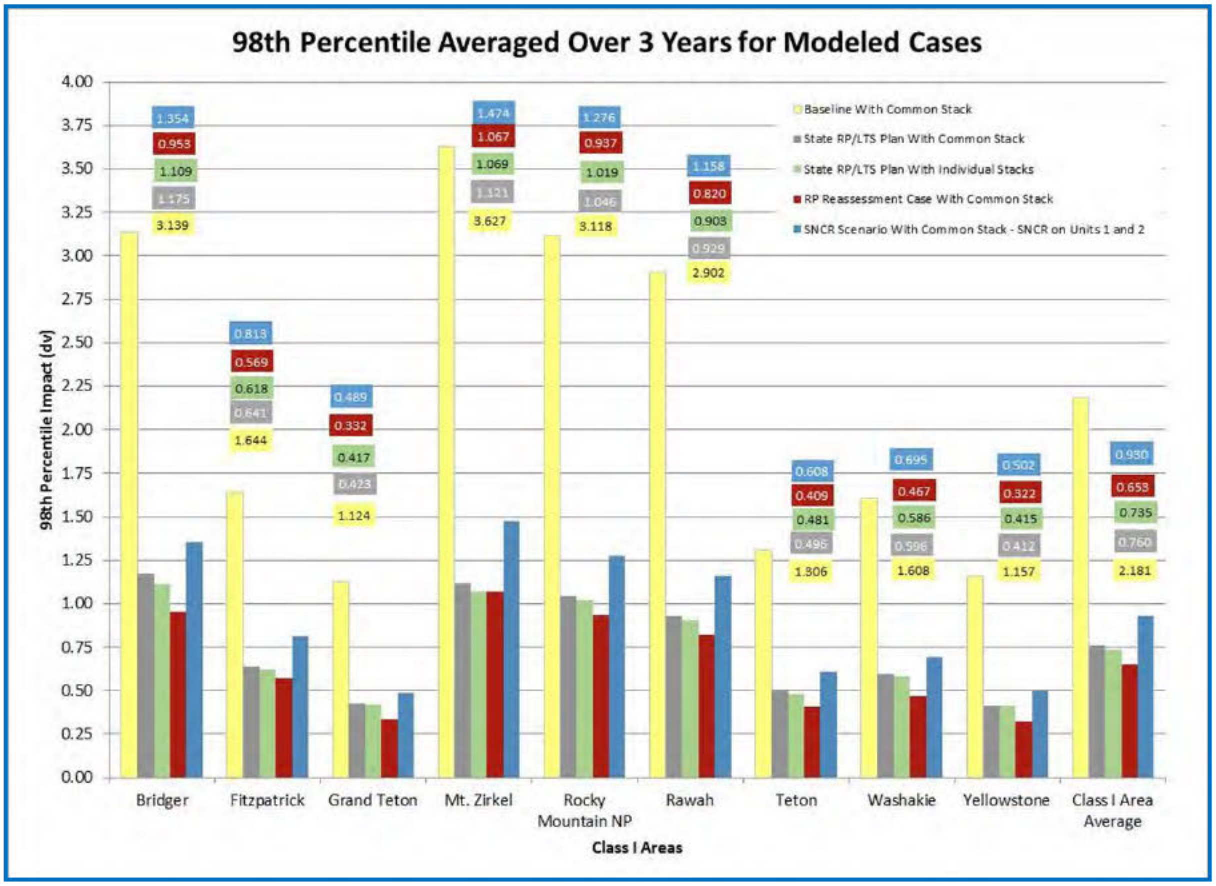

Chart 2 below shows the number of days (on average over 3 years) that the Jim Bridger power plant will have a 0.5 dv impact on a given Class I area, based on the CALPUFF modeling results. Chart 2 demonstrates that the RP Reassessment (based on the number of days of visibility impacts) will result in a lesser (better) visibility impact than the other two control scenarios (SCR and SNCR).

Specifically, when modeled as a combined stack, the number of days with visibility impacts above 0.5 dv for the SCR,[39] SNCR, and the RP Reassessment scenarios are 475, 597, and 371 days, respectively. Thus, under any scenario using this metric, the RP Reassessment, represented by the red column, demonstrates the least impacts to visibility at Class I Areas. Significantly, the RP Reassessment results in 104 less days (over three years) of visibility impacts over 0.5 dvs than the existing SCR requirement.

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[39] When modeling as individual stacks, the SCR scenario has visibility impacts over 0.5 dvs for 459 days.

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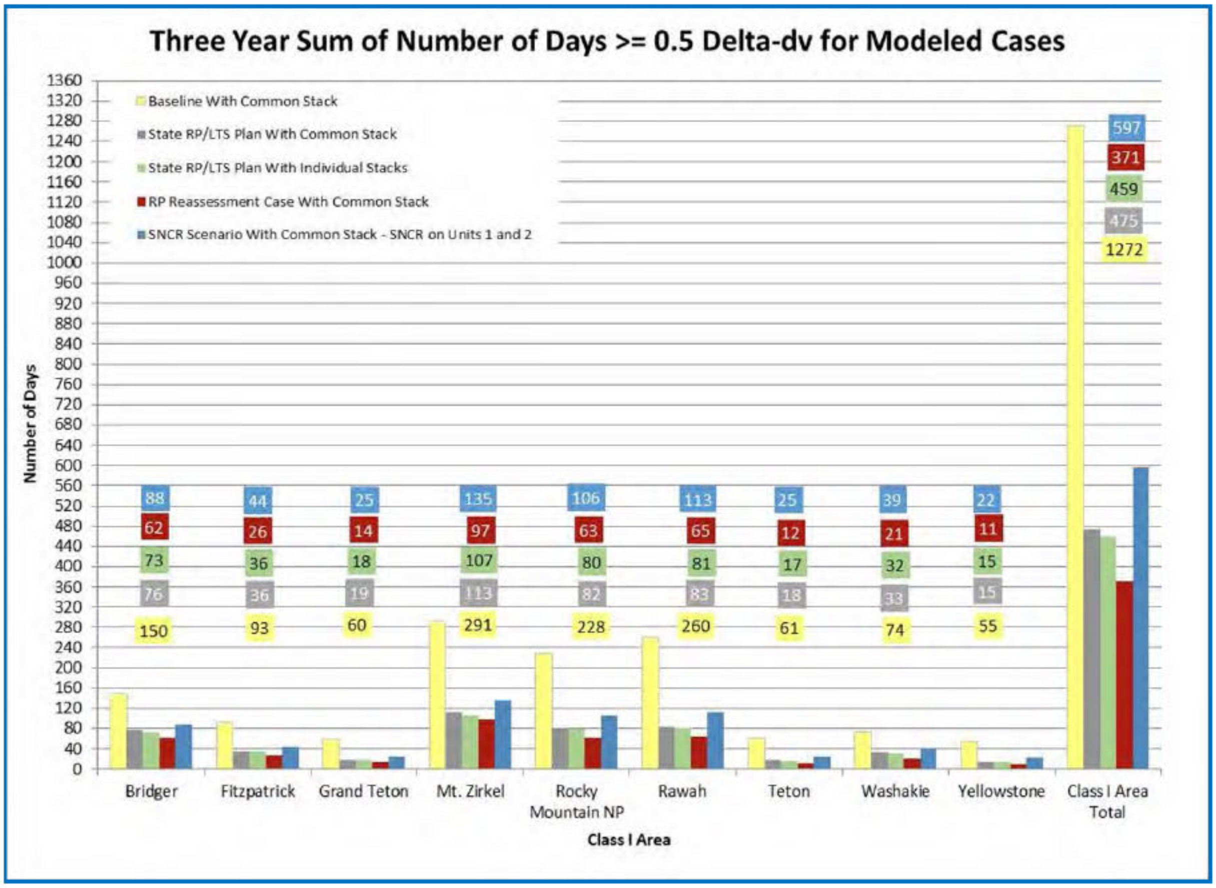
CHART 2: TOTAL NUMBER OF MODELED DAYS OVER 3 YEARS WITH VISIBILITY IMPACTS ABOVE 0.5 Δ-dv



Finally, Chart 3 below shows the number of days (on average over 3 years) that the Jim Bridger power plant will have a 1.0 dv impact on a given Class I area, based on the CALPUFF modeling results. Similar to the 0.5 dv results in Chart 2 above, Chart 3 demonstrates that when modeled as a combined stack, the number of days with visibility impacts above 1.0 dv for the SCR,[40] SNCR, and the RP Reassessment scenarios are 127, 195, and 108 days, respectively.

Thus, under any scenario using this metric, the RP Reassessment, represented by the red column, demonstrates the least impacts to visibility at Class I Areas. The RP Reassessment results in almost three less weeks of visibility impairment over 1.0 dv compared to the existing SCR requirements.

[40] When modeling as individual stacks, the SCR scenario has visibility impacts above 1.0 dv for 123 days.

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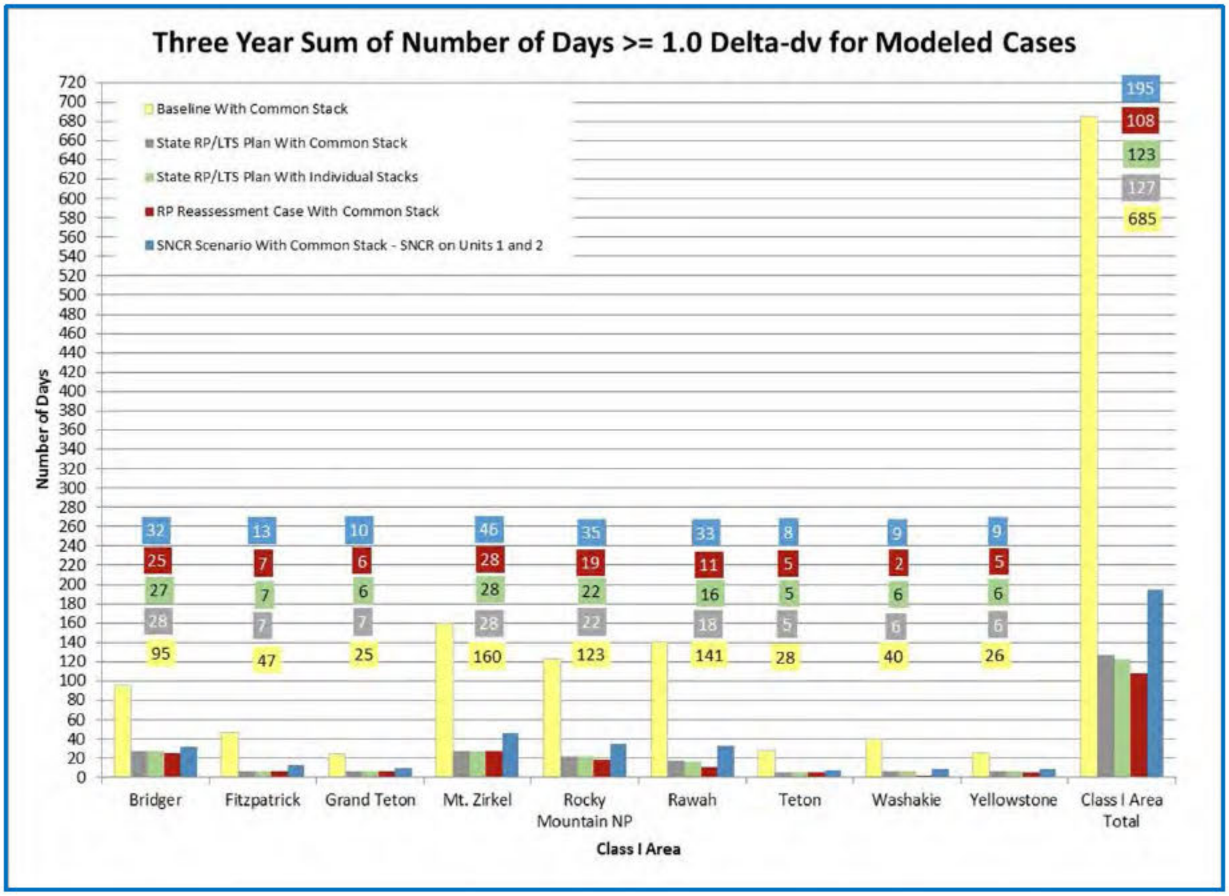
CHART 3: TOTAL NUMBER OF MODELED DAYS OVER 3 YEARS WITH VISIBILITY IMPACTS ABOVE 1.0 Δ-dv



It is appropriate for Wyoming replace the SCR requirements of the RP/LTS for Jim Bridger Units 1 and 2 with the plant-wide Operational Limits of the RP Reassessment because the RP Reassessment results in better modeled visibility improvements, as measured by the three metrics. Moreover, the RP Reassessment was superior to the SNCR scenario.

III. Consistency with SO2 Backstop Trading Program

To address concerns that the RP Reassessment's sulfur dioxide (SO2) reductions could result in complications with the SO2 Backstop Trading Program, PacifiCorp proposes modifying the 309 SIP regarding Wyoming's SO2 emissions reporting requirements. This SIP revision ensures that the SO2 emissions reductions in the RP Reassessment are not "double-counted" in the SO2 Backstop Trading Program.

Specifically, the annual SO2 emission rates of: 5,865 tons/yr for Bridger Unit 1; 5,710 tons/yr for Jim Bridger Unit 2; 6,139 tons/yr for Jim Bridger Unit 3; and 3,916 tons/yr for Bridger Unit 4, reflect the actual average emission rates from 2001 to 2003 for these units, herein referred to as the "309 Baseline" or "Baseline Rates." As part of the SO2 Backstop Trading Program and to ensure the milestones of the Program were met, PacifiCorp and Wyoming agreed that PacifiCorp would lower its SO2 emissions rates at the Jim Bridger plant from the Baseline Rates to the following: 3,012 tons/yr; for Jim Bridger Unit 1; 3,649 tons/yr; for Jim Bridger Unit 2; 3,430 tons/yr for Jim Bridger Unit 3; and 3,441 tons/yr for Jim Bridger Unit 4, referred to herein as the "Jim Bridger Plant 2018 Milestone Allocation." The SO2 emissions reductions between the Baseline Rates and the Jim Bridger Plant 2018 Milestone Allocation are the SO2 emissions reductions attributable to the Section 309 SO2 Backstop Trading Program, and will continue to be reported as creditable to that Program through the aforementioned 309 SIP amendment.

Therefore, for purposes of the SO2 Backstop Trading Program, Wyoming will account for SO2 emissions using the Jim Bridger Plant 2018 Milestone Allocation when reporting to emissions to the Western Regional Air Partnership (WRAP). Thus, these Section 309 SIP revisions will ensure that the SO2 emissions reductions achieved under the RP Reassessment are only accounted for under the NOx Reasonable Progress requirements of the 309(g) SIP, and are not "double-counted" towards the Section 309 requirements. Chart 4 below depicts the Section 309 Baseline Rates compared to: the Jim Bridger Plant 2018 Milestone Allocation; and the Jim Bridger plant's actual SO2 emissions. Chart 4 also depicts (in red) the SO2 emission reductions that can be attributed to compliance with Section 309, and those (in green) that can be attributed to compliance with Section 309(g).

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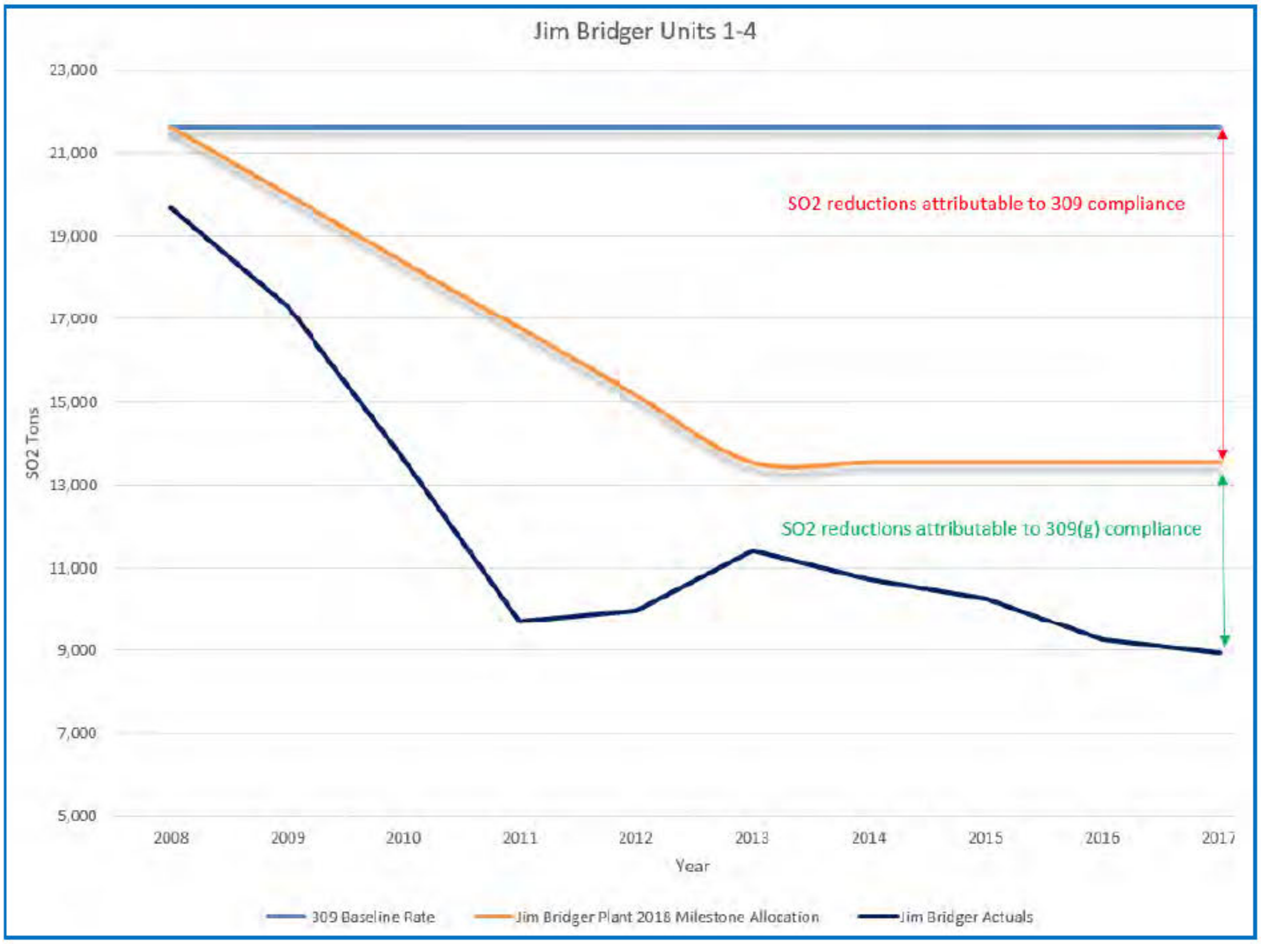
CHART 4: COMPARISON OF SO2 REDUCTION DEMONSTRATING THE AVOIDANCE OF DOUBLE COUNTING



Under 40 CFR 51.309(d)(4)(ii), documentation of the SO2 emission calculation methodology and any changes to the specific methodology used to calculate the emissions at any emitting unit for any year after the base year must be provided in the Backstop Trading Program implementation plan. PacifiCorp's proposal meets this requirement.

Additionally, pursuant to 40 CFR 51.309(d)(4)(iii), the State- and EPA-approved Reassessment will include provisions requiring the monitoring, recordkeeping, and annual reporting of actual stationary source SO2 emissions within the State that are attributable to the Section 309 SO2 Backstop Trading Program, (Chapter 14, Section 3(b)). These requirements continue to apply to the Jim Bridger Power Plant and will not be modified. Likewise, the requirements found in 40 CFR 51.309(d)(4)(iv), 40 CFR 51.309(d)(4)(v) and 40 CFR 51.309(d)(4)(vi) pertaining to the market trading program and provisions for the 2018 milestone will not be modified in Wyoming's 2019 SIP submittal.

IV. Implementation, Monitoring, Reporting and Record Keeping

On December 21, 2017, PacifiCorp submitted an application to the Wyoming Air Quality Division to permit the installation of SCR on Jim Bridger plant Units 1 and 2. The December 2017 application was provided to the Wyoming Air Quality Division to meet requirements included in the November 3, 2010 BART Appeal Settlement Agreement.

Concurrent with the submission of this reasonable progress determination for the RP Reassessment, PacifiCorp will submit to the Wyoming Air Quality Division, a state permit application requesting that the RP Reassessment Operating Limits, as describes in Table 1 in Section I(a) above be imposed on the four Jim Bridger Units. In addition to the plant-wide monthly average NO_X and SO_2 emission limits included in Table 1, PacifiCorp will also request that a plant-wide 12-month rolling total emissions cap of 17,500 tons/year be established on the Jim Bridger Units 1-4 boilers. The application will request that the proposed Operating Limits have an effective enforcement date of January 1, 2022, commensurate with the compliance requirement to install the earlier of the two remaining SCR systems on Jim Bridger Units 1 and 2.

As it relates to compliance with the Operating Limits, PacifiCorp will comply will all applicable state and federal monitoring performance criteria, as well as reporting and recordkeeping requirements, in accordance with the Wyoming Air Quality Standards and Regulations, Chapter 7, Sections 3(c)(ii) and (i), as well as the NOx and SO2 flow monitor requirements of 40 CFR Part 75.

Attachment 1 – Reasonable Progress Reassessment Cost and Emissions Analysis

JIM BRIDGER POWER PLANT

REASONABLE PROGRESS REASSESSMENT

COST AND EMISSIONS ANALYSIS

Prepared for:

PACIFICORP

Final Report

February 4, 2019
Project 11736-041

Prepared by:

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603

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Attachments

1. BACKGROUND

On January 30, 2014, EPA published a final regional haze rule (79 FR 5032) that established stringent controls of nitrogen oxide (NO_X) emissions from the four units at the Jim Bridger Power Plant, located near Point of Rocks, Wyoming. For NO_X controls, EPA determined that Wyoming's selection of the then-current NO_X controls of low NO_X burners (LNB) and separated over-fire air (SOFA) qualified for Best Available Retrofit Technology (BART) controls. Additionally, Wyoming required that LNB/SOFA plus Selective Catalytic Reduction (SCR) technology be installed at Jim Bridger Units 1-4 as part of the State's Reasonable Progress / Long-Term Strategy (RP/LTS) instead of BART.

The resulting Wyoming SIP required, as part of its RP/LTS, installation of SCR for NO_X control (30-day rolling average emission rate of 0.07 lb/MMBtu) on the Jim Bridger units in a phased approach:

- December 31, 2022 for Unit 1
- December 31, 2021 for Unit 2
- December 31, 2015 for Unit 3
- December 31, 2016 for Unit 4.

The installation of SCR on Jim Bridger Units 3 & 4 has been completed as stated above. For Units 1 and 2, PacifiCorp/Idaho Power are proposing an alternative to the SCR installations on these remaining Jim Bridger units that will result in equivalent or better visibility than Wyoming's RP/LTS that was approved by EPA ("State SIP"). PacifiCorp/Idaho Power's alternative emission control strategy, referred to herein as the "RP Reassessment," will set month-by-month mass emission limits for two principal haze-causing pollutants, sulfur dioxide (SO_2) and nitrogen oxides (NO_X). It also establishes a 12-month rolling total NO_X and SO_2 plant-wide emission limit.

The average annual mass emissions of SO_2 plus NO_X for the proposed RP Reassessment on a pound per hour basis will be nearly 20% lower than those of the State SIP (all four units controlled by SCR). The RP Reassessment plan will generally have higher NO_X emissions relative to the State SIP on a month-to-month basis, but much lower SO_2 emissions that will result in better visibility than the State SIP. The reduction in emissions for the RP Reassessment will be brought about through a combination of emissions management and operational restrictions on the Jim Bridger units.

PacifiCorp engaged Sargent & Lundy LLC (S&L) to develop cost estimates for the RP Reassessment, the State SIP's requirement to install SCRs on Units 1 and 2, and a scenario where SNCR would be installed on Units 1 and 2. Capital costs are based on the actual cost to install SCR technology on Units 3 and 4 at

Jim Bridger. Similarly, operating and maintenance (O&M) costs are based on the actual current operating costs for the Jim Bridger Unit 3 and 4 SCR systems. Capital costs for SNCR technology were estimated by S&L based on recent similarly sized projects. Finally, capital costs associated with additional SO_2 control for the RP Reassessment were provided by PacifiCorp.

2. INTRODUCTION

S&L is a leading global engineering, design, and consulting company, focused exclusively on the power generating industry. Since its inception in 1891, S&L has remained an independent evaluator of power generating technologies, power generating technology subsystems, and air pollution control systems.

S&L has considerable experience with the specification, evaluation, selection and implementation of emission control technologies for fossil fuel-fired power plants. With respect to the control of NO_X emissions from coal-fired power plants, S&L has completed, or is currently in the process of completing, more than 150 SCR and SNCR projects, representing more than 54,000 MW of generation, including the Jim Bridger Unit 3 and 4 SCR systems.

Our NO_X control experience includes conceptual studies and preparing control system specifications, as well as the engineering, procurement, and installation of various control systems. S&L has participated in the design and installation of more than 30 selective non-catalytic reduction (SNCR) control systems and more than 125 selective catalytic reduction (SCR) control systems for coal and gas units. In addition, S&L has performed considerable work with respect to Best Available Retrofit Technology (BART) controls for coal-fired power plants. Our BART work includes control technology feasibility evaluations, cost estimating, and cost-effectiveness evaluations.

S&L was retained by PacifiCorp to prepare cost analyses for the RP Reassessment presented in this report. This report provides a summary of the capital and O&M cost estimates prepared for PacifiCorp, and includes an overview of the approach, design parameters, and assumptions. This report also includes an evaluation of the cost-effectiveness of the RP Reassessment compared to the current RP/LTS and compared to a SNCR-installation scenario for Units 1 and 2.

3. REASONABLE PROGRESS COST ESTIMATING

The first factor in a "reasonable progress" determination is an analysis of the "costs of compliance." To analyze this factor for an individual source, EPA's 2007 Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program suggests using "established control cost analysis techniques," and identifies the "BART Guidelines" as a helpful source. The Appendix Y BART Guidelines describe a methodology that could be used to determine control system costs and to calculate control system cost-effectiveness. The 2007 Reasonable Progress Guidance and BART Guidelines state that in order "to maintain and improve consistency," the "cost estimates should be based on the Control Cost Manual," where possible.[1] The Control Cost Manual describes the equipment and other direct costs that are typically included in a cost estimate, and provides cost factors that can be used to calculate certain indirect costs, if needed.

Both the 2007 Reasonable Progress Guidance and BART Guidelines describe a three step process to prepare control technology cost estimates:

(1) identify the emissions units being controlled;
(2) identify design parameters for emission controls; and
(3) develop cost estimates based upon those design parameters.

The basis for equipment cost estimates should be documented, with data supplied by an equipment vendor or by a referenced source. The cost analysis should take into account any site-specific design or other conditions that affect the cost of a particular control technology, provided that the cost estimate includes documentation of information that was used for the cost calculations that affects assumptions regarding purchased equipment costs, equipment life, and replacement of major components.

EPA's BART Guidelines specify that the cost impact analysis consider both the costs and cost-effectiveness of the controls, on a dollar-per-ton of air pollutant removed. Controlled annual emissions are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. Total annual costs are calculated by adding the annualized cost of capital to the annual operation and maintenance (O&M) costs of an option. Cost-effectiveness ($/ton) of an option is simply the total annual cost ($/yr.) divided by the annual pollution controlled (ton/yr.).

4. CONTROL COST MANUAL METHODOLOGY

The Control Cost Manual is intended to provide guidance to regulatory authorities and industry for the development of capital costs, operating and maintenance expenses, and others costs, for air pollution control devices.[2] The introduction to the Control Cost Manual states that it "does not directly address the controls needed to control air pollution at electrical generating units (EGUs) because of the differences in

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[1] See, 70 FR 39166, referencing EPA's Control Cost Manual (2018), available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution
[2] Control Cost Manual, Section 1, Chapter 1, page 1-4.

accounting for utility sources," and explains that while the cost methodology in the Manual may be helpful, it differs from the methodology generally used by the utility industry.[3]

The Control Cost Manual mandates a study-level cost estimate. When an industrial user has site-specific information available, inputs to the cost estimating methodology may differ from the broad assumptions made by the Cost Control Manual, but will produce more accurate results for the site in question. Under these circumstances, the Manual expressly provides flexibility for users, stating that "the user has to be able to exercise 'engineering judgment' on those occasions when the procedures [described in the Manual] may need to be modified or disregarded."[4]

4.1 Site Specific Cost Estimates

PacifiCorp recently installed SCR systems on Jim Bridger Unit 3 and 4. S&L was the Owner's Engineer for that project and is therefore familiar with the design basis and actual costs associated with that project. During the conceptual design and specification development for the Jim Bridger Units 3 and 4, S&L based the design on the operating parameters for all four units to ensure that the SCR design was appropriate for all of the units. The Jim Bridger Unit 3 and 4 SCR Design Basis, provided in Attachment 1, shows that the design was developed based on all four units.

Because the design methodology for the Unit 3 and 4 SCR systems was based on all four units at Jim Bridger, the actual costs for the recent Unit 3 and 4 SCR project will be used as the basis of the Unit 1 and 2 SCR cost estimates which will represent site specific cost estimates.

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[3] *Id.*, at page 1-3.
[4] Cost Manual, Section 1, Chapter 1, page 1-7.

5. CAPITAL AND O&M COST ESTIMATES

S&L generally followed the approach described in the Appendix Y BART Guidelines, and the methodology described in EPA's Control Cost Manual, to the greatest extent possible, to develop NO_X control system cost estimates for the Jim Bridger Station.

5.1 Design Parameters

The Jim Bridger Power Plant is located near Point of Rocks, Wyoming, and is comprised of four identical boilers (nominally 570 MW gross each). All four units are Combustion Engineering tangentially-fired boilers firing a local western bituminous coal from the nearby coal mine. All of the units were recently retrofit with low-NO_X burners (LNB) and Separated Over-Fire Air (SOFA) to control NO_X emissions. Furthermore, Units 3 and 4 were recently equipped with SCR for additional NO_X control. All four units are also equipped with cold-side electrostatic precipitators (ESPs) and flue gas conditioning for particulate matter (PM) control and wet sodium-based flue gas desulfurization (WFGD) control systems for sulfur dioxide (SO_2) control.

Design and operating parameters affecting the design of SCR systems include, but are not limited to, boiler heat input, flue gas volume, flue gas temperature, inlet NO_X, and the design target NO_X emission rate. Operating parameters for the Jim Bridger units, and design parameters for the control systems, were developed based on input and data available from the station during the 2012 Unit 3 & 4 SCR Project (see Attachment 1), as well as experience with similar projects. Design and operating parameters used as the basis of the Jim Bridger units are summarized in Table 1.

Table 1: Jim Bridger Design & Operating Parameters (from 2012 Design Basis)

PLANT DATA		UNIT 1	UNIT 2	UNIT 3	UNIT 4	DESIGN	SOURCE
Design Heat Input	MMBtu/hr	6,000	6,000	6,000	6,000	6,000	PacifiCorp
Design Full Load	MW (gross)	570	570	570	570	570	PacifiCorp
Fuel(s)	---	Local Mine	Local Mine	Local Mine	Local Mine	Local Mine	PacifiCorp
Air H_2O	lb/lb dry air	0.012	0.012	0.012	0.012	0.012	Design
Ash-Boiler	wt%	20.0	20.0	20.0	20.0	20.0	Assumption
Ambient Pressure	Psia	11.46	11.46	11.46	11.46	11.46	Calculated
Ambient Temperature	°F	100	100	100	100	100	PacifiCorp
Econ. Outlet Temp	°F	816	817	760	807	780 ± 20	PI Data / Design[1]
Econ. Outlet Pressure	in. w.c.	-8.0	-8.0	-8.0	-8.0	-8.0	Estimated
Econ. Outlet O_2	vol% wet	4.6	4.5	4.8	5.1	4.75	PI Data
Boiler SO_2 Oxidation	wt% SO_2	1.0	1.0	1.0	1.0	1.0	Assumption

Note 1: Economizer modifications were included in scope for Units 3 and 4 to ensure temperatures met 780 ± 20°F.

5.2 SNCR Capital Cost Estimate Methodology & Assumptions

PacifiCorp/Idaho Power requested that the cost effectiveness of SNCR technology be included in this evaluation. Therefore, S&L used unit-specific operating data (e.g., fuel characteristics, boiler design data, temperature data, and NO_X emission rates), as well as experience from similar SNCR system installations, to develop capital and O&M costs specific to Jim Bridger Station. Equipment costs were estimated for the SNCR system based on equipment costs provided by SNCR original equipment manufacturers (OEMs) for control systems on similar coal-fired boilers.

5.2.1 Factors Affecting the SNCR Design

Several site-specific factors affect the design and effectiveness of SNCR control systems. Operating conditions that have the most impact on SNCR system design and achievable performance include the temperature profile through the boiler, and the average concentration and distribution at the injection locations of O_2, CO, and NO_X. Industry experience has shown that temperatures in the range of 1,800 to 2,200°F and CO levels below 1,000 ppm at the boiler's bull nose are needed to obtain the highest SNCR NO_X removal efficiency. The achievable NO_X removal is dependent on the location of this temperature regime in conjunction with the injection locations, as well as the residence time of the flue gas within this range. If CO levels exceed 5,000 ppm at the bull nose, SNCR is not a feasible technology due to a number of factors, including low urea utilization, low removal efficiency and high ammonia slip.

The temperature profile and CO concentration at the injection levels are not currently known for the Jim Bridger units, and boiler mapping would be required by any SNCR OEM to obtain performance guarantees[5]. SNCR equipment cost estimates will be based on the assumption that CO concentrations at the bull nose in each boiler can be controlled to a level that allows for effective NO_X removal. In addition, due to the size of the boilers it was assumed that achieving adequate injection and mixing within the required temperature profile will be challenging. Thus, the cost estimate includes a conservative equipment design with multiple levels and types of injection lances.

Based on control efficiencies achieved on other large coal-fired boilers, SNCR technology can typically achieve 15-25% reduction from a baseline NO_X emission rate of approximately 0.20 lb/MMBtu (post-LNB emission rates). Assuming CO concentrations and temperatures are within the design windows

[5] It is typical that the temperature profile and CO concentrations at the SNCR injection levels are unknown. Performance Guarantees provided by vendors are often indicative at the time of award and are finalized once boiler mapping is completed as part of initial detailed design. Therefore, the predicted performance is based on similar boilers (size, type, and fuel).

identified above, and assuming a conservative equipment design, S&L has assumed a NO_X reduction of 20% could be achieved on the Jim Bridger units, resulting in an emission rate of 0.15 lb/MMBtu.

5.2.2 SNCR Design

Based on a site-specific review of the NO_X reduction requirements and retrofit challenges for the installation of SNCR systems, the following project-specific issues were taken into consideration in the development of the SNCR cost estimates:

- Urea Delivery, Unloading, and Storage. The SNCR cost estimate is based on using urea as the reagent. The urea solution (50% aqueous urea by weight) would be delivered by truck and unloaded via onboard truck pumps into fiberglass reinforced plastic (FRP) storage tanks. The tanks are sized for a total storage capacity of 14 days of continuous operation at full load, and would be heat traced and insulated in order to keep the 50% urea solution above 80°F to prevent precipitation of urea solids out of solution.
- Urea Circulation. The urea storage tanks would be cross tied, providing a common storage area for Units 1 & 2. The urea solution would be transferred using stainless steel piping. A loop from the storage tanks to each unit's metering modules and back to the storage tanks would continuously circulate the 50% urea solution. Process heat tracing would be required to keep the urea solution above 80°F.
- Urea Dilution and Metering. Dilution water would be pumped to the metering modules located in the unit, where it would mix with the 50% urea solution prior to injection into the boiler. Dilution of the urea solution to approximately 5 wt% urea is required prior to injection. Variable frequency drives would be utilized to maintain a constant pressure of dilution water in response to changing flow demands. The metering modules provide flow and pressure control of the fluids used in the SNCR process.
- Diluted Urea Distribution and Injection. The distribution modules would provide diluted urea solution and atomizing air to individual injectors. The modules are typically located near the injectors on the same elevation. Diluted urea solution is fed from the dilution/metering modules to the distribution modules. The distribution module distributes atomizing air and urea solution to each injector. The injectors are used for dispersion of diluted urea solution within targeted areas of the boiler. Design, quantity, type and placement of the injectors are critical to SNCR performance; furnace temperature, residence time, and droplet size are important design parameters controlled by injector placement. The exact locations of the injectors would be determined by the SNCR OEM based on computational fluid dynamics (CFD) modeling of the furnace. For the SNCR cost estimate, exact injector locations were not selected; however, it was assumed that the units would require a minimum of three injection levels to cover the entire load and temperature profile within the boiler.
- Raw Water & Water Treatment. It was assumed that raw water would be utilized for urea dilution water; therefore, no water treatment system was included in this cost estimate.
- Plant and Instrument Air System. The addition of the SNCR system adds a large air user to each unit. To meet the air consumption requirements for the atomizing air, compressors would be added per unit. These compressors would also provide compressed air to all new intermittent-

users (e.g., valves, instruments, tools, etc.); therefore, no additional compressed air load would be added to the plant's existing compressed air systems. All air would be dried to -40°F dew point by implementing regenerative desiccant dryers. Instrument air piping would be stainless steel.

- Air Heater Evaluation. At the temperatures typically found in the air heater, excess ammonia from the SNCR can react with sulfur trioxide in the flue gas to form ammonium bisulfate in the intermediate section of the air heater. Based on operating experience with medium sulfur fuel, air heater plugging and corrosion may become an issue on the Jim Bridger units. Therefore, an allowance for air heater modifications was included in the estimate.

- Fire Protection System. Fire protection for the new pre-engineered buildings would include alarm and detection, as well as fire extinguishers. It is anticipated no additional fire hydrants or a dispersion system will be required for the urea unloading area.

- Furnace Modifications. Penetrations in the boiler water wall would be required at the injector locations. To support the injector penetrations, water wall tubes would need to be removed and replaced with tubes curved around the penetration location, a boot, and a flange, to which the injectors are mounted. In some instances additional structural reinforcement may be required to support the injectors.

- Process and Freeze Protection Heat Tracing System. A freeze protection system would be provided for outdoor piping (8" and smaller), instruments, and other devices subject to freezing in cold weather. The freeze protection system would be designed to accommodate both normal plant operations and extended plant shutdowns during cold weather. All urea piping and tanks would be process heat traced to a minimum temperature of 80ºF to avoid crystallization.

5.2.3 SNCR Capital Cost Estimate

The following items are included in the scope of the SNCR cost estimate:

- Boiler wall modifications and injectors
- Dilution and metering skids
- Boiler mapping and CFD modeling for each unit
- Common urea unloading area storage tanks and tank equipment
- Circulating urea loop to each unit
- Foundations, buildings and support steel
- Piping and auxiliaries
- Electrical equipment
- Controls modifications

Based on the design parameters, costs, site constraints, and assumptions outlined above, capital cost estimates were developed for the Jim Bridger units, assuming a common urea unloading and storage area for Units 1 and 2. The cost estimate represents a firm price Engineer-Procure-Construct (EPC) project similar to the SCR. The estimate includes all indirect capital costs such as engineering costs, construction and field expenses, contractor fees, start-up and performance test costs. PacifiCorp's Owner's Costs for Owner's Engineer, labor and permitting are included in the cost estimate.

Table 2 shows the estimated costs for the complete SNCR Project at Jim Bridger, and an estimate of a single unit cost (assuming the common storage area is split among Units 1 & 2).

Table 2: SNCR Capital Costs

Item	Units 1&2 SNCR Cost Estimate	Single Unit SNCR Cost Estimate	Notes
Direct Costs			
SNCR Equipment Cost	$3,700,000	$1,850,000	Based on similar sized project costs.
Platforms and Support	$2,500,000	$1,250,000	Based on similar sized project costs.
Foundation and Buildings	$720,000	$360,000	Based on similar sized project costs.
Boiler Modifications	$1,000,000	$500,000	Based on similar sized project costs.
Piping and Auxiliaries	$4,500,000	$2,250,000	Based on similar sized project costs.
Electrical Equipment	$3,080,000	$1,540,000	Based on similar sized project costs.
Controls Modifications	$1,200,000	$600,000	Based on similar sized project costs.
Total Direct Costs	***$16,700,000***	***$8,350,000***	
Project Indirect Costs			
Construction Costs	$6,680,000	$3,340,000	Calculated based on 40% of Direct Costs
Engineering	$2,806,000	$1,403,000	Calculated based on 12% of Direct + Construction Costs
Permitting	$400,000	$200,000	Allowance for each unit
Construction Management Support	$1,169,000	$584,500	Calculated based on 5% of Direct + Construction Costs
Initial Fill	$234,000	$117,000	Calculated based on 1% of Direct + Construction Costs
Spare-Parts	$234,000	$117,000	Calculated based on 1% of Direct + Construction Costs
EPC Fee	$2,619,000	$1,309,500	Calculated based on 10% of Direct + Construction Costs
Owner's Costs	$234,000	$117,000	Calculated based on 1% of Direct + Construction Costs
Total Capital Investment (TCI)	**$31,076,000**	**$15,538,000**	
Capital Recovery Factor $i(1+i)^n / (1+i)^n - 1$	0.0944	0.0944	Calculated using an interest rate of 7% and a control system life of 20 years.
Annualized Capital Cost	**$2,934,000**	**$1,467,000**	**Capital Recovery Factor x TCI**

5.3 SNCR Operating & Maintenance Cost Methodology & Assumptions

Annual O&M costs include both fixed and variable costs. Variable O&M costs are items that generally vary in proportion to the plant capacity factor. Variable costs associated with SNCR systems include: reagent costs (e.g., urea solution); dilution water costs; and auxiliary power costs associated with operating the new equipment. Fixed costs are independent of the level of production, and would be incurred even if the control system were shut down, and include costs such as maintenance labor and materials, administrative charges, property taxes, and insurance. Both fixed and variable O&M costs were developed based on site specific design conditions for the Jim Bridger units.

Variable O&M costs were calculated assuming a capacity factor of 81.8% for Unit 1 and 77.8% for Unit 2 (based on average operation from 2001-2003). Annual O&M and total annual costs for the Jim Bridger SNCR systems are summarized in Table 3.

Table 3: SNCR O&M Costs

OPERATING & MAINTENANCE COSTS	UNIT 1	UNIT 2	Basis
Variable O&M Costs			
Urea Solution Cost	$2,594,000	$2,800,000	$300 per ton of solution.
Auxiliary Power Cost	$90,000	$85,000	$50/MWh.
Water Cost	$37,000	$40,000	$2/1,000 gallons
Total Variable O&M Cost	**$2,721,000**	**$2,925,000**	
Fixed O&M Costs			
Operating Labor	$0	$0	No additional operators required.
Supervisory Labor	$0	$0	Not included.
Maintenance Materials and Labor	$233,000	$233,000	1.5% of Total Capital Investment
Property Taxes	$0	$0	Not included.
Insurance	$0	$0	Not included.
Administration	$0	$0	Not included.
Total Fixed O&M Cost	**$233,000**	**$233,000**	
Total Annual O&M Cost	**$2,954,000**	**$3,158,000**	

5.4 SCR Capital Cost Estimate Methodology & Assumptions

As discussed previously, PacifiCorp recently installed SCR systems on Jim Bridger Unit 3 and 4. The conceptual design for Jim Bridger Units 3 and 4 was based on the operating parameters of all four units; therefore, the Unit 1 and 2 SCR capital cost have been developed based on actual costs from the recent Unit 3 and 4 SCR retrofit. The Jim Bridger Unit 3 and 4 SCR Design Basis, provided in Attachment 1, confirms that the design was developed based on all four units.

5.4.1 SCR Design

The following summarizes the major components of the SCR system design and any variation or considerations for applying the Unit 3 and 4 SCR design to Units 1 and 2.

- <u>SCR Location</u>. The proposed SCR reactors will be located above the existing fan bay alley road and ESP inlet ductwork. The SCR structure will be supported on columns that avoid interferences with the ESP inlet ductwork and at grade. The SCR will be a high-dust configuration installed between the economizer outlet and the air heater inlet. Galleries were provided at each catalyst level and at the ammonia injection grid to allow for maintenance and inspection of the SCR system. The relative location of the SCRs will be based on the Unit 3 and 4 General Arrangement Drawing provided in Attachment 2.

- Boiler Building Reinforcement. Due to the fact that the boiler building walls are load bearing walls, some of the existing boiler building steel columns and upper framing will have to be removed to make room for the new ductwork.

- SCR Reactors and Catalyst. The SCR system will consist of two reactors per unit. The SCRs will use anhydrous ammonia as the reagent. To achieve the required NO_X emission reductions on a consistent basis with low SO_2 to SO_3 conversion, three layers of catalyst are required for each of the SCRs. The SCRs would be designed to hold four layers of catalyst, with three layers being loaded initially. The fourth layer of catalyst would be added after approximately four years of operation (32,000 operating hours).

- Economizer Modifications. At temperatures greater than 800°F, SCR catalyst is known to sinter and become permanently damaged. In order to ensure that the SCR operating temperature stays within the design condition of 780 ± 20°F modifications to the economizer are necessary. Based on historical operating data, economizer modifications were required for Units 3 and 4, and are expected to be required for Units 1 and 2.

- Air Heater Modifications. At the temperatures typically found in the air heater, excess ammonia from the SCR can react with sulfur trioxide (SO_3) in the flue gas to form ammonium bisulfate in the intermediate section of the air heater. However, based on operating experience with Units 3 and 4, air heater plugging and corrosion is not expected to be a significant issue. Alternatively, the higher pressure drop required an upgrade to duplex seals, including the addition of diaphragms and stay plate stiffened rotors for the increased pressure drop. The cost of this modification was included.

- SCR Cleaning. The method of cleaning the fly ash that settles on the catalyst is extremely important to obtain the guaranteed life of the catalyst. For this reason, the use of steam sootblowers, in addition to sonic horns, is recommended. Steam sootblowers will remove fly ash that settles on the catalyst and the sonic horns will keep the fly ash moving through the catalyst. The conceptual design includes steam sootblowers for the top layer of catalyst, and sonic horns for the balance of the catalyst layer. The sonic horn system will require compressed air to operate. Separate compressors were assumed for each unit for the cost estimate.

- Large Particle Ash Screen. To collect large particle ash (LPA) upstream of the SCR, a large particle ash screen will be installed in each economizer outlet duct. Due to very high velocities at the economizer outlet, the LPA screens will be located at the base of each of the SCR riser ducts. New ash hoppers and handling equipment is included in the design to tie the LPA hoppers into the economizer ash system.

- Ammonia System. The existing anhydrous ammonia system for Units 3 and 4 is located in a remote location, to the south of the units. A pipe rack is already installed to deliver ammonia from the storage area to Units 3 and 4. The existing anhydrous ammonia system will be expanded to double the storage capacity and a new pipe rack extension will be installed to connect the existing pipe rack to Units 1 and 2. The SCR cost estimate was based on the assumption that the storage capacity for the anhydrous ammonia system expansion would be the same as the Unit 3 and 4 storage capacity. The scope of this expansion includes not only the storage tanks but also the foundation, feed pumps, feed piping, and necessary safety systems.

- SO_3 Mitigation System. The SCR catalyst will oxidize a portion of the SO_2 present in the flue gas to SO_3. For Units 3 and 4, the increase in SO_3 was intended to be offset by reduced injection of the ESP SO_3 flue gas conditioning system. A similar assumption will be made for Units 1 and 2; therefore, no costs for SO_3 mitigation are included.

- Auxiliary Power Upgrades. Units 1 and 2, similar to Unit 3, were previously equipped with larger ID fans and electrical system upgrades to accommodate the additional flue gas pressure loss generated by the SCR. The previous project included new ID fans and electrical system upgrades for Unit 4; these costs will be excluded from the cost estimate.

- Structural Stiffening. Structural stiffening of the ductwork and equipment downstream of the boiler and upstream of the new ID fans will be required by NFPA regulations to operate at more negative pressures due to the installation of the SCR. Due to the similarity in ductwork design pressures of these units, the scope of structural stiffening is expected to be the same as the previous project.

- Control Systems. The existing distributed control system (DCS) will need to be expanded to accommodate the additional signals from the SCR system.

- Construction Costs and Special Cranes. A review of the site arrangement shows that the free space between the units is severely limited. Due to general site congestion, special cranes were used in the construction of Units 3 and 4. A similar construction approach is assumed for Units 1 and 2.

5.4.2 SCR Capital Cost Estimate

The following items are included in the scope of the SCR cost estimate:

- Economizer outlet / air heater inlet ductwork modifications
- Economizer modifications for temperature control
- SCR equipment & ductwork (including catalyst, LPA screens, and cleaning equipment)
- Equipment and ductwork reinforcement for NFPA requirements
- Ammonia unloading area expansion consisting of two (2) storage tanks and tank equipment
- Ammonia delivery and vaporization equipment
- Foundations and support steel

Based on the design parameters, costs, site constraints, and assumptions outlined above, capital cost estimates were prepared for Unit 1 and 2 SCR systems. The cost estimate was developed from the actual cost of the Unit 3 and 4 SCR project and represents a firm price Engineer-Procure-Construct (EPC) project.

Because the cost estimate is based on an actual EPC project cost, it is assumed that all indirect capital costs such as engineering costs, construction and field expenses, contractor fees, start-up and performance test costs, and contingencies are included. Therefore, no additional indirect capital costs are applied to the cost estimate. Also included in the cost estimate are PacifiCorp's actual Owner's Costs for Owner's Engineer, labor and permitting. Table 4 shows the actual costs for the Unit 3 and 4 SCR Project at Jim Bridger, broken down by unit. Table 4 also shows the basis for the SCR capital cost estimate for Unit 1 or 2 for this evaluation.

Table 4: SCR Capital Costs

Item	Unit 3 Actual Construction Costs	Unit 4 Actual Construction Costs	Unit 1 or 2 Cost Estimate	Notes
Direct Costs				
EPC Contract and Change-Orders	$120,308,000	$127,965,000	$120,308,000	Pricing based on Unit 3; Unit 4 scope includes ID fan and electrical upgrades.
Ductwork Reinforcement for NFPA	$10,424,000	$14,713,000	$10,424,000	Pricing based on Unit 3; Unit 4 scope includes ID fan and electrical upgrades.
Economizer Modifications for Temperature Control	$6,136,000	$5,666,000	$5,901,000	Average of Unit 3 and 4 pricing.
Site and Controls Upgrades	$506,000	$414,000	$460,000	Average of Unit 3 and 4 pricing.
Total Direct Costs	***$137,374,000***	***$148,758,000***	***$137,093,000***	
Project Indirect Costs				
Misc. Construction Costs	$52,000	$70,000	$61,000	Average of Unit 3 and 4 pricing.
Owner's Engineer (Prelim Design, Procurement, Oversight)	$1,267,000	$1,486,000	$1,267,000	Pricing based on Unit 3; Unit 4 scope includes ID fan and electrical upgrades.
Permitting	$190,000	$202,000	$196,000	Average of Unit 3 and 4 pricing.
Construction Management Support	$1,227,000	$2,018,000	$1,227,000	Pricing based on Unit 3; Unit 4 scope includes ID fan and electrical upgrades.
Initial Fill	$225,000	$282,000	$225,000	Pricing based on Unit 3; Unit 4 scope includes ID fan and electrical upgrades.
Spare-Parts	$359,000	$1,014,000	$359,000	Pricing based on Unit 3; Unit 4 scope includes ID fan and electrical upgrades.
Total Capital Investment (TCI)	**$140,694,000**	**$153,830,000**	**$140,428,000**	
Capital Recovery Factor $i(1+i)^n / (1+i)^n - 1$	N/A	N/A	0.0806	Calculated using an interest rate of 7% and a control system life of 30 years.
Annualized Capital Cost	**N/A**	**N/A**	**$11,318,000**	**Capital Recovery Factor x TCI**

No escalation of the Unit 3 and 4 costs has been included to develop the SCR Capital Cost Estimate for Unit 1 or 2. While, the Unit 3 and 4 SCR project was awarded in 2013 and the project was completed at the end of 2016, S&L does not believe that any significant escalation of the equipment cost has occurred. Local labor costs have increased in Wyoming since 2013; however, no escalation has been included, which represents a conservative estimate. Figure 1 below shows a comparison of recent SCR pricing (equipment only based on awarded projects) in the western region of the United States.

Figure 1: Historical SCR Pricing Comparison

As can be seen in Figure 1, the unit cost of SCR systems has fluctuated quite a bit from 2011 to 2016, and therefore, assuming no escalation or de-escalation is a conservative approach.

5.5 SCR Operating & Maintenance Cost Methodology & Assumptions

Annual O&M costs include both fixed and variable costs. Variable O&M costs are items that generally vary in proportion to the plant capacity factor. Variable costs associated with SCR systems include: reagent costs (e.g., anhydrous ammonia); catalyst replacement costs; and auxiliary power costs associated with operating the new equipment. Fixed costs are independent of the level of production, and would be incurred even if the control system were shut down, and include costs such as maintenance labor and materials, administrative charges, property taxes, and insurance. Both fixed and variable O&M costs were developed based on actual annual O&M costs incurred at Jim Bridger for the Unit 3 and 4 SCR systems.

Variable O&M costs were calculated assuming a capacity factor of 81.8% for Unit 1, 77.8% for Unit 2, 80.2% for Unit 3, and 78.1% for Unit 4 (based on average operation from 2001-2003).

Annual O&M costs, and total annual costs, for both the current Unit 3 & 4 SCR operation and the current RP/LTS are summarized in Table 5 and 6, respectively.

Table 5: Current SCR O&M Costs for Units 3 & 4

OPERATING & MAINTENANCE COSTS	UNIT 3	UNIT 4	Basis
Variable O&M Costs			
Anhydrous Ammonia Cost	$667,000	$695,000	$550 per ton, and average annual NO_X emission pre-SCR.
Auxiliary Power Cost	$948,000	$924,000	$30/MWh
Catalyst Replacement Cost	$376,000	$376,000	Note 1
Steam Cost	$35,000	$34,000	$5/MMBtu
Outage Penalty	$0	$0	Not included
Total Variable O&M Cost	**$2,026,000**	**$2,029,000**	
Fixed O&M Costs			
Operating Labor	$0	$0	No additional operators required.
Supervisory Labor	$0	$0	Not included.
Maintenance Materials and Labor	$550,000	$550,000	Based on actual costs for Units 3 & 4.
Property Taxes	$0	$0	Not included.
Insurance	$0	$0	Not included.
Administration	$0	$0	Not included.
Total Fixed O&M Cost	**$550,000**	**$550,000**	
Total Annual O&M Cost	**$2,576,000**	**$2,579,000**	

Note 1. Annual catalyst replacement costs were calculated based on replacing one (1) layer of catalyst (approximately 155 m^3 per layer) once every two years. Catalyst costs were calculated by multiplying the volume of catalyst by the installed unit cost of $\$5,000/m^3$ and using a future worth factor of 0.48 calculated as follows:

FWF = i * [1 / $(1 + i)^y$ - 1]; where i = an assumed interest rate of 7.0% and y = 2 (i.e., replacing one layer every other year). See, Control Cost Manual, Section 4.2, Chapter 2, pg. 2-47

Table 6: SCR O&M Costs for Units 1 & 2

OPERATING & MAINTENANCE COSTS	UNIT 1	UNIT 2	Basis
Variable O&M Costs			
Anhydrous Ammonia Cost	$651,000	$647,000	$550 per ton, and average annual NO_X emission pre-SCR.
Auxiliary Power Cost	$967,000	$920,000	$30/MWh
Catalyst Replacement Cost	$376,000	$376,000	See Note 1 (Table 5)
Steam Cost	$36,000	$34,000	$5/MMBtu
Outage Penalty	$0	$0	Not included
Total Variable O&M Cost	**$2,030,000**	**$1,977,000**	
Fixed O&M Costs			
Operating Labor	$0	$0	No additional operators required.
Supervisory Labor	$0	$0	Not included.
Maintenance Materials and Labor	$550,000	$550,000	Based on actual costs for Units 3 & 4.
Property Taxes	$0	$0	Not included.
Insurance	$0	$0	Not included.
Administration	$0	$0	Not included.
Total Fixed O&M Cost	**$550,000**	**$550,000**	
Total Annual O&M Cost	**$2,580,000**	**$2,527,000**	

5.5.1 SCR O&M Costs for RP Reassessment

As discussed above, the RP Reassessment will result in a small reduction of NO_X emissions on Units 3 & 4 by implementing operational restrictions on the units. Variable O&M costs for the RP Reassessment were calculated using a limited capacity factor for Units 3& 4 provided by PacifiCorp. The predicted capacity factor is confidential and has not been disclosed. The SCR O&M costs are for the RP Reassessment shown in Table 7 are represented as an incremental change from current operation and show an overall net savings due to the reduced load.

Table 7: SCR O&M Costs for RP Reassessment

OPERATING & MAINTENANCE COSTS	UNIT 3	UNIT 4	Basis
Variable O&M Costs			
Anhydrous Ammonia Cost	$635,000	$679,000	$550 per ton, and average annual NO_X emission pre-SCR.
Auxiliary Power Cost	$902,000	$902,000	$30/MWh
Catalyst Replacement Cost	$376,000	$376,000	See Note 1 (Table 5)
Steam Cost	$33,000	$33,000	$5/MMBtu
Outage Penalty	$0	$0	Not included
Total Variable O&M Cost	**$1,946,000**	**$1,990,000**	
Fixed O&M Costs			
Operating Labor	$0	$0	No additional operators required.
Supervisory Labor	$0	$0	Not included.
Maintenance Materials and Labor	$550,000	$550,000	Based on actual costs for Units 3 & 4.
Property Taxes	$0	$0	Not included.
Insurance	$0	$0	Not included.
Administration	$0	$0	Not included.
Total Fixed O&M Cost	**$550,000**	**$550,000**	
Total Annual O&M Cost	**$2,496,000**	**$2,540,000**	
Reduction in Annual O&M Cost ($/year)	**($80,000)**	**($39,000)**	Compared to Annual O&M Cost at 80.2% for Unit 3, and 78.1% for Unit 4.

5.6 FGD Upgrade Capital Cost Estimates for RP Reassessment

As discussed above, the RP Reassessment will result in a large reduction of SO_2 emissions, and some NO_X emission reductions, through a combination of emissions management and operational restrictions on the Jim Bridger units. For operation of the current FGD system, PacifiCorp has proposed to implement the following changes to limit SO_2 emissions:

- Restricting the quantity of bypass on Units 1-3 to maximize flue gas scrubbing while maintaining stack conditions within the design of the chimney.
- Implementing upgrades to the existing mist eliminator system on Units 1-3 to reduce the moisture carry-over due to increased scrubbing and higher velocities through the absorber.

- Modifying the stack drain system and gutters on Units 1-3 to collect additional moisture carry-over due to increased scrubbing and reduced stack temperatures.
- Installing weather enclosures on the existing ESP outlet process monitors and certifying these to be used for compliance reporting.
- Limiting all four units operation to a reduced capacity factor.

PacifiCorp has determined that replacing the stack/chimney on Units 1-3 is not needed to implement the RP Reassessment. However, PacifiCorp determined that to meet the proposed emission limits, some modifications would be necessary to maintain wet operation of the stacks. PacifiCorp provided order of magnitude pricing for these proposed changes, which are summarized in Table 8; the costs presented are for a single unit. As these are order of magnitude prices, a 15% contingency has been added to the overall capital cost of the RP Reassessment SO_2 control. No physical modifications to Unit 4 are expected.

Table 8: RP Reassessment SO_2 Control Capital Costs

Item	Units 1-3 SO_2 Control Cost Estimate	Notes
Order of Magnitude Costs		
Bypass Restriction	$0	Modifications to control logic.
Mist Eliminator Upgrades	$800,000	Provided by PacifiCorp
Stack Drain Modification	$250,000	Provided by PacifiCorp
Chimney/Stack Replacement	Not included	Operation restricted to maintain operation within stack design.
ESP Outlet CEM Certification	$300,000	Provided by PacifiCorp
Operating Restrictions	$0	No capital modifications.
Contingency	$203,000	Applied at 15% of Total Costs
Total Capital Investment (TCI)	**$1,553,000**	
Capital Recovery Factor $i(1+i)^n / (1+i)^n - 1$	0.1058	Calculated using an interest rate of 7% and an estimated end of life of 2037
Annualized Capital Cost	**$164,000**	**Capital Recovery Factor x TCI**

5.7 O&M Costs for SO_2 Reduction RP Reassessment

Variable O&M costs for historical operation were calculated assuming a capacity factor of 81.8% for Unit 1, 77.8% for Unit 2, 80.2% for Unit 3, and 78.1% for Unit 4 (based on average operation from 2001-2003). Variable O&M costs for the RP Reassessment were calculated assuming a limited capacity factor for the station provided by PacifiCorp. The predicted capacity factor is confidential and has not been disclosed.

Table 9: O&M Costs for RP Reassessment SO_2 Reduction

OPERATING & MAINTENANCE COSTS	UNIT 1	UNIT 2	UNIT 3	UNIT 4	Basis
Variable O&M Costs					
Current Soda Ash Cost	$2,060,000	$1,914,000	$1,899,000	$1,880,000	Estimated based on historical operation.
Future Soda Ash Cost	$2,186,000	$2,186,000	$2,186,000	$2,186,000	$117 per ton delivered (average), estimated increase in usage (average)
Incremental Soda Ash Cost	$126,000	$272,000	$287,000	$306,000	-
Incremental Auxiliary Power Cost	$0	$0	$0	$0	No significant increase expected.
Total Incremental Variable O&M Cost	**$126,000**	**$272,000**	**$287,000**	**$306,000**	-
Fixed O&M Costs					
Operating Labor	$0	$0	$0	$0	No additional operators required.
Incremental Maintenance Materials and Labor	$250,000	$250,000	$250,000	$0	Assumes a 5% increase in maintenance materials and labor.
Total Incremental Fixed O&M Cost	**$250,000**	**$250,000**	**$250,000**	**$0**	
Total Incremental Annual O&M Cost	**$376,000**	**$522,000**	**$537,000**	**$306,000**	Compared to Annual O&M Cost at historical capacity factors.

6. COST EFFECTIVENESS

PacifiCorp is evaluating the cost of its proposed RP Reassessment against the costs of additional NO_X controls at the Jim Bridger station to address Regional Haze. As noted in this report, PacifiCorp has already installed LNB on all four units at Jim Bridger and SCR on Units 3 & 4. The additional NO_X control options, beyond those currently installed, that are considered as part of this evaluation, include:

- SNCR installation on Units 1 & 2
- SCR installation on Units 1 & 2 (RP/LTS)
- Restricted operation for all Units and some physical changes to enable the restricted operation (RP Reassessment)

For this evaluation, baseline NO_X emissions for Units 1 and 2 were calculated based on the 2013-2015 year period after the installation of LNBs. Alternatively, the Units 3 and 4 SCR technology was installed in 2016 and 2017, respectively. Therefore, the baseline NO_X emissions for Units 3 and 4 were based on a 0.05 lb./MMBtu emission rate consistent with the minimal operational history with SCR on Units 3 and 4. The basis for the baseline heat input is from 2001-2003. The NO_X Emissions Baseline and SO_2 Emissions Baseline (post FGD upgrades) are summarized in Table 10.

Table 10: Emission Baseline Summary

BASELINE INFORMATION	UNIT 1	UNIT 2	UNIT 3	UNIT 4
Heat Input Baseline				
Full Load Heat Input (MMBtu/hr)	6,000	6,000	6,000	6,000
2001-2003 Average Annual Heat Input (MMBtu/year)	42,977,652	40,898,999	42,166,755	41,034,206
NO_X Emission Baseline (for Cost-Effectiveness)				
Annual NO_X Emission (tons/year)	4,018	3,926	1,054	1,026
SO_2 Emission Baseline				
309 Allocations (tons/year)	3,012	3,649	3,430	3,441

The cost effectiveness of the additional control options are compared to the post-LNB and post-SCR (for Units 3 & 4) baseline. Total annual costs were calculated as the sum of the annualized capital costs and total fixed and variable O&M costs. Capital costs were annualized using the capital recovery factor (CRF) approach described in Section 1, Chapter 2 of the Control Cost Manual. The total capital costs, capital recovery factor, and annualized capital costs for the SNCR and SCR technologies are provided in Section 5 of this report.

Total annual costs include the annualized cost of capital and the fixed and variable O&M costs. Variable O&M costs, which include the annual cost of reagents (anhydrous ammonia or urea solution), water, steam, auxiliary power, and catalyst replacement are provided in Section 5 of this report.

The cost-effectiveness of each control system was calculated on a dollar-per-ton-removed basis by dividing total annual costs by the reduction in annual emissions. Annual emissions using a particular control device were subtracted from baseline emissions to calculate tons removed per year.

6.1 SNCR Cost Effectiveness

Annual NO_X emissions with SNCR were calculated based on a NO_X reduction efficiency of 20% from post-LNB emission rates. Table 11 shows the total annual cost, average annual reduction in NO_X emissions, and average annual cost effectiveness, based on a 20-year life.

Table 11: SNCR Cost Effectiveness

COST EFFECTIVENESS	UNIT 1	UNIT 2	UNIT 3	UNIT 4	PLANT
Revised Baseline (Post-LNB, U3&4 SCR, & FGD Upgrades)					
Annual Baseline Heat Input (MMBtu)	42,977,652	40,898,999	42,166,755	41,034,206	167,077,611
Baseline NO_X Emission (lb/MMBtu)	0.187	0.192	0.05	0.05	0.120
Baseline NO_X Emission (tons/year)	**4,018**	**3,926**	**1,054**	**1,026**	**10,025**
NO_X Emissions with SNCR			(SCR)	(SCR)	
Controlled NO_X Emission (lb/MMBtu)	0.15	0.15	0.05	0.05	0.103
Controlled NO_X Emission (tons/year)	**3,223**	**3,067**	**1,054**	**1,026**	**8,371**
SNCR Cost Effectiveness					
Annualized Capital Costs (20-year life)	$1,467,000	$1,467,000	N/A	N/A	$2,934,000
Total Annual O&M Costs	$2,954,000	$3,158,000	N/A	N/A	$6,112,000
Total Annual Cost	**$4,421,000**	**$4,625,000**	**N/A**	**N/A**	**$9,046,000**
COST EFFECTIVENESS ($/TON)	**$5,560**	**$5,385**	**N/A**	**N/A**	**$5,469**

6.2 Cost Effectiveness for Reasonable Progress Plan

Annual NO_X emissions with SCR were calculated based on controlled NO_X emission rates of 0.05 lb/MMBtu for the current RP/LTS. The 0.05 lb/MMBtu emission rate is consistent with the current NO_X emission rate for Jim Bridger Units 3 and 4 and the NO_X permit limit of 0.07 lb/MMBtu.

Table 12 shows the total annual cost, average annual reduction in NO_X emissions, and average annual cost effectiveness for the Reasonable Progress Plan, based on a 30-year life.

Table 12: Current RP Plan Cost Effectiveness

COST EFFECTIVENESS	UNIT 1	UNIT 2	UNIT 3	UNIT 4	PLANT
Baseline (Post-LNB, U3&4 SCR)					
Annual Baseline Heat Input (MMBtu)	42,977,652	40,898,999	42,166,755	41,034,206	167,077,611
Baseline NO_X Emission (lb/MMBtu)	0.187	0.192	0.05	0.05	0.120
Baseline NO_X Emission (tons/year)	**4,018**	**3,926**	**1,054**	**1,026**	**10,025**
Total Baseline Emissions (tons/year)	**4,018**	**3,926**	**1,054**	**1,026**	**10,025**
NO_X Emissions with SCR					
Controlled NO_X Emission (lb/MMBtu)	0.05	0.05	0.05	0.05	0.05
Controlled NO_X Emission (tons/year)	**1,074**	**1,023**	**1,054**	**1,026**	**4,177**
SCR Cost Effectiveness					
Annualized Capital Costs (30-year life)	$11,318,000	$11,318,000	N/A	N/A	$22,636,000
Total Annual O&M Costs	$2,580,000	$2,527,000	N/A	N/A	$5,107,000
Total Annual Cost	**$13,898,000**	**$13,845,000**	**N/A**	**N/A**	**$27,743,000**
NO_X COST EFFECTIVENESS ($/TON)	**$4,720**	**$4,769**	**N/A**	**N/A**	**$4,744**

6.3 Cost Effectiveness for RP Reassessment

Annual NO_X emissions for the RP Reassessment are based on reducing the overall plant capacity factor. The controlled NO_X emission rates (lb./MMBtu) for the Jim Bridger Units will remain consistent with the revised baseline rates and the annual tons emitted will be reduced. The incremental SCR O&M costs for the RP Reassessment show an overall net savings due to the reduced load.

Annual SO_2 emissions for the RP Reassessment are based on the modifications described in Section 5.6 as well as reducing the overall plant capacity factor. The controlled SO_2 emissions for the Jim Bridger Units will be limited to a monthly emission rate (lb./hour) and an overall annual limit (tons/year).

Table 13 shows the total annual cost, average annual reduction in NO_X and SO_2 emissions, and average annual cost effectiveness for the RP Reassessment, based on a retirement date of December 31, 2037.

Table 13: RP Reassessment Cost Effectiveness

COST EFFECTIVENESS	**UNIT 1**	**UNIT 2**	**UNIT 3**	**UNIT 4**	**PLANT**
Revised Baseline (Post-LNB, U3&4 SCR, & FGD Upgrades)					
Annual Heat Input (MMBtu)	42,977,652	40,898,999	42,166,755	41,034,206	167,077,611
Baseline NO_X Emission (lb/MMBtu)	0.187	0.192	0.05	0.05	0.120
Baseline NO_X Emission (tons/year)	**4,018**	**3,926**	**1,054**	**1,026**	**10,025**
Baseline SO_2 Emission (lb/MMBtu)	0.140	0.178	0.163	0.168	0.162
Baseline SO_2 Emission (tons/year)	**3,012**	**3,649**	**3,430**	**3,441**	**13,532**
Total Baseline Emissions (tons/year)	**7,030**	**7,575**	**4,484**	**4,467**	**23,557**
Controlled NO_X Emission					
Controlled NO_X Emission (lb/hour)	750	750	359	375	559
Controlled NO_X Emission (tons/year)	**3,506**	**3,506**	**1,003**	**1,003**	**9,018**
Reassessment Cost Effectiveness					
Annualized Capital Costs	$0	$0	$0	$0	$0
Total Annual O&M Costs	$0	$0	($80,000)	($39,000)	($119,000)
Total Annual Cost	$0	$0	**($80,000)**	**($39,000)**	**($119,000)**
NO_X COST EFFECTIVENESS ($/TON)	$0	$0	**($1,569)**	**($1,696)**	**($118)**
RP Reassessment SO_2 Emissions					
Controlled SO_2 Emission (lb/hour)	525	525	525	525	2,100
Controlled SO_2 Emission (tons/year)	**2,121**	**2,121**	**2,121**	**2,121**	**8,483**
RP Reassessment SO_2 Cost Effectiveness					
Annualized Capital Costs (19- year life)	$164,000	$164,000	$164,000	$0	$492,000
Total Annual O&M Costs	$376,000	$522,000	$537,000	$306,000	$1,741,000
Total Annual Cost	**$540,000**	**$686,000**	**$701,000**	**$306,000**	**$2,233,000**
SO_2 COST EFFECTIVENESS ($/TON)	**$606**	**$449**	**$535**	**$232**	**$442**
OVERALL RP REASSESSMENT COST EFFECTIVENESS ($/TON)	**$385**	**$352**	**$457**	**$199**	**$349**

6.4 Cost Effectiveness Summary

Table 14 summarizes the cost-effectiveness of the three control options evaluated.

Table 14: Cost Effectiveness Summary

TECHNOLOGY / BASIS	PLANT EMISSIONS	EVALUATION PERIOD (YEARS)	COST ($/TON)
Revised Emission Baseline			
Annual Heat Input (MMBtu)	167,077,611		
Baseline NO_X Emission (lb/MMBtu)	0.120		
Baseline NO_X Emission (tons/year)	**10,025**	N/A	N/A
Baseline SO_2 Emission (lb/MMBtu)	0.162		
Baseline SO_2 Emission (tons/year)	**13,532**		
Total Baseline Emissions (tons/year)	**23,557**		
SNCR on Units 1&2			
Controlled NO_X Emission (lb/MMBtu)	0.100	20	$5,469
Controlled NO_X Emission (tons/year)	**8,371**		
RP/LTS (SCR)			
Controlled NO_X Emission (lb/MMBtu)	0.05	30	$4,744
Controlled NO_X Emission (tons/year)	**4,177**		
Total Controlled Emissions (tons/year)	**17,709**		
RP Reassessment			
Controlled NO_X Emission (lb/hour)	2,234		
Controlled NO_X Emission (tons/year)	**9,017**	16	$349
Controlled SO_2 Emission (lb/hour)	2,100		
Controlled SO_2 Emission (tons/year)	**8,483**		
Total Controlled Emissions (tons/year)	**17,500**		

ATTACHMENTS

Attachments

ATTACHMENT 1

JIM BRIDGER SCR UNITS 3&4 DESIGN BASIS

Bridger 3 & 4 SCR Project - Design Basis Calculation

ISSUE SUMMARY
Form SOP-0402-07

DESIGN CONTROL SUMMARY

CLIENT: PacifiCorp — UNIT NO.: 3 & 4 — PAGE NO.: 1

PROJECT NAME: Bridger SCR Project

PROJECT NO.: 11736-035

CALC. NO..:

S&L NUCLEAR QA PROGRAM APPLICABLE ☐ YES ☒ NO

TITLE: SCR Design Basis Calculation

EQUIPMENT NO.:

IDENTIFICATION OF PAGES ADDED/REVISED/SUPERSEDED/VOIDED & REVIEW METHOD

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Bridger 3 & 4 SCR Project - Design Basis Calculation

INDEX

EXHIBITS

Bridger 3 & 4 SCR Project - Design Basis Calculation

1.0 PURPOSE AND SCOPE

The purpose of this calculation was to determine the design basis for the Bridger Units 3 & 4 SCR systems. All of the Bridger units (Units 1-4) were evaluated in developing the design basis for the Units 3 & 4 SCR; this methodology allows for an identical design basis for the future Units 1 & 2 SCR systems.

2.0 DESIGN INPUT

Summary of design input:

Variable	Units	Value	Source[1]
Fuel Data			
Carbon	wt%	53.69	Exhibit A
Hydrogen	wt%	3.56	
Nitrogen	wt%	1.08	
Sulfur	wt%	0.64 [2]	
Oxygen	wt%	10.76	
Chlorine	wt%	0.00	
Fluorine	wt%	0.00	
Moisture	wt%	19.10	
Ash	wt%	11.31	
Calculated HHV	Btu/lb	9,237	
Plant Data			
Heat Input	MMBtu/hr	5,700	Exhibit E
O_2 at economizer outlet	vol% wet	4.75 [3]	Exhibit C
Excess Air	%	33.1	calculated
Air H_2O	lb/lb dry air	0.012	v
Ash-Boiler	wt%	20.0	ej
Ambient P	psia	11.46 [4]	calculated
Ambient T	^oF	100	PacifiCorp
Econ. Outlet P	in. w.c.	- 8.0	ej
Boiler SO_2 to SO_3 Oxidation	wt% SO_2	1.0	ej
SCR Design Parameters			
SCR SO_2 to SO_3 Oxidation	wt% SO_2	1.5	design
Economizer outlet temperature	^oF	780 [5]	design
SCR Pressure Drop	in. w.c.	8.0	design
NH_3 Slip	ppmvd @ 3% O_2	2.0	design
Inlet NO_X	lb/MMBtu	0.30	CEMS Data
Outlet NO_X	lb/MMBtu	0.04	ej

Note 1: ej = "engineering judgment"
Note 2: The maximum sulfur content provided in the coal analyses was used to estimate the maximum SO_3 concentration in the flue gas.
Note 3: The average of the highest 5% of the full load design values for Units 1-4.
Note 4: Ambient pressure is calculated based upon a plant elevation of 6,700 feet above MSL.
Note 5: Economizer modifications may be required to accommodate economizer outlet temperatures of 780^{o}F.

Bridger 3 & 4 SCR Project - Design Basis Calculation

1) Coal Analysis

The Bridger units currently burn sub-bituminous coal; however, it was indicated by PacifiCorp that the units may burn PRB coal in the future. The coal analyses provided by PacifiCorp for the Bridger Station are attached in Exhibit A. The fuel data shown in Exhibit A is on a dry basis. The data was converted to a wet basis (Hydrogen = 4.4% dry basis, Moisture = 19.10%; Hydrogen = 4.40 x (100-19.10)/100 = 3.56% wet basis) as shown in the above table. In addition to the measured higher heating value (HHV), a theoretical HHV value was calculated based upon the ultimate analysis provided (HHV = 14,544 x (%C / 100) + 4,050 x (%S / 100) + 62,028 x [(%H / 100) – (%O / 100 / 8)]). The PRB coals were evaluated to identify whether a future PRB conversion will significantly impact the design flue gas volumetric flow rate. The following table shows a comparison of the PRB coals to the typical Bridger coal as well as the volumetric flow rate for each at full load.

Mine/Name	Bridger Typical (with Max S)	Northern Basin PRB	Mid-Basin PRB	Southern Basin PRB
Ultimate Analysis (Converted to Wet Basis)				
Carbon (%)	53.69	47.00	48.42	50.66
Hydrogen (%)	3.56	3.25	3.32	3.48
Nitrogen (%)	1.08	0.68	0.74	0.73
Sulfur (%)	0.64	0.41	0.33	0.30
Oxygen (%)	10.76	12.38	11.86	12.53
Moisture (%)	19.10	30.85	30.08	27.29
Ash (%)	11.31	5.32	5.26	5.00
HHV (Btu/lb) - Measured	9,350	8,164	8,440	8,769
HHV (Btu/lb) – Calculated	9,208	7,906	8,196	8,569
Calculated Flue Gas Rate (acfm)	4,317,419	4,510,520	4,476,099	4,437,531
% difference	0.00	4.47	3.68	2.78

It was determined that the flue gas volume will vary by less than 5%; this will not have an impact on the overall SCR design. For design purposes, the typical Bridger fuel was used, as it is the fuel currently being burned at the plant; while the PRB fuels may be burned in the future the flue gas volume generated with PRB fuel should not be the basis for the design. Additionally, though the PRB fuels result in slightly higher volumetric flow rates, it is preferable for those fuels to be designed for a higher velocity through the reactor; therefore, using the typical Bridger coal as the basis of design will not negatively impact the performance of the SCR if the PRB conversion occurs in the future.

Bridger 3 & 4 SCR Project - Design Basis Calculation

Based on the coal data provided, the typical CaO content in the fly ash is 5.0%, and can range from 3.2 – 7.0%. With this level of CaO in the fly ash, it is anticipated that there will be no negative impacts due to arsenic in the flue gas.

2) Load

Maximum and minimum boiler loads of 570 MW (gross) and 250 MW (gross), respectively, were selected from the historical PI data for the SCR design basis.

3) Heat Input

The full load heat input identified by PacifiCorp for the Bridger units is 5,700 MMBtu/hr (see Exhibit E). The heat input was scaled by 250/570 to estimate the minimum load heat input of 2,500 MMBtu/hr.

4) Pressure at Economizer Outlet

There is no instrumentation at the economizer outlet on any of the Bridger Units. The economizer outlet pressure was calculated using various methodologies for each of the units. However, there was no consistent or reliable data for any of the units; therefore, a conservative design value of -8.0 in.w.g. was used as the basis for design.

5) Temperature at Economizer Outlet (Air Heater Inlet)

<u>Maximum SCR Operating Temperature:</u>

Maximum full load temperatures were evaluated, from the Bridger PI data, to see if catalyst sintering would be a concern when an SCR system is installed at Bridger. The economizer outlet temperatures for all of the Bridger units were evaluated, these graphs can be found in Exhibit B.

The maximum full load temperature was selected by taking an average of the highest 5% of all temperature readings between the performance loads of 550 and 570 MW. The maximum temperature was evaluated using the average inlet temperature from both air preheaters, for each unit.

The full load economizer outlet temperatures evaluated for Units 1-4 were 816°F, 817°F, 760°F and 807°F, respectively. These temperatures (with the exception of Unit 3) are above those recommended for normal SCR operation. It is generally recommended to maintain

Bridger 3 & 4 SCR Project - Design Basis Calculation

780°F ± 20°F at the SCR inlet to avoid sintering of the catalyst and to allow the use of carbon steel for duct fabrication. An economizer outlet temperature of 780°F ± 50°F is acceptable with static mixers upstream of the SCR to ensure the 780°F ± 20°F is met by the time the gas reaches the catalyst inlet. The maximum full load design temperature was selected as 780°F. S&L recommends that the Unit 4 economizer be modified with a larger surface area to ensure the economizer gas side outlet temperatures remain within 780°F ± 50°F in the dirty condition. If Units 1 and 2 are retrofit with SCR technology in the future, similar economizer modifications would be required. The maximum SCR operating temperature for the SCR system design basis was selected as 780°F.

Minimum SCR Operating Temperature:

Operating the SCR system with ammonia injection in-service below approximately 600°F for extended periods at the SCR inlet would promote the generation of both ammonium sulfate and ammonium bisulfate deposits. The deposits would accumulate over time, block catalyst sites, and reduce catalyst activity in the long term. These deposits would be removed as the system is heated back up above 600°F at the SCR inlet. However, it typically requires operation at full capacity for 1 to 2 times the duration spent below 600°F to fully remove the sulfate deposits from the catalyst surface. Therefore, the minimum continuous operating temperature for the SCR system is approximately 600°F.

6) Oxygen at Economizer Outlet

The amount of oxygen at the economizer outlet was selected based on PI data points provided for the Bridger units. A graph for each of the units is included in Exhibit C. The full load oxygen concentration was selected by taking an average of the highest 5% of all pressure readings between loads of 550 and 570 MW. The full load oxygen concentration was selected using the data from both air preheaters. The values for Units 1-4 were 4.6%, 4.5%, 4.8% and 5.1%, respectively; therefore, the average of these, 4.75%, was used as the design basis.

7) Inlet NO_X

The baseline NO_X emissions exiting the Bridger boilers was selected based on CEMS data provided for each of the Bridger units. A graph for each of the units is included in Exhibit D. The baseline NO_X emission was selected by taking an average of the highest 5% of all emissions between the performance loads of 550 and 570 MW. The baseline NO_X emission

Bridger 3 & 4 SCR Project - Design Basis Calculation

for Units 1-4 are 0.25 lb/MMBtu, 0.28 lb/MMBtu, 0.26 lb/MMBtu and 0.29 lb/MMBtu, respectively. A conservative value of 0.30 lb/MMBtu was selected as the design basis for the baseline NO_X emission.

8) Atmospheric Pressure

The elevation of the Bridger Power Station is approximately 6,700 ft, which converts to an atmospheric pressure of 11.46 psia.

9) SO_3 Concentration in Flue Gas

The proposed MACT regulation includes a total particulate emission of 0.03 lb/MMBtu, including both condensable and filterable particulate. The condensable particulate emissions consist of sulfuric acid that forms because SO_3 reacts with moisture in the flue gas. SCR systems oxidize SO_2 in the flue gas to SO_3, thereby increasing the condensable emissions. However, catalyst can be designed to limit SO_2 oxidation. Very low oxidation catalysts are required for high sulfur bituminous fuels. Low oxidation catalyst requires more catalyst volume and increases catalyst costs over the life of the plant. Because Bridger 3 and 4 have a fuel agreement which limits the sulfur in the fuel to 0.80%, the amount of SO_2 that can oxidize is relatively low. Presently, the Bridger units are equipped with SO_3 injection to increase ESP performance. The SO_3 oxidation rate was set to limit the increase in SO_3 due to oxidation in the catalyst to match the maximum SO_3 injection rate for ESP performance. It was assumed that the SO3 injection system would be decommissioned after the installation of the SCR. S&L estimated that the total SO_2 oxidation across the SCR (with all layers in service) needs to be 1.5% or lower, based on the following assumptions:

- 0.4% SO_2 oxidation in the boiler. The baseline test value confirmed this is a conservative assumption.
- 40% SO_3 removal in the air heater. This is assumed based on high CaO content in the flyash which is consistent with PRB applications.

Bridger 3 & 4 SCR Project - Design Basis Calculation

3.0 ASSUMPTIONS

- Heat inputs for the minimum load case were calculated from the ratios of the loads and are not based on actual data.
- The distribution of bottom ash and fly ash was assumed to be 20% / 80%.
- Concentrations of SO_2 and SO_3 were determined based upon the assumptions that all of the sulfur in the coal was converted to SO_2 during combustion and 0.4% of the SO_2 was oxidized to SO_3.
- The absolute humidity was assumed to be 0.012 lb water per lb of dry air.
- The site design data provided by PacifiCorp indicated the highest ambient air temperature for design was 100°F.

4.0 METHODOLOGY & ACCEPTANCE CRITERIA

4.1 Determination of Flue Gas Flow

4.1.1 Fuel Flow

The fuel flow is calculated by dividing the maximum heat input (MMBtu/hr) by the heating value (Btu/lb) of the fuel.

4.1.2 Gas-Phase Reactions

The stoichiometric calculation models the following gas-phase reactions between the coal and combustion air:

$$C_{fuel} + O_2 \rightarrow CO_2$$
$$2\ H_{fuel} + \tfrac{1}{2}O_2 \rightarrow H_2O$$
$$S_{fuel} + O_2 \rightarrow SO_2$$
$$N_{2\ air} \rightarrow N_{2,flue\ gas}$$
$$H_2O_{air} \rightarrow H_2O_{flue\ gas}$$

The total oxygen requirements for complete oxidation of carbon, hydrogen and sulfur are calculated. A small portion of the oxygen demand is provided by oxygen inherent in the fuel. Combustion air provides the remainder of the oxygen demand. The stoichiometric quantity of dry air is calculated from the remaining oxygen demand and is corrected for relative humidity and economizer O_2% to determine the required wet combustion air at the burners. The gas-phase combustion reactions predict the expected flue gas composition and flow rate. See section 5.0 for the specific calculations.

Bridger 3 & 4 SCR Project - Design Basis Calculation

4.2 Ammonia Required to Achieve NO_X Reduction

In an SCR system, ammonia, the chemical reagent, is injected into the flue gas at a specific temperature and concentration to reduce nitrogen oxide (NO_X) emissions. The ammonia is adsorbed on the catalyst surface in the SCR reactor and then reacts with NO_X to form molecular nitrogen and water vapor:

$$4NH_3 + 4NO + O_2 \xrightarrow{\text{catalyst}} 4N_2 + 6H_2O \qquad \textbf{Equation 1}$$

$$4NH_3 + 2NO_2 + O_2 \xrightarrow{\text{catalyst}} 3N_2 + 6H_2O \qquad \textbf{Equation 2}$$

For the calculations shown in section 5.0, sample values shown are indicative of the design coal.

5.0 CALCULATIONS

5.1 Flue Gas Volumetric Flow

The spreadsheet used to determine the mass flows was the validated wet FGD material balance. Data not relevant to the Bridger SCR project was hidden, but the formulas in the spreadsheet were not altered. The design mass balances are included in Exhibit G. The report used to validate this spreadsheet is SL-2010-05502; and can be referenced if required.

DESIGN PARAMETERS

COAL ANALYSIS		
Carbon	wt%	53.69
Hydrogen	wt%	3.56
Nitrogen	wt%	1.08
Sulfur	wt%	0.64
Oxygen	wt%	10.76
Chlorine	wt%	0.00
Fluorine	wt%	0.00
Moisture	wt%	19.10
Ash	wt%	11.31
Meas. HHV	Btu/lb	9,208

PLANT PRODUCTION		
MCR Output	MW	570.0
Heat Input	mmBtu/hr	5,700.0
Firing Rate	lb/hr	619,027
AIR DATA		
Excess Air	wt%	33.1
Air H_2O	lb/lb dry air	0.012
SULFUR TRIOXIDE PRODUCTION		
Boiler	wt% SO_2	1.0
SCR	wt% SO_2	0.8

REMOVAL EFFICIENCIES		
Ash-Boiler	wt%	20.0
FLUE GAS TEMPERATURE		
Ambient	°F	100
Econ. Out	°F	780
SCR Out	°F	780
FLUE GAS PRESSURE		
Ambient	psia	11.46
Econ. Out	in. w.g.	-8
SCR Out	in. w.g.	-16

GAS STREAMS

Stream Characteristics		Combustion Air		Economizer Outlet		SCR Outlet	
Temperature	°F	100		780		780	
Pressure	psia	11.460		11.172		10.883	
N_2	lb/hr-vol%	4,417,571	77.65	4,424,231	72.62	4,424,231	72.62
O_2	lb/hr-vol%	1,330,732	20.47	330,874	4.75	330,874	4.75
H_2O	lb/hr-vol%	68,980	1.89	385,528	9.84	385,528	9.84
CO_2	lb/hr-vol%	0	0.00	1,218,529	12.73	1,218,529	12.73
SO_2	lb/hr-ppmv	0	0	7,844	563	7,782	559
SO_3	lb/hr-ppmv	0	0	99	6	177	10
HCl	lb/hr-ppmv	0	0	0	0	0	0
HF	lb/hr-ppmv	0	0	0	0	0	0
Total Flow	lb/hr-acfm	5,817,282	1,774,994	6,367,105	4,317,419	6,367,121	4,431,782
MW & Moist.	g/mol-lb/lb	28.630	0.012	29.263	0.064	29.263	0.064
Ash	lb/hr-gr/acf	0	0.000	56,009	1.513	56,009	1.474

Exhibit PAC/4003
Owen/64

Bridger 3 & 4 SCR Project - Design Basis Calculation

5.2 Ammonia Required to Achieve NO_X Reduction

NO_X is reported in units of lb/MMBtu. However, it is not lb of NO_X, but lb of NO_2 per MBtu that is reported. Even though NO_X is typically formed in a molar distribution of 95% NO / 5% NO_2, the values are reported in lb NO_2 because the NO portion of the NO_X is rapidly oxidized to NO_2 once emitted from the stack. Reaction equations 1 and 2 above show that for each mole of NO removed, 1 mole of NH_3 is required, and for each mole of NO_2 removed, 2 moles of NH_3 are required. Equation 3 below converts the inlet NO_X to equivalent lb moles of NO_2 that are removed in the SCR (units shown in parentheses).

Equation 3

$$\frac{\text{NOxRemEff}}{100}\left(\frac{\text{lb NO}_2\text{ removed}}{\text{lb NO}_2\text{inlet}}\right)*\text{Inlet NOx}\left(\frac{\text{lb NO}_2\text{ inlet}}{\text{MMBtu}}\right)*\text{Heat Input}\left(\frac{\text{MMBtu}}{\text{hr}}\right)*\frac{1}{46}\left(\frac{\text{lbmol NO}_2\text{removed}}{\text{lb NO}_2\text{removed}}\right)$$

Equation 4 then takes into account the 95% / 5% distribution of NO to NO_2 and determines the mass flow of NH_3 required.

Equation 4

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$$\text{NH}_3\text{Req}_M=\frac{\text{lbmolNO}_2\text{removed}}{\text{hr}}*\left[\left(\frac{0.95\text{lbmolNO}}{\text{lbmolNO}_2\text{removed}}*\frac{1\text{lbmolNH}_3}{\text{lbmolNO}}\right)+\left(\frac{0.05\text{lbmolNO}_2}{\text{lbmolNO}_2\text{removed}}*\frac{2\text{ lbmolNH}_3}{\text{lbmolNO}_2}\right)\right]*\frac{17\text{ lb NH}_3}{\text{lbmoleNH}_3}$$

Equations 3 and 4 can be combined and rewritten in the form below:

Equation 5

$$\text{NH3Req}_M=\frac{\text{NOxRemEff}}{100}*\text{Inlet NO}_X*\text{Heat Input}*\frac{\text{MWtNH}_3}{\text{MWtNO}_2}*1.05$$

Equations 3, 4, and 5 use the following terms; Example values are shown to the right of each definition for the maximum load case; the values shown are on a per Unit basis.

NH_3Req_M	**= Mass flow rate of ammonia required, lb/hr – 575**
NOxRemEff	= NOx removal efficiency, % - 86.7
Inlet NOx	= Amount of SCR inlet NOx, lb/MMBtu – 0.30
Heat Input	= Heat Input to Boiler, MMBtu/hr – 5,700

Bridger 3 & 4 SCR Project - Design Basis Calculation

$MWtNH_3$	= Molecular weight of ammonia, lb/lbmol - 17
$MWtNO_2$	= Molecular weight of NO_2, lb/lbmol – 46

5.3 Ammonia slip

The ammonia slip is based on calculating the weight of ammonia that represents the maximum allowable ammonia slip at 3% O_2. The amount of ammonia slip is then added to the amount of ammonia required. The ammonia slip is calculated as follows; the example values shown are on a per Unit basis:

Equation 6

$$NH_3slip_M = \left(\frac{FG_M}{MWt_{FG}}\right)\left(1-\frac{H_2O}{100}\right)(NH_3slip)\left[\frac{\left(O_{2,air}-\frac{O_{2,FG}}{1-\frac{H_2O}{100}}\right)}{O_{2,air}-3\%}\right]\left(\frac{1}{1,000,000}\right)(MWt_{NH_3})$$

NH_3slip_M	**= Mass flow rate of ammonia slip, lb/hr – 5.8**
FG_M	= Maximum design flue gas mass flow rate, lb/hr – 6,270,407
MWt_{FG}	= Molecular weight of flue gas, lb/lbmol – 29.263
H_2O	= Moisture content of flue gas, % vol – 9.84
NH_3slip	= Rate of ammonia slip, ppmvd@3%O_2 – 2.0
$O_{2,air}$	= Oxygen content in air, % vol – 20.79
$O_{2,FG}$	= Oxygen content in flue gas, % vol – 4.75
MWt_{NH3}	= Molecular weight of ammonia, lb/lbmol – 17

5.4 Total Ammonia Required

$$NH_3Req_{Mtot} = NH_3Req_M + NH_3slip_M$$
$$NH_3Req_{Mtot} = 575 + 5.8 = 580.8\,\text{lb/hr per Unit}$$

6.0 RESULTS

Based upon the results of this calculation, the following table should be used as the design criteria for the Bridger Units 3 & 4 SCR reactor sizing and catalyst design. The values provided in the following table are on a per Unit basis.

Characteristic	SCR System	SCR System
Bridger Units 3& 4 Design Case	100% MCR (570 MW)	Low Load (250MW)
Heat input to boiler (MMBtu/hr)	5,700	2,500
SCR inlet flue gas flow including excess air, at the average flue gas temperature. Design Basis (acfm) (lb/hr)	4,317,000 6,367,000	1,554,000 2,726,000
Inlet flue gas temperature (°F) assuming economizer in dirty operating condition.	780°F average bulk temperature ±20°F distribution across the duct	600°F average bulk temperature ±20°F distribution across the duct
Flue gas static pressure at economizer outlet system inlet (in. H_2O)	-8.0	-3.0
Inlet NO_X level, (lb/hr) (lb/MMBtu)	1,710 0.30	375 0.15
Inlet SO_2 level (maximum), (lb/hr) (lb/MMBtu)	7,844 1.38	3,440 1.38
Inlet SO_3 level (maximum), (lb/hr) (lb/MMBtu)	99 0.02	43 0.02
Inlet design fly ash dust loading, (lb/hr) (lb/MMBtu)	56,000 9.82	24,550 9.82
Inlet maximum fly ash dust loading, (lb/hr) (lb/MMBtu)	89,200 15.6	39,000 15.6

EXHIBIT A – BRIDGER COAL ANALYSES

Bridger Plant
Typical Burned Coal Quality

		Typical	Max	Min
Ultimate (Dry Basis)	Moisture %	19.10	21.40	17.50
	Ash %	11.30	16.00	8.00
	Volatile %	30.10	33.00	25.00
	F.C. %	39.50	44.00	34.00
	Btu/lb	9,350	10,030	8,800
	Sulfur %	0.51	0.64	0.32
	MAF Btus	13,434	13,955	13,000
	Hydrogen	4.40	4.80	3.90
	Carbon	66.36	69.00	61.00
	Sulfur	0.63	0.77	0.40
	Nitrogen	1.33	2.00	1.18
	Oxygen	13.30	14.80	9.50
	Ash	13.98	18.00	10.00
	HGI	55	63	48
Minerals Analysis of Ash (Dry Basis)	B/A	0.19	0.26	0.15
	SiO_2	62.92	71.00	57.00
	Al_2O_3	14.54	18.00	12.00
	Fe_2O_3	4.48	6.00	3.55
	CaO	5.03	7.00	3.20
	MgO	1.75	2.70	1.10
	Na_2O	2.50	4.60	1.35
	K_2O	1.05	1.75	0.60
	TiO_2	0.85	1.10	0.65
	P_2O_5	0.28	0.60	0.10
	SO_3	5.98	8.90	3.00
Ash Fusion Temperatures (Reducing)	Initial	2162	2300	2130
	Soft.	2244	2430	2070
	Hemi.	2313	2500	2100
	Fluid	2518	2700	2275
	Range	356	550	225

Typical PRB Quality
Based on actual deliveries to PacifiCorp Plants
and predicted quality from supplier proposals.

		Northern Basin	Mid-Basin	Southern Basin
Ultimate (Dry Basis)	Moisture %	30.85	30.08	27.29
	Ash %	5.63	5.23	5.04
	Volatile %	30.81	30.20	32.33
	F.C. %	33.75	33.11	35.49
	Btu/lb	8164	8440	8769
	Sulfur %	0.44	0.35	0.30
	MAF Btus	12853	13046	12963
	Hydrogen	4.69	4.75	4.79
	Carbon	67.97	69.24	69.68
	Sulfur	0.60	0.47	0.41
	Nitrogen	0.98	1.05	1.01
	Oxygen	17.90	16.97	17.23
	Ash	7.69	7.52	6.88
	HGI	58	59	53
Minerals Analysis of Ash (Dry Basis)	B/A	0.72	0.69	0.62
	SiO2	32.93	32.32	35.53
	Al2O3	14.75	16.37	15.60
	Fe2O3	5.56	5.28	5.96
	CaO	22.26	22.74	20.73
	MgO	5.19	4.18	4.48
	Na2O	1.42	1.44	1.55
	K2O	0.31	0.31	0.37
	TiO2	1.00	1.34	1.17
	P2O5	0.68	1.02	1.08
	SO3	15.15	14.12	12.23
Ash Fusion Temperatures (Reducing)	Initial	2149	2124	2116
	Soft.	2174	2160	2143
	Hemi.	2186	2177	2162
	Fluid	2243	2252	2234
	Range	94	128	119

EXHIBIT B – BRIDGER UNITS 1-4 AIR PREHEATER INLET TEMPERATURE

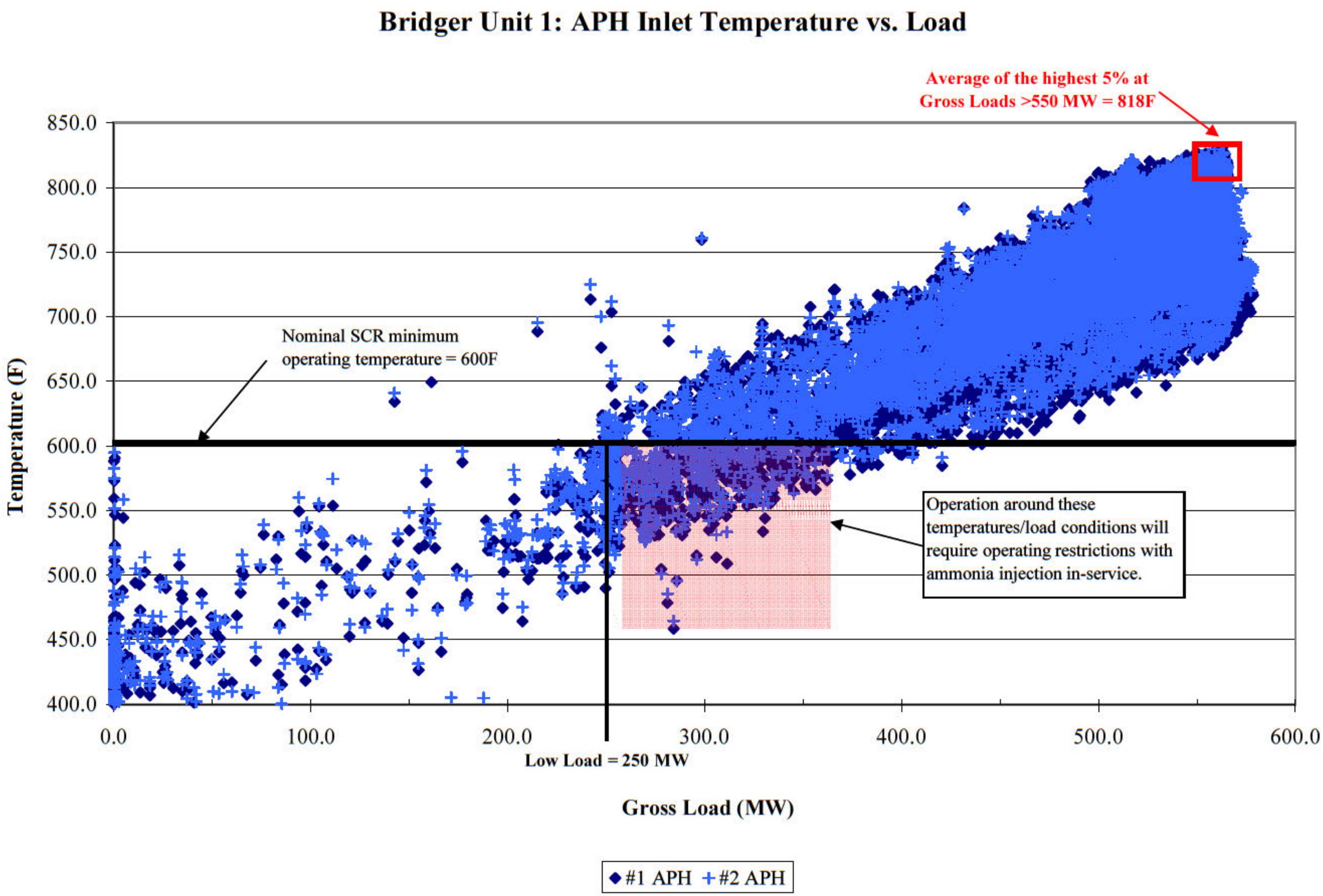
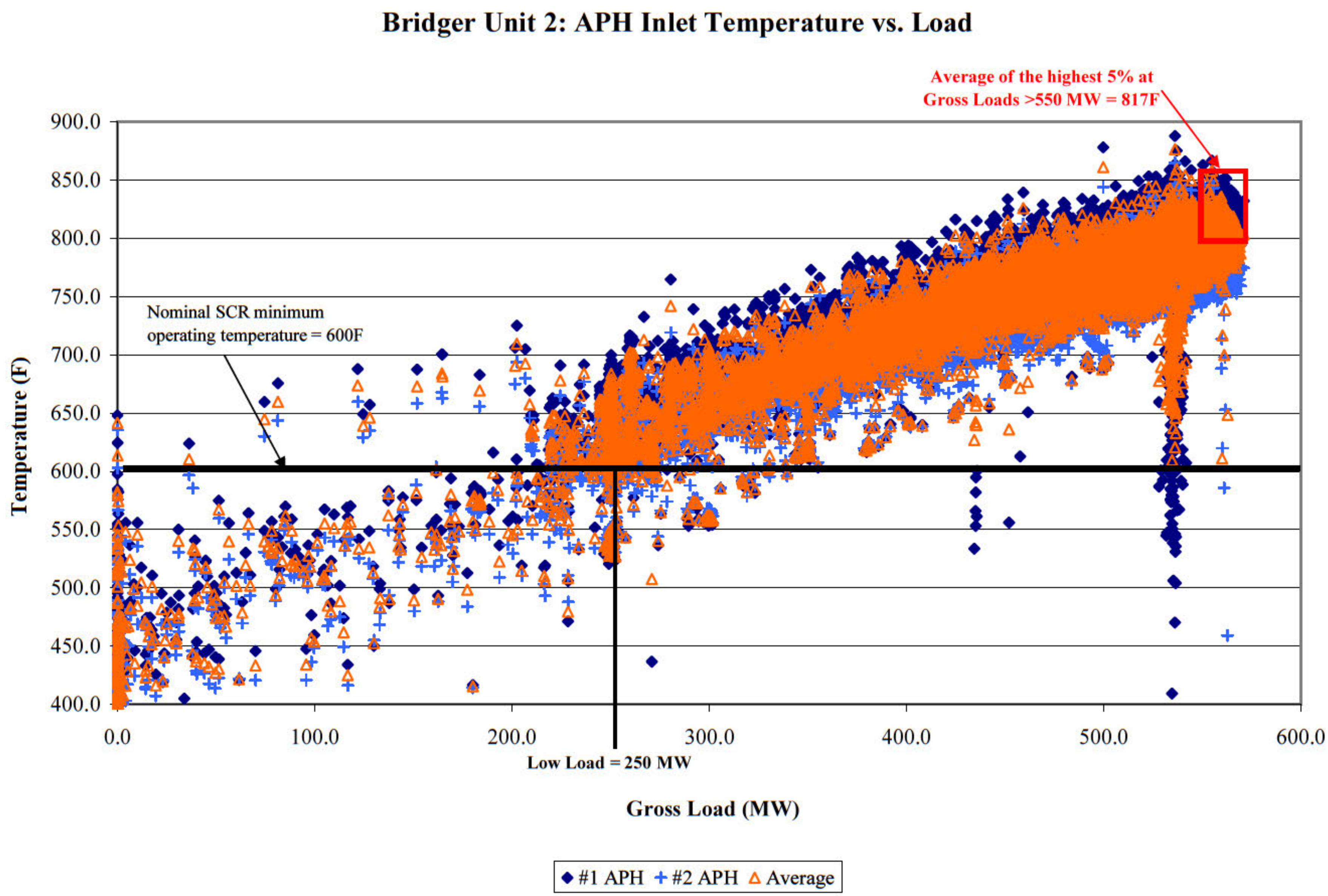


Exhibit PAC/4003
Owen/72


Bridger Unit 2: APH Inlet Temperature vs. Load
Average of the highest 5% at
Gross Loads >550 MW = 817F
Nominal SCR minimum
operating temperature = 600F
Temperature (F)
900.0
850.0
800.0
750.0
700.0
650.0
600.0
550.0
500.0
450.0
400.0
0.0
100.0
200.0
300.0
400.0
500.0
600.0
Low Load = 250 MW
Gross Load (MW)
#1 APH
#2 APH
Average

Bridger Unit 3: APH Inlet Temperature vs. Load

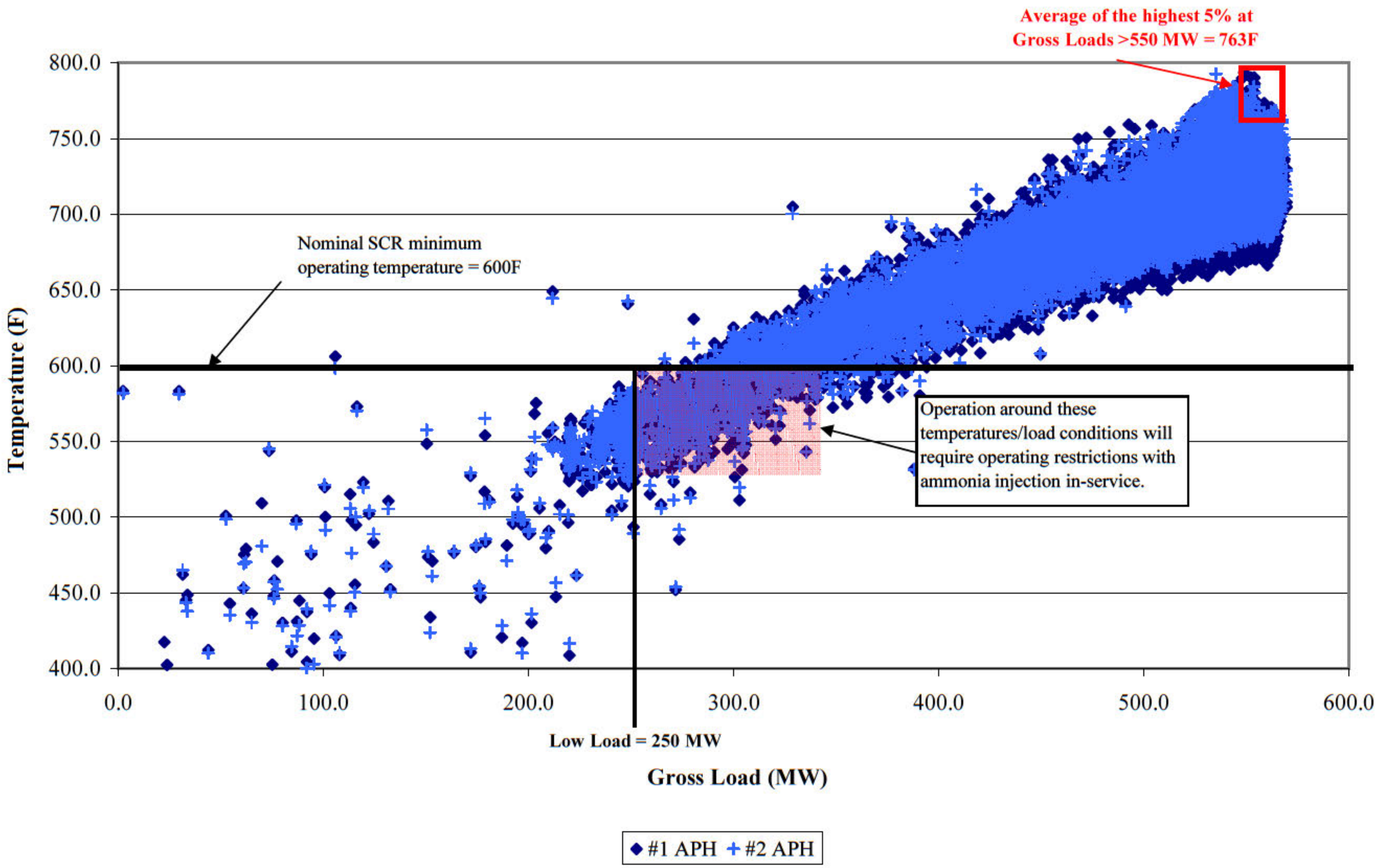


Exhibit PAC/4003
Owen/74

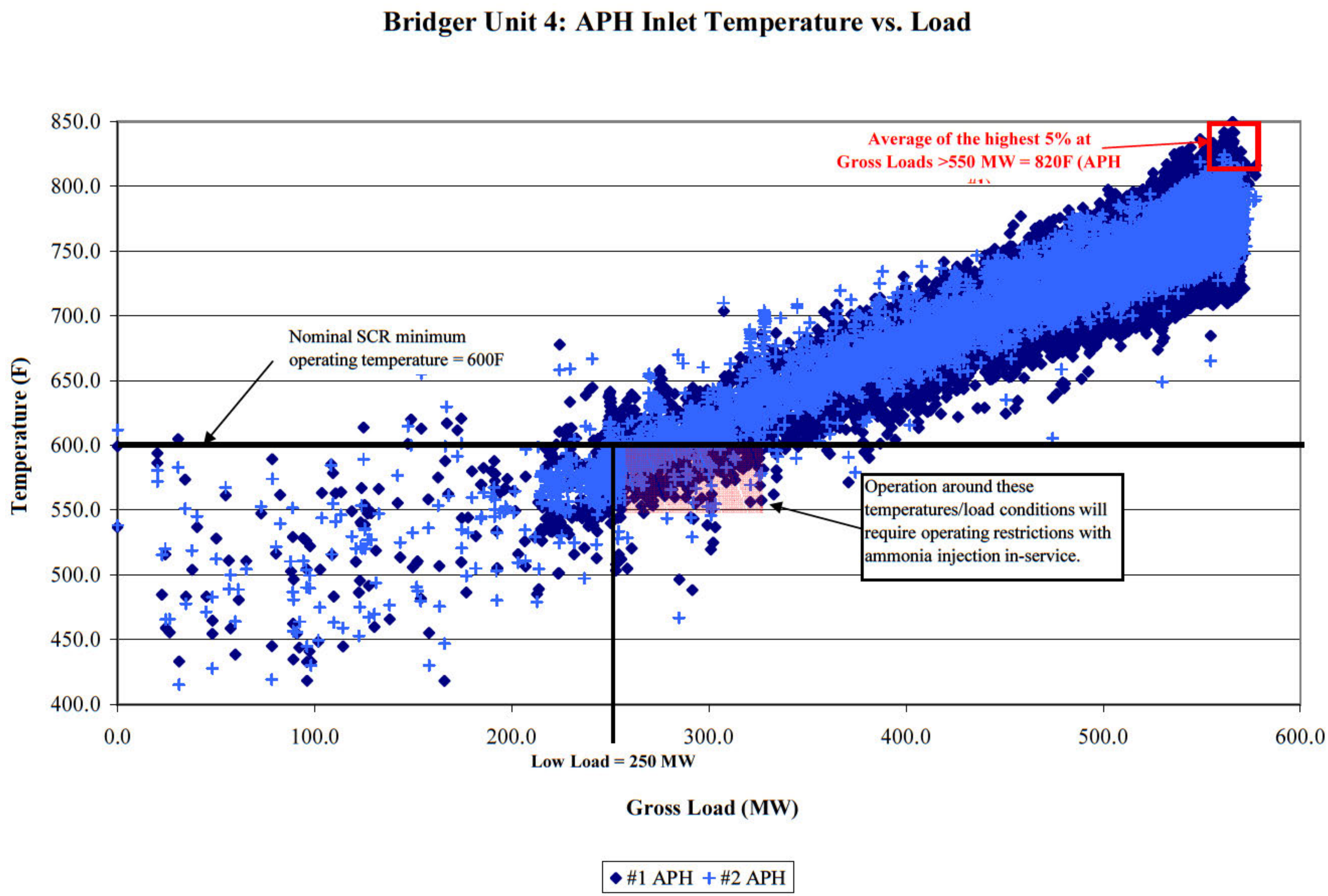

Bridger Unit 4: APH Inlet Temperature vs. Load
Average of the highest 5% at Gross Loads >550 MW = 820F (APH
Nominal SCR minimum operating temperature = 600F
Operation around these temperatures/load conditions will require operating restrictions with ammonia injection in-service.
850.0
800.0
750.0
700.0
650.0
600.0
550.0
500.0
450.0
400.0
Temperature (F)
0.0
100.0
200.0
300.0
400.0
500.0
600.0
Low Load = 250 MW
Gross Load (MW)
#1 APH
#2 APH

EXHIBIT C – BRIDGER UNITS 1-4 OXYGEN AT AIR PREHEATER INLET

Bridger Unit 1: Economizer Outlet O_2 vs. Load

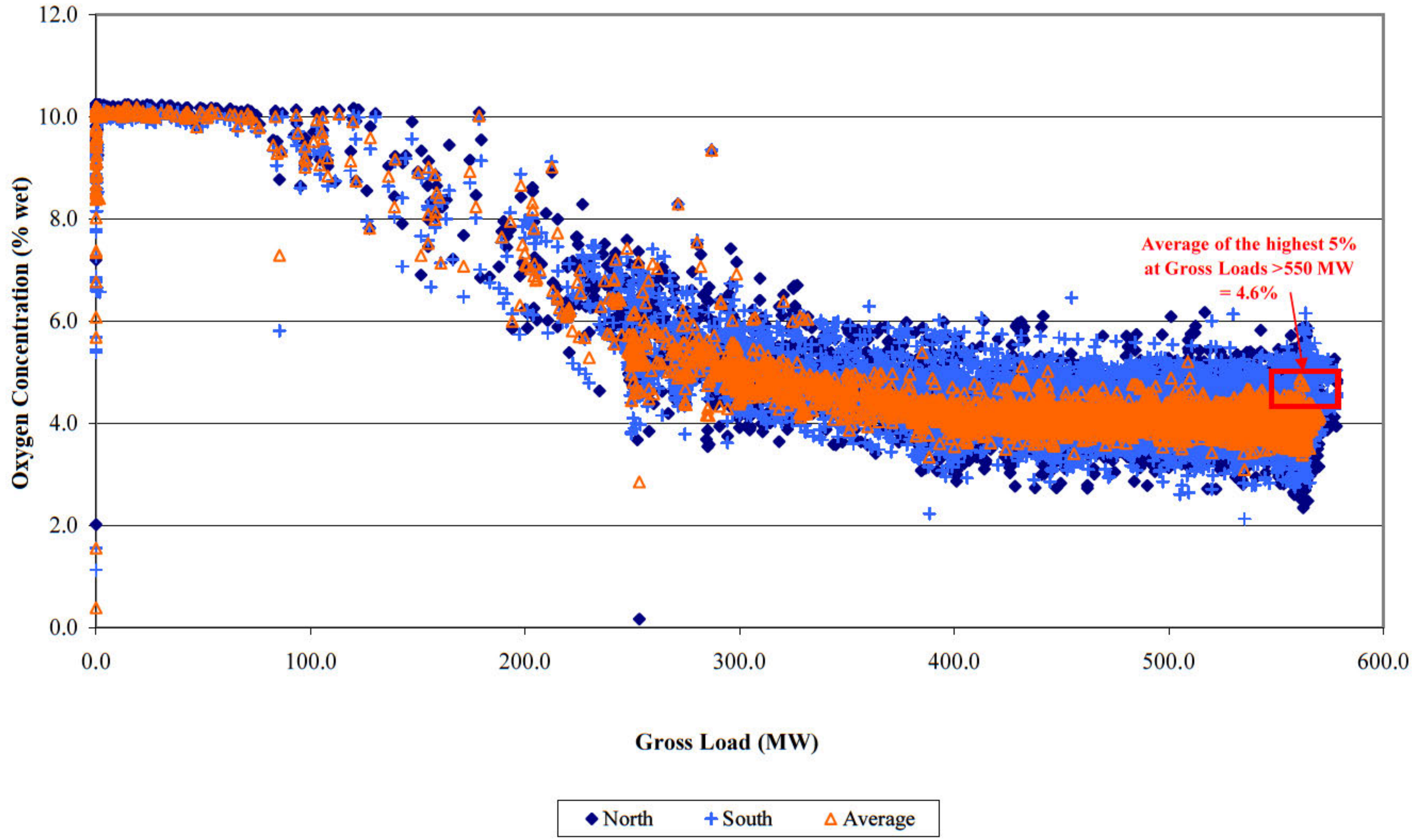
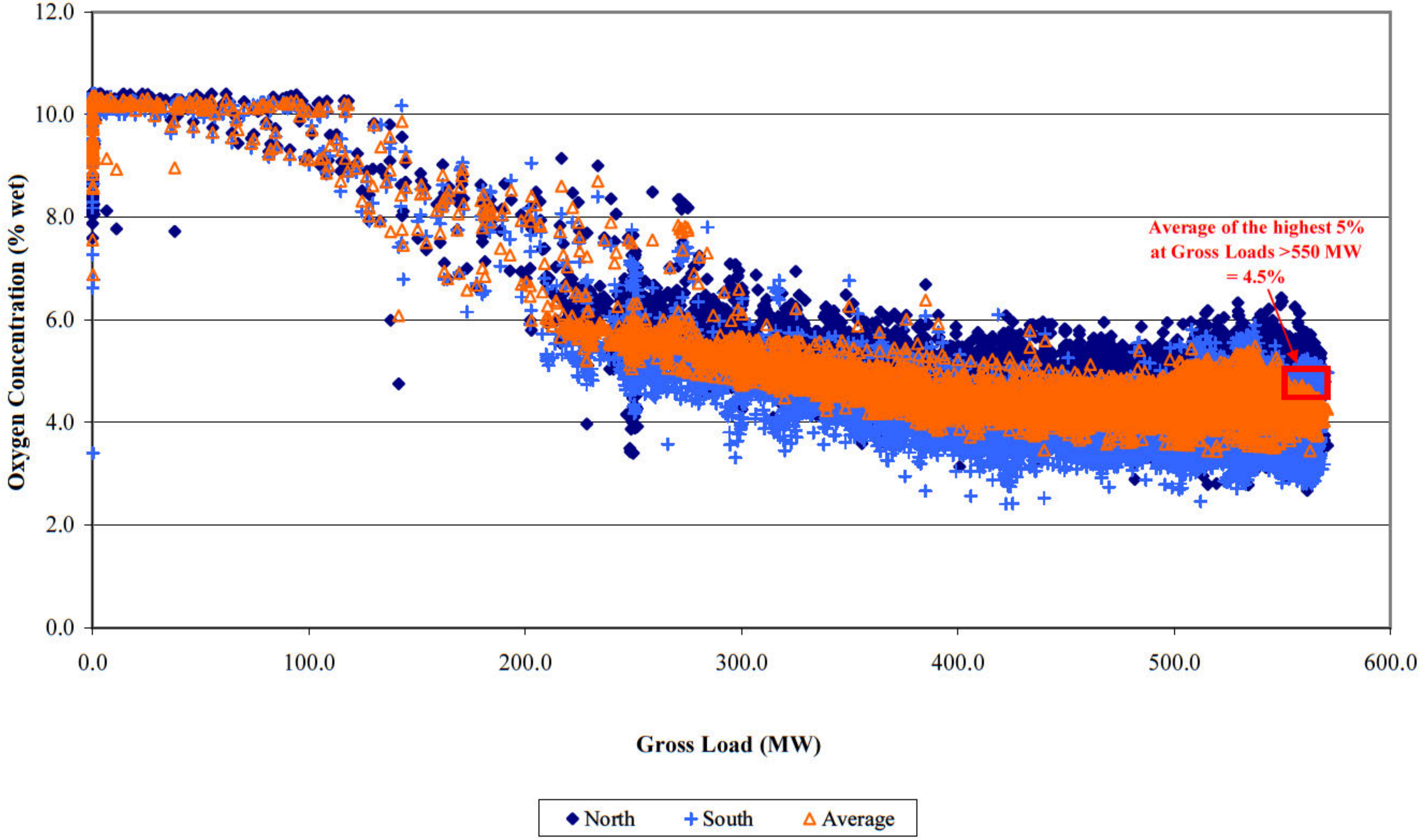


Exhibit PAC/4003
Owen/77

Bridger Unit 2: Economizer Outlet O_2 vs. Load



Bridger Unit 3: Economizer Outlet O_2 vs. Load

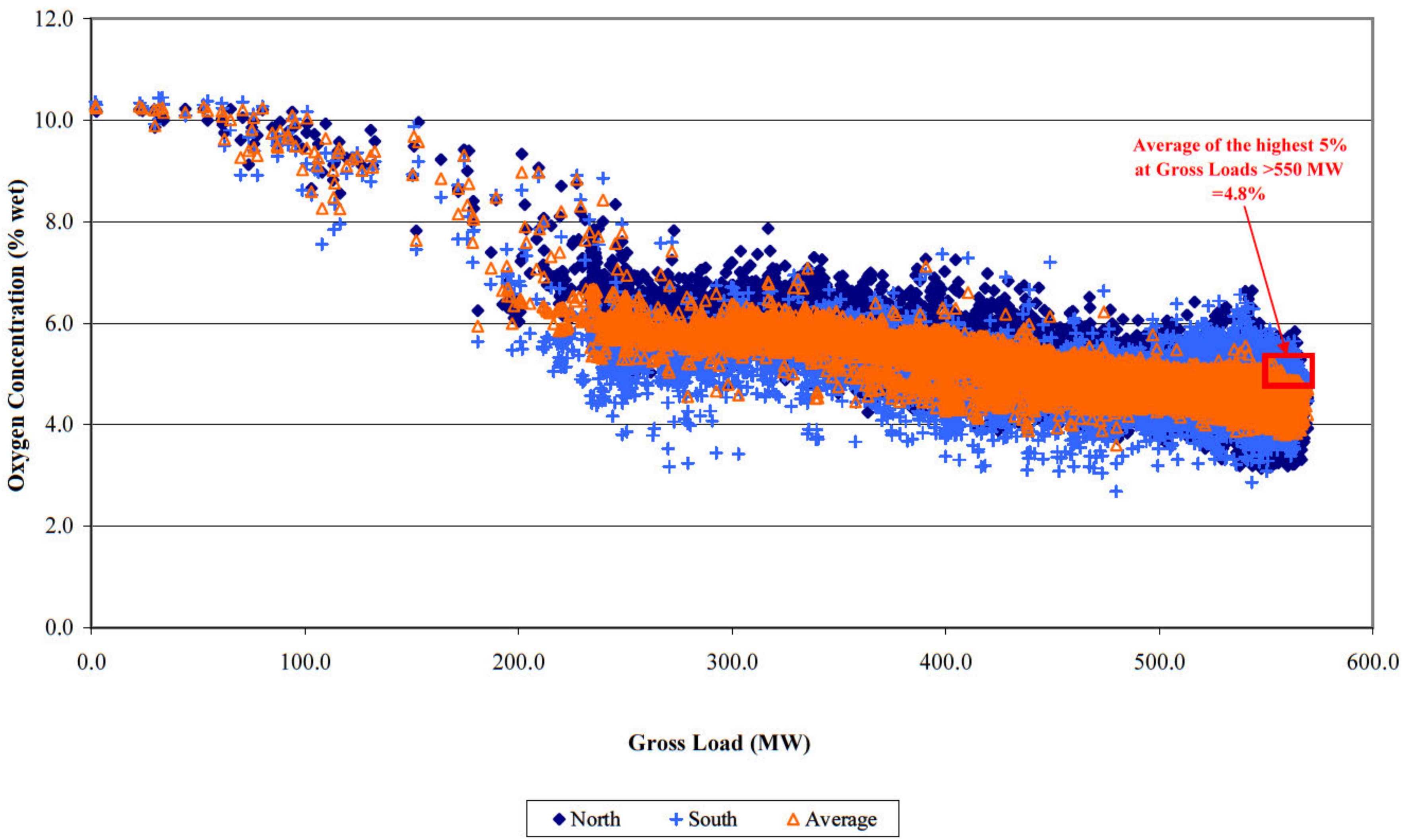


Exhibit PAC/4003
Owen/79

Bridger Unit 4: Economizer Outlet O_2 vs. Load

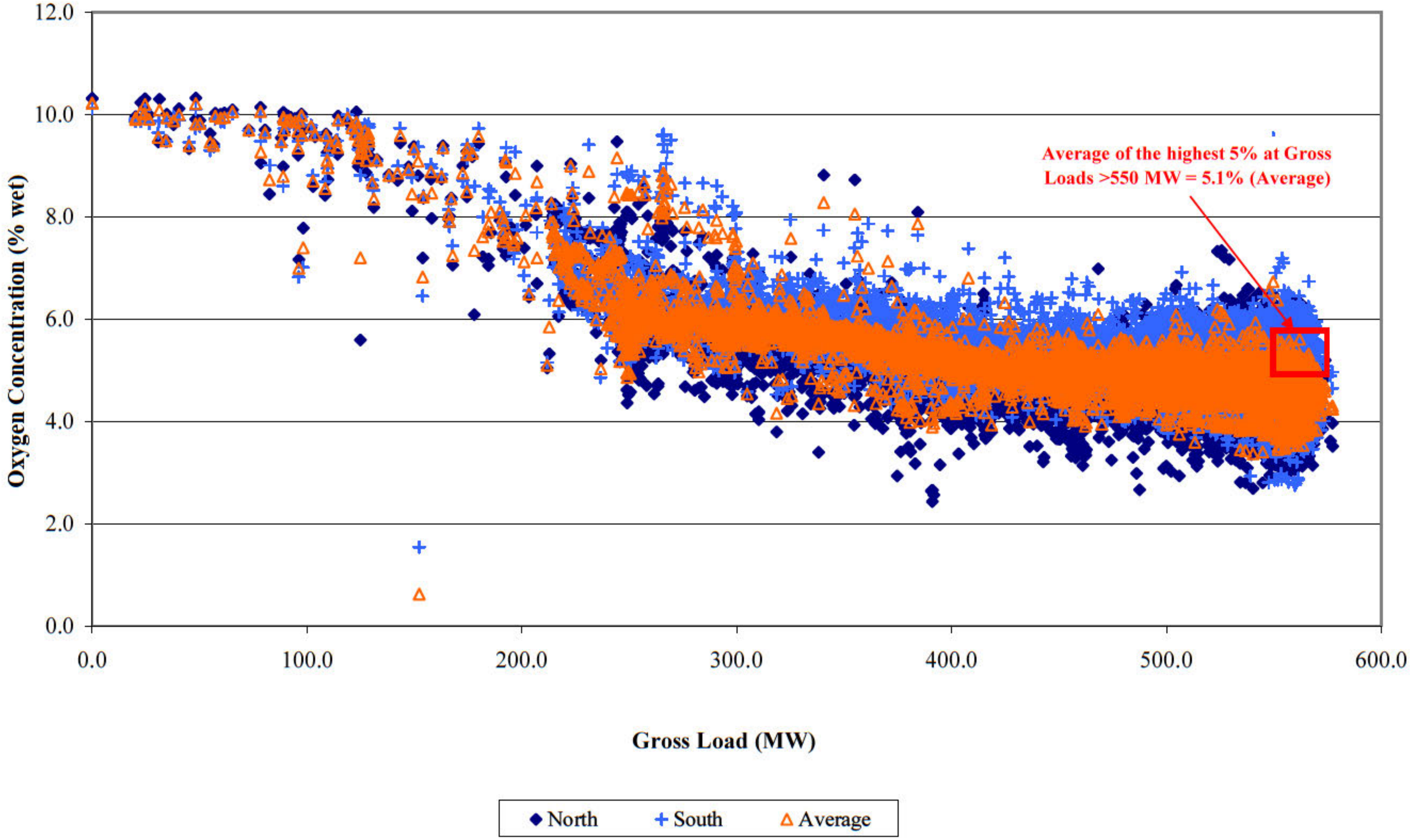


Exhibit PAC/4003
Owen/80

EXHIBIT D – BRIDGER UNITS 1-4 CEMS NOX DATA

Bridger Unit 1: NO_X vs. Load
(08/2010 to Present)

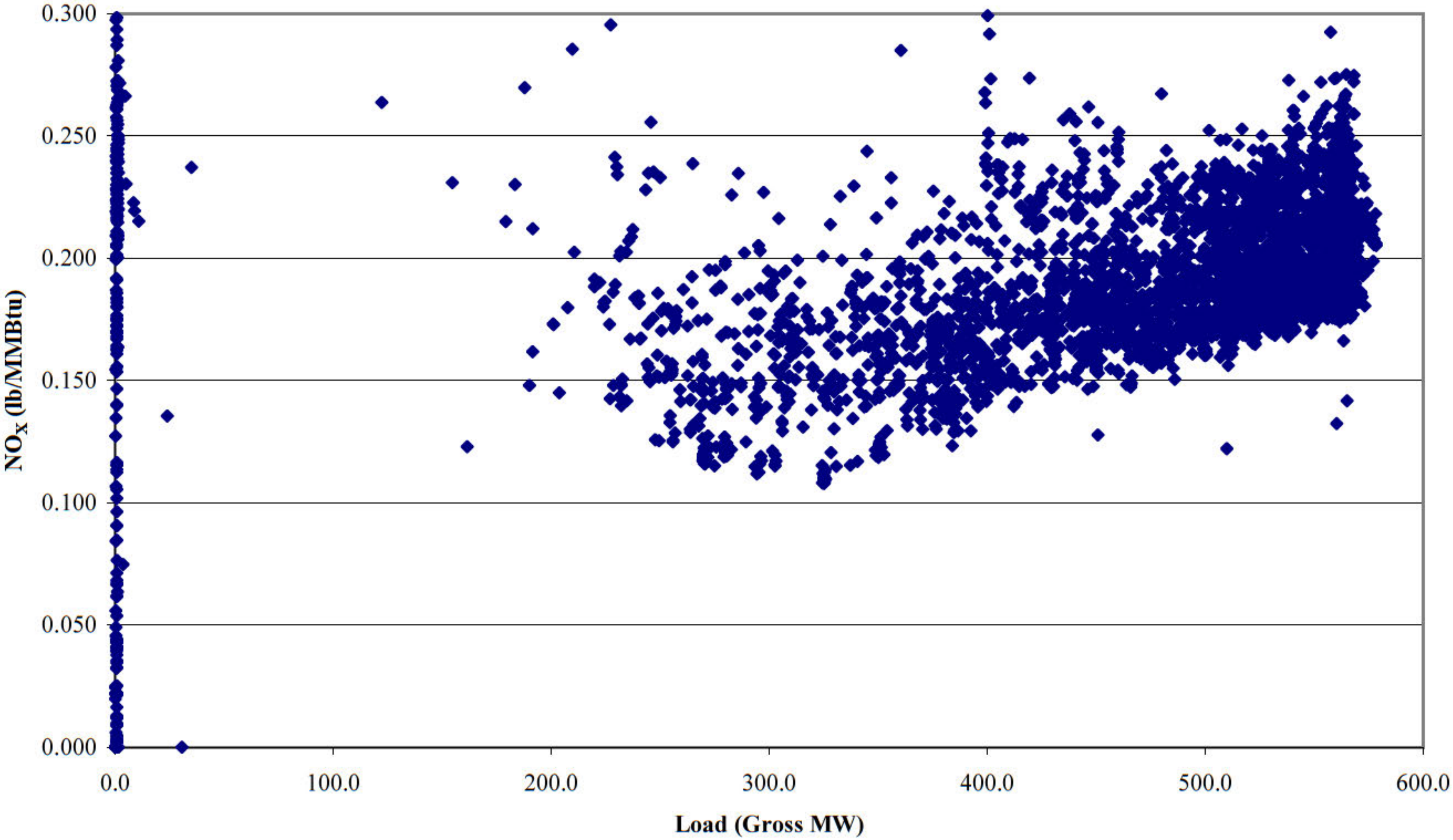
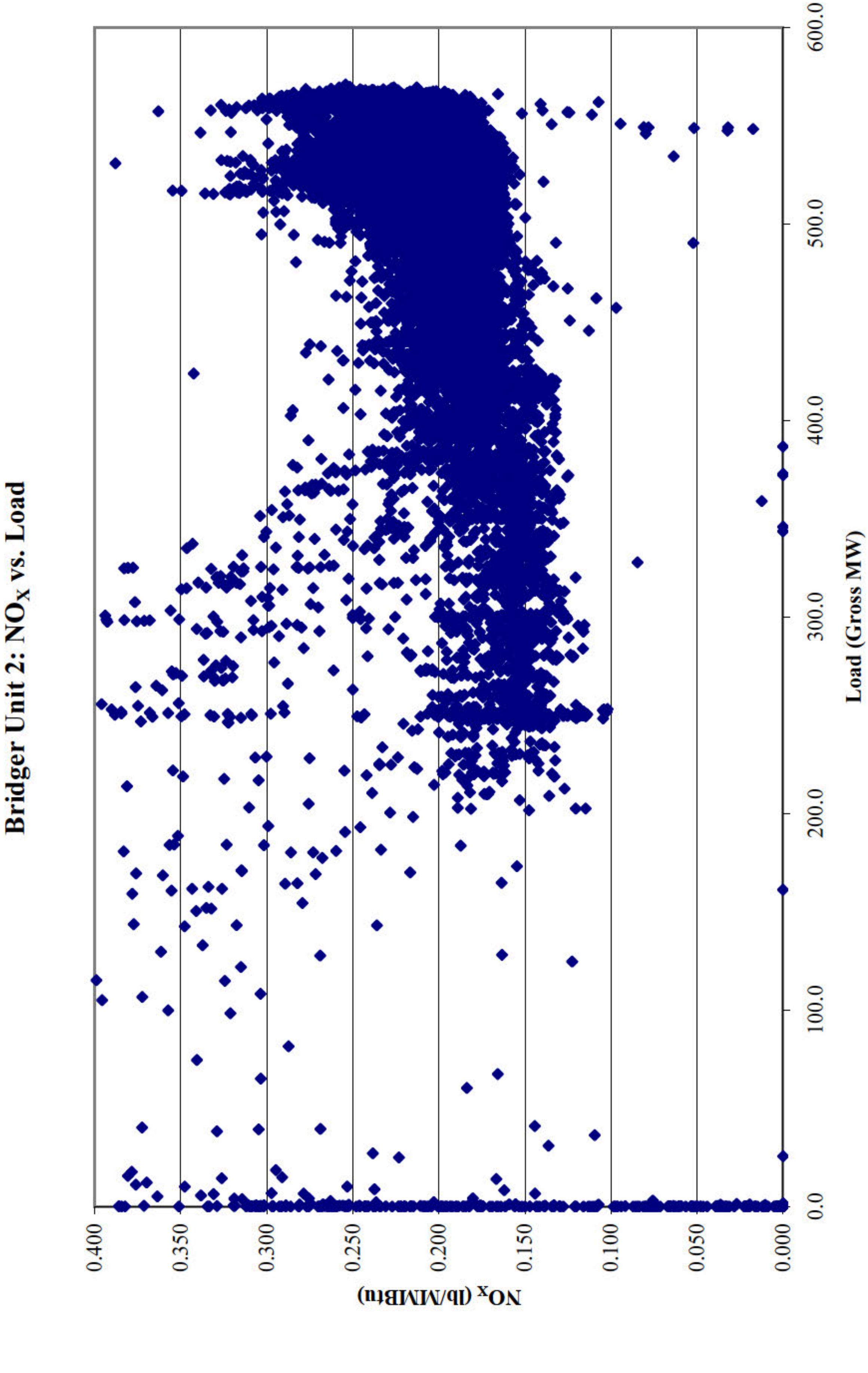


Exhibit PAC/4003
Owen/82


Bridger Unit 2: NO_X vs. Load
NO_X (lb/MMBtu)
0.400
0.350
0.300
0.250
0.200
0.150
0.100
0.050
0.000
Load (Gross MW)
0.0
100.0
200.0
300.0
400.0
500.0
600.0

Bridger Unit 3: NO_X vs. Load

(Adjusted to remove outliers)

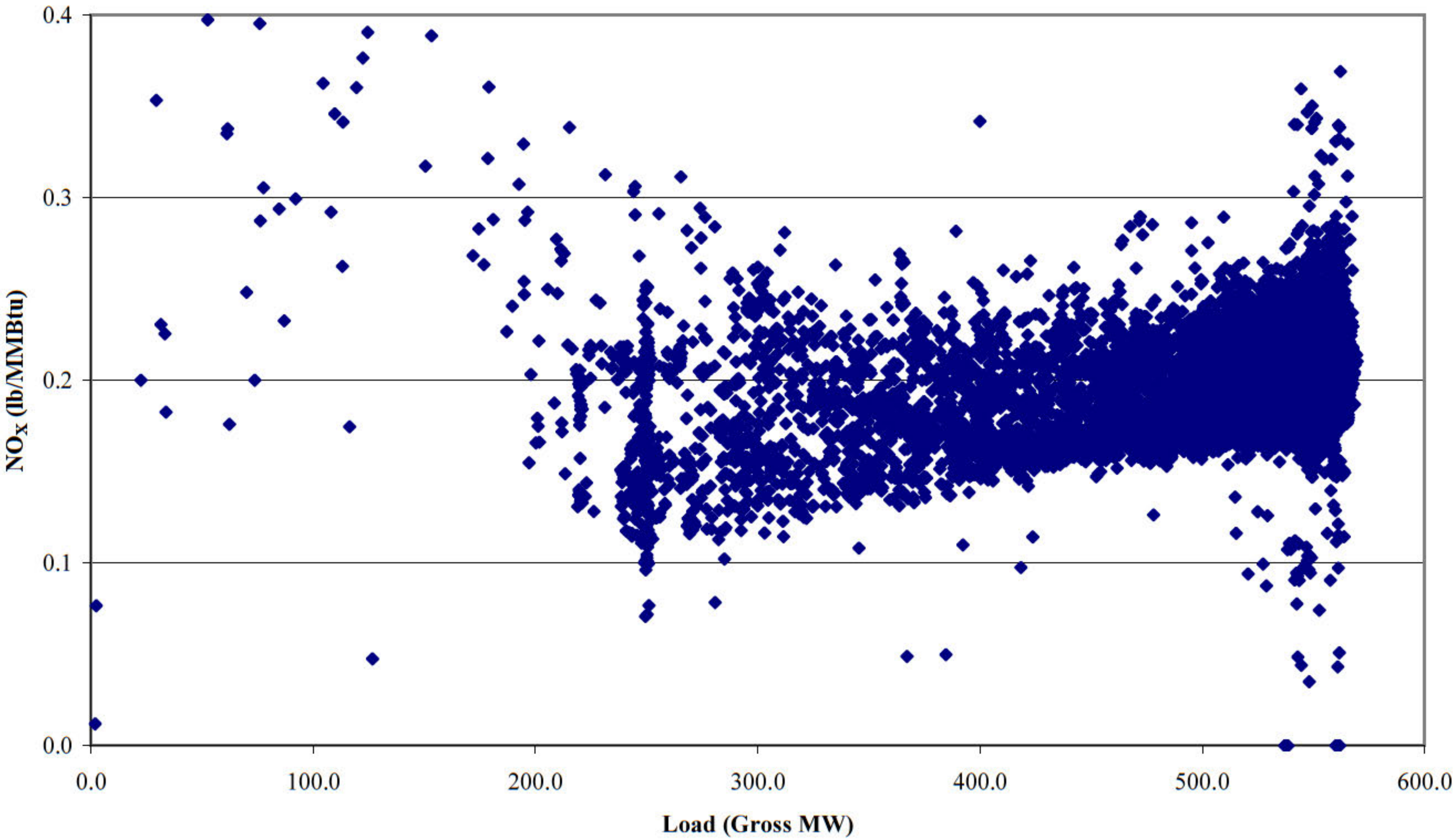


Exhibit PAC/4003
Owen/84

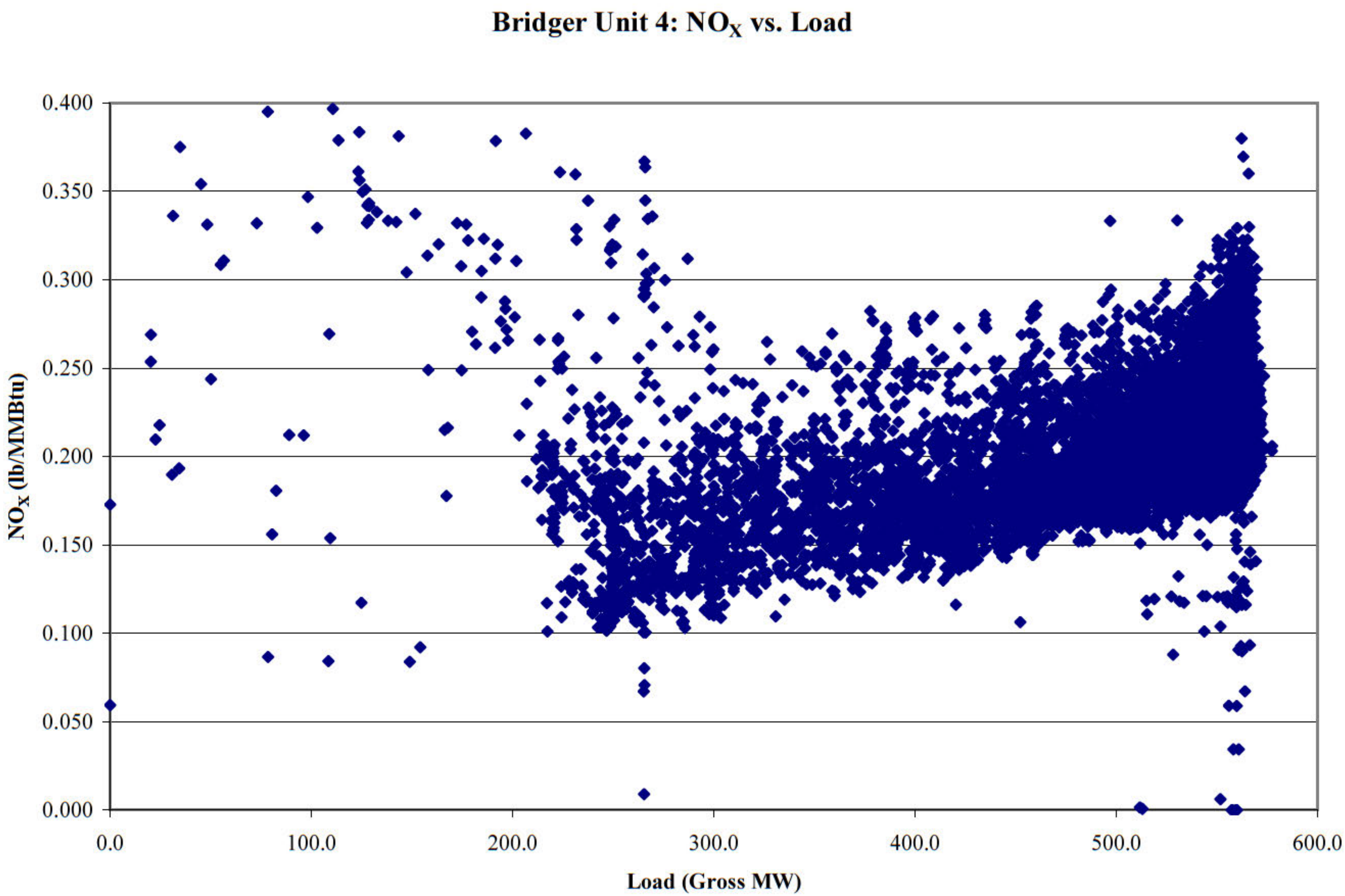

Bridger Unit 4: NO_X vs. Load
NO_X (lb/MMBtu)
0.400
0.350
0.300
0.250
0.200
0.150
0.100
0.050
0.000
0.0
100.0
200.0
300.0
400.0
500.0
600.0
Load (Gross MW)

EXHIBIT E – BRIDGER DESIGN HEAT INPUT

FW: 20110513pf_Design Heat Input for SCR
Goff, Richard
to:
DANIELLE.A.FLAGG@sargentlundy.com
05/13/2011 11:45 AM
Show Details

History: This message has been replied to.

From: Fahlsing, Paul
Sent: Friday, May 13, 2011 10:43 AM
To: andrew cartens (andrew.j.cartens@sargentlundy.com); Arambel, Bob; Goff, Richard; John Dederich (john.f.dederich@sargentlundy.com); Ruffini, Leroy; Saunders, Michael; Scott Nowinski (donald.s.nowinski@sargentlundy.com); Sedey Jr., James
Cc: Caulfield, Bernie
Subject: 20110513pf_Design Heat Input for SCR

Andy,
Please use 5,700 MMBtu per hour as the design heat input to the unit for the SCR. This would enable us to reach full output with a heat rate slightly above 10,500 Btu/kWh.

Paul M. Fahlsing
Director, Operations
Jim Bridger Plant
Phone - (307) 352-4226
Cell - (307) 389-6558

EXHIBIT F – BRIDGER UNITS 1-4 LOAD PROFILES

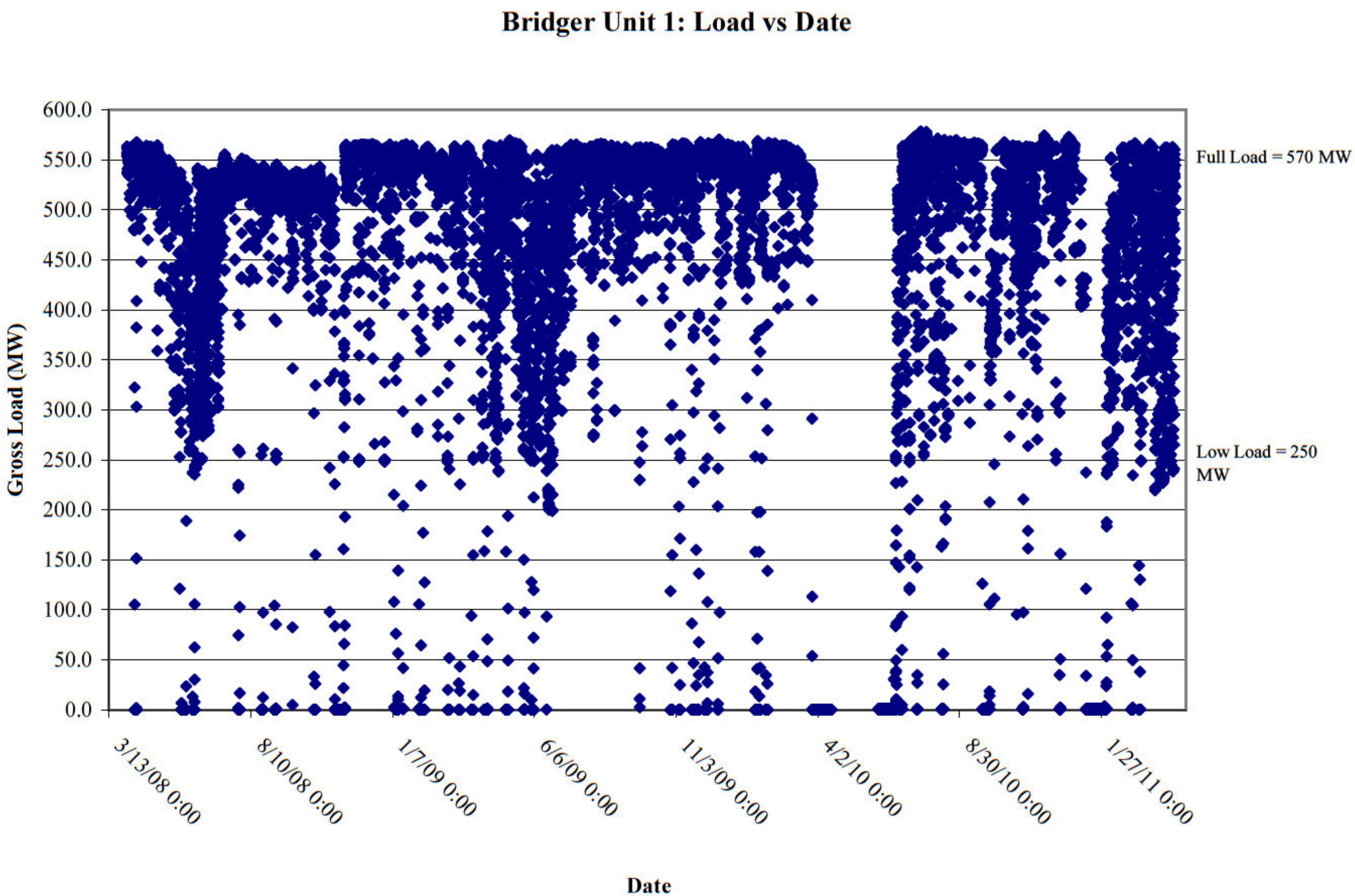


Exhibit PAC/4003
Owen/89

Bridger Unit 2: Load vs Date

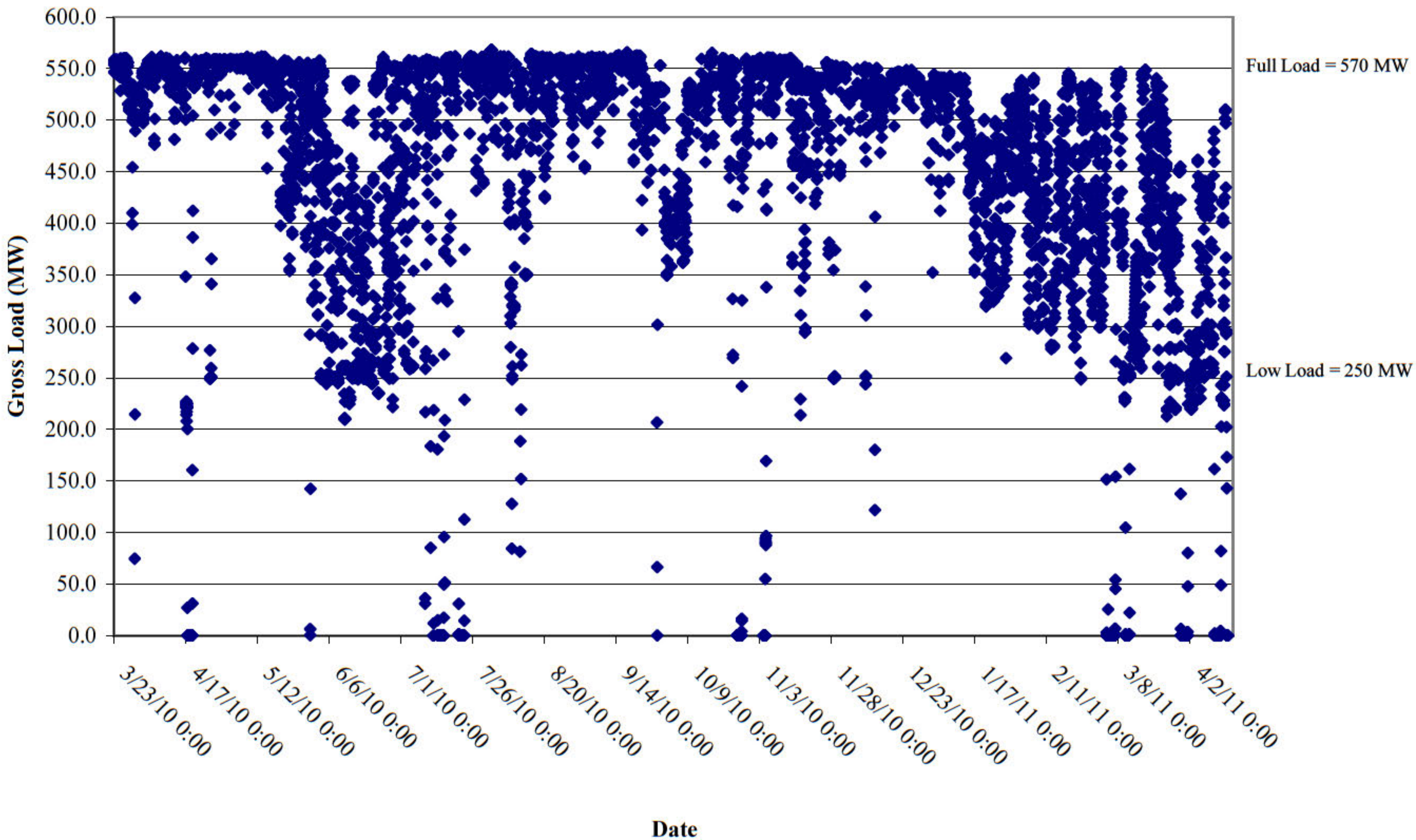


Exhibit PAC/4003
Owen/90

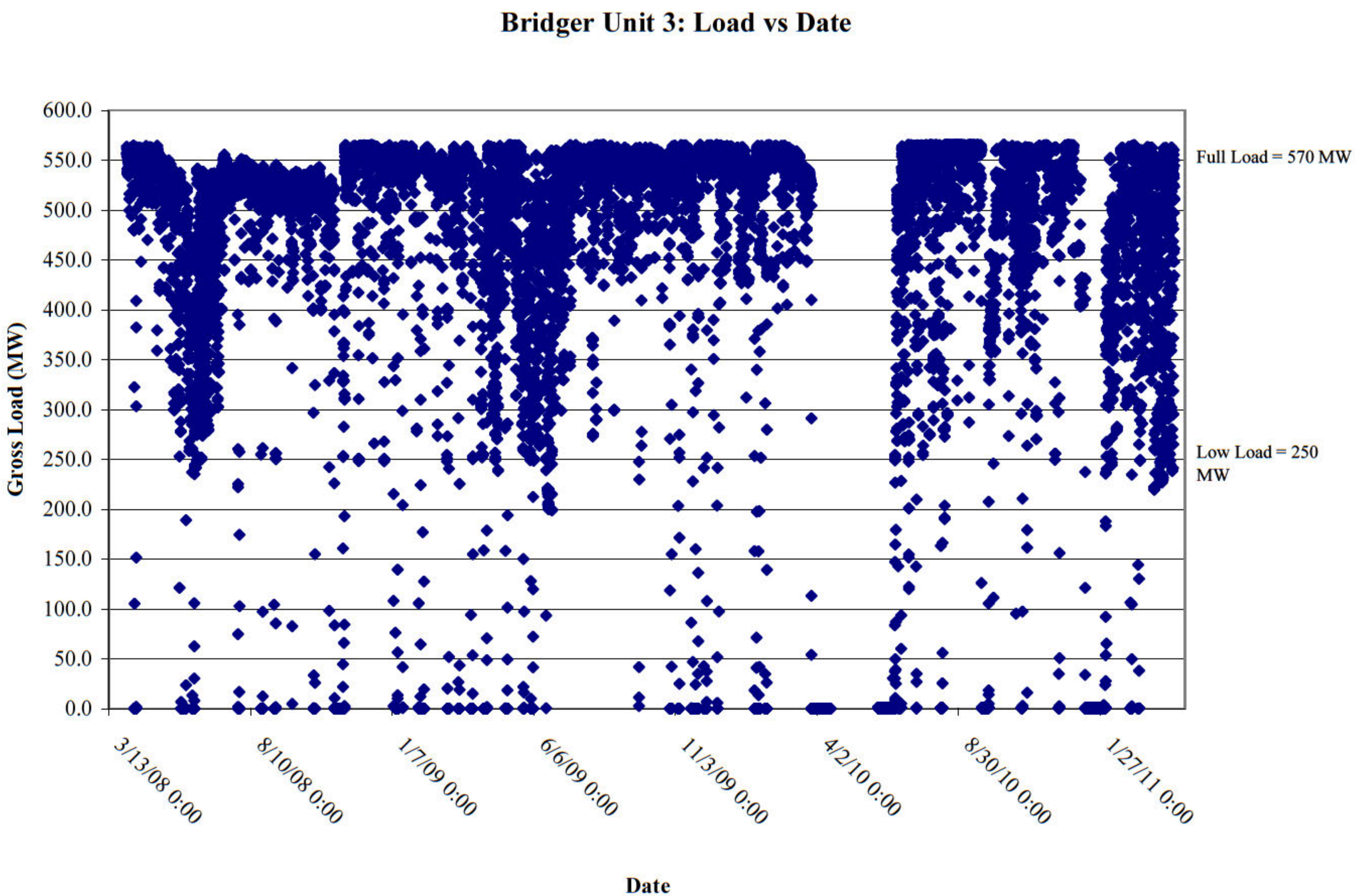


Exhibit PAC/4003
Owen/91

Bridger Unit 4: Load vs Date

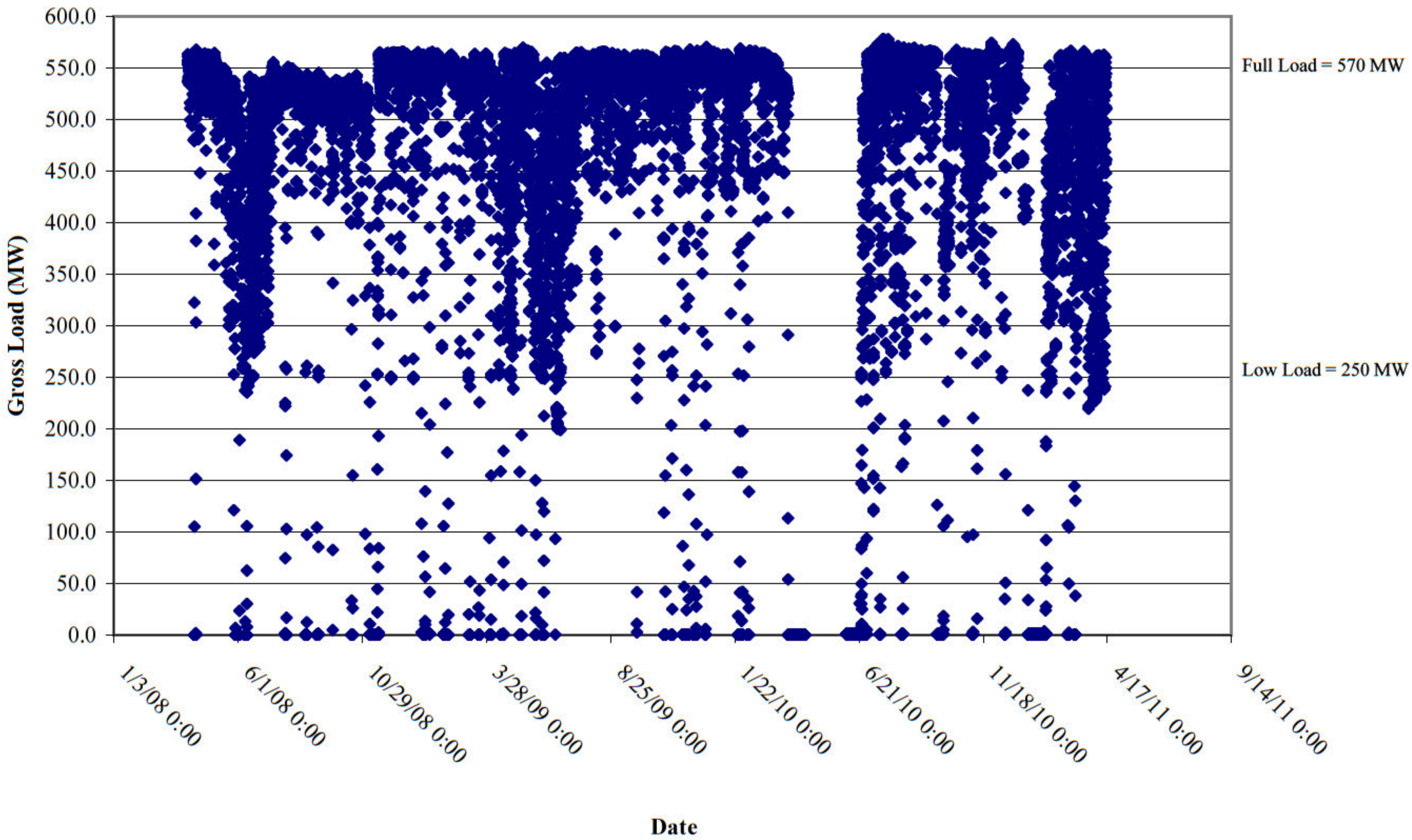


Exhibit PAC/4003
Owen/92

EXHIBIT G – BRIDGER SCR DESIGN BASIS MASS BALANCES

SCR Mass Balance
Full Load Design

DESIGN PARAMETERS

COAL ANALYSIS		
Carbon	wt%	53.69
Hydrogen	wt%	3.56
Nitrogen	wt%	1.08
Sulfur	wt%	0.64
Oxygen	wt%	10.76
Chlorine	wt%	0.00
Fluorine	wt%	0.00
Moisture	wt%	19.10
Ash	wt%	11.31
Meas. HHV	Btu/lb	9,208

PLANT PRODUCTION		
MCR Output	MW	570.0
Heat Input	mmBtu/hr	5,700.0
Firing Rate	lb/hr	619,027
AIR DATA		
Excess Air	wt%	33.1
Air H_2O	lb/lb dry air	0.012
SULFUR TRIOXIDE PRODUCTION		
Boiler	wt% SO_2	0.4
SCR	wt% SO_2	1.5

REMOVAL EFFICIENCIES		
Ash-Boiler	wt%	20.0
FLUE GAS TEMPERATURE		
Ambient	°F	100
Econ. Out	°F	780
SCR Out	°F	780
FLUE GAS PRESSURE		
Ambient	psia	11.46
Econ. Out	in. w.g.	-8
SCR Out	in. w.g.	-16

GAS STREAMS

Stream Characteristics		Combustion Air		Economizer Outlet		SCR Outlet	
Temperature	°F	100		780		780	
Pressure	psia	11.460		11.172		10.883	
N_2	lb/hr-vol%	4,417,676	77.65	4,424,336	72.62	4,424,336	72.62
O_2	lb/hr-vol%	1,330,764	20.47	330,917	4.75	330,917	4.75
H_2O	lb/hr-vol%	68,981	1.89	385,529	9.84	385,529	9.84
CO_2	lb/hr-vol%	0	0.00	1,218,529	12.73	1,218,529	12.73
SO_2	lb/hr-ppmv	0	0	7,892	567	7,773	558
SO_3	lb/hr-ppmv	0	0	40	2	188	11
HCl	lb/hr-ppmv	0	0	0	0	0	0
HF	lb/hr-ppmv	0	0	0	0	0	0
Total Flow	lb/hr-acfm	5,817,421	1,775,036	6,367,243	4,317,522	6,367,273	4,431,888
MW & Moist.	g/mol-lb/lb	28.630	0.012	29.263	0.064	29.263	0.064
Ash	lb/hr-gr/acf	0	0.000	56,009	1.513	56,009	1.474

SCR Mass Balance
Full Load Design (High S)

DESIGN PARAMETERS

COAL ANALYSIS		
Carbon	wt%	53.69
Hydrogen	wt%	3.56
Nitrogen	wt%	1.08
Sulfur	wt%	0.80
Oxygen	wt%	10.76
Chlorine	wt%	0.00
Fluorine	wt%	0.00
Moisture	wt%	19.10
Ash	wt%	11.31
Meas. HHV	Btu/lb	9,208

PLANT PRODUCTION		
MCR Output	MW	570.0
Heat Input	mmBtu/hr	5,700.0
Firing Rate	lb/hr	619,027
AIR DATA		
Excess Air	wt%	33.1
Air H_2O	lb/lb dry air	0.012
SULFUR TRIOXIDE PRODUCTION		
Boiler	wt% SO_2	0.4
SCR	wt% SO_2	1.5

REMOVAL EFFICIENCIES		
Ash-Boiler	wt%	20.0
FLUE GAS TEMPERATURE		
Ambient	°F	100
Econ. Out	°F	780
SCR Out	°F	780
FLUE GAS PRESSURE		
Ambient	psia	11.46
Econ. Out	in. w.g.	-8
SCR Out	in. w.g.	-16

GAS STREAMS

Stream Characteristics		Combustion Air		Economizer Outlet		SCR Outlet	
Temperature	°F	100		780		780	
Pressure	psia	11.460		11.172		10.883	
N_2	lb/hr-vol%	4,422,034	77.65	4,428,695	72.62	4,428,695	72.62
O_2	lb/hr-vol%	1,332,077	20.47	331,238	4.75	331,238	4.75
H_2O	lb/hr-vol%	69,049	1.89	385,597	9.84	385,597	9.84
CO_2	lb/hr-vol%	0	0.00	1,218,529	12.72	1,218,529	12.72
SO_2	lb/hr-ppmv	0	0	9,865	708	9,717	697
SO_3	lb/hr-ppmv	0	0	50	3	234	13
HCl	lb/hr-ppmv	0	0	0	0	0	0
HF	lb/hr-ppmv	0	0	0	0	0	0
Total Flow	lb/hr-acfm	5,823,160	1,776,787	6,373,974	4,321,499	6,374,011	4,435,970
MW & Moist.	g/mol-lb/lb	28.630	0.012	29.267	0.064	29.267	0.064
Ash	lb/hr-gr/acf	0	0.000	56,009	1.512	56,009	1.473

SCR Mass Balance
Low Load Design

DESIGN PARAMETERS

COAL ANALYSIS		
Carbon	wt%	53.69
Hydrogen	wt%	3.56
Nitrogen	wt%	1.08
Sulfur	wt%	0.64
Oxygen	wt%	10.76
Chlorine	wt%	0.00
Fluorine	wt%	0.00
Moisture	wt%	19.10
Ash	wt%	11.31
Meas. HHV	Btu/lb	9,208

PLANT PRODUCTION		
MCR Output	MW	250.0
Heat Input	mmBtu/hr	2,500
Firing Rate	lb/hr	271,503
AIR DATA		
Excess Air	wt%	29.650
Air H_2O	lb/lb dry air	0.012
SULFUR TRIOXIDE PRODUCTION		
Boiler	wt% SO_2	1.0
SCR	wt% SO_2	0.8

REMOVAL EFFICIENCIES		
Ash-Boiler	wt%	20.0
FLUE GAS TEMPERATURE		
Ambient	°F	100
Econ. Out	°F	600
SCR Out	°F	600
FLUE GAS PRESSURE		
Ambient	psia	11.46
Econ. Out	in. w.g.	-3
SCR Out	in. w.g.	-11

GAS STREAMS

Stream Characteristics		Combustion Air		Economizer Outlet		SCR Outlet	
Temperature	°F	100		600		600	
Pressure	psia	11.460		11.352		11.064	
N_2	lb/hr-vol%	1,887,309	77.65	1,890,231	72.49	1,890,231	72.49
O_2	lb/hr-vol%	568,526	20.47	129,992	4.36	129,992	4.36
H_2O	lb/hr-vol%	29,470	1.89	168,307	10.04	168,307	10.04
CO_2	lb/hr-vol%	0	0.00	534,443	13.04	534,443	13.04
SO_2	lb/hr-ppmv	0	0	3,440	577	3,413	573
SO_3	lb/hr-ppmv	0	0	43	6	78	10
HCl	lb/hr-ppmv	0	0	0	0	0	0
HF	lb/hr-ppmv	0	0	0	0	0	0
Total Flow	lb/hr-acfm	2,485,305	758,327	2,726,456	1,554,474	2,726,463	1,594,979
MW & Moist.	g/mol-lb/lb	28.630	0.012	29.278	0.066	29.279	0.066
Ash	lb/hr-gr/acf	0	0.000	24,565	1.844	24,565	1.797

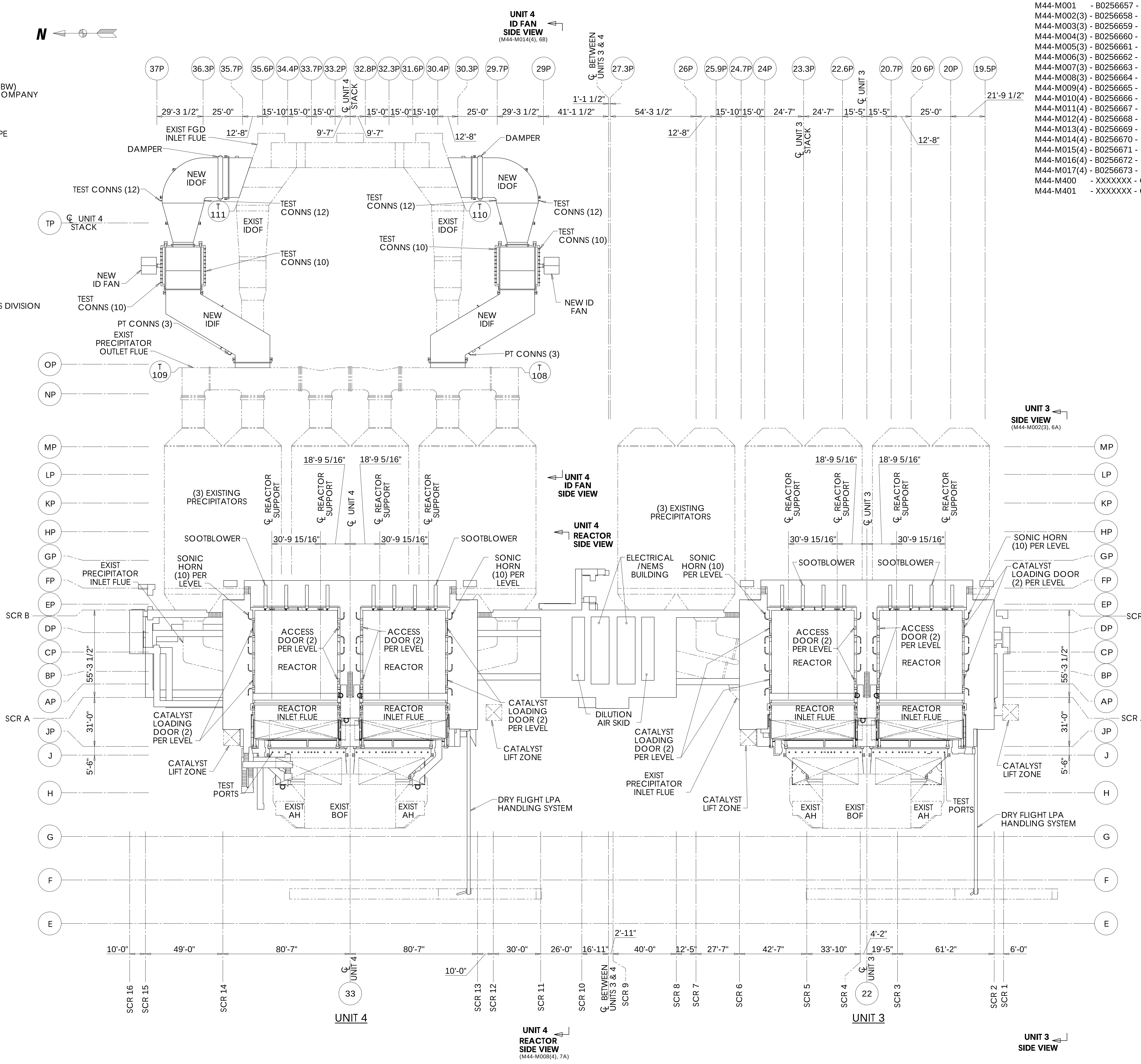
Exhibit PAC/4003
Owen/96

ATTACHMENT 2

JIM BRIDGER SCR UNITS 3&4 GENERAL ARRANGEMENT DRAWING

ABBREVIATIONS

- & - AND
- ~ - APPROXIMATELY
- @ - AT
- # - POUND
- AD - ACCESS DOOR
- AH - AIR HEATER
- AHOF - AIR HEATER OUTLET FLUE
- AIG - AMMONIA INJECTION GRID
- APC - AIR POLLUTION CONTROL
- ARRGT - ARRANGEMENT
- ASSY - ASSEMBLY
- AV - AMMONIA VAPOR
- B/B - BACK TO BACK
- B&W - BABCOCK & WILCOX (ALSO SHOWN AS BW)
- BWCC - BABCOCK & WILCOX CONSTRUCTION COMPANY
- BL - BEND LINE
- BLR - BOILER
- BNR - BURNER
- BOF - BOILER OUTLET FLUE
- BOP - BALANCE OF PLANT -OR- BOTTOM OF PIPE
- BOTT - BOTTOM
- BT - BENT
- BW - BUTTWELD -OR- BABCOCK & WILCOX
- C/C - CENTERLINE TO CENTERLINE
- CHAN - CHANNEL
- CHGD - CHANGED
- CJP - COMPLETE JOINT PENETRATION
- ℄ - CENTERLINE
- CL - CLEARANCE LINE
- COL - COLUMN
- CONN(S) - CONNECTION(S)
- CONT. - CONTINUED
- CSG - CASING
- DEA - DESIGN ERECTION ARRANGEMENT
- DIA - DIAMETER (ALSO SHOWN AS ∅)
- DIM(S) - DIMENSION(S)
- DPR - DAMPER
- DWG(S) - DRAWING(S)
- EA - ERECTION ARRANGEMENT
- EL - ELEVATION
- EOF - ECONOMIZER OUTLET FLUE
- EPSD - ENVIRONMENTAL PRODUCTS & SERVICES DIVISION
- EXIST - EXISTING
- EXP - EXPANSION
- F/A - FORE/AFT
- F/F - FACE OF FLANGE
- F.W. - FIELD WELD
- FAB - FABRICATED
- FGD - FLUE GAS DESULFURIZATION
- FIG. - FIGURE
- FIN - FINISHING
- FLD - FIELD
- FLG - FLANGE
- FLR. - FLOOR
- FS - FAR SIDE
- FS - FIELD SPLICE
- FURN - FURNACE
- FW - FRONT WALL
- GA - GAUGE -OR- GENERAL ARRANGEMENT
- GAS/GAS - GAS TO GAS
- GEN - GENERAL
- GRT'G - GRATING
- HGR - HANGER
- HP - HIGH POINT
- HVY - HEAVY
- HRN - SONIC HORN
- HT - HEAT
- ID - INDUCED DRAFT -OR- INSIDE DIAMETER
- ISO - ISOMETRIC
- IDIF - INDUCED DRAFT FAN INLET FLUE
- IDOF - INDUCED DRAFT FAN OUTLET FLUE
- INS - INSIDE
- INS/INS - INSIDE TO INSIDE
- INSUL - INSULATION
- L.H. - LEFT HAND
- LF - LINEAL FEET
- LG - LENGTH -OR- LONG
- LHSW - LEFT HAND SIDE WALL
- LLV - LONG LEG VERTICAL
- LPA - LARGE PARTICLE ASH
- MAX - MAXIMUM
- MIN - MINIMUM
- MOD - MODIFICATION
- MVS - MANIFOLD VALVE STATION
- NA - NOT APPLICABLE
- NE - ERECTOR NOTE
- NEMS - NOX EMISSIONS MONITORING SYSTEM
- NO. - NUMBER
- NS - NEAR SIDE
- NTE - NOT TO EXCEED
- NTS - NOT TO SCALE
- OAL - OVERALL LENGTH
- OD - OUTSIDE DIAMETER
- OPP - OPPOSITE
- ORIG - ORIGINAL
- PDT - PRESSURE DIFFERENTIAL TRANSMITTER
- PERF - PERFORATED
- PGG - POWER GENERATION GROUP
- PGL - PERRY GROUP LTD.
- PL - PLATE (ALSO SHOWN AS ℙ)
- PLAT(S) - PLATFORM(S)
- PN - PART NUMBER
- PT - PRESSURE TRANSMITTER
- QTY - QUANTITY
- R - RADIUS
- R.H. - RIGHT HAND
- REC - REACTOR
- REF - REFERENCE
- REQ'D - REQUIRED
- REV - REVISION
- RHSW - RIGHT HAND SIDE WALL
- RIF - REACTOR INLET FLUE
- ROF - REACTOR OUTLET FLUE
- RW - REAR WALL
- S/S - SIDE TO SIDE
- S&L - SARGENT & LUNDY
- SB - SOOTBLOWER
- SCH - SCHEDULE
- SCR - SELECTIVE CATALYTIC REDUCTION
- SECT(S) - SECTION(S)
- SPCS - SPACES
- SQ - SQUARE
- SS - STAINLESS STEEL
- STD - STANDARD
- STIF - STIFFENER
- STL - STEEL
- SUB - SUBLET
- SUP - SUPPORT
- SYMM - SYMMETRICAL
- SYS - SYSTEM
- T/ - TOP OF
- TAN/TAN - TANGENT TO TANGENT
- TE - TEMPERATURE ELEMENT
- THK - THICK
- TOC - TOP OF CONCRETE
- TOS - TOP OF STEEL
- TV(S) - TURNING VANE(S)
- TYP - TYPICAL
- U3 - UNIT 3
- U4 - UNIT 4
- UNO - UNLESS NOTED OTHERWISE
- W/ - WITH
- WP - WORK POINT
- XJ - EXPANSION JOINT



KEY PLAN VIEW

DRAWING LIST

- M44-M001 - B0256657 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - KEY PLAN, GENERAL NOTES - & DRAWING LIST
- M44-M002(3) - B0256658 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 3 SIDE VIEW - LOOKING NORTH
- M44-M003(3) - B0256659 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 3 PLAN VIEW A-A
- M44-M004(3) - B0256660 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 3 PLAN SECTION B-B
- M44-M005(3) - B0256661 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 3 PLAN SECTION C-C
- M44-M006(3) - B0256662 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 3 SECTION D-D - LOOKING EAST
- M44-M007(3) - B0256663 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 3 SECTION E-E - LOOKING EAST
- M44-M008(3) - B0256664 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 3 VIEW F-F - LOOKING WEST
- M44-M009(4) - B0256665 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 4 REACTOR SIDE VIEW - LOOKING NORTH
- M44-M010(4) - B0256666 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 4 PLAN VIEW G-G
- M44-M011(4) - B0256667 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 4 PLAN SECTION H-H
- M44-M012(4) - B0256668 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 4 PLAN SECTION J-J
- M44-M013(4) - B0256669 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 4 SECTION K-K - LOOKING EAST
- M44-M014(4) - B0256670 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 4 SECTION L-L - LOOKING EAST
- M44-M015(4) - B0256671 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 4 VIEW M-M - LOOKING WEST
- M44-M016(4) - B0256672 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 4 ID FAN SIDE VIEW - LOOKING NORTH
- M44-M017(4) - B0256673 - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 4 PLAN VIEW N-N
- M44-M400 - XXXXXXX - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 3 & 4 AMMONIA STORAGE PLAN
- M44-M401 - XXXXXXX - GENERAL ARRANGEMENT - PACIFICORP JIM BRIDGER - UNIT 3 & 4 AMMONIA STORAGE ELEVATION

SYMBOL NOMENCLATURE

- ANCHOR POINT
- CLEARANCE LINE
- COLUMN ROW INDICATOR
- GAS FLOW DIRECTION
- TERMINATION OF B&W WORK
- THERMAL EXPANSION
- PLATFORM GRATING
- 4MO0001 - DAMPER TAG NUMBER (NUMBER, SYSTEM, *=UNIT NUMBER)
- *XJ0002 - EXPANSION JOINT TAG NUMBER (NUMBER, EQUIPMENT TYPE, *=UNIT NUMBER)
- *SH0003 - SONIC HORN TAG NUMBER (NUMBER, EQUIPMENT TYPE, *=UNIT NUMBER)
- *SB0004 - SOOTBLOWER TAG NUMBER (NUMBER, EQUIPMENT TYPE, *=UNIT NUMBER)
- * RIF 4A02 - SUPPORT TAG NUMBER (NUMBER, MODULE NUMBER, SYSTEM, *=UNIT NUMBER)

NOTE A:

ANY STEEL OR EQUIPMENT THAT EXTENDS INTO CLEARANCE LINES IS TO HAVE SPECIAL CONSIDERATION FOR: BRIL, STIFFENER LOCATIONS, STIFFENER SIZING, AND CONSTRUCTION SEQUENCING.

NOTES:

DO NOT USE THIS DRAWING FOR FIELD CUTS OR FOR ERECTION PURPOSES. SEE APPLICABLE DESIGN ERECTION ARRANGEMENT DRAWING.

ATTENTION ALL DOWNSTREAM USERS: ANY CHANGE IN LOCATION OF WORK POINTS, SUPPORTS, TIES, DOORS, ETC., FROM THAT SHOWN MUST FIRST BE CLEARED WITH BABCOCK AND WILCOX POWER GENERATION GROUP, INC.

No.	DATE	REVISION
1	8/30/13	SEE REVISION TRANSMITTAL DRAWINGS M44-M018 THRU M44-M020.

ELECTRONIC FILE NAME = B0256657.idw.idw — PLOT SCALE : 1 = 1

Babcock & Wilcox Power Generation Group, Inc.
20 SOUTH VAN BUREN AVENUE, BARBERTON, OHIO

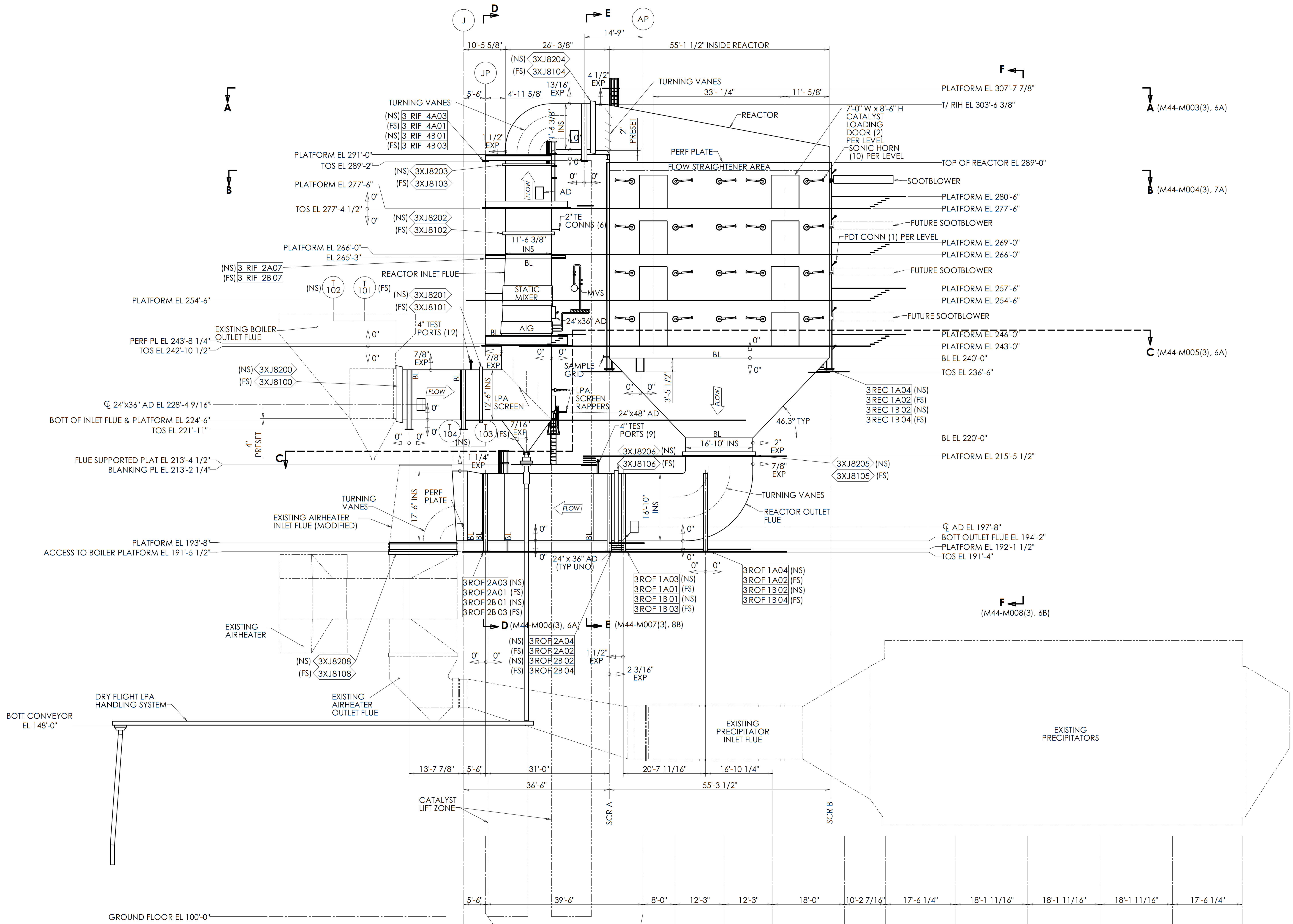
PROJECT NO	0635-2827
COA	B00000
DWG NO	B0256657 J
REV	1
PROJ #	M44
DATE	05/24/13
DR	Cunningham
CH	D.A.RADTKA
APPROVAL	T.DAVEY

GENERAL ARRANGEMENT
PACIFICORP JIM BRIDGER
KEY PLAN, GENERAL NOTES
& DRAWING LIST

PACIFICORP ENERGY — JIM BRIDGER PLANT

SCALE 3/64"=1'-0" — SHEET 1 of 1 — M44-M001 — REV 1

DWG NO B0256657 REV 1



UNIT 3 SIDE VIEW
LOOKING NORTH
(M44-M001, 4G)

NOTES:

1. FOR GENERAL NOTES, SYMBOLS, AND DRAWING LIST SEE DRAWING M44-M001/B0256657.

Babcock & Wilcox Power Generation Group, Inc.
20 SOUTH VAN BUREN AVENUE, BARBERTON, OHIO

PROJECT NO	0635-282T
COA	B00000
DWG NO	B0256658
REV	1
PROJ #	M44
DATE	05/24/13
DR	D.W.OVER
CK	D.A.RADTKA

GENERAL ARRANGEMENT
PACIFICORP JIM BRIDGER
UNIT 3 SIDE VIEW
LOOKING NORTH

APPROVAL

REDRAWN FROM

PACIFICORP ENERGY

JIM BRIDGER PLANT

SCALE 1/8"=1'-0" SHEET 1 of 1 M44-M002(3) REV 1

REVISION: 1 8/30/13 SEE REVISION TRANSMITTAL DRAWINGS M44-M018 THRU M44-M020.

ELECTRONIC FILE NAME = B0256658.slddrw

ATTACHMENT 3A

AVERAGE COST EFFECTIVENESS CALCULATIONS

(20 YEAR REMAINING LIFE)

Cost Effectiveness Calculation Worksheet (20 Year Life)

Jim Bridger Station: Cost-Effectiveness Calculations

Unit 1-4 - Baseline (w/LNB and FGD Upgrade on All & SCR on Units 3&4)

	Average Emission Rate (2013-2015)	Annual Heat Input (2001-2003)	Total Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.120	167,077,611	10,025
SO_2	0.162	167,077,611	13,532
Total			**23,557**

SNCR on Unit 1&2

	Average Emission Rate[1]	Annual Heat Input (2001-2003)	Total Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.100	167,077,611	8,371	1,654	$ 31,076,000	0.0944	$ 2,934,000	$ 6,112,000	$ 9,046,000	$ 5,469
SO_2	0.162	167,077,611	13,532	-	$ -		$ -	$ -	$ -	$ -
Total			**21,903**	**1,654**	$ 31,076,000	0.0944	$ 2,934,000	$ 6,112,000	$ 9,046,000	$ 5,469

SCR on Units 1 & 2

	Average Emission Rate	Annual Heat Input (2001-2003)	Total Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	1463	167,077,611	4,177	5,847	$ 280,856,000	0.0944	$ 26,512,000	$ 5,107,000	$ 31,619,000	$ 5,407
SO_2	3917	167,077,611	13,532	-	$ -	-	$ -	$ -	$ -	$ -
Total			**17,709**	**5,847**	$ 280,856,000	0.0944	$ 26,512,000	$ 5,107,000	$ 31,619,000	$ 5,407

RP Reassessment (Operational Limits on Units 1-4)

	Average Emission Rate	Annual Heat Input[3]	Total Annual Emissions[2]	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	2234	N/A	9,018	1,007	$ -	0.0944	$ -	$ (119,000)	$ (119,000)	$ (118)
SO_2	2100	N/A	8,483	5,049	$ 4,659,000	0.0944	$ 441,000	$ 1,741,000	$ 2,182,000	$ 432
Total			**17,501**	**6,056**	$ 4,659,000	0.0944	$ 440,000	$ 1,622,000	$ 2,062,000	$ 341

[1]Controlled NO_X Emission Rate with SNCR was assumed to be 0.15 lb./MMBtu; corresponding to reduction of approximately 20%.

[2]Proposed emissions from PacifiCorp for RP Reassessment.

[3]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.

Cost Effectiveness Calculation Worksheet (20 Year Life)

Jim Bridger Station: Cost-Effectiveness Calculations

Unit 1 - Baseline with LNB & FGD Upgrades (2013-2015)

	Emission Rate (2013-2015)	Annual Heat Input (2001-2003)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.187	42,977,652	4,018
SO_2	0.140	42,977,652	3,012
Total			**7,030**

Unit 1 - SNCR

	Emission Rate[1]	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.150	42,977,652	3,223	795	$ 15,538,000	0.0944	$ 1,467,000	$ 2,954,000	$ 4,421,000	$ 5,560
SO_2	0.140	42,977,652	3,012	-	$ -	0.0944	$ -	$ -	$ -	$ -
Total			**6,235**	**795**	$ 15,538,000	0.0944	$ 1,467,000	$ 2,954,000	$ 4,421,000	$ 5,560

Unit 1 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	355	42,977,652	1,074	2,944	$ 140,428,000	0.0944	$ 13,256,000	$ 2,580,000	$ 15,836,000	$ 5,379
SO_2	907	42,977,652	3,012	-	$ -	0.0944	$ -	$ -	$ -	$ -
Total			**4,086**	**2,944**	$ 140,428,000	0.0944	$ 13,256,000	$ 2,580,000	$ 15,836,000	$ 5,379

Unit 1 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[3]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	750	N/A	3,506	512	$ -	0.0944	$ -	$ -	$ -	$ -
SO_2	525	N/A	2,121	891	$ 1,553,000	0.0944	$ 147,000	$ 376,000	$ 523,000	$ 587
Total			**5,627**	**1,404**	$ 1,553,000	0.0944	$ 147,000	$ 376,000	$ 523,000	$ 373

[1]Controlled NO_X Emission Rate with SNCR was assumed to be 0.15 lb./MMBtu; corresponding to reduction of approximately 20%.
[2]Proposed emissions from PacifiCorp for RP Reassessment.
[3]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.

Cost Effectiveness Calculation Worksheet (20 Year Life)

Unit 2 - Baseline with LNB & FGD Upgrades (2013-2015)

	Emission Rate (2013-2015)	Annual Heat Input (2001-2003)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.192	40,898,999	3,926
SO_2	0.178	40,898,999	3,649
Total			**7,575**

Unit 2 - SNCR

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	0.150	40,898,999	3,067	859	$ 15,538,000	0.0944	$ 1,467,000	$ 3,158,000	$ 4,625,000	$ 5,385
SO_2	0.178	40,898,999	3,649	-	$ -	0.0944	$ -	$ -	$ -	$ -
Total			**6,716**	**859**	$ 15,538,000	0.0944	$ 1,467,000	$ 3,158,000	$ 4,625,000	$ 5,385

Unit 2 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	374	40,898,999	1,023	2,903	$ 140,428,000	0.0944	$ 13,256,000	$ 2,527,000	$ 15,783,000	$ 5,436
SO_2	1118	40,898,999	3,649	-	$ -	0.0944	$ -	$ -	$ -	$ -
Total			**4,672**	**2,903**	$ 140,428,000	0.0944	$ 13,256,000	$ 2,527,000	$ 15,783,000	$ 5,436

Unit 2 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[3]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	750	N/A	3,506	420	$ -	0.0944	$ -	$ -	$ -	$ -
SO_2	525	N/A	2,121	1,528	$ 1,553,000	0.0944	$ 147,000	$ 522,000	$ 669,000	$ 438
Total			**5,627**	**1,949**	$ 1,553,000	0.0944	$ 147,000	$ 522,000	$ 669,000	$ 343

[1]Controlled NO_X Emission Rate with SNCR was assumed to be 0.15 lb./MMBtu; corresponding to reduction of approximately 20%.

[2]Proposed emissions from PacifiCorp for RP Reassessment.

[3]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.

Cost Effectiveness Calculation Worksheet (20 Year Life)

Unit 3 - Baseline with LNB, SCR & FGD Upgrades (2013-2015)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions
	lb/hour	MMBtu	tpy
NO_X	359	42,166,755	1,054
SO_2	1010	42,166,755	3,430
Total			**4,484**

Unit 3 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	359	42,166,755	1,054	-	$ -	0.0944	$ -	$ -	$ -	$ -
SO_2	1010	42,166,755	3,430	-	$ -	0.0944	$ -	$ -	$ -	$ -
Total			**4,484**	**-**	$ -	0.0944	$ -	$ -	$ -	$ -

Unit 3 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[1]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	359	N/A	1,003	51	$ -	0.0944	$ -	$ (80,000)	$ (80,000)	$ (1,569)
SO_2	525	N/A	2,121	1,309	$ 1,553,000	0.0944	$ 147,000	$ 537,000	$ 684,000	$ 522
Total			**3,124**	**1,360**	$ 1,553,000	0.0944	$ 147,000	$ 457,000	$ 604,000	$ 444

[1]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.
[2]Proposed emissions from PacifiCorp for RP Reassessment.

Cost Effectiveness Calculation Worksheet (20 Year Life)

Unit 4 - Revised Baseline with LNB, SCR & FGD Upgrades (2013-2015)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions
	lb/hour	MMBtu	tpy
NO_X	375	41,034,206	1,026
SO_2	882	41,034,206	3,441
Total			**4,467**

Unit 4 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	375	41,034,206	1,026	-	$ -	0.0944	$ -	$ -	$ -	$ -
SO_2	882	41,034,206	3,441	-	$ -	0.0944	$ -	$ -	$ -	$ -
Total			**4,467**	**-**	$ -	0.0944	$ -	$ -	$ -	$ -

Unit 4 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[1]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	375	N/A	1,003	23	$ -	0.0944	$ -	$ (39,000)	$ (39,000)	$ (1,696)
SO_2	525	N/A	2,121	1,320	$ -	0.0944	$ -	$ 306,000	$ 306,000	$ 232
Total			**3,124**	**1,343**	$ -	0.0944	$ -	$ 267,000	$ 267,000	$ 199

[1]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.
[2]Proposed emissions from PacifiCorp for RP Reassessment.

ATTACHMENT 3B

AVERAGE COST EFFECTIVENESS CALCULATIONS

(30 YEAR REMAINING LIFE)

Cost Effectiveness Calculation Worksheet (30 Year Life)

Jim Bridger Station: Cost-Effectiveness Calculations

Unit 1-4 - Baseline (w/LNB and FGD Upgrade on All & SCR on Units 3&4)

	Average Emission Rate (2013-2015)	Annual Heat Input (2001-2003)	Total Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.120	167,077,611	10,025
SO_2	0.162	167,077,611	13,532
Total			**23,557**

SNCR on Unit 1&2

	Average Emission Rate[1]	Annual Heat Input (2001-2003)	Total Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.100	167,077,611	8,371	1,654	$ 31,076,000	0.0806	$ 2,504,000	$ 6,112,000	$ 8,616,000	$ 5,209
SO_2	0.162	167,077,611	13,532	-	$ -		$ -	$ -	$ -	$ -
Total			**21,903**	**1,654**	$ 31,076,000	0.0806	$ 2,504,000	$ 6,112,000	$ 8,616,000	$ 5,209

SCR on Units 1 & 2

	Average Emission Rate	Annual Heat Input (2001-2003)	Total Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	1463	167,077,611	4,177	5,848	$ 280,856,000	0.0806	$ 22,636,000	$ 5,107,000	$ 27,743,000	$ 4,744
SO_2	3917	167,077,611	13,532	-	$ -	-	$ -	$ -	$ -	$ -
Total			**17,709**	**5,848**	$ 280,856,000	0.0806	$ 22,636,000	$ 5,107,000	$ 27,743,000	$ 4,744

RP Reassessment (Operational Limits on Units 1-4)

	Average Emission Rate	Annual Heat Input[3]	Total Annual Emissions[2]	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	2234	N/A	9,018	1,007	$ -	0.0806	$ -	$ (119,000)	$ (119,000)	$ (118)
SO_2	2100	N/A	8,483	5,049	$ 4,659,000	0.0806	$ 375,000	$ 1,741,000	$ 2,116,000	$ 419
Total			**17,501**	**6,056**	$ 4,659,000	0.0806	$ 376,000	$ 1,622,000	$ 1,998,000	$ 330

[1]Controlled NO_X Emission Rate with SNCR was assumed to be 0.15 lb./MMBtu; corresponding to reduction of approximately 20%.

[2]Proposed emissions from PacifiCorp for RP Reassessment.

[3]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.

Cost Effectiveness Calculation Worksheet (30 Year Life)

Jim Bridger Station: Cost-Effectiveness Calculations

Unit 1 - Baseline with LNB & FGD Upgrades (2013-2015)

	Emission Rate (2013-2015)	Annual Heat Input (2001-2003)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.187	42,977,652	4,018
SO_2	0.140	42,977,652	3,012
Total			**7,030**

Unit 1 - SNCR

	Emission Rate[1]	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.150	42,977,652	3,223	795	$ 15,538,000	0.0806	$ 1,252,000	$ 2,954,000	$ 4,206,000	$ 5,290
SO_2	0.140	42,977,652	3,012	-	$ -	0.0806	$ -	$ -	$ -	$ -
Total			**6,235**	**795**	$ 15,538,000	0.0806	$ 1,252,000	$ 2,954,000	$ 4,206,000	$ 5,290

Unit 1 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	355	42,977,652	1,074	2,944	$ 140,428,000	0.0806	$ 11,318,000	$ 2,580,000	$ 13,898,000	$ 4,720
SO_2	907	42,977,652	3,012	-	$ -	0.0806	$ -	$ -	$ -	$ -
Total			**4,086**	**2,944**	$ 140,428,000	0.0806	$ 11,318,000	$ 2,580,000	$ 13,898,000	$ 4,720

Unit 1 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[3]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	750	N/A	3,506	512	$ -	0.0806	$ -	$ -	$ -	$ -
SO_2	525	N/A	2,121	891	$ 1,553,000	0.0806	$ 125,000	$ 376,000	$ 501,000	$ 562
Total			**5,627**	**1,404**	$ 1,553,000	0.0806	$ 125,000	$ 376,000	$ 501,000	$ 357

[1]Controlled NO_X Emission Rate with SNCR was assumed to be 0.15 lb./MMBtu; corresponding to reduction of approximately 20%.
[2]Proposed emissions from PacifiCorp for RP Reassessment.
[3]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.

Cost Effectiveness Calculation Worksheet (30 Year Life)

Unit 2 - Baseline with LNB & FGD Upgrades (2013-2015)

	Emission Rate (2013-2015)	Annual Heat Input (2001-2003)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.192	40,898,999	3,926
SO_2	0.178	40,898,999	3,649
Total			**7,575**

Unit 2 - SNCR

	Emission Rate[1]	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	0.150	40,898,999	3,067	859	$ 15,538,000	0.0806	$ 1,252,000	$ 3,158,000	$ 4,410,000	$ 5,135
SO_2	0.178	40,898,999	3,649	-	$ -	0.0806	$ -	$ -	$ -	$ -
Total			**6,716**	**859**	$ 15,538,000	0.0806	$ 1,252,000	$ 3,158,000	$ 4,410,000	$ 5,135

Unit 2 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	374	40,898,999	1,023	2,903	$ 140,428,000	0.0806	$ 11,318,000	$ 2,527,000	$ 13,845,000	$ 4,769
SO_2	1118	40,898,999	3,649	-	$ -	0.0806	$ -	$ -	$ -	$ -
Total			**4,672**	**2,903**	$ 140,428,000	0.0806	$ 11,318,000	$ 2,527,000	$ 13,845,000	$ 4,769

Unit 2 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[3]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	750	N/A	3,506	420	$ -	0.0806	$ -	$ -	$ -	$ -
SO_2	525	N/A	2,121	1,528	$ 1,553,000	0.0806	$ 125,000	$ 522,000	$ 647,000	$ 423
Total			**5,627**	**1,949**	$ 1,553,000	0.0806	$ 125,000	$ 522,000	$ 647,000	$ 332

[1]Controlled NO_X Emission Rate with SNCR was assumed to be 0.15 lb./MMBtu; corresponding to reduction of approximately 20%.

[2]Proposed emissions from PacifiCorp for RP Reassessment.

[3]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.

Cost Effectiveness Calculation Worksheet (30 Year Life)

Unit 3 - Baseline with LNB, SCR & FGD Upgrades (2013-2015)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions
	lb/hour	MMBtu	tpy
NO_X	359	42,166,755	1,054
SO_2	1010	42,166,755	3,430
Total			**4,484**

Unit 3 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	359	42,166,755	1,054	-	$ -	0.0806	$ -	$ -	$ -	$ -
SO_2	1010	42,166,755	3,430	-	$ -	0.0806	$ -	$ -	$ -	$ -
Total			**4,484**	**-**	$ -	0.0806	$ -	$ -	$ -	$ -

Unit 3 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[1]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	359	N/A	1,003	51	$ -	0.0806	$ -	$ (80,000)	$ (80,000)	$ (1,569)
SO_2	525	N/A	2,121	1,309	$ 1,553,000	0.0806	$ 125,000	$ 537,000	$ 662,000	$ 506
Total			**3,124**	**1,360**	$ 1,553,000	0.0806	$ 125,000	$ 457,000	$ 582,000	$ 428

[1]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.
[2]Proposed emissions from PacifiCorp for RP Reassessment.

Cost Effectiveness Calculation Worksheet (30 Year Life)

Unit 4 - Revised Baseline with LNB, SCR & FGD Upgrades (2013-2015)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions
	lb/hour	MMBtu	tpy
NO_X	375	41,034,206	1,026
SO_2	882	41,034,206	3,441
Total			**4,467**

Unit 4 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	375	41,034,206	1,026	-	$ -	0.0806	$ -	$ -	$ -	$ -
SO_2	882	41,034,206	3,441	-	$ -	0.0806	$ -	$ -	$ -	$ -
Total			**4,467**	**-**	$ -	0.0806	$ -	$ -	$ -	$ -

Unit 4 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[1]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	375	N/A	1,003	23	$ -	0.0806	$ -	$ (39,000)	$ (39,000)	$ (1,696)
SO_2	525	N/A	2,121	1,320	$ -	0.0806	$ -	$ 306,000	$ 306,000	$ 232
Total			**3,124**	**1,343**	$ -	0.0806	$ -	$ 267,000	$ 267,000	$ 199

[1]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.
[2]Proposed emissions from PacifiCorp for RP Reassessment.

ATTACHMENT 3C

AVERAGE COST EFFECTIVENESS CALCULATIONS

(RETIREMENT BY 12/31/2037)

Cost Effectiveness Calculation Worksheet (12/31/2037 Retirement Date)

Jim Bridger Station: Cost-Effectiveness Calculations

Unit 1-4 - Baseline (w/LNB and FGD Upgrade on All & SCR on Units 3&4)

	Average Emission Rate (2013-2015)	Annual Heat Input (2001-2003)	Total Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.120	167,077,611	10,025
SO_2	0.162	167,077,611	13,532
Total			**23,557**

SNCR on Unit 1&2

	Average Emission Rate[1]	Annual Heat Input (2001-2003)	Total Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.100	167,077,611	8,371	1,654	$ 31,076,000	0.1059	$ 3,290,000	$ 6,112,000	$ 9,402,000	$ 5,685
SO_2	0.162	167,077,611	13,532	-	$ -		$ -	$ -	$ -	$ -
Total			**21,903**	**1,654**	$ 31,076,000	0.1059	$ 3,290,000	$ 6,112,000	$ 9,402,000	$ 5,685

SCR on Units 1 & 2

	Average Emission Rate	Annual Heat Input (2001-2003)	Total Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	1463	N/A	4,177	5,848	$ 280,856,000	0.1059	$ 29,742,000	$ 5,107,000	$ 34,849,000	$ 5,959
SO_2	3917	N/A	13,532	-	$ -	-	$ -	$ -	$ -	$ -
Total			**17,709**	**5,848**	$ 280,856,000	0.1059	$ 29,742,000	$ 5,107,000	$ 34,849,000	$ 5,959

RP Reassessment (Operational Limits on Units 1-4)

	Average Emission Rate	Annual Heat Input[3]	Total Annual Emissions[2]	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	2234	N/A	9,018	1,007	$ -	0.1059	$ -	$ (119,000)	$ (119,000)	$ (118)
SO_2	2100	N/A	8,483	5,049	$ 4,659,000	0.1059	$ 492,000	$ 1,741,000	$ 2,233,000	$ 442
Total			**17,501**	**6,056**	$ 4,659,000	0.1059	$ 493,000	$ 1,622,000	$ 2,115,000	$ 349

[1]Controlled NO_X Emission Rate with SNCR was assumed to be 0.15 lb./MMBtu; corresponding to reduction of approximately 20%.
[2]Proposed emissions from PacifiCorp for RP Reassessment.
[3]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.

Cost Effectiveness Calculation Worksheet (12/31/2037 Retirement Date)

Jim Bridger Station: Cost-Effectiveness Calculations

Unit 1 - Baseline with LNB & FGD Upgrades (2013-2015)

	Emission Rate (2013-2015)	Annual Heat Input (2001-2003)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.187	42,977,652	4,018
SO_2	0.140	42,977,652	3,012
Total			**7,030**

Unit 1 - SNCR

	Emission Rate[1]	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.150	42,977,652	3,223	795	$ 15,538,000	0.1059	$ 1,645,000	$ 2,954,000	$ 4,599,000	$ 5,784
SO_2	0.140	42,977,652	3,012	-	$ -	0.1059	$ -	$ -	$ -	$ -
Total			**6,235**	**795**	$ 15,538,000	0.1059	$ 1,645,000	$ 2,954,000	$ 4,599,000	$ 5,784

Unit 1 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	355	42,977,652	1,074	2,944	$ 140,428,000	0.1059	$ 14,871,000	$ 2,580,000	$ 17,451,000	$ 5,927
SO_2	907	42,977,652	3,012	-	$ -	0.1059	$ -	$ -	$ -	$ -
Total			**4,086**	**2,944**	$ 140,428,000	0.1059	$ 14,871,000	$ 2,580,000	$ 17,451,000	$ 5,927

Unit 1 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[3]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	750	N/A	3,506	512	$ -	0.1059	$ -	$ -	$ -	$ -
SO_2	525	N/A	2,121	891	$ 1,553,000	0.1059	$ 164,000	$ 376,000	$ 540,000	$ 606
Total			**5,627**	**1,404**	$ 1,553,000	0.1059	$ 164,000	$ 376,000	$ 540,000	$ 385

[1]Controlled NO_X Emission Rate with SNCR was assumed to be 0.15 lb./MMBtu; corresponding to reduction of approximately 20%.
[2]Proposed emissions from PacifiCorp for RP Reassessment.
[3]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.

Cost Effectiveness Calculation Worksheet (12/31/2037 Retirement Date)

Unit 2 - Baseline with LNB & FGD Upgrades (2013-2015)

	Emission Rate (2013-2015)	Annual Heat Input (2001-2003)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.192	40,898,999	3,926
SO_2	0.178	40,898,999	3,649
Total			**7,575**

Unit 2 - SNCR

	Emission Rate[1]	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	0.150	40,898,999	3,067	859	$ 15,538,000	0.1059	$ 1,645,000	$ 3,158,000	$ 4,803,000	$ 5,592
SO_2	0.178	40,898,999	3,649	-	$ -	0.1059	$ -	$ -	$ -	$ -
Total			**6,716**	**859**	$ 15,538,000	0.1059	$ 1,645,000	$ 3,158,000	$ 4,803,000	$ 5,592

Unit 2 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	374	40,898,999	1,023	2,903	$ 140,428,000	0.1059	$ 14,871,000	$ 2,527,000	$ 17,398,000	$ 5,992
SO_2	1118	40,898,999	3,649	-	$ -	0.1059	$ -	$ -	$ -	$ -
Total			**4,672**	**2,903**	$ 140,428,000	0.1059	$ 14,871,000	$ 2,527,000	$ 17,398,000	$ 5,992

Unit 2 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[3]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	750	N/A	3,506	420	$ -	0.1059	$ -	$ -	$ -	$ -
SO_2	525	N/A	2,121	1,528	$ 1,553,000	0.1059	$ 164,000	$ 522,000	$ 686,000	$ 449
Total			**5,627**	**1,949**	$ 1,553,000	0.1059	$ 164,000	$ 522,000	$ 686,000	$ 352

[1]Controlled NO_X Emission Rate with SNCR was assumed to be 0.15 lb./MMBtu; corresponding to reduction of approximately 20%.
[2]Proposed emissions from PacifiCorp for RP Reassessment.
[3]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.

Cost Effectiveness Calculation Worksheet (12/31/2037 Retirement Date)

Unit 3 - Baseline with LNB, SCR & FGD Upgrades (2013-2015)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions
	lb/hour	MMBtu	tpy
NO_X	359	42,166,755	1,054
SO_2	1010	42,166,755	3,430
Total			**4,484**

Unit 3 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	359	42,166,755	1,054	-	$ -	0.1059	$ -	$ -	$ -	$ -
SO_2	1010	42,166,755	3,430	-	$ -	0.1059	$ -	$ -	$ -	$ -
Total			**4,484**	**-**	$ -	0.1059	$ -	$ -	$ -	$ -

Unit 3 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[1]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	359	N/A	1,003	51	$ -	0.1059	$ -	$ (80,000)	$ (80,000)	$ (1,569)
SO_2	525	N/A	2,121	1,309	$ 1,553,000	0.1059	$ 164,000	$ 537,000	$ 701,000	$ 535
Total			**3,124**	**1,360**	$ 1,553,000	0.1059	$ 164,000	$ 457,000	$ 621,000	$ 457

[1]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.
[2]Proposed emissions from PacifiCorp for RP Reassessment.

Cost Effectiveness Calculation Worksheet (12/31/2037 Retirement Date)

Unit 4 - Revised Baseline with LNB, SCR & FGD Upgrades (2013-2015)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions
	lb/hour	MMBtu	tpy
NO_X	375	41,034,206	1,026
SO_2	882	41,034,206	3,441
Total			**4,467**

Unit 4 - Reasonable Progress Plan (SCR)

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	375	41,034,206	1,026	-	$ -	0.1059	$ -	$ -	$ -	$ -
SO_2	882	41,034,206	3,441	-	$ -	0.1059	$ -	$ -	$ -	$ -
Total			**4,467**	**-**	$ -	0.1059	$ -	$ -	$ -	$ -

Unit 4 - Reasonable Progress Reassessment (Operational Limits)

	Emission Rate	Annual Heat Input[1]	Annual Emissions[2]	Reduction from Revised Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy						
NO_X	375	N/A	1,003	23	$ -	0.1059	$ -	$ (39,000)	$ (39,000)	$ (1,696)
SO_2	525	N/A	2,121	1,320	$ -	0.1059	$ -	$ 306,000	$ 306,000	$ 232
Total			**3,124**	**1,343**	$ -	0.1059	$ -	$ 267,000	$ 267,000	$ 199

[1]Annual Heat Input not disclosed to confidentiality of forecasted capacity factors.
[2]Proposed emissions from PacifiCorp for RP Reassessment.

Attachment 2 – Energy and Non-Air Quality Related Impacts Support Calculations

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Energy and Non-Air Quality Related Impacts Support Calculations

Energy Impacts

SCR Electrical Power Requirement

Unit 1 SCR Power Requirment:	5.2	MW
Unit 2 SCR Power Requirment:	5.2	MW
Units 1 +2 Annual Total Power Requirement:	(5.2 MW + 5.2 MW) x (8760 hours/year)	
Units 1 +2 Annual Total Power Requirement:	91,104	MWh
Average Residential Customer Annual Power Usage:	10,399	kWh
Average Residential Customer Annual Power Usage:	10.399	MWh
Units 1+2 SCR Annual Electrical Power Avoidance:	(91,104 MWh) / (10.399 MWh/customer)	
Units 1+2 SCR Annual Electrical Power Avoidance:	8,761	customers

Avoiding Units 1 and 2 SCR installation provides enough electrial energy to provide power to 8,761 residential customers

Consumption of Natural Resources

Potential Annual Coal Consumption

Unit 1 Boiler Heat Input Rating:	6,000	MMBtu/hour
Unit 2 Boiler Heat Input Rating:	6,000	MMBtu/hour
Unit 3 Boiler Heat Input Rating:	6,000	MMBtu/hour
Unit 4 Boiler Heat Input Rating:	6,000	MMBtu/hour
Total Boiler Heat Input Rating:	24,000	MMBtu/hour
Potential Annual Boiler Heat Input:	(24,000 MMBtu/hour) * 8,760 hours/year	
Potential Annual Boiler Heat Input:	210,240,000	MMBtu/year
Potential Annual Boiler Heat Input:	2.10E+14	Btu/year
Average Coal Heating Value:	9,300	Btu/lb
Potential Annual Coal Usage:	(Potential Annual Boiler Heat Input) / (Average Coal Heating Value)	
Potential Annual Coal Usage:	(2.10E+14 Btu/year) / (9,300 Btu/lb)	
Potential Annual Coal Usage:	2.26E+10	lb/year
Potential Annual Coal Usage:	11,303,226	tons/year

However, per Wyoming Air Quality Division permit OP-267, Jim Bridger annual coal throughput is limited to 9,500,000 tons/year.

Annual Coal Consumption Under 76.3% Average Annual Capacity Factor

76.3% Capacity Factor Unit 1 Boiler Heat Input Rating:	4,578	MMBtu/hour
76.3% Capacity Factor Unit 2 Boiler Heat Input Rating:	4,578	MMBtu/hour
76.3% Capacity Factor Unit 3 Boiler Heat Input Rating:	4,578	MMBtu/hour
76.3% Capacity Factor Unit 4 Boiler Heat Input Rating:	4,578	MMBtu/hour
Total 76.3% Capacity Factor Boiler Heat Input Rating:	18,312	MMBtu/hour
76.3% CF Potential Annual Boiler Heat Input:	(18,312 MMBtu/hour) * 8,760 hours/year	
76.3% CF Potential Annual Boiler Heat Input:	160,413,120	MMBtu/year
76.3% CF Potential Annual Boiler Heat Input:	1.60E+14	Btu/year
Average Coal Heating Value:	9,300	Btu/lb
76.3% Capacity Factor Annual Coal Usage:	(76.3% CF Annual Boiler Heat Input) / (Average Coal Heating Value)	
76.3% Capacity Factor Annual Coal Usage:	(1.60E+14 Btu/year) / (9,300 Btu/lb)	
76.3% Capacity Factor Annual Coal Usage:	1.72E+10	lb/year
76.3% Capacity Factor Annual Coal Usage:	8,624,361	tons/year

Annual Coal Consumption Avoidance

Potential Unrestricted Annual Coal Consumption:	9,500,000	tons/year	(permit OP-267 limit)
76.3% Capacity Factor Annual Coal Consumption:	8,624,361	tons/year	
Potential Annual Coal Consumption Avoidance:	875,639	tons/year	

Potential Annual Raw Water Consumption for Cooling Tower Make-up

2016 Raw Water Requirement		
Green River:	4,075,418,457	gallons/year
Mine Water:	1,763,505,612	gallons/year
Total 2016 Raw Water Requirement:	5,838,924,069	gallons/year
2016 Coal Combustion		
Unit 1:	1,796,121	tons/year
Unit 2:	1,859,609	tons/year
Unit 3:	1,494,824	tons/year
Unit 4:	1,478,750	tons/year
Total 2016 Coal Combustion:	6,629,303	tons/year

Potential Annual Raw Water Demand at 9,500,000 tons/year Coal Throughput Limit

Potential Annual Raw Water Demand:	[(9,500,000 tons) / (6,629,303 tons)] * (5,838,924,069 gallons/year)	
Potential Annual Raw Water Demand:	8,367,362,098	gallons/year
Potential Annual Raw Water Demand:	25,678	acre-feet/year

Annual Raw Water Consumption Under 76.3% Average Annual Capacity Factor

Unit 1 Cooling Tower Design Make-up:	4,700	gallons/minute	
Unit 2 Cooling Tower Design Make-up:	4,700	gallons/minute	
Unit 3 Cooling Tower Design Make-up:	4,700	gallons/minute	
Unit 4 Cooling Tower Design Make-up:	4,700	gallons/minute	
Total Cooling Tower Make-up Demand:	18,800	gallons/minute	
76.3% CF Unit 1 Cooling Tower Make-up Water Requirement:	3,586	gallons/minute	(4700 gpm * 0.763)
76.3% CF Unit 2 Cooling Tower Make-up Water Requirement:	3,586	gallons/minute	(4700 gpm * 0.763)
76.3% CF Unit 3 Cooling Tower Make-up Water Requirement:	3,586	gallons/minute	(4700 gpm * 0.763)
76.3% CF Unit 4 Cooling Tower Make-up Water Requirement:	3,586	gallons/minute	(4700 gpm * 0.763)
Total 76.3% CF Cooling Tower Make-up Requirement:	14,344	gallons/minute	

76.3% CF Annual CT Make-up Requirement:	(14,344 gallons/minute) * (60 minutes/hour) * (8,760 hours/year)	
76.3% CF Annual CT Make-up Requirement:	7,539,416,640	gallons/year
76.3% CF Annual CT Make-up Requirement:	(7,539,416,640 gallons/year) * (acre-foot/325,851 gallons)	
76.3% CF Annual CT Make-up Requirement:	23,138	acre-feet/year

Greenhouse Gas Emissions

Potential Annual CO_2 Emissions

Annual Coal Combustion Limit:	9,500,000	tons/year
Average Coal Heating Value:	9,300	Btu/lb
Coal Combustion CO2 Emission Factor:	209.76	lb/MMBtu
Potential Annual Heat Input (coal combustion basis):	(9,500,000 tons/year) * (2,000 lb/ton) * (9,300 Btu/lb)	
Potential Annual Heat Input (coal combustion basis):	1.767E+14	Btu/year
Potential Annual Heat Input (coal combustion basis):	176,700,000	MMBtu/year
Potential Annual CO2 Emissions:	(176,700,000 MMBtu/year) * (209.76 lb/MMBtu)	
Potential Annual CO2 Emissions:	37,064,592,000	lb/year
Potential Annual CO2 Emissions:	18,532,296	tons/year

Annual CO2 Emissions Under 76.3% Average Annual Capacity Factor

76.3% Capacity Factor Annual Coal Combustion:	8,624,361	tons/year	(from above)
76.3% CF Annual Heat Input:	(8,624,361 tons/year) * (2,000 lb/ton) * (9,300 Btu/lb)		
76.3% CF Annual Heat Input:	1.60413E+14	Btu/year	
76.3% CF Annual Heat Input:	160,413,120	MMBtu/year	
76.3% CF Annual CO2 Emissions:	(160,413,120 MMBtu/year) * (209.76 lb/MMBtu)		
76.3% CF Annual CO2 Emissions:	33,648,256,051	lb/year	
76.3% CF Annual CO2 Emissions:	16,824,128	tons/year	

CCR Impacts

Potential Annual Total Ash Production

Potential Annual Coal Combustion:	9,500,000	tons/year	(permit OP-267 limit)
Jim Bridger Coal Ash Concentration:	11.0%		
Potential Annual Total Ash Production:	(9,500,000 tons/year) * (11.0% ash)		
Potential Annual Total Ash Production:	1,045,000	tons/year	
Potential Annual Fly Ash Production:	(total annual ash production) * (75%)		
Potential Annual Fly Ash Production:	(1,045,000 tons/year) * (75%)		
Potential Annual Fly Ash Production:	783,750	tons/year	
Potential Annual Bottom Ash Production:	(total annual ash production) * (25%)		
Potential Annual Bottom Ash Production:	(1,045,000 tons/year) * (75%)		
Potential Annual Bottom Ash Production:	261,250	tons/year	

Annual Total Ash Production Under 76.3% Average Annual Capacity Factor

76.3% Capacity Factor Annual Coal Combustion:	8,624,361 tons/year	(from above)
Jim Bridger Coal Ash Concentration:	11.0%	
76.3% CF Annual Total Ash Production:	(8,624,361 tons/year) * (11.0% ash)	
76.3% CF Annual Total Ash Production:	948,680 tons/year	
76.3% CF Annual Fly Ash Production:	(76.3% CF Annual Total Ash Production) * (75%)	
76.3% CF Annual Fly Ash Production:	(948,680 tons/year) * (75%)	
76.3% CF Annual Fly Ash Production:	711,510 tons/year	
76.3% CF Annual Bottom Ash Production:	(76.3% CF Annual Total Ash Production) * (25%)	
76.3% CF Annual Bottom Ash Production:	(948,680 tons/year) * (25%)	
76.3% CF Annual Bottom Ash Production:	237,170 tons/year	

Additional Benefits

Crieria Pollutant Emissions Evalution

Notes: Unless otherwise noted, the following annual emissions are calculated on a CEM heat input basis.

Under unrestricted or SCR/SNCR operation, each boiler has a CEM-based heat input of 6,000 MMBtu/hour, however, per Wyoming Air Quality Division permit OP-267, Jim Bridger annual coal throughput is limited to 9,500,000 tons/year, assuming Average Coal Heating Value 9,300 BTU/lb., equates to approximately 5,043 MMBtu/hour/unit.

Under the Regional Haze Reassessment operaing scenario and 76.3% capacity factor, each boiler has a CEM-based average annual heat input rate of 4,578 MMBtu/hour

Potential Annual Boiler Heat Input	(4 boilers) * (5,043 MMBtu/hour) * (8,760 hours/year)
Potential Annual Boiler Heat Input	176,700,000 MMBtu/year
Mercury Emission Limit	1.2 lb/TBtu
Potential Annual Hg Emissions (SIP and SNCR):	(176,700,000 MMBtu/year) * (1.2 lb/TBtu) * (TBtu/1,000,000 MMBtu)
Potential Annual Hg Emissions (SIP and SNCR):	212 lb/year

Annual Mercury Emissions Under 76.3% Average Annual Capacity Factor

76.3% CF Annual Heat Input:	(4 boilers) * (4,578 MMBtu/hour) * (8,760 hours/year)
76.3% CF Annual Heat Input:	160,413,120 MMBtu/year
Mercury Emission Limit	1.2 lb/TBtu
76.3% CF Annual Hg Emissions:	(160,413,120 MMBtu/year) * (1.2 lb/TBtu) * (TBtu/1,000,000 MMBtu)
76.3% CF Annual Hg Emissions:	192 lb/year

Potential Annual Carbon Monoxide (CO) Emissions

Potential Annual Boiler Heat Input	(4 boilers) * (5,043 MMBtu/hour) * (8,760 hours/year)
Potential Annual Boiler Heat Input	176,700,000 MMBtu/year
Carbon Monoxide Emission Limit	0.2 lb/MMBtu
Potential Annual CO Emissions (SIP and SNCR):	(176,700,000 MMBtu/year) * (0.2 lb/MMBtu)
Potential Annual CO Emissions (SIP and SNCR):	35,340,000 lb/year
Potential Annual CO Emissions (SIP and SNCR):	17,670 tons/year

Annual Carbon Monoxide (CO) Emissions Under 76.3% Average Annual Capacity Factor

76.3% CF Annual Heat Input:	(4 boilers) * (4,578 MMBtu/hour) * (8,760 hours/year)
76.3% CF Annual Heat Input:	160,413,120 MMBtu/year
Carbon Monoxide Emission Limit	0.2 lb/MMBtu
76.3% CF Annual CO Emissions:	(160,413,120 MMBtu/year) * (0.2 lb/MMBtu)
76.3% CF Annual CO Emissions:	32,082,624 lb/year
76.3% CF Annual CO Emissions:	16,041 tons/year

Potential Annual Particulate Matter (PM) Emissions

Potential Annual Boiler Heat Input	(4 boilers) * (5,043 MMBtu/hour) * (8,760 hours/year)
Potential Annual Boiler Heat Input	176,700,000 MMBtu/year
Particulate Matter Emission Limit	0.030 lb/MMBtu
Potential Annual PM Emissions (SIP and SNCR):	(176,700,000 MMBtu/year) * (0.030 lb/MMBtu)
Potential Annual PM Emissions (SIP and SNCR):	5,301,000 lb/year
Potential Annual PM Emissions (SIP and SNCR):	2,651 tons/year

Annual Particulate Matter (PM) Emissions Under 76.3% Average Annual Capacity Factor

76.3% CF Annual Heat Input:	(4 boilers) * (4,578 MMBtu/hour) * (8,760 hours/year)
76.3% CF Annual Heat Input:	160,413,120 MMBtu/year
Particulate Matter Emission Limit	0.030 lb/MMBtu
76.3% CF Annual PM Emissions:	(160,413,120 MMBtu/year) * (0.030 lb/MMBtu)
76.3% CF Annual PM Emissions:	4,812,394 lb/year
76.3% CF Annual PM Emissions:	2,406 tons/year

Potential Annual Sulfuric Acid Emissions

Potential Annual Boiler Heat Input	(4 boilers) * (5,043 MMBtu/hour) * (8,760 hours/year)	
Potential Annual Boiler Heat Input	176,700,000	MMBtu/year
Sulfuric Acid Emission Limit	0.004	lb/MMBtu
Potential Annual H_2SO_4 Emissions:	(176,700,000 MMBtu/year) * (0.004 lb/MMBtu)	
Potential Annual H_2SO_4 Emissions:	706,800	lb/year
Potential Annual H_2SO_4 Emissions:	353	tons/year

Annual Sulfuric Acid Emissions Under 76.3% Average Annual Capacity Factor

76.3% CF Annual Heat Input:	(4 boilers) * (4,578 MMBtu/hour) * (8,760 hours/year)	
76.3% CF Annual Heat Input:	160,413,120	MMBtu/year
Sulfuric Acid Emission Limit	0.004	lb/MMBtu
76.3% CF Annual H_2SO_4 Emissions:	(160,413,120 MMBtu/year) * (0.004 lb/MMBtu)	
76.3% CF Annual H_2SO_4 Emissions:	641,652	lb/year
76.3% CF Annual H_2SO_4 Emissions:	321	tons/year

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Attachment 3 – Reasonable Progress Reassessment Visibility Improvement Modeling Report for Jim Bridger Power Plant

(photo provided by PacifiCorp)

Reasonable Progress Reassessment Visibility Improvement Modeling Report for Jim Bridger Power Plant

PacifiCorp/Idaho Power

Project Number: 60544863

January 2019

Quality information

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1. Introduction

1.1 Overview

On January 30, 2014, EPA published a final regional haze rule (79 FR 5032) that established stringent controls of nitrogen oxide (NOx) emissions from the four units at the Jim Bridger Power Plant, located near Point of Rocks, Wyoming. For NOx controls, EPA determined that Wyoming's selection of the then-current NOx controls of low-NOx burners (LNB) and separated over-fire air (SOFA) qualified for Best Available Retrofit Technology (BART) controls. Additionally, EPA approved Wyoming's requirement that LNB/OFA plus SCR be installed at Jim Bridger Units 1-4 as part of the State's Reasonable Progress / Long-Term Strategy (RP/LTS).

The resulting Wyoming SIP required, as part of its RP/LTS, installation of SCR controls for NOx (30-day rolling average emission rate of 0.07 lb/MMBtu) on Jim Bridger units in a phased approach:

- December 31, 2022 for Unit 1
- December 31, 2021 for Unit 2
- December 31, 2015 for Unit 3
- December 31, 2016 for Unit 4.

The installations of SCR controls on Jim Bridger Units 3 and 4 have been completed as stated above. For Units 1 and 2, PacifiCorp/Idaho Power are proposing an alternative to the SCR installations on the remaining Jim Bridger units that will result in equivalent or better visibility improvement than Wyoming's RP/LTS that was approved by EPA ("State SIP"). This alternative emission control strategy, referred to herein as the "RP Reassessment," will set month-by-month mass emission limits for two principal haze-causing pollutants, sulfur dioxide (SO_2) and nitrogen oxides (NOx). The average annual mass emissions of SO_2 plus NOx for the RP Reassessment as proposed on a pound-per-hour basis will be nearly 20% lower than those of the State SIP (all four units controlled by SCR). The RP Reassessment plan will have higher NOx emissions relative to the State SIP on a month-to-month basis, but much lower SO_2 emissions that will result in better visibility than the State SIP. The reduction in emissions for the RP Reassessment will be brought about through a combination of emissions management and operational restrictions on the Jim Bridger units. This report analyzes the relative modeled visibility impacts from the RP Reassessment and the State SIP. A second "SNCR scenario" (with SNCR controls on Units 1 and 2) has also been evaluated relative to the State SIP and RP Reassessment.

This modeling report follows the procedures set out in a modeling protocol (included as Appendix A). The protocol was initially submitted to Wyoming and EPA in June 2018, and was revised to incorporate comments from Wyoming and EPA.

1.2 Haze Composition Overview

A review of haze composition at the Class I areas in the Wyoming and northern Colorado area is useful to better understand the expected benefits of the proposed RP Reassessment, which reduces SO_2 emissions relative to the State SIP and SNCR scenarios. Since the Regional Haze Rule's focus for each decadal review is to improve the visibility on the 20% worst haze days (while not degrading[1] visibility for the 20% best days), it is helpful to look at the monitored haze composition for the critical 20% worst haze days. Figure 1-1[2] shows the 2015 haze "pie chart" for various Class I areas in the vicinity of the Jim Bridger plant. Figure 1-2 shows a close-up of areas near

[1] It is generally accepted that emissions reduction that improve visibility on the worst 20% haze days will also improve visibility on the best 20% days as well. Therefore, the modeling analysis focuses upon improving visibility for the worst 20% haze days.
[2] http://vista.cira.colostate.edu/improve/wp-content/uploads/2016/12/2015-IMPROVE-NR-Bext-SIA-Annual-MOH20-w-Canada.jpg

the Jim Bridger plant (red ellipse), while Figure 1-3 shows a 2015 time series daily haze composition plot for the Mount Zirkel Wilderness Area. What can be determined from these plots is as follows.

- The most important component of the worst 20% haze days is organic matter from wildfires (green portion of pie chart), plus coarse matter and elemental carbon (black and brown) that are also emitted in large quantities by wildfires.
- In terms of pollutants from Jim Bridger that contribute to haze in the most-impacted areas (within the red ellipse in Figure 1-2), sulfate haze has a year-round effect, while nitrate haze is most important during the cold months of the year, when the park visitation is lowest. The sulfate fraction of the pie charts in Figure 1-2 is also much larger than the nitrate fraction, demonstrating that sulfates are more significant contributors to haze at these locations than nitrates.
- The RP Reassessment addresses these haze issues by applying monthly-varying restrictions on SO_2 and NOx emissions.

Figure 1-1: Haze Composition Plot for 20% Worst Days in 2015

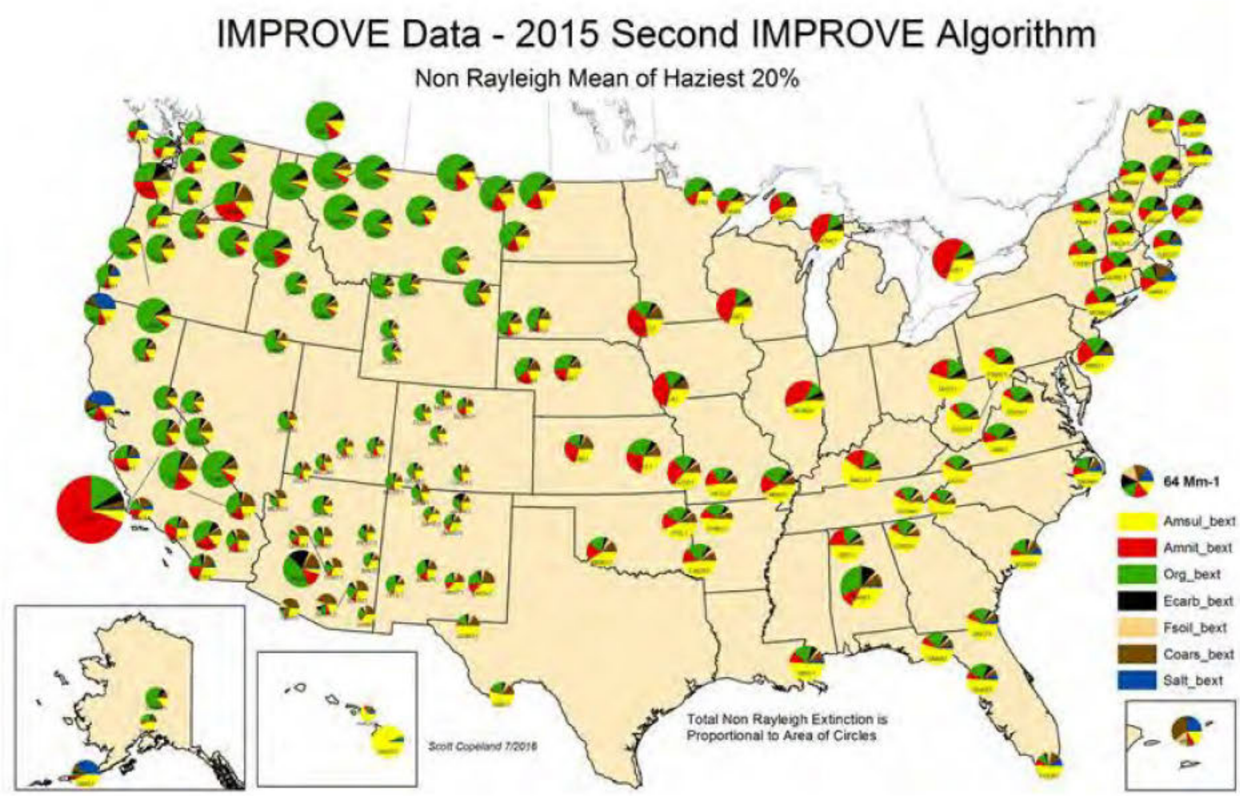


Figure 1-2: Haze Composition for 20% Worst Days Near Jim Bridger Power Plant

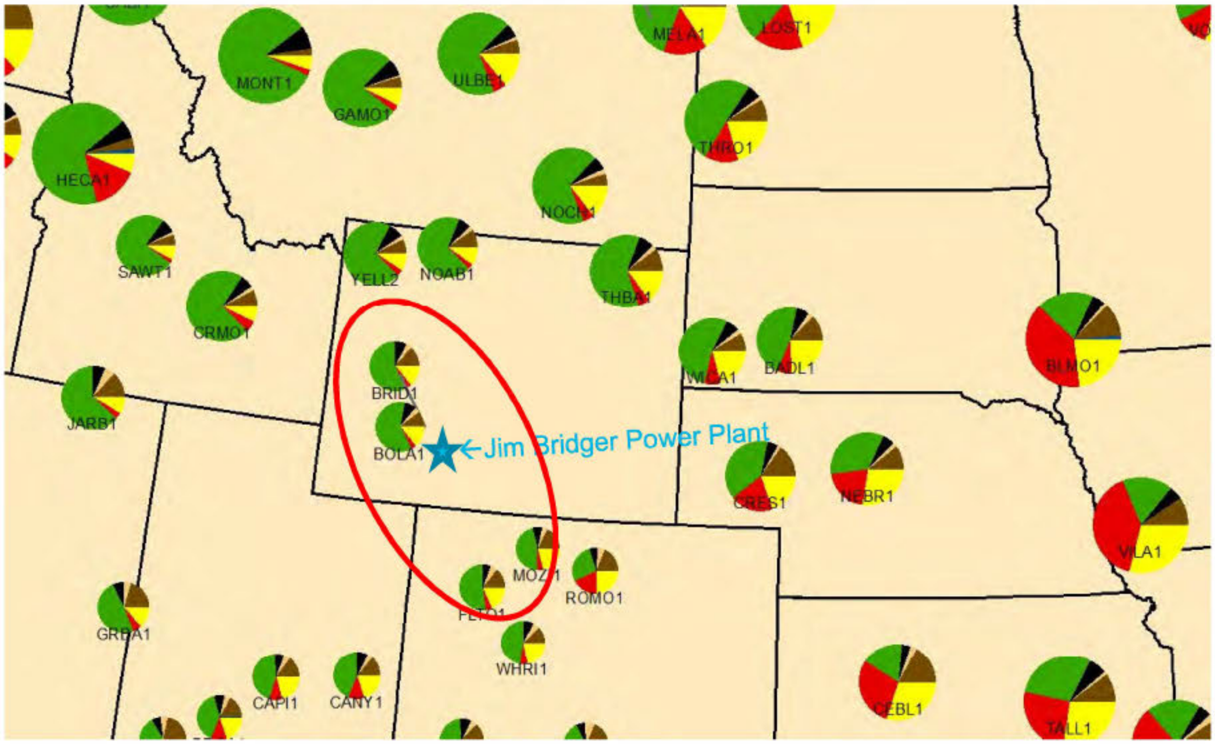
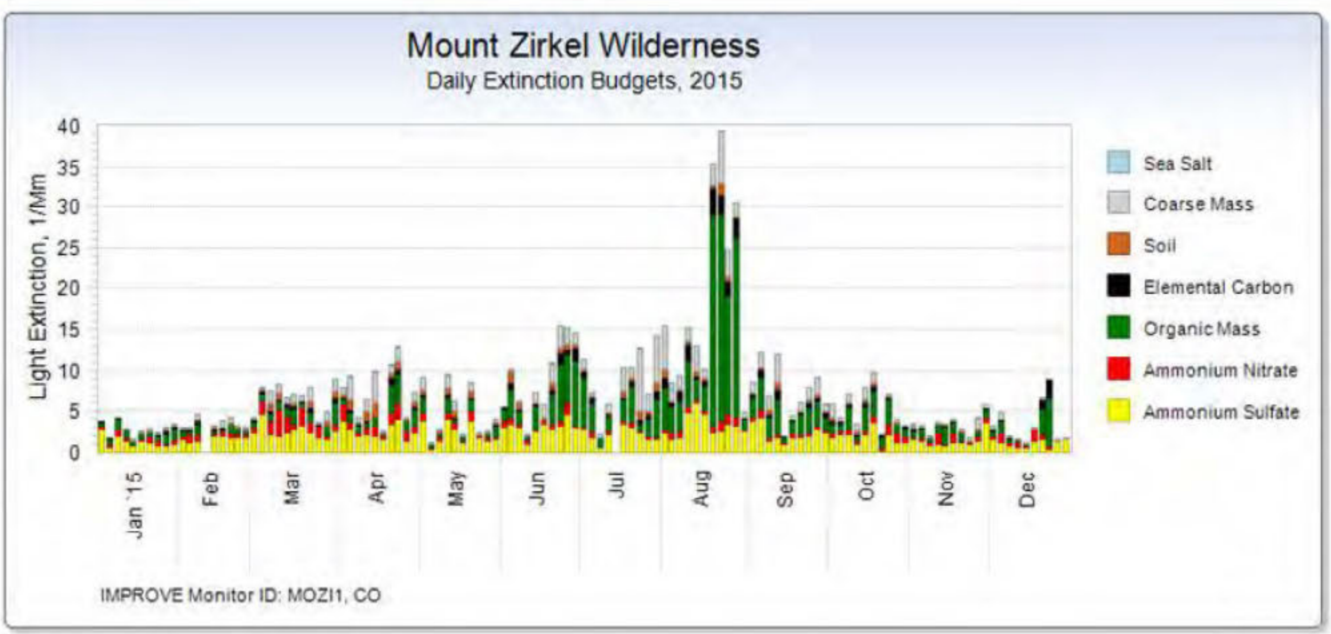


Figure 1-3: Daily Extinction Haze Composition Plot for Mount Zirkel, 2015



1.3 Organization of This Modeling Report

Section 2 of this report provides a description of the main emission sources at the Jim Bridger Power Plant. The emissions associated with the Baseline Case, the State SIP, the RP Reassessment, and the SNCR scenario cases are presented in Section 3. Section 4 provides a discussion of the CALPUFF modeling procedures that were used. The results of the comparison of the visibility improvement between the State SIP and the RP Reassessment and SNCR scenario cases are presented in Section 5.

2. Overview of Jim Bridger Power Plant

PacifiCorp and Idaho Power co-own, and PacifiCorp operates, the Jim Bridger Power Plant, a coal-fired steam electric generating station located 9 miles north of Point of Rocks, Wyoming. Jim Bridger is comprised of four coal-fired boilers which came online from 1974 to 1979 (see plant photo on the cover page and Figure 2-1). Units 1-4 each have a nominal net generation capacity of roughly 530 MW, for a total net power generating capacity of about 2,119 MW. Each unit has a single stack with a height of 152 meters. The facility is approximately 97.8 kilometers from the southern boundary of Bridger Wilderness, which is the closest Class I area to the facility.

Table 2-1 lists the modeled stack parameters for each of the sources, corresponding to full-load conditions. Note that the stack parameters are identical for units 1, 2, and 3, and the differences for unit 4 are modest in that the larger diameter offsets the lower exit velocity, and the resulting buoyancy flux is within 15% of that of units 1-3.

Table 2-1: Modeled Stack Parameters for Jim Bridger Units

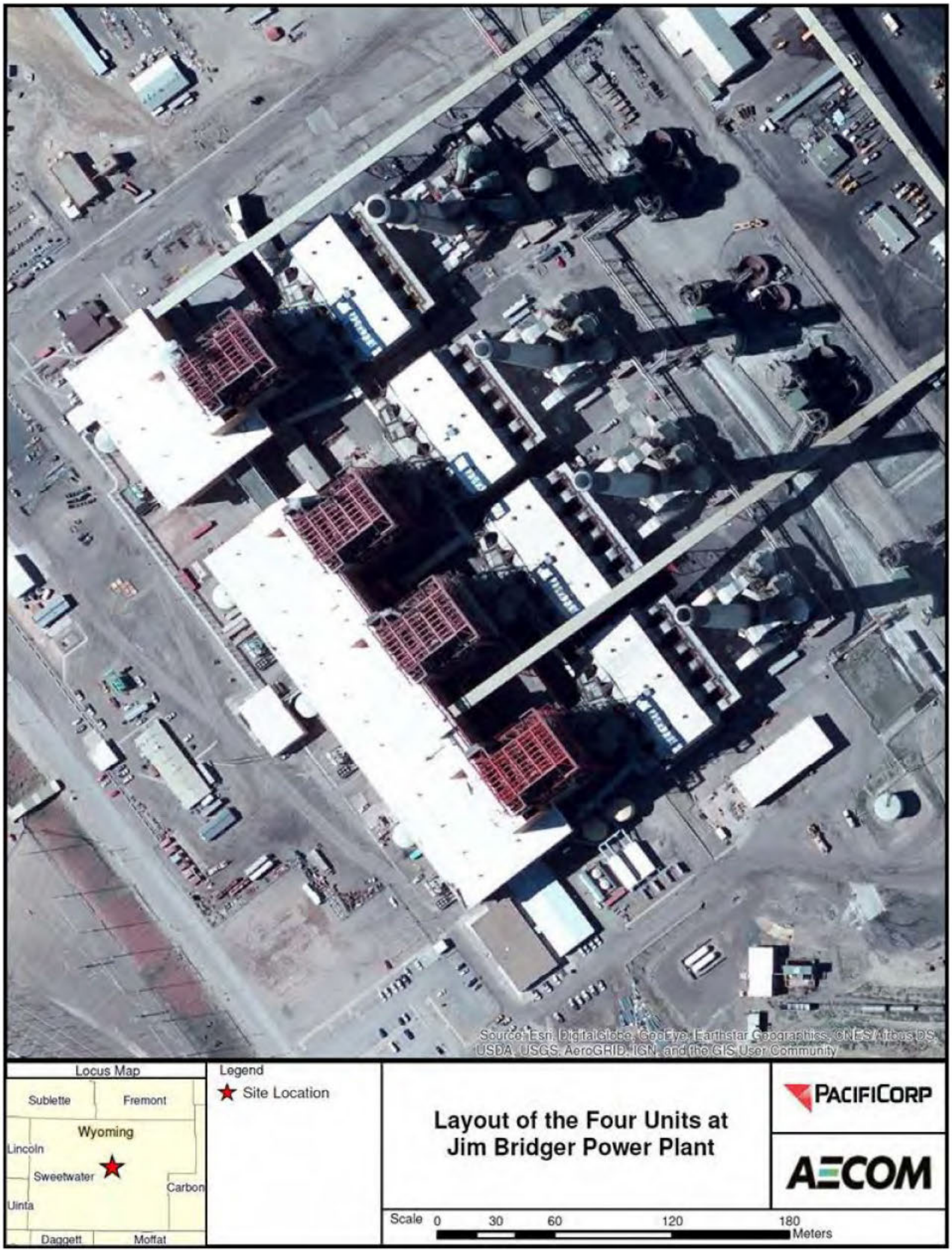
Stack Parameter	Unit 1	Unit 2	Unit 3	Unit 4
Stack height (m)	152	152	152	152
Base elevation (m)	2,036	2,036	2,036	2,033
Stack Diameter (m)	7.32	7.32	7.32	9.45
Exit Velocity (m/s)	24.7	24.7	24.7	12.9
Exit Temperature (°K)	328	328	328	322

Due to the similarity of the stack exhaust parameters, it is reasonable due to the large distances to the Class I areas involved to model a single stack that represents emissions from all four units. The characteristics of this "common" stack, which for modeling is located between the stacks for Units 2 and 3, are provided in Table 2-2. Section 3 provides a discussion of how the results of the common stack were compared to that of separate stacks for the RP Reassessment to show that the common stack results are either equivalent to or higher than those obtained with separate stacks. The common stack modeling results are generally slightly higher than the same emissions distributed among separate stacks because the emissions are concentrated into a single unit. Therefore, to remove any doubt that the RP Reassessment case has better modeled visibility than the State SIP case, the common stack results for the RP Reassessment were tested against the State SIP run two ways: with the common and separated stacks. The RP Reassessment case needed to show better or equal visibility than the State SIP case run both ways to be determined to be acceptable as a replacement for the State SIP.

Table 2-2: Modeled Parameters for Common Jim Bridger Stack

Stack Parameter	Common Stack
Stack height (m)	152
Base elevation (m)	2,036
Stack Diameter (m)	7.32
Exit Velocity (m/s)	24.7
Exit Temperature (°K)	328

Figure 2-1: Layout of Jim Bridger Power Plant



Due to the tall stacks at the facility and the dominance of long-range dispersion for CALPUFF predictions, building downwash effects were not included in the modeling.

3. Emission Controls for BART Visibility Improvement

Current emission controls for sulfur dioxide emissions at Jim Bridger include the use of low-sulfur coal and scrubbers on all four units. Particulate matter for all units is controlled by electrostatic precipitators (ESPs). Fabric filters (baghouses) are installed on various coal-handling emission sources. Units 1 and 2 currently use low NOx burner technology with Separated Over-fire Air systems (LNB/SOFA) to control oxides of nitrogen. Units 3 and 4 also use LNB/SOFA technology with the addition of SCR. These control devices were installed after the Baseline period of 2001-2003.

The State SIP currently requires SCR to be added to Units 1 and 2 as part of Wyoming's current Long-Term Strategy (LTS), as discussed in Section 1. All other controls on Units 1 and 2 would remain the same for the State SIP. At EPA's suggestion, the Baseline Case reflects emissions characteristic of controls in place during the Regional Haze Rule baseline period (2001-2003), which did not yet involve scrubber upgrades, LNB/SOFA controls, nor the NOx emission controls that have been made for Units 3 and 4.

PacifiCorp/Idaho Power are considering a Reasonable Progress Reassessment (RP Reassessment) that would involve an alternative to installation of SCR controls on Units 1 and 2. This RP Reassessment incorporates additional controls on SO_2 and NOx installed since 2001-2003, and also incorporates operational limits to further reduce emissions, as discussed further below. The RP Reassessment will have lower total plant-wide annual emissions for SO_2 + NOx than the State SIP, as described below. A second "SNCR scenario" that involves Selective Non-catalytic Reduction (SNCR) controls for Units 1 and 2, but with no operational restrictions on plant-wide utilization, will also be tested at the request of the state.

EPA provided preliminary input on the Baseline, State SIP, and RP Reassessment emissions to be modeled for the visibility comparison. Emissions for the visibility modeling of the Baseline Case, the State SIP, the SNCR scenario, and the RP Reassessment are provided in Tables 3-1, 3-2, 3-3, and 3-4, respectively. As shown in Table 3-4 on the "Plant Total" line, the annual-average emissions of SO_2 + NOx are listed for the RP Reassessment. Due to seasonal changes in effectiveness of emission controls and plant utilization needs, the final visibility modeling for the RP Reassessment incorporates monthly-varying emission rates that are provided in Table 3-5. The RP Reassessment Emission Rates provided in Tables 3-4 and 3-5 result in emission reductions and better visibility improvement than the State SIP, while also taking into consideration operational feasibility, seasonal variability, scrubbing potential, and multiple capacity factor forecast scenarios.

The emissions for the cases modeled were combined into a common stack for modeling purposes, as noted in Section 2. For the RP Reassessment, a demonstration is included in this report (Appendix B) showing that this treatment results in equivalent[3] or (most likely) higher results to the modeling of the four separate stacks. The demonstration that the common stack case provides equivalent or higher results for this RP Reassessment has been made for five hypothetical cases, summarized below, that shift emissions among the Jim Bridger units. The documentation (CALPUFF modeling runs) for the equivalent common stack is also provided separately in the computer archive to support this RP Reassessment specification of plant-wide emission rates on a monthly block basis. The cases modeled for the common stack demonstration are as follows:

1) Unit 1 emissions are set to zero, and the plant emissions are distributed among the other three units;
2) Unit 2 emissions are set to zero, and the plant emissions are distributed among the other three units;
3) Unit 3 emissions are set to zero, and the plant emissions are distributed among the other three units;
4) Unit 4 emissions are set to zero, and the plant emissions are distributed among the other three units;
5) Plant emissions are equally distributed among the four 4 units.

[3] EPA's Appendix W, Section 3.2.2 defines "equivalent" results are such that the controlling modeling result is within 2% of the reference case. In this case, that means that the 3-year average of the 98^{th} percentile delta-dv impact modeled by CALPUFF for the single stack with all haze emissions for the Jim Bridger plant is within 2% of the result when the 4 stacks are modeled separately. If the results of the common stack are higher than those of the separate stacks (even if more than 2%), this conservative result is also acceptable.

For each case modeled, the total plant emissions are listed in Table 3-5 (monthly-varying emissions). A satisfactory showing to support the use of the common stack in the modeling of the RP Reassessment case occurs if the results for the common stack are either higher than or within 2% of the results for the cases with emissions variations noted above.

The July 6, 2005 BART Rule (70 FR 39172) provides for allowing sources to average emissions over all BART units within a fenceline. Specifically, the language in the rule provides this instruction to the States:

> *You should consider allowing sources to "average" emissions across any set of BART-eligible emission units within a fenceline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible units that constitute BART-eligible source.*

Therefore, the interpretation of the RP Reassessment emissions is that the plant-wide monthly block emission limit for each pollutant summed over all four units will be the enforceable limit.

The emission rates proposed for the RP Reassessment represent a significant reduction (nearly 20%) in SO_2 + NOx emissions from the State SIP, and are designed to result in an equivalent or better visibility improvement relative to the State SIP, as defined by the visibility metrics described in Section 5.

Table 3-1: Baseline Case Emissions

Pollutant*	SO_2	NOx
Unit	(lb/hr)	(lb/hr)
1	1,765	2,788
2	1,749	2,772
3	1,808	2,670
4	1,003	2,969
Plant Total	6,327	11,199

*for each unit modeled, the SO_4, PM_{10}, and $PM_{2.5}$ emission rates will be 54.1, 77.4, and 102.6 lb/hr, respectively.

Table 3-2: State RP/LTS (SIP) Emissions

State RP/LTS (SIP) Plan					
Pollutant*	SO_2		NOx		SO_2 + NOx
Unit	Reduction from Baseline (%)	(lb/hr)	Reduction from Baseline (%)	(lb/hr)	(lb/hr)
1	48.6%	907	87.3%	355	
2	36.1%	1,118	86.5%	374	
3	44.1%	1,010	86.5%	359	
4	12.1%	882	87.4%	375	
Plant Total	37.3%	3,917	86.9%	1,463	5,380

*for each unit modeled, the SO_4, PM_{10}, and $PM_{2.5}$ emission rates will be 54.1, 77.4, and 102.6 lb/hr, respectively.

Table 3-3: SNCR Scenario Emissions

SNCR Scenario					
Pollutant*	SO_2		NOx		SO_2 + NOx
Unit	Reduction from Baseline (%)	(lb/hr)	Reduction from Baseline (%)	(lb/hr)	(lb/hr)
1	48.6%	907	61.8%	1,066	
2	36.1%	1,118	59.5%	1,123	
3	44.1%	1,010	86.5%	359	
4	12.1%	882	87.4%	375	
Plant Total	37.3%	3,917	86.9%	2,922	6,839

*for each unit modeled, the SO_4, PM_{10}, and $PM_{2.5}$ emission rates will be 54.1, 77.4, and 102.6 lb/hr, respectively.

Table 3-4: RP Reassessment Emissions

RP Reassessment					
Pollutant[1]	SO_2		NOx		SO_2 + NOx
Unit	Reduction from Baseline (%)	(lb/hr)	Reduction from Baseline (%)	(lb/hr)	(lb/hr)
Plant Total[2]	66.40%	2,100	80.05%	2,232	4,332

[1] for each unit modeled, the SO_4, PM_{10}, and $PM_{2.5}$ emission rates will be 54.1, 77.4, and 102.6 lb/hr, respectively.
[2] Annual-average plant-wide emissions

Table 3-5: Monthly Plant-wide Emission Rates for RP Reassessment Modeling

Month	SO_2 (lb/hr)	NO_X (lb/hr)
January	2,100	2,050
February	2,100	2,050
March	2,100	2,050
April	2,100	2,050
May	2,100	2,200
June	2,100	2,500
July	2,100	2,500
August	2,100	2,500
September	2,100	2,500
October	2,100	2,300
November	2,100	2,030
December	2,100	2,050
Annual Average*	2,100	2,232

*The annual average weights each month by the number of days in the month for a non-leap year.

4. Visibility Improvement Modeling Procedures

The original FIP modeling utilized CALPUFF version 5.8. Due to several updates to the CALPUFF modeling system since the state of Wyoming conducted their original modeling, the modeling analysis used the current EPA-approved version 5.8.5 of CALPUFF.

4.1 CALMET

The CALMET input data has been provided by the State of Wyoming for years 2001, 2002, and 2003. CALMET version 5.8.5 (Level 151214) was used to process the meteorological data. Specifics about the CALMET preprocessing are described below.

CALMET was processed using 12-km resolution MM5 prognostic meteorological data as well as surface, precipitation, and upper air stations. CALMET technical options were based on the WDEQ-recommended settings provided with the Wyoming Regional Haze Rule State Implementation Plan. Table 4-1 lists the key user-defined settings.

Table 4-1: Key User-Defined CALMET Settings

Variable	Description	Value
PMAP	Map projection	LCC (Lambert Conformal Conic)
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	10
ZFACE	Cell face heights (m)	0, 20, 40, 100, 140, 320, 580, 1020, 1480, 2220, 3500
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model output	14 (MM5 data)
RMAX1	Maximum radius of influence (surface layer, km)	30
RMAX2	Maximum radius of influence (layers aloft, km)	50
TERRAD	Radius of influence for terrain (km)	15
R1	Relative weighting of first guess wind field and observations (km)	5
R2	Relative weighting aloft (km)	25

4.2 CALPUFF

CALPUFF version 5.8.5 (Level 151214) was used in the modeling. CALPUFF was run for all three years of meteorological data and the cases as described in Section 3. The modeling was conducted at nine Class I areas (all such areas that are within 300 km of the plant) which are listed below and shown in relation to Jim Bridger in Figure 4-1.

- Bridger Wilderness (WY)
- Fitzpatrick Wilderness (WY)
- Grand Teton National Park (WY)
- Mt. Zirkel Wilderness Area (CO)
- Rocky Mountain National Park (CO)
- Rawah Wilderness Area (CO)
- Teton Wilderness (WY)
- Washakie Wilderness (WY)
- Yellowstone National Park (WY)

The CALPUFF modeling was conducted in a manner that is consistent with State SIP modeling approach, as discussed below.

- Hourly ozone files were used to define background ozone concentrations. A value of 44.0 ppb was used when ozone data was missing in the files.
- As requested by EPA, the monthly background ammonia concentrations were specified, consistent with the IWAQM Phase 2 recommendation, as a constant value of 0.5 ppb.
- CALPUFF was run with regulatory default options as outlined in the 2006 EPA memo[4].
- Pollutant species that were modeled included SO_2, SO_4, NOx, HNO_3, NO_3, PMC, and PMF.

In the State SIP modeling, EPA modeled each unit in separate CALPUFF runs for each model scenario. Then the CALPUFF-predicted results for all units were summed using POSTUTIL. As an equivalent approach (and for simplicity), AECOM modeled all units in the same CALPUFF file for each model scenario. AECOM has conducted sensitivity tests using the modeling of separate CALPUFF runs for each model scenario and CALPUFF runs with all four units modeled in one run and determined that both approaches give the same predicted results for the Base Case and State SIP case. AECOM's sensitivity test runs are included in the CALPUFF modeling archive.

4.3 POSTUTIL

POSTUTIL was used to apply the ammonia-limiting method to repartition the nitrates among all of the sources if more than 1 stack was modeled. POSTUTIL version 1.56 (Level 070627) was used in the modeling.

4.4 CALPOST

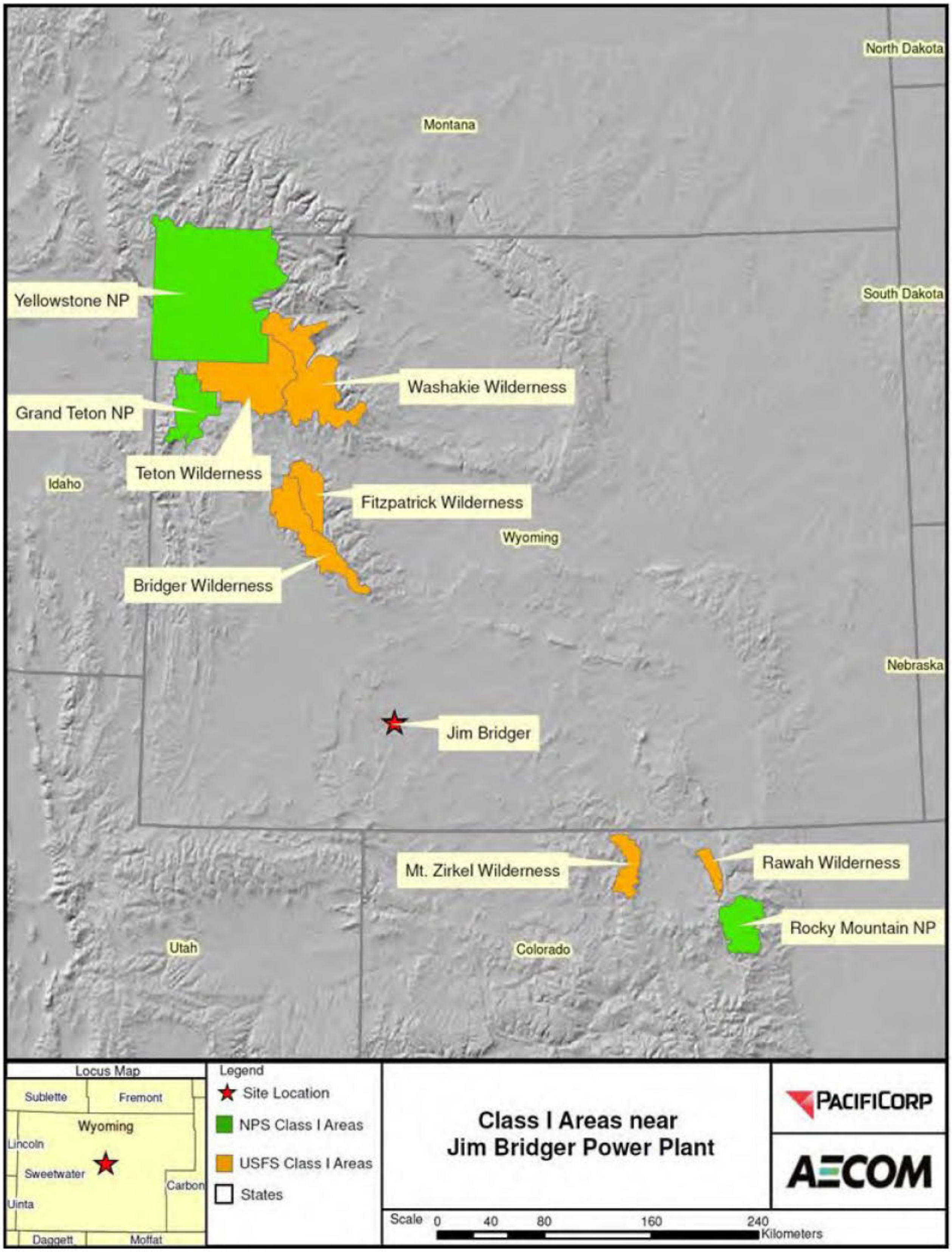
CALPOST Version 6.211 (Level 080724) was used for the regional haze analysis.

In accordance with FLAG 2010 guidance, the visibility impacts were processed using CALPOST Method 8 (MVISBK=8) and sub-mode five (M8_MODE=5). The Method 8 (new IMPROVE equation) allows a split between large and small sulfate, nitrate, and organic particles when calculating natural background conditions and change in light extinction.

The annual average concentrations, Rayleigh scattering coefficient, and sea salt concentrations were taken from FLAG[5] Table 6. The monthly relative humidity adjustment factors for large sulfate and nitrate particles were taken from FLAG Table 7 and for small particles from FLAG Table 8. The sea salt relative humidity adjustment factors were taken from FLAG Table 9.

[4] Atkinson, D. and T. Fox. 2006. Dispersion Coefficients for Regulatory Air Quality Modeling in CALPUFF. Memorandum from U.S. EPA/OAQPS to Kay T. Prince, EPA Region 4. March 16.
[5] FLAG, 2010. Federal Land Managers' Air Quality Related Values Workgroup Phase I Report – Revised (2010). U.S. Forest Service-Air Quality Program, National Park Service-Air Resources Division, U.S. Fish and Wildlife Service-Air Quality Branch. October 2010.

Figure 4-1: Class I Areas Near Jim Bridger Power Plant



5. Results of Visibility Metrics Comparing RP Reassessment and SNCR Cases to the State SIP

The results from the CALPUFF modeling that are listed below can be used to inform the decision as to whether either the RP Reassessment and/or SNCR scenario is acceptable to replace the State SIP. The results from the 3 years combined were used to provide a statistically robust result (as compared to using results from each separate year). The following three metrics were used:

1) the 98th percentile modeled delta-dv, averaged over the 3 years modeled, applied to each Class I area individually;
2) the number of modeled days (summed over the 3 years modeled) with a plant impact above 0.5 delta-dv, applied to each Class I area individually; and
3) the number of modeled days (summed over the 3 years modeled) with a plant impact above 1.0 delta-dv, applied to each Class I area individually.

All of the cases were modeled with the common stack, except that the State SIP case was also modeled with separate stacks.

Figure 5-1 provides the results in bar chart form for the 98th percentile day's modeled delta-dv, averaged over the 3 years modeled, and shown for each Class I area. The results show that the RP Reassessment case is better than the State SIP case (run with both common and separate stacks). The SNCR case has higher visibility impacts than the State SIP case, and much higher than the RP Reassessment.

Figures 5-2 and 5-3 provide the results in bar chart form for the number of modeled days (summed over the 3 years modeled) with a plant impact above 0.5 and 1.0 deciview, at the respective Class I areas respectively. The results show that the RP Reassessment case is better than the State SIP case (the SCR scenario run with both common and separate stacks) and the SNCR scenario.

The results for the RP Reassessment case were better (lower) or equal to the results of the State SIP (for both the common and separated stacks) for each of the metrics listed above for every Class I area modeled. Therefore, the RP Reassessment case demonstrates improved visibility benefits relative to the State SIP case. The SNCR scenario does not meet this test, and therefore is not better than the State SIP.

A separate computer modeling archive includes all of the CALMET, CALPUFF, POSTUTIL, and CALPOST modeling files that can be used to verify the results provided in this report.

Figure 5-1: 98th Percentile Visibility Impact Averaged Over 3 Years Modeled

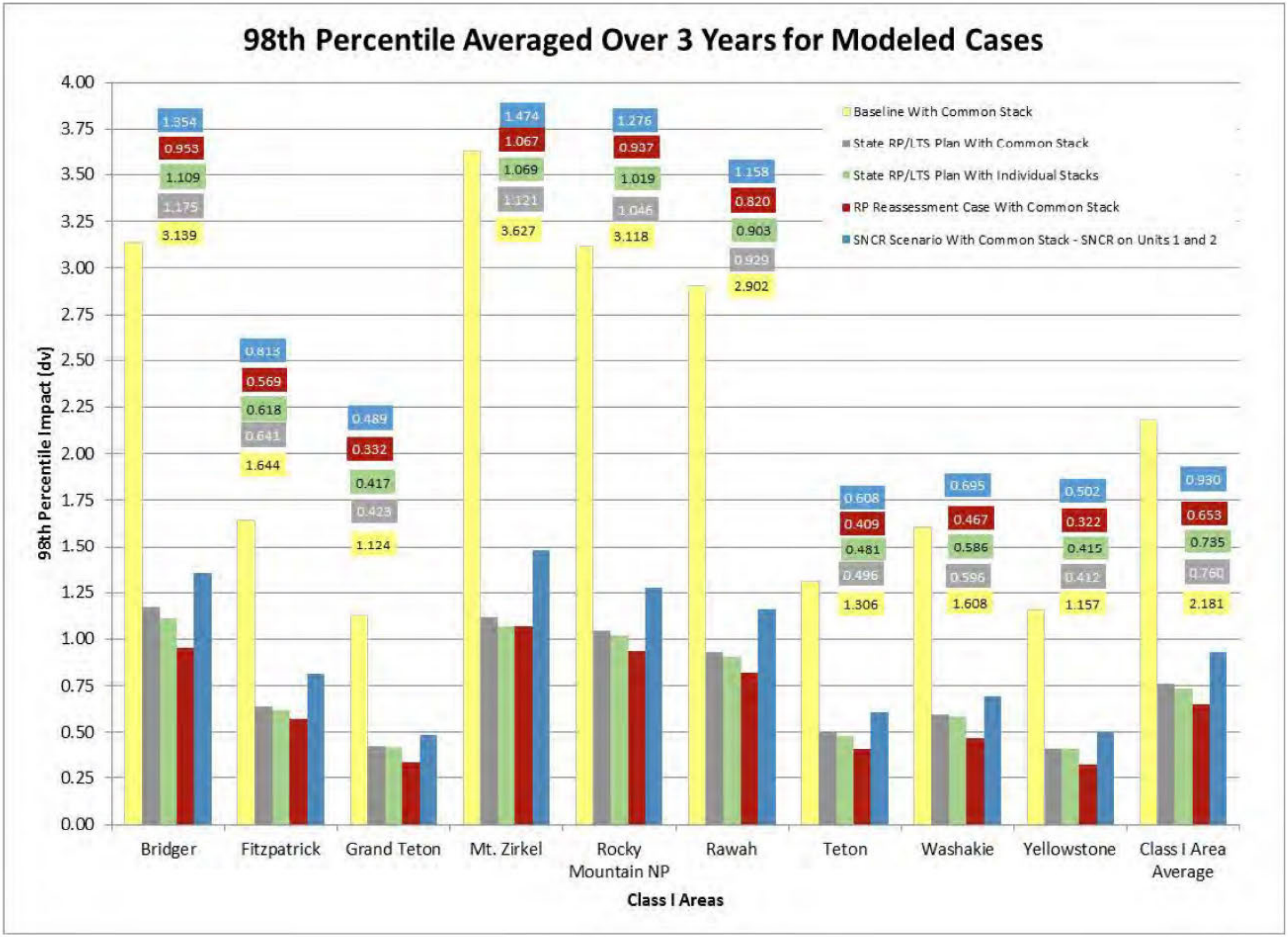


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Figure 5-2: Total Number of Modeled Days Over 3 Years with Visibility Impacts Above 0.5 Delta-Dv

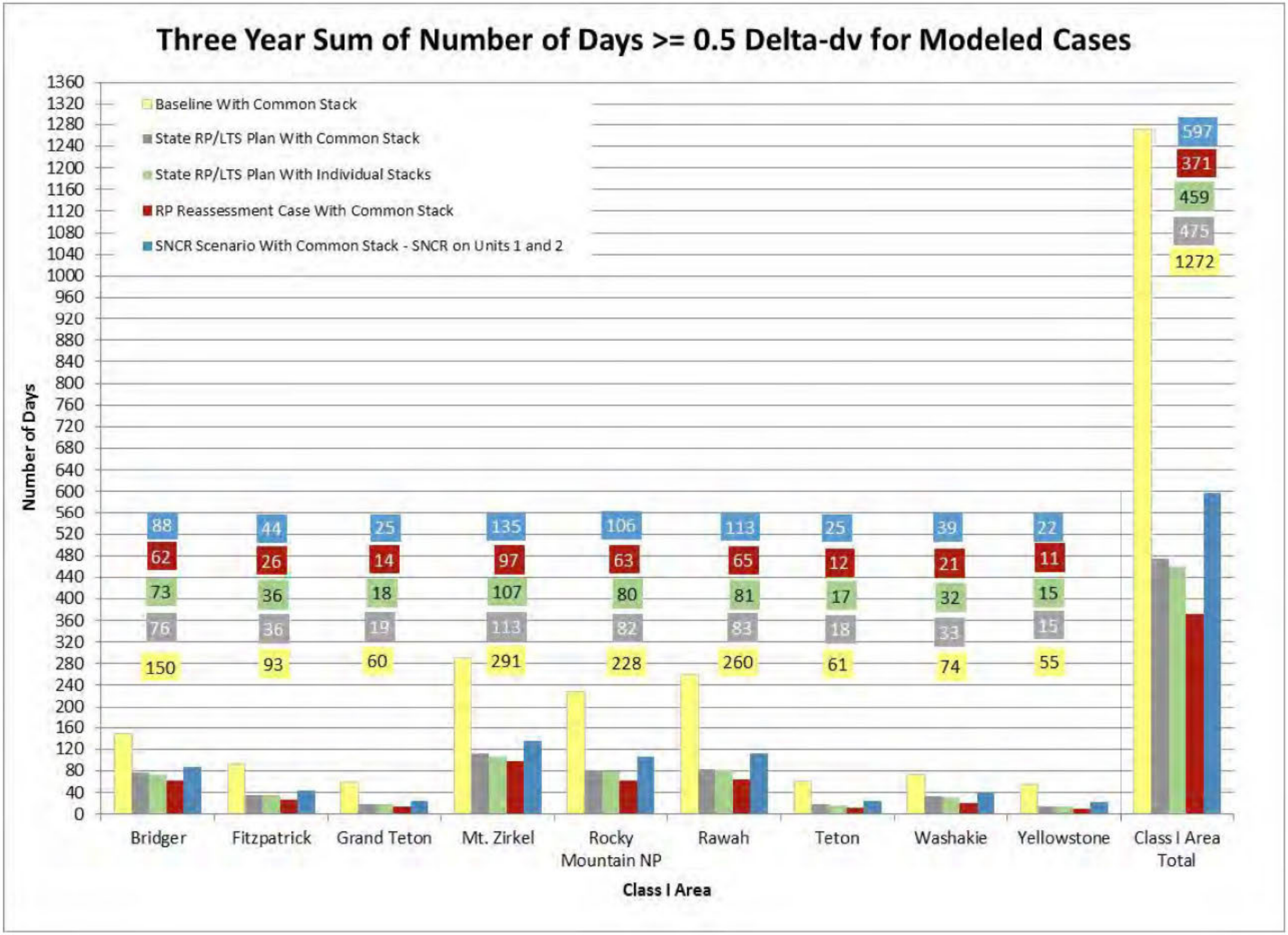

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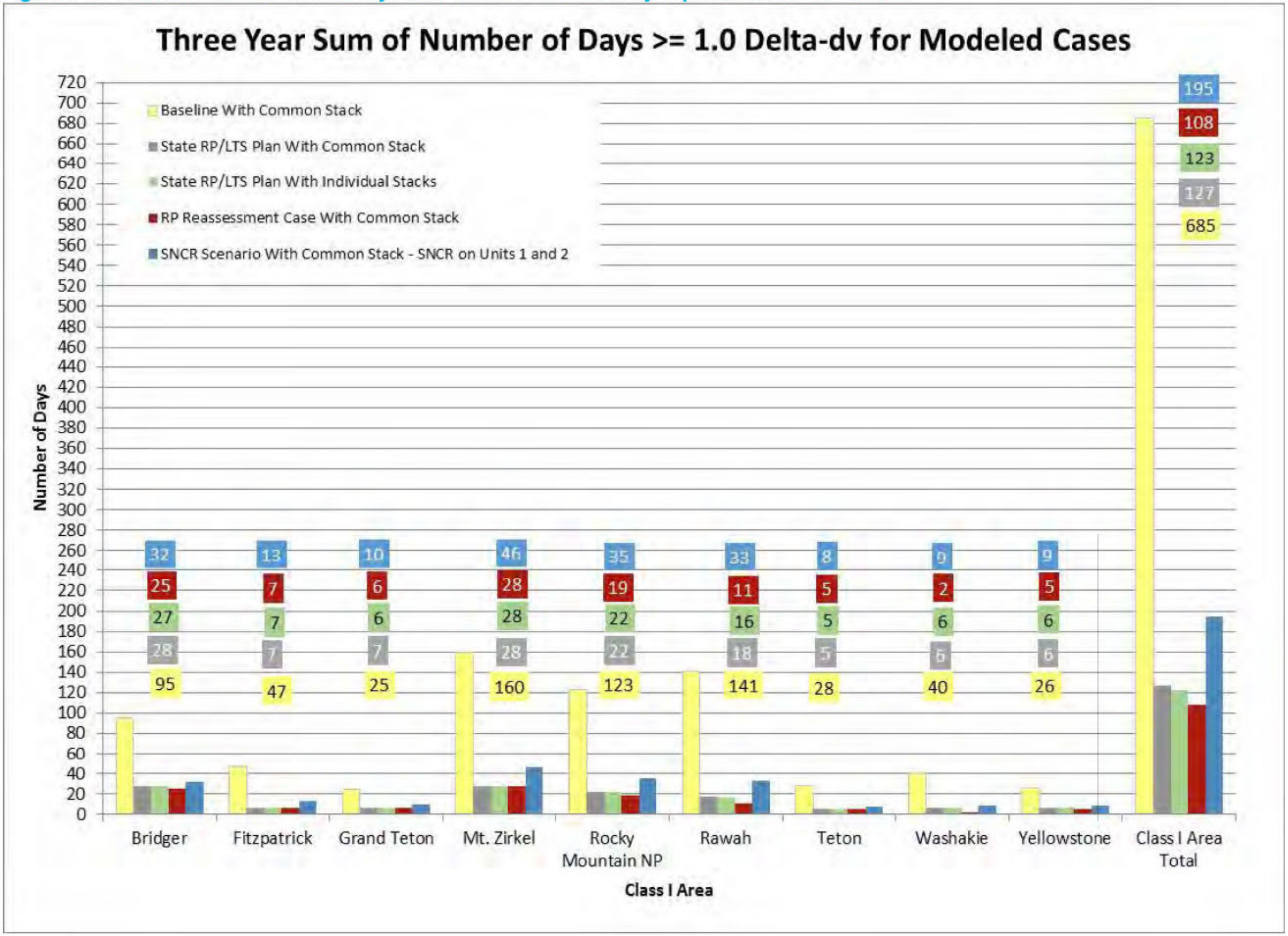
Figure 5-3: Total Number of Modeled Days Over 3 Years with Visibility Impacts Above 1.0 Delta-Dv



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Appendix A – Reasonable Progress Reassessment Visibility Improvement Modeling Protocol for Jim Bridger Power Plant

(photo provided by PacifiCorp)

Reasonable Progress Reassessment Visibility Improvement Modeling Protocol for Jim Bridger Power Plant

PacifiCorp/Idaho Power

Project Number: 60544863

January 2019

Quality information

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1. Introduction

1.1 Overview

On January 30, 2014, EPA published a final regional haze rule (79 FR 5032) that established stringent controls of nitrogen oxide (NOx) emissions from the four units at the Jim Bridger Power Plant, located near Point of Rocks, Wyoming. For NOx controls, EPA determined that Wyoming's selection of the then-current NOx controls of low-NOx burners (LNB) and separated overfire air (SOFA) qualified for Best Available Retrofit Technology (BART) controls. Additionally, EPA approved Wyoming's requirement that LNB/OFA plus SCR be installed at Jim Bridger Units 1-4 as part of the State's Reasonable Progress / Long-Term Strategy (RP/LTS).

The resulting Wyoming SIP required, as part of its RP/LTS, installation of SCR controls for NOx (30-day rolling average emission rate of 0.07 lb/MMBtu) on Jim Bridger units in a phased approach:

- December 31, 2022 for Unit 1
- December 31, 2021 for Unit 2
- December 31, 2015 for Unit 3
- December 31, 2016 for Unit 4.

The installations of SCR controls on Jim Bridger Units 3 and 4 have been completed as stated above. For Units 1 and 2, PacifiCorp/Idaho Power are proposing an alternative to the SCR installations on the remaining Jim Bridger units that will result in equivalent or better visibility improvement than Wyoming's RP/LTS that was approved by EPA ("State SIP"). This alternative emission control strategy, referred to herein as the "RP Reassessment," will set month-by-month mass emission limits for two principal haze-causing pollutants, sulfur dioxide (SO_2) and nitrogen oxides (NOx). The average annual mass emissions of SO_2 plus NOx for the RP Reassessment as proposed on a pound-per-hour basis will be nearly 20% lower than those of the State SIP (all four units controlled by SCR). The RP Reassessment plan will have higher NOx emissions relative to the State SIP on a month-to-month basis, but much lower SO_2 emissions that will result in better visibility than the State SIP. The reduction in emissions for the RP Reassessment will be brought about through a combination of emissions management and operational restrictions on the Jim Bridger units. This report analyzes the relative modeled visibility impacts from the RP Reassessment and the State SIP. A second "SNCR scenario" (with SNCR controls on Units 1 and 2) has also been evaluated relative to the State SIP and RP Reassessment.

This modeling protocol, revised from a June 2018 document with incorporation of Wyoming and EPA comments, provides a description of the visibility modeling approach that will be used to make the determination that the RP Reassessment case will result in better visibility than the State SIP.

1.2 Haze Composition Overview

A review of haze composition at the Class I areas in the Wyoming and northern Colorado area is useful to better understand the expected benefits of the proposed RP Reassessment, which reduces SO_2 emissions relative to the State SIP and SNCR scenarios. Since the Regional Haze Rule's focus for each decadal review is to improve the visibility on the 20% worst haze days (while not degrading[1] visibility for the 20% best days), it is helpful to look at the monitored haze composition for the critical 20% worst haze days. Figure 1-1[2] shows the 2015 haze "pie chart" for various Class I areas in the vicinity of the Jim Bridger plant. Figure 1-2 shows a close-up of areas near

[1] It is generally accepted that emissions reduction that improve visibility on the worst 20% haze days will also improve visibility on the best 20% days as well. Therefore, the modeling analysis focuses upon improving visibility for the worst 20% haze days.
[2] http://vista.cira.colostate.edu/improve/wp-content/uploads/2016/12/2015-IMPROVE-NR-Bext-SIA-Annual-MOH20-w-Canada.jpg

the Jim Bridger plant (red ellipse), while Figure 1-3 shows a 2015 time series daily haze composition plot for the Mount Zirkel Wilderness Area. What can be determined from these plots is as follows.

- The most important component of the worst 20% haze days is organic matter from wildfires (green portion of pie chart), plus coarse matter and elemental carbon (black and brown) that are also emitted in large quantities by wildfires.
- In terms of pollutants from Jim Bridger that contribute to haze in the most-impacted areas (within the red ellipse in Figure 1-2), sulfate haze has a year-round effect, while nitrate haze is most important during the cold months of the year, when the park visitation is lowest. The sulfate fraction of the pie charts in Figure 1-2 is also much larger than the nitrate fraction, demonstrating that sulfates are more significant contributors to haze at these locations than nitrates.
- The RP Reassessment will address the haze issues by applying monthly-varying restrictions on SO_2 and NOx emissions.

Figure 1-1: Haze Composition Plot for 20% Worst Days in 2015

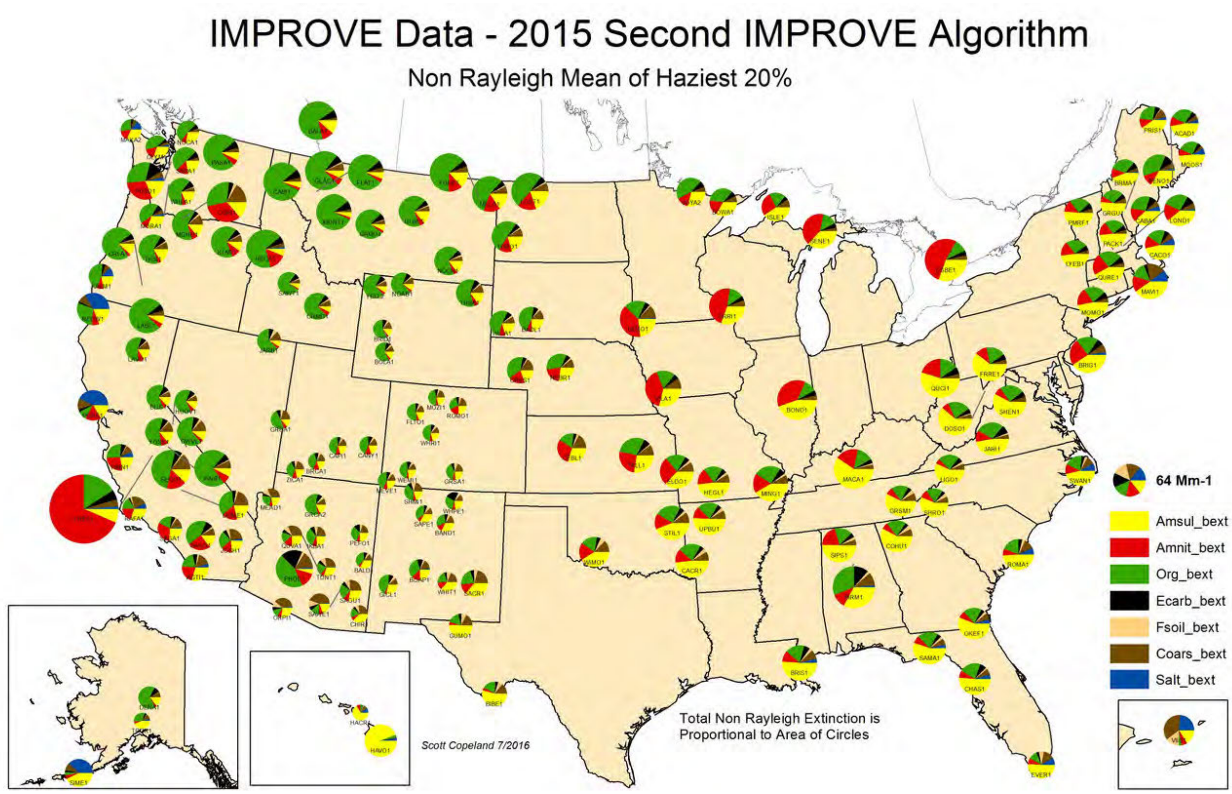


Figure 1-2: Haze Composition for 20% Worst Days Near Jim Bridger Power Plant

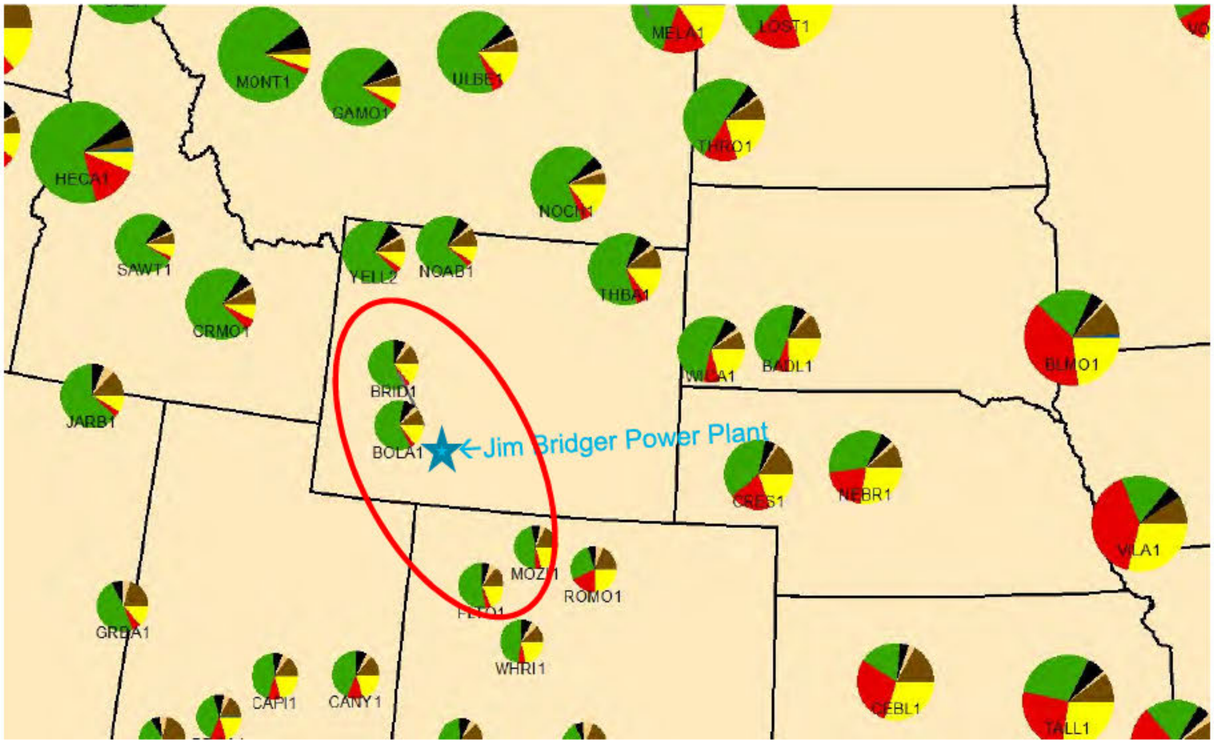
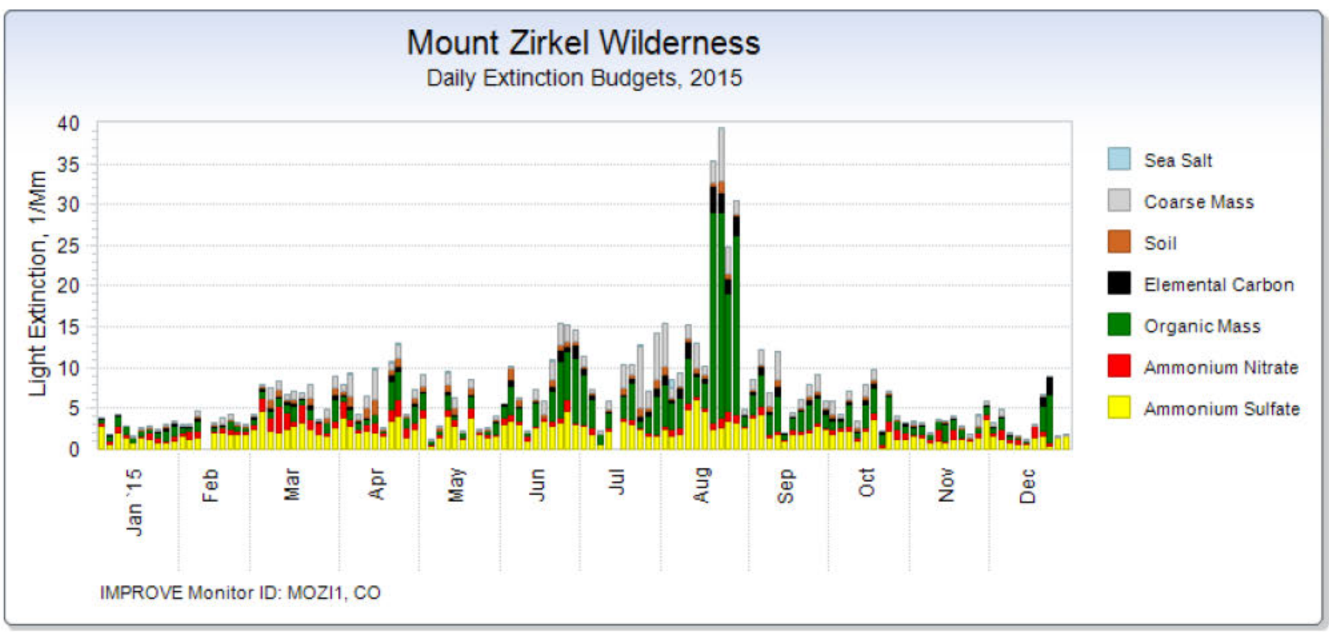


Figure 1-3: Daily Extinction Haze Composition Plot for Mount Zirkel, 2015



1.3 Organization of This Protocol Document

Section 2 of this report provides a description of the main emission sources at the Jim Bridger Power Plant. The emissions associated with the Baseline Case, the State SIP, the RP Reassessment, and the SNCR scenario cases are presented in Section 3. Section 4 provides a discussion of the proposed CALPUFF modeling procedures. The metrics to be used in the comparison of the visibility improvement between the State SIP and the RP Reassessment and SNCR scenario cases are presented in Section 5.

2. Overview of Jim Bridger Power Plant

PacifiCorp and Idaho Power co-own, and PacifiCorp operates, the Jim Bridger Power Plant, a coal-fired steam electric generating station located 9 miles north of Point of Rocks, Wyoming. Jim Bridger is comprised of four coal-fired boilers which came online from 1974 to 1979 (see plant photo on the cover page and Figure 2-1). Units 1-4 each have a nominal net generation capacity of roughly 530 MW, for a total net power generating capacity of about 2,119 MW. Each unit has a single stack with a height of 152 meters. The facility is approximately 97.8 kilometers from the southern boundary of Bridger Wilderness, which is the closest Class I area to the facility.

Table 2-1 lists the modeled stack parameters for each of the sources, corresponding to full-load conditions. Note that the stack parameters are identical for units 1, 2, and 3, and the differences for unit 4 are modest in that the larger diameter offsets the lower exit velocity, and the resulting buoyancy flux is within 15% of that of units 1-3.

Table 2-1: Modeled Stack Parameters for Jim Bridger Units

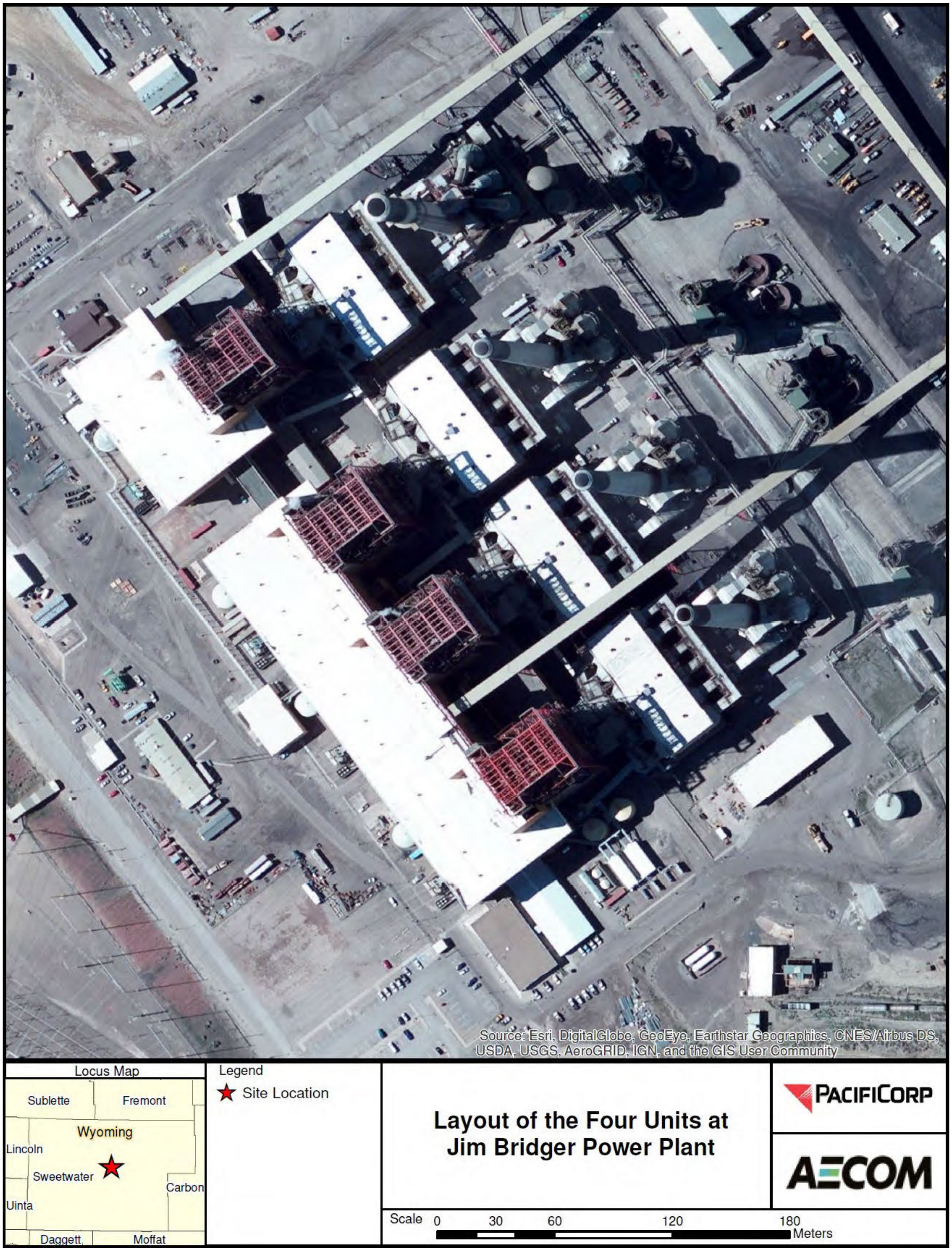
Stack Parameter	Unit 1	Unit 2	Unit 3	Unit 4
Stack height (m)	152	152	152	152
Base elevation (m)	2,036	2,036	2,036	2,033
Stack Diameter (m)	7.32	7.32	7.32	9.45
Exit Velocity (m/s)	24.7	24.7	24.7	12.9
Exit Temperature (K)	328	328	328	322

Due to the similarity of the stack exhaust parameters, it is reasonable due to the large distances to the Class I areas involved to consider a single stack that represents emissions from all four units. The characteristics of this "common" stack, which for modeling will be located between the stacks for Units 2 and 3, are provided in Table 2-2. Section 3 provides a discussion of how the results of the common stack can be compared to that of separate stacks for the RP Reassessment to show that the common stack results are either equivalent to or higher than those obtained with separate stacks. The common stack modeling results are generally slightly higher than the same emissions distributed among separate stacks because the emissions are concentrated into a single unit. Therefore, to remove any doubt that the RP Reassessment case has better modeled visibility than the State SIP case, the combined stack results for the RP Reassessment will be tested against the State SIP run two ways: with the combined and separated stacks. The RP Reassessment case will need to show better visibility than the State SIP case run both ways to be determined to be acceptable as a replacement for the State SIP.

Table 2-2: Modeled Parameters for Common Jim Bridger Stack

Stack Parameter	Common Stack
Stack height (m)	152
Base elevation (m)	2,036
Stack Diameter (m)	7.32
Exit Velocity (m/s)	24.7
Exit Temperature (°K)	328

Figure 2-1: Layout of Jim Bridger Power Plant



Due to the tall stacks at the facility and the dominance of long-range dispersion for CALPUFF predictions, building downwash effects will not be included in the modeling.

3. Emission Controls for BART Visibility Improvement

Current emission controls for sulfur dioxide emissions at Jim Bridger include the use of low-sulfur coal and scrubbers on all four units. Particulate matter for all units is controlled by electrostatic precipitators (ESPs). Fabric filters (baghouses) are installed on various coal-handling emission sources. Units 1 and 2 currently use low NOx burner technology with Separated Over-fire Air systems (LNB/SOFA) to control oxides of nitrogen. Units 3 and 4 also use LNB/SOFA technology with the addition of SCR. These control devices were installed after the Baseline period of 2001-2003.

The State SIP currently requires SCR to be added to Units 1 and 2 as part of Wyoming's current Long-Term Strategy (LTS), as discussed in Section 1. All other controls on Units 1 and 2 would remain the same for the State SIP. At EPA's suggestion, the Baseline Case reflects emissions characteristic of controls in place during the Regional Haze Rule baseline period (2001-2003), which did not yet involve scrubber upgrades, LNB/SOFA controls, or the NOx emission controls that have been made for Units 3 and 4.

PacifiCorp/Idaho Power are considering a Reasonable Progress Reassessment (RP Reassessment) that would involve an alternative to installation of SCR controls on Units 1 and 2. This RP Reassessment incorporates additional controls on SO_2 and NOx installed since 2001-2003, and also incorporates operational limits to further reduce emissions, as discussed further below. The RP Reassessment will have lower total plant-wide annual emissions for SO_2 + NOx than the State SIP, as described below. A second "SNCR scenario" that involves Selective Non-catalytic Reduction (SNCR) controls for Units 1 and 2, but with no operational restrictions on plant-wide utilization, will also be tested at the request of the state.

EPA provided preliminary input on the Baseline, State SIP, and RP Reassessment emissions to be modeled for the visibility comparison. Emissions for the visibility modeling of the Baseline Case, the State SIP, the SNCR scenario, and the RP Reassessment are provided in Tables 3-1, 3-2, 3-3, and 3-4, respectively. As shown in Table 3-4 on the "Plant Total" line, the annual-average emissions of SO_2 + NOx are listed for the RP Reassessment. Due to seasonal changes in effectiveness of emission controls and plant utilization needs, the final visibility modeling for the RP Reassessment incorporates monthly-varying emission rates that are provided in Table 3-5. The RP Reassessment Emission Rates provided in Tables 3-4 and 3-5 result in emission reductions and better visibility improvement than the State SIP, while also taking into consideration operational feasibility, seasonal variability, scrubbing potential, and multiple capacity factor forecast scenarios.

The emissions for the cases modeled will be combined into a common stack for modeling purposes, as noted in Section 2. For the RP Reassessment, a demonstration will be included in the modeling report showing that this treatment results in equivalent[3] or (most likely) higher results to the modeling of the four separate stacks. The demonstration that the common stack case provides equivalent or higher results for this RP Reassessment will be made for five hypothetical cases, summarized below, that shift emissions among the Jim Bridger units. The documentation for the equivalent common stack will be provided in the final modeling report and computer archive to support this RP Reassessment specification of plant-wide emission rates on a monthly block basis.

The equivalency test for the common stack modeling run for the RP Reassessment will be tested with a total of five test runs. One of the runs will assume equal emissions among the four units. Four additional tests will zero out emissions for each one of the units in succession and then distribute the total plant emissions equally among the three remaining operating units. This results in a total of five test runs, as summarized below.

1) Unit 1 emissions are set to zero, and remaining emissions are distributed among the other three units;
2) Unit 2 emissions are set to zero, and remaining emissions are distributed among the other three units;
3) Unit 3 emissions are set to zero, and remaining emissions are distributed among the other three units;
4) Unit 4 emissions are set to zero, and remaining emissions are distributed among the other three units;

[3] EPA's Appendix W, Section 3.2.2 defines "equivalent" results are such that the controlling modeling result is within 2% of the reference case. In this case, that means that the 3-year average of the 98th percentile delta-dv impact modeled by CALPUFF for the single stack with all haze emissions for the Jim Bridger plant is within 2% of the result when the 4 stacks are modeled separately. If the results of the common stack are higher than those of the separate stacks (even if more than 2%), this conservative result is also acceptable.

5) Emissions are equally distributed among the four 4 units.

For each hypothetical equivalency case modeled, the total plant emissions are listed in Table 3-5 (monthly-varying emissions). A satisfactory showing to support the use of the common stack in the modeling of the RP Reassessment case will occur if the results for the common stack are either higher than or within 2% of the results for the cases with emissions variations noted above.

The July 6, 2005 BART Rule (70 FR 39172) provides for allowing sources to average emissions over all BART units within a fenceline. Specifically, the language in the rule provides this instruction to the States:

> ***You should consider allowing sources to "average" emissions across any set of BART-eligible emission units within a fenceline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible units that constitute BART-eligible source.***

Therefore, the interpretation of the RP Reassessment emissions is that the plant-wide monthly block emission limit for each pollutant summed over all four units will be the enforceable limit.

The emission rates proposed for the RP Reassessment represent a significant reduction (nearly 20%) in SO_2 + NOx emissions from the State SIP, and are designed to result in an equivalent or better visibility improvement relative to the State SIP, as defined by the visibility metrics described in Section 5.

Table 3-1: Baseline Case Emissions

Pollutant*	SO_2	NOx
Unit	(lb/hr)	(lb/hr)
1	1,765	2,788
2	1,749	2,772
3	1,808	2,670
4	1,003	2,969
Plant Total	6,327	11,199

*for each unit modeled, the SO_4, PM_{10}, and $PM_{2.5}$ emission rates will be 54.1, 77.4, and 102.6 lb/hr, respectively.

Table 3-2: State RP/LTS (SIP) Emissions

State RP/LTS (SIP) Plan					
Pollutant*	SO_2		NOx		SO_2 + NOx
Unit	Reduction from Baseline (%)	(lb/hr)	Reduction from Baseline (%)	(lb/hr)	(lb/hr)
1	48.6%	907	87.3%	355	
2	36.1%	1,118	86.5%	374	
3	44.1%	1,010	86.5%	359	
4	12.1%	882	87.4%	375	
Plant Total	37.3%	3,917	86.9%	1,463	5,380

*for each unit modeled, the SO_4, PM_{10}, and $PM_{2.5}$ emission rates will be 54.1, 77.4, and 102.6 lb/hr, respectively.

Table 3-3: SNCR Scenario Emissions

RP Reassessment with SNCR					
Pollutant*	**SO_2**		**NOx**		**SO_2 + NOx**
Unit	**Reduction from Baseline (%)**	**(lb/hr)**	**Reduction from Baseline (%)**	**(lb/hr)**	**(lb/hr)**
1	48.6%	907	61.8%	1,066	
2	36.1%	1,118	59.5%	1,123	
3	44.1%	1,010	86.5%	359	
4	12.1%	882	87.4%	375	
Plant Total	37.3%	3,917	86.9%	2,922	6,839

*for each unit modeled, the SO_4, PM_{10}, and $PM_{2.5}$ emission rates will be 54.1, 77.4, and 102.6 lb/hr, respectively.

Table 3-4: RP Reassessment Emissions

RP Reassessment Preferred by PacifiCorp					
Pollutant[1]	**SO_2**		**NOx**		**SO_2 + NOx**
	Reduction from Baseline (%)	**(lb/hr)**	**Reduction from Baseline (%)**	**(lb/hr)**	**(lb/hr)**
Plant Total[2]	66.40%	2,100	80.05%	2,232	4,332

[1] for each unit modeled, the SO_4, PM_{10}, and $PM_{2.5}$ emission rates will be 54.1, 77.4, and 102.6 lb/hr, respectively.
[2] Annual-average plant-wide emissions

Table 3-5: Monthly Plant-wide Emission Rates for RP Reassessment Modeling

Month	SO_2 (lb/hr)	NO_X (lb/hr)
January	2,100	2,050
February	2,100	2,050
March	2,100	2,050
April	2,100	2,050
May	2,100	2,200
June	2,100	2,500
July	2,100	2,500
August	2,100	2,500
September	2,100	2,500
October	2,100	2,300
November	2,100	2,030
December	2,100	2,050
Annual Average*	2,100	2,232

*The annual average weights each month by the number of days in the month for a non-leap year.

4. Visibility Improvement Modeling Procedures

The original FIP modeling utilized CALPUFF version 5.8. Due to several updates to the CALPUFF modeling system since the state of Wyoming conducted their original modeling, the modeling analysis will use the current EPA-approved version 5.8.5.

4.1 CALMET

The CALMET input data has been provided by the State of Wyoming for years 2001, 2002, and 2003. CALMET version 5.8.5 (Level 151214) will be used to process the meteorological data. Specifics about the CALMET preprocessing are described below.

CALMET will be processed using 12-km resolution MM5 prognostic meteorological data as well as surface, precipitation, and upper air stations. CALMET technical options will be based on the WDEQ-recommended settings provided with the Wyoming Regional Haze Rule State Implementation Plan. Table 4-1 lists some of the key user-defined settings.

Table 4-1: Key User-Defined CALMET Settings

Variable	Description	Value
PMAP	Map projection	LCC (Lambert Conformal Conic)
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	10
ZFACE	Cell face heights (m)	0, 20, 40, 100, 140, 320, 580, 1020, 1480, 2220, 3500
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model output	14 (MM5 data)
RMAX1	Maximum radius of influence (surface layer, km)	30
RMAX2	Maximum radius of influence (layers aloft, km)	50
TERRAD	Radius of influence for terrain (km)	15
R1	Relative weighting of first guess wind field and observations (km)	5
R2	Relative weighting aloft (km)	25

4.2 CALPUFF

CALPUFF version 5.8.5 (Level 151214) will be used in the modeling. CALPUFF will be run for all three years of meteorological data and the cases as described in Section 3. The modeling will be conducted at nine Class I areas (all such areas that are within 300 km of the plant) which are listed below and shown in relation to Jim Bridger in Figure 4-1.

- Bridger Wilderness (WY)
- Fitzpatrick Wilderness (WY)
- Grand Teton National Park (WY)
- Mt. Zirkel Wilderness Area (CO)
- Rocky Mountain National Park (CO)
- Rawah Wilderness Area (CO)
- Teton Wilderness (WY)
- Washakie Wilderness (WY)
- Yellowstone National Park (WY)

The CALPUFF modeling will be conducted in a manner that is consistent with State SIP modeling approach, as discussed below.

- Hourly ozone files will be used to define background ozone concentrations. A value of 44.0 ppb will be used when ozone data is missing in the files.
- As requested by EPA, the monthly background ammonia concentrations will be specified, consistent with the IWAQM Phase 2 recommendation, as a constant value of 0.5 ppb.
- CALPUFF will be run with regulatory default options as outlined in the 2006 EPA memo[4].
- Pollutant species to be modeled include SO_2, SO_4, NOx, HNO_3, NO_3, PMC, and PMF.

In the State SIP modeling, EPA modeled each unit in separate CALPUFF runs for each model scenario. Then the CALPUFF-predicted results for all units were summed using POSTUTIL. As an equivalent approach (and for simplicity), AECOM will model all units in the same CALPUFF file for each model scenario. AECOM has conducted sensitivity tests using the modeling of separate CALPUFF runs for each model scenario and CALPUFF runs with all four units modeled in one run and determined that both approaches give the same predicted results for the Base Case and State SIP case.

AECOM's sensitivity test runs will be included in the CALPUFF modeling archive.

4.3 POSTUTIL

POSTUTIL will be used to apply the ammonia-limiting method to repartition the nitrates among all of the sources if more than 1 stack is modeled. POSTUTIL version 1.56 (Level 070627) will be used in the modeling, as needed.

4.4 CALPOST

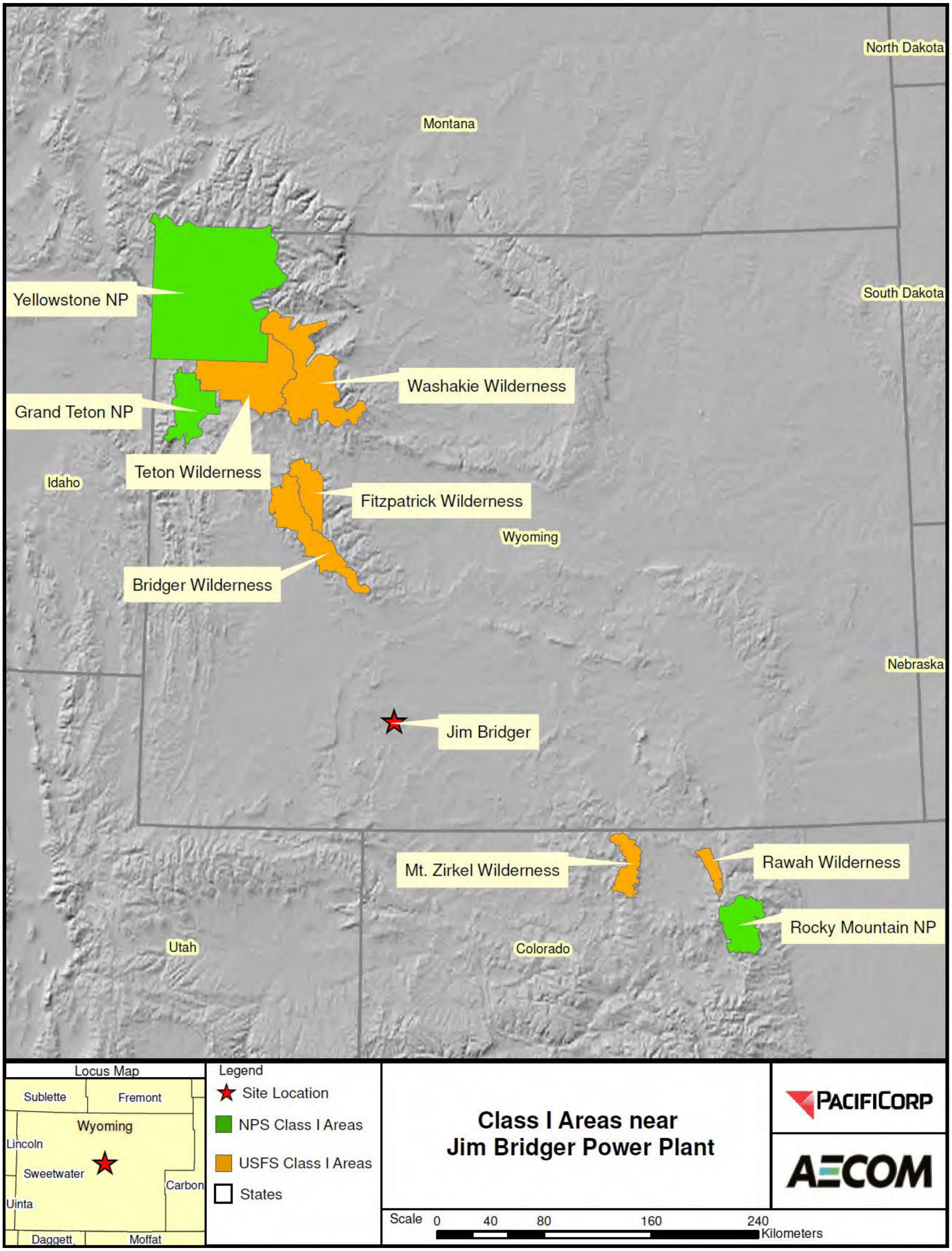
CALPOST Version 6.211 (Level 080724) will be used for the regional haze analysis.

In accordance with FLAG 2010 guidance, the visibility impacts will be processed using CALPOST Method 8 (MVISBK=8) and sub-mode five (M8_MODE=5). The Method 8 (new IMPROVE equation) allows a split between large and small sulfate, nitrate, and organic particles when calculating natural background conditions and change in light extinction.

The annual average concentrations, Rayleigh scattering coefficient, and sea salt concentrations will be taken from FLAG[5] Table 6. The monthly relative humidity adjustment factors for large sulfate and nitrate particles will be taken from FLAG Table 7 and for small particles from FLAG Table 8. The sea salt relative humidity adjustment factors will be taken from FLAG Table 9.

[4] Atkinson, D. and T. Fox. 2006. Dispersion Coefficients for Regulatory Air Quality Modeling in CALPUFF. Memorandum from U.S. EPA/OAQPS to Kay T. Prince, EPA Region 4. March 16.
[5] FLAG, 2010. Federal Land Managers' Air Quality Related Values Workgroup Phase I Report – Revised (2010). U.S. Forest Service-Air Quality Program, National Park Service-Air Resources Division, U.S. Fish and Wildlife Service-Air Quality Branch. October 2010.

Figure 4-1: Class I Areas Near Jim Bridger Power Plant



5. Metrics to Compare the RP Reassessment and SNCR Scenario to the State SIP

The results from the CALPUFF modeling that are listed below will be used to inform the decision as to whether either the RP Reassessment and/or SNCR scenario is acceptable to replace the State SIP. The results from the 3 years combined will be used to provide a statistically robust result (as compared to using results from each separate year). The following three metrics will be included:

1) the 98th percentile modeled delta-dv, averaged over the 3 years modeled, applied to each Class I area individually;
2) the number of modeled days (summed over the 3 years modeled) with a plant impact above 0.5 delta-dv, applied to each Class I area individually; and
3) the number of modeled days (summed over the 3 years modeled) with a plant impact above 1.0 delta-dv, applied to each Class I area individually.

All of the cases will be modeled with the combined stack, except that the State SIP case will also be modeled with separate stacks.

If the results from either the RP Reassessment and/or the SNCR scenario are equal to or better (lower) than the results of the State SIP (run both with the combined and separated stacks) for each of the metrics listed above for every Class I area modeled, then the RP Reassessment and/or the SNCR scenario will be judged to demonstrate better "visibility improvement" than the existing State SIP.

The computer modeling archive will include all of the modeling files for the combined and separated stacks, as well as CALPUFF sensitivity tests as mentioned in Section 4.2.

Appendix B – Comparison of Common Stack vs. Separated Stack Results for RP Reassessment Case

Figure B-1: 98th Percentile Visibility Impact Averaged Over 3 Years Modeled

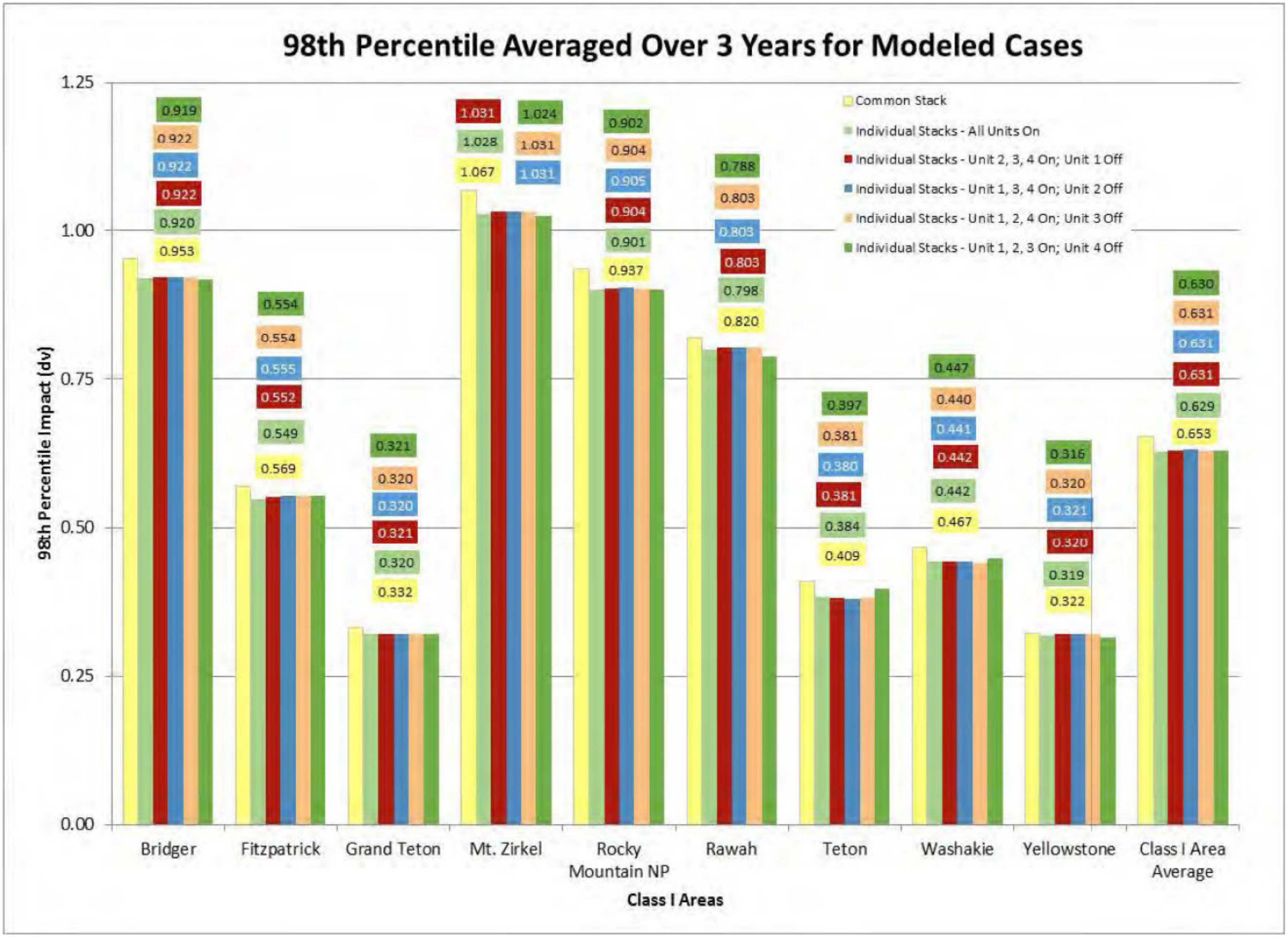


Exhibit PAC/4003
Owen/160

Figure B-2: Total Number of Modeled Days Over 3 Years with Visibility Impacts Above 0.5 Delta-Dv

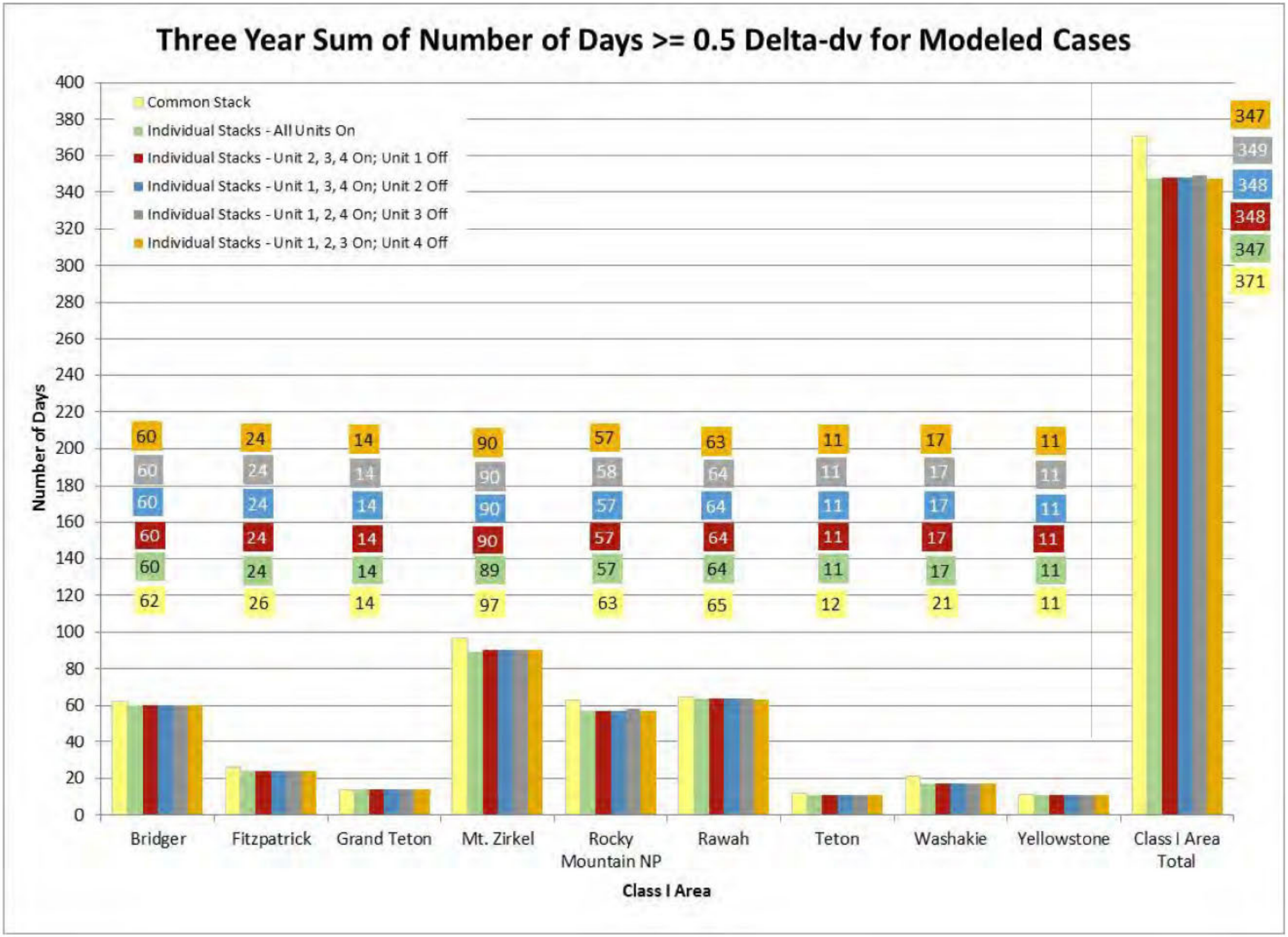


Exhibit PAC/4003
Owen/161

Figure B-3: Total Number of Modeled Days Over 3 Years with Visibility Impacts Above 1.0 Delta-Dv

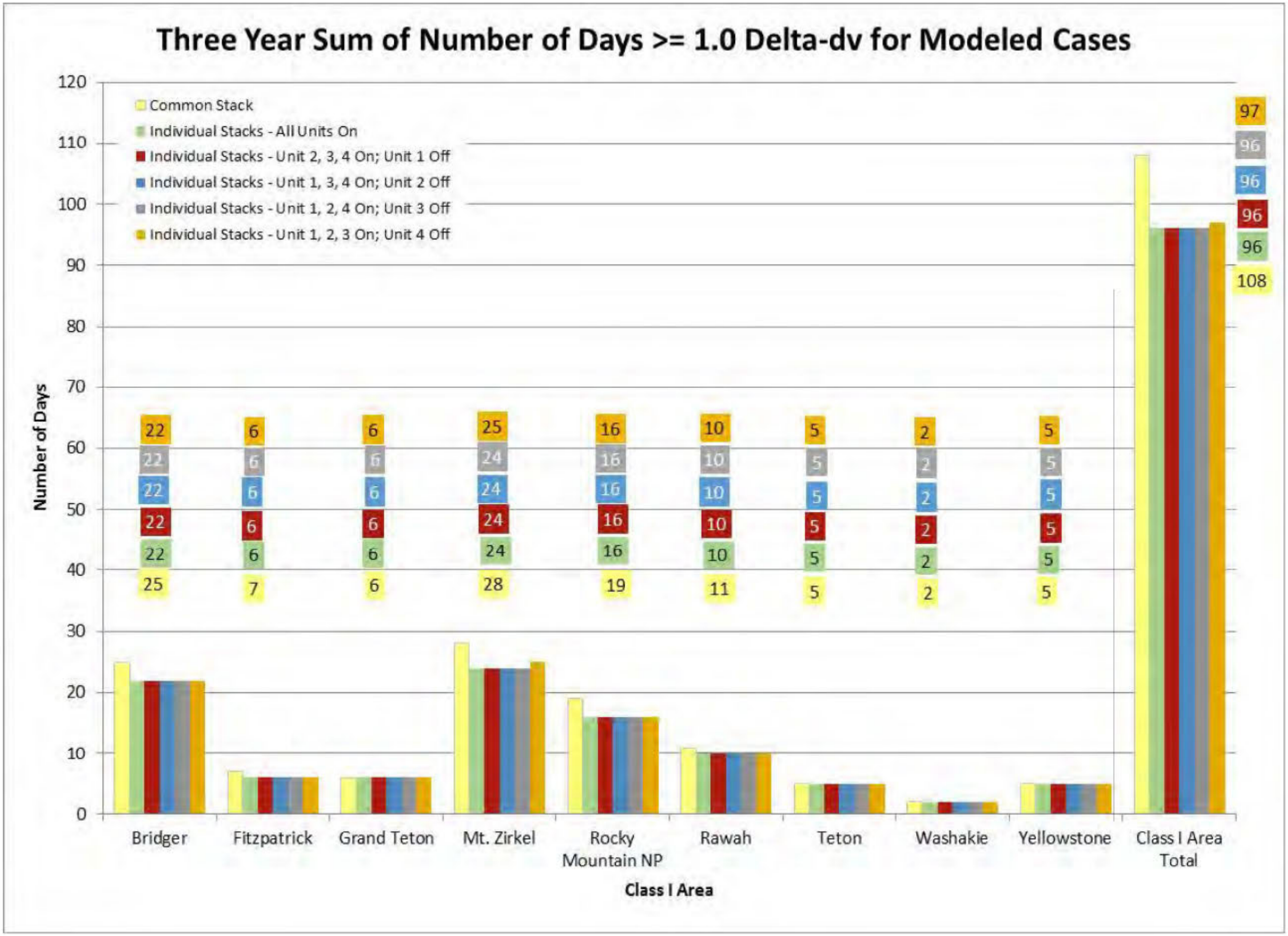


Exhibit PAC/4003
Owen/162

Docket No. UE 374
Exhibit PAC/4004
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of James Owen

Excerpts from the Environmental Protection Agency Cost Reports and Guidance for Air Pollution Regulations, Chapter 2 - Selective Catalytic Reduction Costs (2000) and (2019)

August 2020

EPA/452/B-02-001

Chapter 2

Selective Catalytic Reduction

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October 2000

The term, Y is given by the equation:

$$Y = \frac{h_{catalyst}}{h_{year}} \tag{2.53}$$

where $h_{catalyst}$ is the operating life of the catalyst in hours and h_{year} is the number of hours per year the SCR is operated. The value of Y estimated from the equation is then rounded to the nearest integer.

Indirect Annual Costs

In general, indirect annual costs (fixed costs) include the capital recovery cost, property taxes, insurance, administrative charges, and overhead. Capital recovery cost is based on the anticipated equipment lifetime and the annual interest rate employed. An economic lifetime of 20 years is assumed for the SCR system. The remaining life of the boiler may also be a determining factor for the system lifetime.

In many cases property taxes do not apply to capital improvements such as air pollution control equipment, therefore, for this analysis, taxes are assumed to be zero [19]. The cost of overhead for an SCR system is also considered to be zero. An SCR system is not viewed as risk-increasing hardware (e.g., a high energy device such as a boiler or a turbine). Consequently, insurance on an SCR system is on the order of a few pennies per thousand dollars annually [19]. The administrative charges, covering sales, research and development, accounting, and other home office expenses, incurred in operation of an SCR system are relatively insignificant for the cost estimation procedure presented here. Finally, there are two categories of overhead, payroll and plant. Payroll overhead includes expenses related to labor employed in operation and maintenance of hardware; whereas plant overhead accounts for items such as plant protection, control laboratories, and parking areas. Because this procedure assumes that no additional labor is needed in operation of an SCR system, payroll overhead is zero and plant overhead is considered to be negligible.

Using these assumptions, indirect annual costs in $/yr, *IDAC*, can be expressed as:

$$IDAC = CRF \;\; TCI \tag{2.54}$$

Chapter 2
Selective Catalytic Reduction

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June 2019

Y = term, years.

The term, Y, is given by the equation:

$$Y = \frac{h_{catalyst}}{h_{year}} \qquad (2.66)$$

Where:

$h_{catalyst}$ = operating life of the catalyst, hours
h_{year} = number of hours per year the SCR is operated, hr/yr.

The value of Y estimated from the equation is then rounded to the nearest integer.

Under catalyst replacement cost methodology 2, the cost for catalyst replacement and disposal for a given boiler is part of the S&L cost methodology employed for power plants in this chapter given by [9]:

$$\begin{pmatrix} Annual\,Catalyst \\ Replacement\ Cost \end{pmatrix} = (B_{MW}) \times (0.4) \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3 \qquad (2.67)$$

Where:

Annual Catalyst Replacement Cost = cost to replace the SCR catalyst, \$/yr
CCreplace = cost of catalyst, dollars per cubic meter (\$/ft3)
35.3 = conversion factor for $\$/ft^3$ to $\$/m^3$.

Because high-dust units typically require larger catalyst volume, the replacement costs for the catalyst are also higher. Tail-end units require not only less catalyst volume but also less frequent catalyst replacement, due to minimal ash and catalyst poisons in the flue gas at this point in the equipment train. Lower levels of fly ash and catalyst poisons in the flue gas increase the catalyst life and decrease operating costs related to replacement [57]. In addition, concentrations of SO_2 in the flue gas are low following the wet scrubber and there are fewer concerns related to SO_3 formation and ammonium salt deposition [57].

While catalyst vendors typically provide a 24,000 hour (or 3 year) guarantee for catalysts, catalysts in tail-end units may last for extended periods. One source cites tail-end SCR units in Europe that continue to operate using the initial catalyst that was installed in the 1980's and have up to 130,000 operating hours [116], and another source reports tail-end catalysts that lasted for 100,000 operating hours [57].

<u>Indirect Annual Costs</u>

In general, as mentioned in the Cost Manual Methodology chapter in Section 1 of the Control Cost Manual, indirect annual costs (fixed costs) include the capital recovery cost, property taxes, insurance, administrative charges, and overhead. Capital recovery cost is based on the anticipated equipment lifetime[28] and the annual interest rate employed.[29] For the purposes of this cost example, the equipment lifetime of an SCR system is assumed to be 30 years for power plants and 20 to 25 years for industrial boilers. These assumptions are based on several sources, including estimates by six petroleum refiners that SCR for fluidized catalytic cracking units and other process units would be between 20 and 30 years [26]; results from a survey conducted by the South Coast Air Quality Management District that shows equipment life for SCRs at refineries to be 20 to 25 years [117], an expert report in the North Carolina (NC) lawsuit against the Tennessee Valley Authority (TVA) coal-fired electric generation units indicated expected useful life of an SCR is 30 years [118]; a 2002 study of the economic risks from SCR operation at the Detroit Edison Monroe power plant used 30 years as the anticipated lifetime [119]; and a design lifetime of 40 years was used for an SCR at the San Juan Generating Station [120]. Thus, broadly speaking, a representative value of the equipment life for SCR at power plants can be considered as 30 years. For other sources, the equipment life can be between 20 and 30 years. The remaining life of the boiler may also be a determining factor for the system lifetime.

In many cases, property taxes do not apply to capital improvements such as air pollution control equipment; therefore, for this analysis, taxes are assumed to be zero [45]. The cost of overhead for an SCR system is also considered to be zero. An SCR system is not viewed as risk-increasing hardware (e.g., a high-energy device such as a boiler or a turbine). Consequently, insurance on an SCR system is on the order of a few cents per thousand dollars annually [45]. Finally, there are two categories of overhead, payroll and plant. Payroll overhead includes expenses related to labor employed in operation and maintenance of hardware, whereas plant overhead accounts for items such as plant protection, control laboratories, and parking areas. Because this procedure assumes that no additional labor is needed in operation of an SCR system, payroll overhead is zero and plant overhead is considered to be negligible.

Using these assumptions, indirect annual costs, *IDAC,* in \$/yr, consist of both administrative charges and capital recovery, which can be expressed as:

$$Indirect\ Annual\ Cost = \begin{pmatrix} Administrative \\ Charges \end{pmatrix} + \begin{pmatrix} Capital \\ Recovery \end{pmatrix} \tag{2.68}$$

<u>Administrative Charges</u>

Administrative charges may be calculated as:

$$Administrative\ Charges = 0.03 \times \left(\left(\frac{Operator}{Labor\ Cost} \right) + 0.4 \times \left(\frac{Annual\ Maintenance}{Cost} \right) \right) \tag{2.69}$$

Where

[28] The term "equipment life" as used here in this chapter and through the Control Cost Manual refers to operational or design life. See Section 1, Chapter 2 for more explanation.

[29] The interest rate recommended by EPA can vary by firm or industry, but the bank prime rate is a default rate that can be used for annualization of capital costs. This rate is 5.25 – 5.5 percent as of January 2019. For more information, please consult the cost estimation chapter of this Control Cost Manual (Section 1, Chapter 2).

Operator Labor Cost = t_{SCR} x Operator Hours/day x Labor Rate.

In general, the operating labor cost in this equation will be small because operation of an SCR system requires only minimal, operating or supervisory labor.

Capital Recovery

Capital recovery is estimated as:

$$CR = CRF \times TCI \tag{2.70}$$

where *TCI* is the total investment, and *CRF* is the capital recovery factor and defined by:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \tag{2.71}$$

where *i* is the interest rate, and *n* is the equipment life of the SCR system.

Total Annual Cost

The total annual cost (*TAC)* for owning and operating an SCR system is the sum of direct and indirect annual costs as given in the following equation:

$$Total\ Annual\ Cost = \begin{pmatrix} Direct \\ Annual \\ Cost \end{pmatrix} + \begin{pmatrix} Indirect \\ Annual \\ Cost \end{pmatrix} \tag{2.72}$$

Cost Effectiveness

The cost in dollars per ton of NO_x removed per year is:

$$Cost\ Effectiveness = \frac{TAC}{NO_x\ Removed/yr} \tag{2.73}$$

Where:

Cost Effectiveness = the cost effectiveness, \$/ton
NO_x Removed/yr = annual mass of NO_x removed in the SCR, ton/yr.

2.5 Example Problem #1 – Utility Boiler

An example problem that calculates both the design parameters and capital and annual costs for an SCR system applied to a 120 MW utility boiler firing bituminous coal is presented below. The following assumptions are made to perform the calculations:

Fuel High Heating Value, *HHV*	12,000 Btu/lb
Net Plant Heat Rate, *NPHR*	10 MMBtu/MWh
Maximum Actual Output	102 MW

REDACTED
Docket No. UE 374
Exhibit PAC/4100
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Dana M. Ralston

August 2020

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ATTACHED EXHIBITS

Q. Are you the same Dana M. Ralston who previously submitted reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this case?

A. My surrebuttal testimony responds to the rebuttal testimonies of Sierra Club and the Alliance of Western Energy Consumers (AWEC), challenging the prudence of the Company's decision to install selective catalytic reduction systems (SCR) on Units 3 and 4 of the Jim Bridger plant. I rebut Sierra Club's contention that, as a result of mine plan changes at Bridger Coal Company (BCC) in the fall of 2013, coal costs increased and invalidated the Company's economic analysis. I rebut AWEC's argument that PacifiCorp failed to accurately forecast future coal costs or to account for the potential value of water rights in evaluating the Jim Bridger SCR investments. Finally, I address AWEC's proposed disallowance of certain costs related to the closure of the Deer Creek Mine.

II. SUMMARY OF TESTIMONY

Q. Please summarize your surrebuttal testimony.

A. My surrebuttal testimony is summarized as follows:

- I respond to Sierra Club's efforts to conflate the Company's coal cost analysis associated with the decision to install SCRs at Jim Bridger Units 3 and 4. The Company continues to disagree that it is appropriate to rely on the November 2014 long-term fueling plan because it was developed after the Company made the final decision to proceed with the SCRs. The Company also clarifies its analysis of the October 2013 mine plan's impacts.

- I respond to AWEC's claim that the Company's 2013 Integrated Resource Plan (IRP) forecasts of coal costs were substantially lower than the Company's 2013 Business Plan, and that coal costs would be inevitably higher than expected. This analysis is flawed, and the Company's coal cost forecasts were reasonably reliable.
- I rebut AWEC's assertion that the Company's water rights have a clear and identifiable value appropriate to include in the Company's SCR analysis. I also respond to AWEC's mischaracterization of the Company's [redacted].
- I respond to AWEC's proposal to partially disallow costs associated with the closure of the Deer Creek mine. While the mine's miscellaneous closure costs were higher than expected, this was a result of the Mine Safety and Health Administration (MSHA) imposing more rigorous requirements-based on an accident that occurred at an unrelated, non-Company owned mine. The Company's miscellaneous closure costs were prudently incurred and should be fully recoverable, especially because total project costs associated with closure of the mine were within [redacted] percent of the forecast.
- Finally, I note that no party appears to challenge the prudence of the Company's investments in SCRs at Hayden Units 1 and 2 in their rebuttal testimony.

Q. Do you have any clarification to offer regarding AWEC's characterization of the Company's emissions control investments?

A. Yes. AWEC opposes the Company's investments in SCRs at Jim Bridger Units 3 and 4 and baghouse and low NOx burners (LNB) at Hunter Unit 1. However, Dr. Kaufman repeatedly refers to Hunter Unit 1 as having not only baghouse and LNB emissions controls, but also SCRs.[1] To be clear, an SCR is not installed at Hunter Unit 1.

III. SURREBUTTAL

A. Long-Term Fueling Plan and Mine Plans

Q. Please briefly summarize Sierra Club's argument concerning the November 2014 long-term fueling plan and the October 2013 mine plan.

A. Sierra Club argues that the decision to install the Jim Bridger SCRs was imprudent because a new mine plan adopted by BCC in October 2013 demonstrated that the benefits of the four-unit/SCR scenario had decreased by $59.3 million, relative to the costs of gas conversion.[2] Sierra Club relies on the Company's November 2014 long-term fueling forecast, developed for the Company's 2015 IRP, to support $31 million of this decrease and the October 2013 mine plan to support an additional $28.3 million decrease associated with reclamation-related savings.

[1] AWEC/500, Kaufman/1 (urging the Commission to "[f]ind the cost of PacifiCorp's Jim Bridger Units 3 and 4 SCR and Hunter Unit 1 Baghouse and SCR investments not prudent"); AWEC/500, Kaufman/11 (referring to "Hunter SCRs" and criticizing the Company for failing to explore reduced dispatch "without SCR installation . . . for Jim Bridger 3 and 4 or Hunter Unit 1").
[2] Sierra Club/400, Fisher/13.

Q. Dr. Fisher describes your reply testimony as seeking "to muddy the record" by "attribut[ing] the $31 million modification to Sierra Club[.]"[3] Do you agree with this characterization?

A. No. To clarify, the $31 million figure represents PacifiCorp's analysis correcting Sierra Club's estimate of coal cost increases. PacifiCorp's analysis compared the cost increases between the January 2013 long-term fuel plan and the November 2014 long-term fuel plan and showed that this increase was $31 million, not $143 million as Sierra Club alleged in previous cases. Sierra Club's analysis was tied to the November 2014 long-term fueling plan—*not* the October 2013 mine plan.[4] While PacifiCorp developed this analysis to rebut Sierra Club's incorrect estimation of coal cost increases, the Company does not believe that it is appropriate to rely on the November 2014 long-term fueling plan in this proceeding, as this forecast was not available when the Company made its decision to invest in the Jim Bridger SCRs. As I have previously explained, a long-term fueling plan is not equivalent to a mine plan.[5]

Q. How does Staff respond to Sierra Club's characterization of the Company's analysis?

A. Staff notes that "Sierra Club appears to have misrepresented the Company's position on the effect that the October 2013 mine plan had on the economics of SCRs."[6] Staff also agrees that the November 2014 long-term fueling plan "was not available when

[3] Sierra Club/400, Fisher/13.
[4] PAC/2600, Ralston/10.
[5] PAC/2600, Ralston/7-9.
[6] Staff/2300, Soldavini/35.

the Company was forced to decide whether to move forward," and therefore "Sierra Club's $31 million cost estimate [is] outside the scope of this review."[7]

Q. Sierra Club claims that your reply testimony "once again" re-quantifies the difference in coal costs resulting from the October 2013 mine plan, and that this "new" estimate "conflict[s]" with the $31 million estimate, described above.[8] How do you respond?

A. I have two comments in response. First, Sierra Club attempts to create confusion where none exists. The $16.7 million differential is the only instance in which I quantify the difference in coal costs resulting from the October 2013 mine plan. As noted above, and as I explained in reply testimony,[9] the $31 million figure is tied to the November 2014 long-term fueling plan—*not* the October 2013 mine plan. My assessment of the coal cost impacts of the October 2013 mine plan are different because the underlying assumptions on which the forecasts are based are also different.

Second, the analysis I present is not new, and was previously included in the Company's Washington and California rate cases.[10] Sierra Club's witness, Dr. Fisher, was an active participant in those cases. Nonetheless, Dr. Fisher chose to focus his opening testimony on the analysis of the November 2014 long-term fueling plan, as opposed to the more applicable analysis concerning the October 2013 mine plan. My reply testimony therefore attempted to both correct Dr. Fisher's analysis

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[7] Staff/2300, Soldavini/35.
[8] Sierra Club/400, Fisher/16.
[9] PAC/2600, Ralston/10-11.
[10] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-152253, Supplemental Rebuttal Testimony of Cindy Crane, Exh. CAC-1CT; Cal. Pub. Util. Comm'n, Docket Application 18-04-002, Rebuttal Testimony of Dana Ralston, Exh. 1703.

based on the November 2014 long-term fueling plan, and explain what an updated analysis would have shown in the fall of 2013, with the information available to the Company at the time.

Q. Sierra Club complains about the quality and clarity of the workpapers supporting the Company's $16.7 million estimated decrease in the four-unit/SCR case associated with the October 2013 mine plan. How do you respond?

A. As I explained in my reply testimony, the $16.7 million calculation is based on (1) calculating the overall coal cost changes between the January 2013 long-term fuel plan and the October 2013 mine plan, which amounts to a 2.8 percent overall increase; and (2) applying that percentage increase to both the four-unit/SCR scenario and the two-unit/no SCR scenario. This analysis was based on information available to PacifiCorp in the fall of 2013. As Staff notes, PacifiCorp provided its methodology for developing its $16.7 million estimate in Exhibit PAC/2603.[11]

Q. Does any other party question PacifiCorp's response to the October 2013 mine plan on rebuttal?

A. Yes. Staff states that the Company did not properly assess the impact of the October 2013 mining plan on the decision to install SCRs.[12] Staff points out that the Company's analysis of the cost impact of the October 2013 mine plan was performed "after the fact, for the purpose of refuting Sierra Club's analysis[.]" Staff states that the October 2013 mine plan represented a "significant enough" change that

[11] Staff/2300, Soldavini/33.
[12] Staff/2300, Soldavini/35.

"a reasonable utility would have sought to quantify the effects" before proceeding with the SCR investments.[13]

Q. Do you agree that the Company failed to assess the impact of the October 2013 mining plan on the decision to install SCRs?

A. No. As I explained in my reply testimony, the October 2013 mine plan did not forecast material changes in BCC costs on either a short- or long-term basis.[14] The Company was also aware of other offsetting cost decreases, including decreased capital costs in the underground mine in an amount that approximately offset the increase in operating costs for the surface mine.[15] There was no reason to believe that the October 2013 mine plan would have substantially impacted the SCR analysis. Indeed, as demonstrated by my analysis offered in this proceeding—which was based on information known to PacifiCorp at the time—such an update would have continued to support the Company's decision to install SCRs at Jim Bridger Units 3 and 4.

Q. Sierra Club argues that the magnitude of the offsetting cost decrease was "relatively insignificant relative to the cost increase realized at BCC."[16] How do you respond?

A. Neither the cost increase nor the cost decrease was particularly significant. As my analysis demonstrates, for those costs covered by the October 2013 mine plan, coal costs for the Jim Bridger plant increased by only 2.8 percent during the 10-year

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[13] Staff/2300, Soldavini/36.
[14] PAC/2600, Ralston/9.
[15] PAC/2600, Ralston/9.
[16] Sierra Club/400, Fisher/17.

budget horizon (2014-2023) relative to the January 2013 long-term fuel plan.[17] This reflects a 0.5 percent decrease in third-party coal costs (inclusive of inventory changes) which accounts for approximately 25 percent of fuel costs. The fluctuations in the coal cost forecasts for Jim Bridger in the fall of 2013 were not substantial.

Q. In your reply testimony, you stated that Sierra Club inappropriately added $28.3 million in reclamation costs associated with the October 2013 mine plan to the $31 million cost increase estimate associated with the 2014 long-term fuel plan, referring to this as a "double count." Can you clarify this testimony?

A. Yes, the Company interpreted Sierra Club's testimony as incorrectly contending that reclamation cost changes were not factored into the $31 million cost increase estimate, so I referred to this as a "double count." At the same time, as noted by Staff witness Sabrinna Soldavini, my reply testimony made clear that the two-unit/no SCR analysis under the October 2013 mine plan would remove the $28.3 million reclamation cost increase, but this was only one of several cost changes that would need to be considered.[18] I pointed to the Company's analysis demonstrating that a reasonable estimate of the overall change to the value of the four-unit/SCR analysis under the October 2013 mine plan was a decrease of $16.7 million, an amount that did not materially change the Company's analysis showing that the SCRs were more beneficial for customers than other alternatives.

Based on Sierra Club's rebuttal testimony, it is clear that Sierra Club is not necessarily "double counting," but instead is selectively combining costs derived

[17] PAC/2600, Ralston/10.
[18] Staff/2300, Soldavini/34 ("PacifiCorp states the Sierra Club is correct in stating that a two-unit analysis based on information available in fall of 2013 'would remove the increased costs associated with accelerated remediation[.]'").

from two different analyses. It is not analytically correct to simply add one cost component in isolation to the estimate of the total change in costs from the 20-year January 2013 long-term fuel plan to the 20-year November 2014 long-term fuel plan.

Q. Please explain.

A. While Sierra Club is correct that an updated two-unit/no-SCR scenario based on the October 2013 mine plan would not include accelerated reclamation costs for the surface mine, a fully updated analysis would include other offsetting costs not accounted for in Sierra Club's simplistic and mismatched calculation. For instance, Sierra Club does not account for the $51.5 million[19] reduction in capital spend from the January 2013 long-term fueling plan to the October 2013 mine plan. This factor would offset Sierra Club's $28.3 million for accelerated reclamation.

The Company provided indicative analysis calculating the impact of the October 2013 mine plan on the two-unit/no SCR and four-unit/SCR differentiation based on the 10-year budget horizon, which showed a $16.7 million decrease in the value of the four-unit/SCR alternative.[20] Sierra Club's alternate estimate of a $59.3 million decrease in value is based on two parts, first, information that was not known to the Company at the time (the $31 million cost change from January 2013 to November 2014) and second, the selective and mismatched addition of a single cost change associated with the October 2013 mine plan (the $28.3 million change in reclamation costs).

[19] This $51.5 million figure is on a present-value basis in 2014 dollars.
[20] PAC/2603.

Q. Sierra Club argues that assessing the SCR investment relative to the cost of other projects "flies in the face of system planning" because "[t]he overall value of a project is assessed on its own merits."[21] Do you agree?

A. No. Any option in system planning has strengths and weaknesses relative to the other options available. When a costly investment is still far less expensive than other available options on a forward-looking basis, then that costly investment may still be the least-cost, least-risk option. Sierra Club appears to object not merely to the Company's decision to invest in SCRs, but the Company's very approach to considering a range of alternatives to determine which yielded the least-cost, least-risk outcome for customers.

Moreover, Sierra Club appears confused regarding the nature of the Company's analysis, suggesting that the Company compared the relative cost of investing in SCRs to "the overall size of PacifiCorp's multi-billion [dollar] system[.]"[22] This is incorrect. The Company's SCR alternatives analysis, as described in more detail by Mr. Rick T. Link, compared the relative cost of alternatives for the Jim Bridger plant. This analysis demonstrated that investing in SCRs at Jim Bridger Units 3 and 4 was the least-cost, least-risk available option to serve customers.

B. <u>Accuracy of Coal Cost Forecasts</u>

Q. Please summarize your understanding of AWEC's position regarding the accuracy of the Company's coal cost forecasts.

A. AWEC claims that the decision to install the Jim Bridger SCRs was imprudent

[21] Sierra Club/400, Fisher/47.
[22] Sierra Club/400, Fisher/47.

because the Company's coal cost forecasts were unrealistically low.

Q. In opening testimony, AWEC argued that the Company had systematically under-forecast coal costs for the Jim Bridger plant by approximately [redacted].[23] Does AWEC continue to support this position on rebuttal?

A. Not exactly. On rebuttal, AWEC appears to abandon its previous claim that the Company systematically under-forecast coal costs. AWEC now states that the Company's 2013 IRP forecasts used a price per one million British Thermal units (MMBtu) that was, on average [redacted] than the Company's 2013 business plan coal forecast, and notes that these forecasts were generated at the same time.[24] While AWEC's witness Dr. Kaufman does not explain the implications of his assertion, it appears that he continues to believe that the Company's coal cost forecasts used in the SCR analysis were too low.

Q. Is AWEC correct that the Company's 2013 business plan coal forecast estimated coal costs that were, on average, 23 percent higher than the 2013 IRP?

A. No, this is not correct. The 2013 IRP costs are based on a cash basis and the 2013 10-year business plan is based on total operating costs. After adjusting the 2013 IRP costs to include the non-cash costs that were removed (depreciation, depletion, and coal inventory adjustments), the 2013 business plan is only four percent[25] higher than what was assumed in the 2013 IRP.

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[23] AWEC/300, Kaufman/36.
[24] AWEC/500, Kaufman/9.
[25] CONF Exhibit PAC/4101.

Q. On rebuttal, AWEC claims that the Company should have known that coal costs would be higher than expected.[26] Please summarize your understanding of AWEC's reasoning.

A. AWEC claims that the Company should have known that its coal costs would increase because low consumption rates triggered higher prices, while medium and high consumption rates would have triggered the need for a substantial new [redacted] railroad investment.[27]

Q. For the low-consumption scenario, is AWEC correct that coal costs would have been reasonably expected to increase?

A. No. AWEC is once again conflating total coal costs with cost-per-unit. As I explained in reply testimony, when coal consumption is lower than expected, the costs on a dollar per MMBtu basis increase. However, the total costs in a low-consumption scenario are generally lower because of lower volumes.

Q. For the medium- and high-consumption scenarios, is AWEC correct that costs would have been reasonably expected to increase?

A. No. AWEC's contention that coal costs would have increased in a medium- or high-consumption scenario mistakenly assumes that PacifiCorp would have incurred an additional [redacted] investment in railroad unloading facilities to maintain the plant's operation. Dr. Kaufman cites his own testimony on behalf of Staff in docket UE 307 to support this allegation.[28] But in Order No. 16-482 in that docket, the Commission upheld the Company's decision in 2013 *not* to make an investment in

[26] AWEC/500, Kaufman/8.
[27] AWEC/500, Kaufman/8-9.
[28] AWEC/500, Kaufman 8.

these rail facilities and instead continue to rely on its historical fuel strategy.[29] Thus, there is no basis for claiming that PacifiCorp should have included the cost of the rail investment in its economic analysis at that time.

Q. Does any other party comment on the accuracy of the Company's coal cost forecasts?

A. Yes. In response to the concerns raised by AWEC's opening testimony, Staff urged PacifiCorp to provide additional evidence of the accuracy of the Company's previous BCC coal cost forecasts for years leading up to 2012.[30]

Q. Have you responded to Staff's request for further analysis?

A. Yes. In addition to BCC budget and actual information previously provided,[31] the Company has supplemented this filing with 2008 through 2013 cost data presented in Figure 1. The Company used this six-year period because the first full year of longwall mining at the BCC underground mine, which represented a major change in operations, occurred in 2008 and the final notice to proceed for the Jim Bridger SCRs was issued in December 2013. Figure 1 demonstrates improved accuracy of budget estimates on an annual basis during this period. The chart also highlights that cost increases are significantly impacted by declining coal delivered volumes.

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[29] *In the Matter of PacifiCorp, d/b/a/ Pacific Power's 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 (Dec. 20, 2016).
[30] Staff/2300, Soldavini/38.
[31] DR AWEC 0133 CONF.

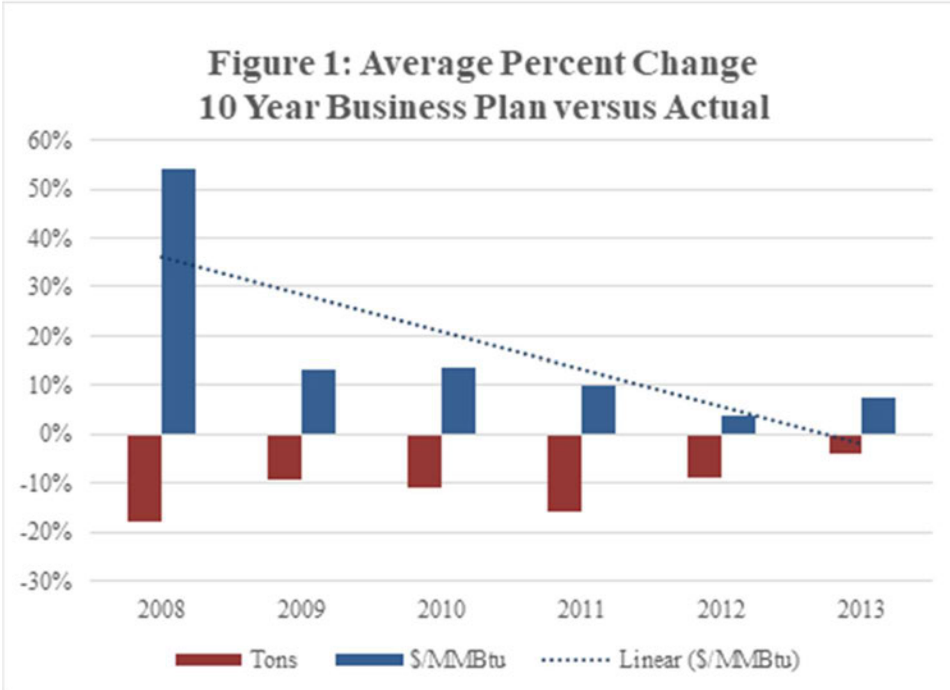

Figure 1: Average Percent Change
10 Year Business Plan versus Actual

C. <u>Water Rights</u>

Q. Please summarize AWEC's claim regarding water rights for the Jim Bridger plant.

A. AWEC argues that PacifiCorp should have accounted for the potential resale value of the Company's water rights associated with the Jim Bridger plant, as part of its analysis of the costs and benefits of closing Jim Bridger Units 3 and 4.[32]

Q. AWEC states that "PacifiCorp admits that Jim Bridger water rights have value."[33] Is this a complete and accurate characterization of the Company's position?

A. No. AWEC's rebuttal testimony relies on PacifiCorp's response to a data request, which asked (a) if PacifiCorp agrees that Jim Bridger water rights can be transferred,

[32] AWEC/500, Kaufman/11. While AWEC previously claimed that the Company should have incorporated a potential value for water rights at the Hunter plant—a claim which I addressed in reply testimony—AWEC witness Dr. Kaufman no longer appears to advance this claim regarding the Hunter plant. PAC/2600, Ralston/5.
[33] AWEC/500, Kaufman/11.

and (b) whether those water rights have monetary value.[34] For the first question, PacifiCorp stated its belief that "some portion of the water rights for the Jim Bridger plant could be available for transfer . . . subject to requirements of Wyoming law and assuming a market for the particular water rights exists."[35] For the second question, PacifiCorp said, "Yes, *subject to the limitations addressed in the response to (a) above*."[36]

Q. Have you previously addressed the potential complications associated with transferring water rights under Wyoming law and the possibility that a market for the Company's water rights may not exist?

A. Yes. I addressed these issues in detail in my reply testimony.[37]

Q. AWEC argues that the Company must assign a value to water rights associated with closing Jim Bridger Units 3 and 4 because those rights have not been shown to be wholly without value.[38] Do you agree?

A. No. The Company must be able to justify and support its analysis with something beyond mere speculation. In the absence of a factual basis for a particular value, it would be unreasonable to use the possible value of water rights as the basis to support a concrete decision. As explained in reply testimony, the value and marketability of water rights is extremely difficult to forecast and would have been highly speculative as part of the SCR analysis.[39] For example, my reply testimony discusses numerous restraints on the transfer and sale of water rights in Wyoming as well as water rights

[34] AWEC/501, Kaufman/29.
[35] AWEC/501, Kaufman/29.
[36] AWEC/501, Kaufman/29 (emphasis added).
[37] PAC/2600, Ralston/18-27.
[38] AWEC/500, Kaufman/11.
[39] PAC/2600, Ralston/25.

that are currently available for lease but remain unclaimed.[40] The most valuable rights in the drainage predate the Colorado River Compact of 1922. PacifiCorp's water rights are post-compact and thus potentially subject to any water right curtailment associated with the Colorado River Compact. In addition, the Green River basin is not fully allocated, so anyone wishing to secure a water right could simply apply for such a right directly with the Wyoming State Engineer. The Company reasonably chose not to include that value in the SCR analysis.

Q. [redacted][41] **Is this correct?**

A. No. [redacted].

Q. What is Staff's position concerning the valuation of water rights?

A. Staff does not believe that the Company's approach to water rights demonstrated imprudence.[42] While Staff witness Ms. Soldavini indicated that the difficulty of modeling water rights is not sufficient basis for declining to consider potentially valuable benefits, Ms. Soldavini also stated that, in this case, a reasonable utility might not have found analysis of the potential value of water rights to be necessary.[43]

[40] PAC/2600, Ralston/23.
[41] AWEC/500, Kaufman/38.
[42] Staff/2300, Soldavini/47.
[43] Staff/2300, Soldavini/47.

Moreover, Staff concluded that there was no evidence to suggest that the value of water rights was a "major concern" in the period leading up to the SCR investment.

D. Deer Creek Mine

Q. Please summarize AWEC's proposal concerning the Deer Creek mine's closure costs.

A. AWEC witness Dr. Kaufman proposes disallowing all costs associated with closing the Deer Creek mine in excess of the Company's forecast mine closure costs. The Company's forecasted miscellaneous closure costs were $[redacted][44], while actual miscellaneous closure costs were $[redacted], as of June 2019. In reply testimony, PacifiCorp witness Ms. Shelley E. McCoy explained that this cost increase was primarily due to the inability to gain MHSA approval of the bulkhead engineering designs, as well as the time required to permit and construct the alternate de-watering pipeline to the Huntington plant.[45] Nonetheless, AWEC argues that the Company has failed to explain why it was unable to gain engineering design approval and—by extension—why the associated cost increase was prudently incurred.[46]

Q. Does AWEC object to the increased costs associated with the alternate de-watering pipeline?

A. No.

Q. What was the basis for the increased costs associated with the initial bulkhead engineering design?

A. The increased costs were associated with heightened regulatory requirements for mine closures following the August 2015 Gold King mine spill, which occurred while

[44] Exhibit PAC/201, miscellaneous, incl. on-going labor (miscellaneous closure costs).
[45] PAC/3100, McCoy/42.
[46] AWEC/500, Kaufman/22.

PacifiCorp's mine closure application was pending. To be clear, the Gold King mine is not owned by or related to PacifiCorp's operations.

Q. What was the anticipated timeline for the Deer Creek mine closure, as described to the Commission in docket UM 1712?

A. The application in docket UM 1712 assumed that the mine closure would proceed as follows: (1) the Deer Creek mine's coal production would terminate in December 2014; (2) the primary equipment/material recovery efforts would cease in March 2015; (3) an idle period would extended through November 2015, pending bulkhead construction approval from the MSHA; and (4) portals would be sealed in March 2016. The mine closure plan was based on prudent, standard industry practices.

Q. Please identify the actual completed timeline for each mine closure activity.

A. Actual coal production terminated in January 2015, primary mine equipment and material recovery efforts ended in May 2015, the idle period extended into July 2017, and the mine portals were sealed in December 2017.

Q. Can you please summarize why mine idling and portal seal construction activities were delayed by 21 months?

A. Yes. The table below summarizes the relevant events that caused the 21-month delay:

Period	Comments
Jan. 2015	PacifiCorp submitted the bulkhead application to MSHA for approval
May 2015	MSHA disapproved PacifiCorp's bulkhead application and requested additional information/analysis
May-July 2015	PacifiCorp and consultants revised and resubmitted the bulkhead application to MSHA for approval
Aug. 2015	Contractors employed by the Environmental Protection Agency breached a dam at the Gold King Mine in Colorado and released toxic water into western streams
Aug.-Sept. 2015	As a result of the Gold King dam breach, MSHA declined to consider PacifiCorp's application
Sept. 2015	PacifiCorp retained John T. Boyd Company to conduct an independent review of the mine closure plan
Dec. 2015	MSHA notified PacifiCorp stating they don't have jurisdictional authority over mine closure
Dec. 2015	PacifiCorp submitted an application to the Utah Division of Oil, Gas and Mining (DOGM) for approval
Apr. 2016	MSHA and DOGM notified PacifiCorp that in-mine bulkheads would not be approved
BOY 2016 - Jun. 2017	PacifiCorp representatives collaborated with representatives from the Bureau of Land Management (BLM), United States Forest Service (USFS), and DOGM to develop an alternative mine de-watering system. Federal law prohibits discharging mine water into a Class 1 stream such as Huntington Creek
May 2017	PacifiCorp applied for a pipeline right-of-way to the BLM and USFS to initiate the National Environmental Policy Act review process
Jul. 2017	The BLM, USFS and DOGM approved the pipeline project
Nov. 2017	The pipeline was installed from the Rilda Canyon portals to the Huntington plant (approximately 6 miles in length)
Dec. 2017	Deer Creek mine portals were sealed

As described above, events beyond the Company's control resulted in very different treatment of the Company's mine closure application than the Company could reasonably have foreseen. The Gold King mine dam breach impacted the acceptable mine de-watering methods allowed by oversight agencies. As a result, the Company's mine closure proposals needed to be substantially modified, which in turn caused the Deer Creek mine portals to be sealed 21 months later than planned. The total time period between cessation of coal production activities and sealing Deer

Creek's mine portals was 36 months—not the 15 months assumed in the original application.

Q. What other impacts did the delay in approving a mine de-watering system have on mine closure activities and costs?

A. As noted above, the idling period was extended by 21 months. During this time, PacifiCorp was required to maintain the mine in a safe operating condition as required by MSHA. PacifiCorp contracted with East Mountain Energy (EME) to complete idling work at the Deer Creek mine in order to comply with federal requirements. The requirement to maintain the mine for 21 additional months and install a de-watering pipeline extending approximately six miles in length significantly increased mine closure costs.

Notably, and contrary to AWEC's assertion,[47] EME is an independent contractor with a United Mine Workers of America (UMWA) affiliation and is not affiliated with PacifiCorp.

Q. Please identify "miscellaneous closure costs" included in docket UM 1712 and comparable costs included in this proceeding.

A. Miscellaneous closure costs included in docket UM 1712 equal $[redacted][48] Miscellaneous closure costs included in this proceeding equal $[redacted][49]

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[47] AWEC/500, Kaufman/23.
[48] Confidential Exhibit PAC/201 in Docket No. UM 1712.
[49] CONF Exhibit PAC/4102 (Miscellaneous Closure Costs including severance and UMWA medical/unemployment ($[redacted]), less non-union severance ($[redacted]), less UMWA medical/unemployment ($[redacted]) equals $[redacted] or $[redacted]).

Q. As a result of increased "miscellaneous closure costs", did total project costs, excluding 1974 UMWA pension costs, increase significantly from the cost forecasts included in docket UM 1712?

A. No. Total project costs, excluding 1974 UMWA pension costs, included in docket UM 1712 were $[redacted][50] Comparable project costs in this case are $[redacted].[51] Costs are projected to increase by $[redacted] or [redacted] percent.

Q. If total project costs, excluding 1974 UMWA pension costs, are estimated to increase by only $[redacted], what change offsets the increase in "miscellaneous closure costs"?

A. The Bureau of Land Management (BLM) agreed with PacifiCorp's assessment that Deer Creek mine production costs exceeded market costs. Therefore, BLM did not impute a coal abandonment royalty penalty. Docket UM 1712 included $[redacted][52] for potential abandoned royalties.

E. <u>Hayden SCRs</u>

Q. Did you address the Company's investment in SCRs at Hayden Units 1 and 2 in your reply testimony?

A. Yes. My reply testimony responded to extensive testimony from Sierra Club witness Dr. Fisher, who claimed that the Company was imprudent for supporting the decision of its co-owner and plant operator, Public Service Company of Colorado (PSCo), to install SCRs at Hayden Units 1 and 2. As I explained, the Company assessed the applicable law and its rights and obligations under the Hayden Participation Agreement, and reasonably concluded that it had no sound basis to challenge PSCo's

[50] Exhibit PAC/201 in Docket No. UM 1712.
[51] CONF Exhibit PAC/4102.
[52] CONF Exhibit PAC/4102.

decision to install SCRs.[53] I also explained that the Company could not reasonably have relied on the change-in-law provision of the Hayden coal supply agreement to avoid the contract's take-or-pay provision.[54]

Q. Did Sierra Club continue to challenge the prudence of the Company's investment in SCRs at Hayden Units 1 and 2 on rebuttal?

A. No. While Sierra Club witness Dr. Fisher contests the significance of the California Public Utility Commission's (CPUC) decision allowing cost recovery for these investments, Dr. Fisher does not respond to my reply testimony addressing his various arguments and concerns. Dr. Fisher's commentary regarding the implications of the CPUC rate case decision is discussed in more detail by Ms. Etta Lockey.

Q. Does any other party challenge the prudence of the Company's investment in SCRs at Hayden Units 1 and 2?

A. No.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

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[53] PAC/2600, Ralston/32-34.
[54] PAC/2600, Ralston/37-38.

REDACTED
Docket No. UE 374
Exhibit PAC/4101
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Redacted Exhibit Accompanying Surrebuttal Testimony of Dana M. Ralston

Bridger Coal Company Costs
2013 Business Plan versus 2013 Integrated Resource Plan

August 2020

THIS ATTACHMENT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 374
Exhibit PAC/4102
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Redacted Exhibit Accompanying Surrebuttal Testimony of Dana M. Ralston

Deer Creek Mine Project Summary

August 2020

Energy West Transaction - Deer Creek Mine
Project Summary (actuals through June 2019)
Updated July 22, 2019

Closure	Dollars (000's)				
	Application	6/30/2019 Actual	Incr. (Decr.) vs. Application	Project Estimate	Incr. (Decr.) vs. Application
Unrecovered Investment					
Unrecovered investment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Loss on assets sold	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mine Closure/Reclamation					
Royalties Triggered by Closure	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coal Lease Abandonment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Inventory write-off	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unrecovered Reclamation Costs 2014 PV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Income Tax Regulatory Asset	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prepayments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Miscellaneous Closure Costs (incl. sev. and UMWA medical/unemployment)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Retiree Medical Settlement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Regulatory Asset Excluding 1974 UMWA Pension	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

REDACTED
Docket No. UE 374
Exhibit PAC/4200
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Redacted Surrebuttal Testimony of Richard A. Vail

August 2020

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Exhibit PAC/4204—Staff Response to PacifiCorp Data Request 53

Exhibit PAC/4205—Staff Response to PacifiCorp Data Request 71

Q. Are you the same Richard A. Vail who submitted direct testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the joint rebuttal testimony of Ms. Nadine Hanhan, Mr. Yassir Rashid, and Mr. Matt Muldoon (Exhibit Staff/2100) on behalf of Staff of the Public Utility Commission of Oregon (Commission). I also respond to one point raised by the Sierra Club witness Dr. Jeremy Fisher related to the Company's decision to install selective catalytic reduction (SCR) systems at Jim Bridger Units 3 and 4.

II. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. My testimony is organized as follows:

- First, I explain that Staff's approach to adjustments for transmission assets based on cost overruns is based on a misunderstanding of the Company's budgeting and project development process. I also explain that Staff's specific adjustments for cost overruns failed to account for the reasons that overruns occurred, and failed to consider whether the Company's incurred costs were prudent despite the fact that costs increased from forecast estimates.
- Second, I explain that Staff's approach to disallowances based on perceived transmission/distribution allocation issues misunderstands the benefits of

dispersed transmission investments on PacifiCorp's system as a whole. I also explain that Staff's specific disallowances for customer interconnections is inappropriate in light of the Company's obligation to serve customers.

- Third, I address Staff's comprehensive disallowance of the Company's remaining pro forma projects. Pro forma projects are those placed in service after the Company's rate filing but before December 31, 2020, and requested to be included in rates based on costs already incurred, plus forecasted 2020 spend. These projects are fully verifiable, and PacifiCorp has provided ample information concerning all projects that cost over $1 million on a system-wide basis. In response to Staff's concerns, the Company has supplemented the evidence for each pro forma project, and has expanded the scope of these explanations to cover all projects $500,000 or more on a system-wide basis. This supplemental detail supports my explanation that dispersed transmission projects still contribute to the reliability of the grid and benefit Oregon customers.
- Fourth, I respond to Staff's proposal to open a new investigation into the allocation of transmission investments. While Ms. Etta Lockey's surrebuttal testimony discusses the problems with Staff's proposal in light of the serious implications for the recently approved 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol), I address Staff's misunderstanding of the Company's open access transmission tariff (OATT), as well as the role the Federal Energy Regulatory Commission (FERC) plays in the classification of transmission investments. I also explain why, if Staff wished to take a new

approach to the treatment of transmission allocation decisions, this change should have been made clear well before Staff's rebuttal testimony, and should be addressed with an understanding of all applicable regulatory requirements and impacts to both customers and the Company.

- Finally, I respond to Sierra Club's argument that retiring Jim Bridger Units 3 and 4 would have allowed the Company to avoid constructing the segment of Gateway West from Jim Bridger to Populus. The need for and customer benefits associated with this transmission segment are not related to the installation of SCRs at Jim Bridger Units 3 and 4.

III. STAFF'S PROPOSED TRANSMISSION ADJUSTMENTS & DISALLOWANCES

Q. Please briefly summarize Staff's approach to adjustments and disallowances in rebuttal testimony.

A. Generally, Staff proposes adjustments where projects experienced cost overruns, and proposes disallowances where Staff believes that projects do not provide a clear and direct benefit to Oregon customers. In addition, Staff proposes to wholly disallow recovery for the Company's remaining pro forma projects, which are projects placed in service after this rate case was filed but before the rate effective date. Staff bases this comprehensive disallowance on the assumption that projects associated with out-of-state transmission facilities under 100 kilovolts (kV) are presumptively not beneficial to Oregon customers, and objects to the level of detail provided about these pro forma projects.

As described in detail below, Staff's adjustments misunderstand the

Company's budgeting and development process and the Commission's prudence standard by simply assuming that all cost overruns are imprudent, while Staff's disallowances misunderstand the integrated nature of PacifiCorp's transmission system by incorrectly concluding that transmission projects in other states fail to benefit Oregon customers. Similarly, the Company's remaining pro forma projects, which are fully verified, are an integral part of PacifiCorp's operation of an integrated multi-state transmission system and should be fully recoverable.

A. Staff Misunderstands the Company's Budgeting Process

Q. Please summarize Staff's proposed adjustments for perceived cost overruns involving the Company's transmission investments in this case.

A. Staff proposes partial adjustments to the following projects based on perceived cost overruns:

- Wallula-to-McNary [redacted] adjustment)
- Vantage-to-Pomona Heights [redacted] adjustment)
- Threemile Canyon Farm [redacted] adjustment)
- Q0542 Pryor Mountain [redacted] adjustment)
- Pavant - Improve Transformer Protection [redacted] adjustment)

1. Background on PacifiCorp's Budgeting and Development Process

Q. What is PacifiCorp's budget process for major projects?

A. PacifiCorp participates in an annual 10-year budget process. Major projects are proposed by Main Grid and Area planners[1] based on various system studies and input from field and dispatch personnel that includes historical system conditions. As part

[1] Main Grid planners address transmission planning for facilities typically 230 kV and above, while Area planners address transmission planning for facilities typically under 230 kV.

of a project proposal, the planner creates a block estimate (+/- 50 percent) based on a preliminary design for the preferred solution and all considered alternative solutions. Each project proposal is reviewed by a group of individuals from across the Company, including members of the engineering, operations, asset management, financial and planning departments. This group looks at the proposed scope, risks, and alternatives, as well as high-level proposed project duration, sequencing, permitting, and right of way needs and estimates for the project. Once project proposals are complete, they are prioritized against projects in the prior year's 10-year plan and those proposed in the current 10-year plan and, based on specific criteria developed for the type of projects being proposed, they are placed in the proposed plan or kept as sensitivities to be considered the following year. A project being placed in the capital plan does not authorize any capital expenditure until an appropriation request is submitted for management approval. The initial project approval process is discussed later in this testimony.

Q. How are initial project budgets estimated and updated through the project cycle?

A. As discussed earlier, as part of an initial project proposal a +/- 50 percent estimate is developed based on the preliminary scope using an internal block estimating tool that is comprised of costs based on projects completed in the past. These estimates are used for high-level studies, alternative analysis, and budget prioritization. Once a project is considered viable, it is placed in the 10-year plan, and the project proposal is submitted to Engineering to develop a detailed scope of work, which is then forwarded to the Cost Estimating Group to produce a +/- 20 percent detailed scope.

These estimates are produced using Sage estimating software where unit costs for specific line items are updated annually.[2]

The +/- 20 percent estimate is then used to support an appropriation request for management approval to spend capital dollars. In some limited cases, the project timeline does not allow for a detailed estimate to be completed for the appropriation request. In these cases, the block estimate can be used for the appropriation request. A detailed estimate is requested by the Project Manager following project approval and a project change order is submitted if necessary. In addition, once the project has gone through full engineering design a Project Manager can request a +/- 10 percent estimate if the scope has changed significantly. Once construction and material bids are awarded those costs are used in project forecasts, which are completed on a monthly basis over the life of the project.

Q. How is the initial project approval received?

A As stated earlier, the inclusion of a project in the approved budget/10-year plan does not constitute project approval; specific project approval must be obtained and documented in accordance with PacifiCorp's corporate governance. Project approvals are submitted through an appropriation request and must include sufficient description and information to allow for a clear understanding of the project need, cost, proposed scope to be delivered and timeline for completion. For capital projects $1 million or above on a net basis, an investment appraisal document must be submitted with the appropriation request.

[2] Following the completion of a project, actual costs are compared against the estimated cost. Current market prices are then updated in the Sage estimating software tool database.

Q. How does the process differ for projects that are less than $1 million?

A. Projects that are less than $1 million make up the program level (or blanket projects) line item in a capital plan. Program level funding is used to allocate capital funds for a certain category of work that is made up of multiple projects. This approach is used to group smaller, similar projects together in the capital plan or where the full scope is unknown during the planning process. However, each specific project, regardless of size, must be approved through the appropriation request process prior to capital dollars being spent.

Q. How are project costs managed?

A. Project costs are managed through competitive bidding for lowest prices, change order review and negotiations, and project management oversight of the project scope, cost and schedule; however, not all aspects of a project can be controlled. The COVID-19 pandemic is a current example of an uncontrollable event that has the potential to impact project costs, due to delays necessary to follow state protocols, protocols that limit work activities for safety, or potential impacts resulting from positive COVID-19 tests in the work force.

Q. Is it uncommon for circumstances to change as projects are actually constructed?

A. No. As with any construction project, large or small, it is not uncommon for circumstances to change, either because of unanticipated external events (e.g., COVID-19 or unexpected tariffs) or because of unanticipated circumstances on the ground that could not have been foreseen or prevented (e.g., a bird of prey choosing to nest within a project work zone).

Q. What controls does PacifiCorp have in place for project cost increases?

A. If there are material changes to either the scope or timing of a project, then the project must be submitted for re-approval through the project change order process as soon as possible. A project's actual and forecast costs are monitored throughout the month by a Project Control Specialist. As variances to estimated funds are identified, the project is reviewed as a whole to determine off-sets or adjustments that can be made to manage project costs.

Monthly forecasts are reviewed by the Project Manager and then submitted to business unit plan owners who are responsible for ensuring the appropriate financial controls are in place to enable timely identification of material variances and notification to management. A project must be submitted for formal re-approval through the project change order process if the project, on a Direct Project Cost Basis, is *forecast* to overrun the approved funding amount by the greater of $250,000 or 5 percent, for projects that include a contingency reserve; or 10 percent, for routine operating projects that do not include or require a contingency reserve.

Q. In light of these comprehensive budget controls, what are the implications of Staff's approach to cost overruns?

A. By simply assuming that cost overruns are imprudently incurred, Staff's approach would incent the Company to adopt budget forecasts based on the worst-case scenario. This would remove the built-in review and approval controls that currently exist when a project's costs increase over the reasonably anticipated forecast amount. Rather than incenting cost controls, Staff's approach would incent increased forecasts to account for greater contingencies.

Q. Is it your understanding that Staff's approach to cost overruns is consistent with Commission precedent?

A. No. While I am not a lawyer, it is my understanding that the Commission's prudence review does not require perfection, but rather considers whether the Company's costs were reasonably incurred. Indeed, my understanding is that this Commission has specifically recognized that "all construction projects inevitably involve some difficulties," and that the Commission "believe[s] that a utility should be . . . allowed to recover the costs of all expenditures reasonably related to the completion of a project that is used and useful in providing utility service."[3] My understanding of this statement is that cost overruns are not in themselves indications that the Company's costs are imprudently incurred.

2. <u>Staff Adjustments to Specific Projects for Perceived Cost Overruns</u>

a. Vantage to Pomona Heights 230 kV Transmission Line

Q. Staff proposes a disallowance for the Vantage to Pomona Heights 230 kV transmission line project because there were cost overruns.[4] Please explain the cost change on the Vantage to Pomona Heights 230 kV transmission line project.

A. The original estimates for the Vantage to Pomona Heights 230 kV transmission line were based on an assumed route outlined by the assigned Planner. As the transmission line goes through the permitting process, the route is revised based on permitting, right of way, and (in this case) federal requirements. Three Records of Decision (ROD) and one Record of Environmental Consideration were required for permitting this project. Each federal agency—Bureau of Land Management (BLM),

[3] *In the Matter of the App. of Nw. Nat. Gas Co. for a Gen. Rate Revision*, Docket No. UG 132, Order No. 99-697 at 52 (Nov. 12, 1999).
[4] Staff/2100, Hanhan-Rashid-Muldoon/29.

Bureau of Reclamation (BOR), Bonneville Power Administration (BPA), and the Department of Defense (DOD)—required an easement and completion of a ROD. Requirements to gain these permits entail changes in the line route, restoration costs, and/or mitigation requirements. Examples of these requirements include revegetation, road and construction area recovery/repair, and wildlife enhancement measures (such as the construction of dip ponds on the Yakima Training Center). These actions are required as part of the permits and can impact costs, but are not known at the time the project scope is developed. Original estimates try to anticipate these costs, but it is impossible to account for them all. However, as these costs were determined, project forecasts were updated and project change notices were developed and routed for approval.

Another impact the permitting process had on the project's costs was in the length of time it took to secure these permits, including a government shut down in early 2019 that delayed the notice to proceed from the DOD and BLM. [redacted]

Construction changes also increased costs. The number of rock drilling sites, increased labor costs, and weather conditions impacted how roads and line construction was accomplished. Labor costs also increased as a result of labor resources being drawn to California for historically high wages that required increases in the contractor costs in order to retain labor forces. Not awarding contractor bids would have delayed the completion well beyond the current schedule. All efforts were made to offset increasing costs, including negotiating contractor change orders that resulted in decreases (but not elimination) of those costs.

Q. What is Staff's recommendation?

A. Staff recommends disallowing [redacted] due to perceived cost overruns.

Q. Does Staff agree that the increased costs were outside PacifiCorp's control?

A. Yes, to an extent. Staff admits that "some of these issues may have been outside the Company's control[.]"[5]

Q. Does Staff identify any cost increases that were within the Company's control or otherwise due to imprudent management?

A. No. Staff also does not provide any evidence that the Company's response to the changing circumstances that occurred as the project moved forward were imprudent or otherwise unreasonable given what was known at the time.

Q. What appears to be the basis for Staff's recommendation?

A. Staff merely states that it is concerned over the magnitude of the "overrun and extent of complications experienced by the Company[.]"[6] As discussed above, however, the mere fact that costs increased as circumstances on the ground changed does not demonstrate that the Company was imprudent or that the increased costs should be disallowed.

Q. How did Staff calculate its recommended disallowance?

A. It appears that Staff based its recommended disallowance on the original project estimate plus a 10 percent contingency. Staff did not provide an assessment of whether PacifiCorp's management of the project and reaction to the unanticipated costs increases were prudent based on the information available to PacifiCorp at the time.

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[5] Staff/2100, Hanhan-Rashid-Muldoon/30.
[6] Staff/2100, Hanhan-Rashid-Muldoon/30.

Q. Did Staff appear to distinguish any costs that may have been outside the Company's control and that could not have been reasonably anticipated by the Company?

A. No. Staff specifically admits that a recent falcon nest lead to a project delay, but does not evaluate that for prudence or allocate a portion of the increased costs to that issue. Staff acknowledges other reasons, but does not discuss how each contributed to the increased costs or whether the Company mismanaged the issue. Instead, the only statement regarding Staff's reasoning for its recommendation appears to relate to the magnitude of the increase.

While I agree this project cost more than originally estimated, unique challenges are an operational reality in project management. PacifiCorp must plan for and maintain a reliable transmission system to comply with its load service requirements, transmission open access (which includes open access for direct access customers in Oregon), and compliance with mandatory reliability standards. PacifiCorp aggressively manages its projects, but for every project that comes in under budget (like the Aeolus to Bridger/Anticline 500 kV Transmission Line) there will be projects such as the Vantage to Pomona Heights 230 kV Transmission Line project that face unanticipated challenges. Costs above a budget forecast should not be disallowed when the Company prudently responds to those unexpected challenges and reasonably manages costs, in the same way that the Company should not be compensated if projects come in under budget.

Q. Please explain the reasons for the change in the Vantage to Pomona Heights project's in-service date.

A. Due to members of the BPA's work force testing positive for COVID-19, they were unable to complete their work within the project timeline and, as a result, the in-service date was moved from July to August 2020.

Q. Has your recommendation regarding the Vantage to Pomona Heights 230 kV transmission line project changed?

A. No. I continue to recommend that the Commission find the project costs identified in my opening testimony prudent, and that the costs be added to PacifiCorp's rate base. Staff's recommendation should be rejected. Staff's recommendation creates essentially an asymmetrical bright-line test for any costs in excess of the original cost estimate. This could lead to unanticipated consequences by encouraging utilities to over-estimate project costs to include all possible costs, rather than manage projects to lower cost estimates based on generally anticipated conditions.

b. Wallula-McNary 230kV Transmission Line Project

Q. Staff also recommends a disallowance related to the Wallula-McNary 230 kV transmission line project because of cost overruns.[7] Please explain how costs changed for that project.

A. The project cost changes were mainly attributable to schedule delays and weather-caused changes in construction. As background, the Wallula-McNary line was constructed, in part, so that the Company could meet its obligations under the OATT to provide transmission service for two customers that had submitted transmission service requests. [redacted]

[7] Staff/2100, Hanhan-Rashid-Muldoon/27.

[redacted] Under the OATT, PacifiCorp cannot unilaterally terminate a transmission service agreement, and the transmission service customer has the right to suspend their service request.[8] PacifiCorp, however, as the transmission provider remained obligated to provide the requested transmission service if the transmission customers moved forward with their transmission service requests.

Q. Did the two customers move forward with their transmission service requests?

A. [redacted] The lack of capacity on the existing system, however, required the construction of the Wallula-McNary line.

Q. What other options were available to the Company?

A. Notwithstanding [redacted], the Company could have moved forward with construction of the line. But if the transmission service request was ultimately terminated, the Company could potentially have constructed a line that was no longer needed. The Company's decision to delay construction pending [redacted] was prudent even though the delay ultimately increased the costs of the line. Staff's position is essentially that a prudent utility would have rushed construction in the face of

[8] *See* PacifiCorp OATT, FERC Electric Tariff Volume No. 11, updated July 10, 2020, Section 17.7(i) ("Transmission Customer can obtain, subject to availability, up to five (5) one-year extensions for the commencement of service"), available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20200710_OATTMASTER.PDF.

uncertainty, just to keep the project costs at the estimated level.

Q. Staff also argues that retail customers should not bear increases in costs resulting from a transmission customer's delay.[9] Is that a reasonable position?

A. No. PacifiCorp is obligated to provide transmission service under its OATT. Under the terms of the OATT, if facilities are required to meet a transmission service request, the transmission provider must expand its transmission system to accommodate the transmission customer.[10] The Wallula-McNary line is required due to system constraints to provide the requested transmission service. PacifiCorp cannot, under its OATT, directly charge the transmission service customer for cost increases associated with a delay.

Q. What were the other reasons that the costs of the Wallula-McNary line increased relative to the initial estimates?

A. The main increase in costs associated with construction were due to weather, which required changes in equipment required to operate in wet conditions and an overall slowdown of construction progress. There were additional smaller increases adding to the total that were associated with condemnation, additional rock drilling and permitting costs.

Q. What was Staff's recommendation?

A. Staff recommended disallowance of [redacted] due to perceived cost overruns.

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[9] Staff/2100, Hanhan-Rashid-Muldoon/28-29.
[10] *See* PacifiCorp OATT, FERC Electric Tariff Volume No. 11, updated July 10, 2020, Section 15.4 ("If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service consistent with its planning obligations in Attachment K....."), available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20200710_OATTMASTER.PDF.

Q. What is Staff's basis for this recommendation?

A. Staff states that it believes the Company should have been aware of the increased costs associated with condemnation and easement laws because those are basic knowledge that the Company should have known and anticipated.[11] Staff also asserts that any costs due to a transmission customer asserting its rights should be the Company's risk.

Q. Does Staff distinguish the amounts attributable to each of its identified causes for the cost increases from the original budget?

A. No. As discussed above, the majority of the cost increase was due to [redacted] and changes in construction costs due to unanticipated weather events. The cost changes associated with condemnation and easement costs were fairly small.

Q. Did PacifiCorp understand the anticipated easement and condemnation costs for the project when the Company made its decision to make the investment?

A. Yes. PacifiCorp estimated the costs associated with obtaining necessary property rights; however, the specific routing of transmission lines is not always known at the time of initial project approval. This was the case for the Wallula-McNary project. The final routing resulted in costs in excess of the original estimate.

Q. Staff also asserts that the disallowance is justified because it relates to [redacted]. How do you respond to this basis for a disallowance?

A. I disagree. As discussed above, this appears to be a new regulatory policy position that could expose a utility to disallowance for any third-party decision that increases

[11] Staff/2100, Hanhan-Rashid-Muldoon/28.

project costs, where the Company remains under a binding legal obligation to serve. Adopting such a standard would place the Company in the untenable position of having the Commission conclude that it was imprudent for PacifiCorp to comply with its obligations under the OATT.

Q. Has your recommendation regarding the Wallula-McNary 230kV transmission line project changed?

A. No. I continue to recommend that the Commission find the project costs identified in my opening testimony prudent, and that the costs be added to PacifiCorp's rate base. Staff's analysis does not address the specific issues with this project and appears to be primarily based on a new position that does not follow the Commission's prudence standard.

c. Threemile Canyon Farm 2,500 Horsepower (HP) Increase Project

Q. Staff recommends a disallowance related to the transmission investment to serve the Threemile Canyon farm because of cost overruns.[12] Please explain the cost change on the Threemile Canyon Farm 2,500 HP Increase project.

A. To accommodate the customer schedule, the initial estimate and appropriation request for this project was routed using a +/-50 percent estimate consistent with the process discussed above. Subsequent change orders were submitted as the project was fully scoped and then as the competitive solicitation process identified winning bids. Ultimately, bids increased the project costs by $2.5 million over the initial +/- 50 percent estimate.

[12] Staff/2100, Hanhan-Rashid-Muldoon/35-36.

Q. Staff claims that a portion of the increased costs was due to "[redacted]."[13] Is that true?

A. No. Staff was describing the fact that the original estimate was a +/-50 percent estimate and that the final costs were based on competitive bids. The high-level nature of the original estimate cannot be described as a "[redacted]."

d. Q542 Pryor Mountain Project

Q. Staff also recommends a disallowance related to the interconnection costs for the Pryor Mountain Wind Project because of cost overruns.[14] Please explain the cost change on the Q542 Pryor Mountain project.

A. The original generation interconnection agreement for this project was signed in July 2015, between the developer, EverPower Wind Holdings, Inc. (EverPower), and PacifiCorp. The generation project was, at the time, a proposed qualifying facility under the Public Utility Regulatory Policy Act (PURPA). As a qualifying facility interconnecting in Wyoming, the customer was responsible for 100 percent of the interconnection costs to design, procure, and construct the interconnection facilities with no reimbursement from PacifiCorp as the transmission provider. In October 2015, the customer suspended the project, in accordance with its rights under the interconnection agreement, to finalize an eagle management plan with the United States (U.S.) Fish and Wildlife Service. In November 2018, PacifiCorp and EverPower signed an amended agreement. The amendment incorporated EverPower's request to procure and construct the point of interconnection facility. This resulted in an $8.8 million reduction to PacifiCorp's estimated costs for the

[13] Staff/2100, Hanhan-Rashid-Muldoon/35-36.
[14] Staff/2100, Hanhan-Rashid-Muldoon/37.

interconnection.

In September 2019, when PacifiCorp purchased the project, the interconnection was assigned from EverPower to PacifiCorp. In accordance with PacifiCorp's OATT process, a restudy was required due to a change in wind turbines, a change in the point-of-interconnection, and a change in the overall configuration of the wind farm. Additionally, the project was no longer a qualifying facility under PURPA.

The restudy determined that, due to system changes since the initial interconnection agreement, a Remedial Action Scheme (RAS) was also required.[15] Additionally, costs to construct the point of interconnection facility were added to the scope of work. Accordingly, the agreed-upon commercial operation date in the new interconnection agreement was December 2020, with estimated costs of $13.7 million—an $800,000 increase from the original 2018 estimate, mainly due to the addition of the RAS and increased overheads due to the delays.

Q. What is Staff's recommendation regarding the Pryor Mountain interconnection project?

A. Staff recommends a [redacted] disallowance.

Q. What is the basis for Staff's recommendation?

A. Staff states that customers "should not be held responsible for [redacted]

[15] A RAS is a scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation, tripping load, or reconfiguring the system. RAS accomplish objectives such as:
- Meet requirements identified in the North American Electric Reliability Corporation Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows; or
- Limit the impact of Cascading or extreme events.

[redacted].”[16]

Staff then states that any costs that exceed the original budget should be disallowed.

Q. Do you agree with Staff's recommendation?

A. No. First, Staff's reasoning ignores the interconnection process. Interconnection customers have the right to suspend or terminate their interconnection agreements.[17] This often leads to a restudy of the proposed interconnection due to changes in the system over time. PacifiCorp, however, is bound by the terms of the interconnection agreement and the rights provided to the interconnection customer under that agreement.

Second, and most importantly, Staff does not address whether the increased costs were prudent at the time the decision was made to purchase and develop the Pryor Mountain wind project—a project Staff recommends the Commission find prudent.[18] Instead, Staff's analysis merely compares the estimated costs in an earlier interconnection agreement to the estimated costs based on a subsequent study five years later for a different interconnection customer. Staff then arbitrarily assigns the risk exclusively to the utility. This superficial review does not acknowledge the changed conditions on the system, the total economics of the project, or requirements of the generation interconnection process. Staff has provided no engineering or regulatory basis for its recommendation other than to imply that costs may have been lower if the first interconnection customer had developed the project. This is simply

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[16] Staff/2100, Hanhan-Rashid-Muldoon/37.
[17] *See generally* PacifiCorp's *pro forma* Large Generator Interconnection Agreement, Section 5.16 ("Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this LGIA...."), available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20200710_OATTMASTER.PDF.
[18] *See* Staff/800 and Staff/2000.

speculation and does not account for the actual system upgrades required to reliably interconnect a wind generation facility that Staff believes is prudent.

Q. Has your recommendation regarding the Q542 Pryor Mountain project changed?

A. No. I continue to recommend that the Commission find the interconnection costs identified in my opening testimony prudent, and that the costs be added to PacifiCorp's rate base.

e. Pavant - Improve Transformer Protection Project[19]

Q. What is Staff's proposed adjustment for the Pavant Improve Transformer Protection project?

A. Staff proposes a [redacted] adjustment to this pro forma project on the basis that the project's costs exceed its original budget.[20]

Q. Please explain the cost change for the Pavant Improve Transformer Protection project.

A. The cost change for the Pavant Improve Transformer Protection project was a cost *decrease*, not a cost overrun. The Company's pro forma budget request for this project was based on the cost estimating process described above, in which an Area Planner developed an initial +/- 50 percent cost estimate as part of the project proposal. After the Company's rate case was filed, and consistent with the Company's budgeting and project development process, a detailed scope was completed by the Cost Estimating group, which produced a +/- 20 percent cost estimate. This amount reduced the estimated costs from [redacted] to [redacted].

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[19] While the estimated budget for this project is confidential, the name of this project is not.
[20] Staff/2100, Hanhan-Rashid-Muldoon/39.

This latter amount was then used for the appropriation request seeking capital dollar approval.

Q. With this budgeting process in mind, does the Company accept Staff's proposed adjustment?

A. Yes, the Company accepts Staff's proposed adjustment as reasonable. PacifiCorp, however, was not able to complete its review of Staff's adjustment in time to include the adjustment in the revised revenue requirement provided by Ms. Shelley E. McCoy. The Company will update following the Commission's decision in this proceeding.

f. Other Changes

Q. Based on its review of the pro forma transmission plant additions, is the Company making additional adjustments?

A. Yes. In addition to the Pavant Improve Transformer Protection project discussed above, two projects identified in PacifiCorp's pro forma transmission plant additions have now been deferred due to current circumstances and will not go into service until 2021. PacifiCorp proposes to remove those from rate base. Those projects are the Jordanelle - Midway 138 kV transmission line project and the reroute of the Jim Bridger - Goshen 345kV transmission line, reducing PacifiCorp's requested rate base additions by approximately $16.5 million and $1.96 million, respectively. Additionally, PacifiCorp identified two distribution projects misclassified as transmission and system allocated. Ms. McCoy addresses these adjustments in her surrebuttal testimony, Exhibit PAC/4400.

B. Staff Misunderstands PacifiCorp's Integrated Transmission System.

Q. Please summarize Staff's proposed disallowances for perceived transmission/distribution allocation concerns.

A. Staff proposes full disallowances to the following projects based on perceived transmission/distribution allocation concerns:

- Goshen-Sugarmill-Rigby ($21.5 million disallowance)
- SW Wyoming Silver Creek ($41.9 million disallowance)
- State Prison at Salt Lake City[21] [redacted] disallowance)
- Lassen Sub-New 69x115 kV sub to replace Mt Shasta Sub[22] ([redacted] disallowance)

Q. Please summarize your understanding of Staff's general position concerning the benefits of out-of-state transmission investments.

A. My understanding of Staff's position is that all out-of-state transmission investments in facilities less than 100 kV should be disallowed unless the Company affirmatively demonstrates that, absent the project, reliability to Oregon customers would be compromised. Staff reasons that "[a]nything under 100 kV is unlikely to deliver system benefits." Staff further recommends that an investigation be opened to examine the Company's categorization of transmission and distribution assets.

Q. Do you agree with Staff's claims that lower voltage transmission facilities do not provide Oregon customers a benefit?

A. No. Customers across the Company's six-state service territory all receive the benefit of the interconnected transmission system through access to generation resources and

[21] While the specific forecast budget for this project is confidential, the name is not.
[22] While the specific forecast budget for this project is confidential, the name is not.

transfer capability across the integrated transmission system to reduce the cost of energy service by optimizing the resource mix across the entire system. As I will discuss in detail with respect to the Goshen-Sugarmill-Rigby 161 kV and Southwest Wyoming Silver Creek projects, Staff's assertion that a load flow analysis would be necessary to show such benefit inaccurately represents the commercial and contractual nature of transmission in providing cost benefits to customers. Indeed, Staff's arguments misunderstand the nature of PacifiCorp's transmission system, its obligations to ensure reliability, and how the Company's transmission investments are assessed by FERC. For this reason, I take this opportunity to provide some background on PacifiCorp's transmission system and the Company's planning, construction, operation, and maintenance obligations, to explain how incremental transmission investments benefit Oregon customers.

1. <u>Background on PacifiCorp's Integrated Transmission System</u>

Q. Please briefly describe PacifiCorp's transmission system.

A. PacifiCorp owns and operates approximately 16,500 miles of transmission lines ranging from 46 kV to 500 kV across 10 western states. Oregon is located (along with Washington and California) in PacifiCorp's western balancing authority area (BAA), PacifiCorp West. PacifiCorp's transmission system also includes an eastern BAA, PacifiCorp East. PacifiCorp's bulk transmission network is designed to reliably transport electric energy from a broad array of generation resources (owned or wholesale contracts for purchases of generation, including market purchases) to load centers. There are many benefits associated with a robust transmission network, some of which are set forth below:

1. Reliable delivery of diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to meet aggregate electrical demand and customers' energy requirements at all times, taking into account scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Economic dispatch of resources within PacifiCorp's diverse system.
4. Economic transfer of electric power to and from other systems as facilitated by the Company's participation in the market, which reduces net power costs and provides opportunities to maintain resource adequacy at a reasonable cost.
5. Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
6. Protection against market disruptions where limited transmission can otherwise constrain energy supply.
7. Ability to meet obligations and requirements of PacifiCorp's OATT.

Each of these benefits is discussed in more detail below.

Q. Is PacifiCorp's transmission system interconnected with any third-party systems?

A. Yes. PacifiCorp is interconnected with 21 other transmission systems and 10 transmission systems operated by Energy Imbalance Market participants.

Q. Is PacifiCorp obligated to operate its transmission system reliably?

A. Yes. PacifiCorp's obligation to operate its transmission system reliably stems from two main requirements: (1) PacifiCorp's obligation to provide firm, reliable service to load; and (2) PacifiCorp's obligation to comply with federal, mandatory reliability standards.

Q. Can PacifiCorp's obligations to operate its transmission system reliably contribute to the need to construct transmission system improvements?

A. Yes. Changes to the resources or loads interconnected with the PacifiCorp transmission system (or the systems interconnected with PacifiCorp's transmission system) often result in the need for transmission system modifications and improvements to ensure continued firm, reliable service to load, as well as the overall reliability of PacifiCorp's individual system and the broader transmission grid as a whole.

Q. Please provide more detail about PacifiCorp's obligation to provide firm, reliable service to load and how that obligation may drive transmission system improvements.

A. In 1996, FERC issued Order No. 888,[23] which required that transmission providers provide third parties transmission service over their transmission systems in accordance with the rates, terms, and conditions set forth in the then newly established FERC OATT. As part of the provision of transmission service, the OATT requires transmission providers to plan, construct, operate, and maintain their transmission systems to continue to reliably deliver their firm transmission customers' power to load.

[23] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

Q. How does PacifiCorp "plan, construct, operate, and maintain" its transmission system to continue to reliably deliver power to load?

A. The OATT states that PacifiCorp must conduct these transmission planning activities in accordance with "good utility practice" and PacifiCorp's planning obligations in Attachment K of the OATT, which sets forth PacifiCorp's inter-regional, regional, and local transmission planning processes.

Q. Please describe the origin of PacifiCorp's Attachment K transmission planning process.

A. PacifiCorp's Attachment K planning process stems from FERC's Order No. 1000—a landmark transmission planning proceeding.[24] This process is overseen by FERC, the North American Electric Reliability Corporation (NERC), and the Western Electricity Coordinating Council (WECC). FERC must review PacifiCorp's Attachment K and approve its inclusion in PacifiCorp's OATT.

Q. What does the OATT Attachment K process involve?

A. As required by Order No. 1000, the OATT Attachment K process places a premium on transmission planning coordination at the local, regional, and interregional level. PacifiCorp participates in open stakeholder planning processes covering its entire transmission footprint. These planning processes result in system plans that incorporate economics, reliability, and public policy inputs and requirements. PacifiCorp must also coordinate with other entities through participation on a regional basis as part of the NorthernGrid regional planning organization and on an

[24] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Util.*, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), *order on reh'g*, Order No. 1000-B 141 FERC ¶ 61,044 (2012).

interregional basis with other regional planning organizations within the WECC region.

Q. Does the OATT Attachment K process also envision coordination with individual transmission customers?

A. Yes. OATT Attachment K states that, when developing transmission plans, PacifiCorp must identify transmission system upgrades and other investments necessary to reliably satisfy its transmission customers' resource and load growth expectations or projected service needs of firm point-to-point transmission service customers over the planning horizon. The OATT provides a process for transmission customers to submit their load and resource information to PacifiCorp's transmission function on an annual basis. With respect to PacifiCorp's retail customers in particular, PacifiCorp's merchant function, in its role as a transmission customer and the entity responsible for making transmission service arrangements to serve PacifiCorp's retail load, provides the OATT-required load and resource information to PacifiCorp's transmission function.

Q. Does PacifiCorp do anything else with the transmission customer load and resource information besides use it to develop PacifiCorp's own transmission plan?

A. Yes. PacifiCorp compiles the load and resource submittals of all transmission customers, and submits the data to WECC in accordance with WECC's 2020 Loads and Resources Data Collection Manual.[25] Load and resource information is then used to develop the Western Interconnection-wide WECC Anchor Data Set. The Anchor

[25] The most recent WECC Loads and Resources Data Collection manual is available at: https://www.wecc.org/Reliability/2020 Loads and Resources Data Collection Manual Final.pdf.

Data Set is the basis for WECC long-term power flow and production cost model base cases that are used in local transmission planning, as well as the FERC Order 1000 regional transmission planning process.

Q. You mentioned above that there are two main drivers behind PacifiCorp's obligation to operate its transmission system reliably. Can you describe the second driver and how it may drive transmission system improvements?

A. Yes. As I described above, PacifiCorp complies with its OATT obligation to "plan, construct, operate, and maintain" its transmission system to continue to reliably deliver power to load by following its OATT Attachment K planning process. This OATT mandate involves an important reliability component, but FERC significantly expanded the reliability-related elements of the federal regulatory structure when it implemented the reliability directives contained in the Energy Policy Act of 2005. FERC did this by instituting mandatory reliability standards that all users of the bulk electric system (BES) must follow, including transmission providers.

Q. Who oversees development of and compliance with transmission provider reliability standards?

A. FERC has delegated authority to NERC to develop reliability standards to ensure the safe and reliable operation of the BES in the U.S. in a variety of operating conditions. On April 1, 2005, NERC established a set of transmission operations reliability standards. A subset of the transmission reliability standards are the transmission planning standards (TPL Standards). The purpose of the TPL Standards is to "establish transmission system planning performance requirements within the planning horizon to develop a BES that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies."[26] The TPL Standards, along with regional planning criteria (*i.e.*, regional planning criteria established by WECC and utility-specific planning criteria), define the minimum transmission system requirements to safely and reliably serve customers.

Q. Is compliance with the reliability standards optional?

A. No. As I mentioned above, the reliability standards are a federal requirement, subject to oversight and enforcement by WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years, and may be required to prove compliance during other NERC or WECC reliability initiatives or investigations. Failure to comply with the reliability standards could expose the Company to penalties of up to $1 million per day, per violation.

Q. Can reliability standard requirements drive or support the need for transmission improvements?

A. Yes. For example, to ensure compliance with applicable NERC and WECC standards and criteria, PacifiCorp conducts system impact studies in response to generation facility interconnection requests, generation facility disconnection requests and transmission service requests to evaluate the performance of the transmission system and to identify system deficiencies.

Q. Do lower voltage transmission lines support higher transfer ratings for higher voltage lines?

A. Yes. Transmission scheduling paths have transfer capabilities established in accordance with the Rated System Path Methodology in NERC Standards MOD-001

[26] *See* NERC Standard TPL-001-4, Transmission System Planning Performance Requirements, available at http://www.nerc.com/files/tpl-001-4.pdf.

and MOD-029. Transfer capability is the measure of the ability of the interconnected electric system to reliably transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions. Transmission lines are not excluded from this capability by any bright line voltage threshold and excluding transmission lines by a bright line voltage threshold would in turn reduce the transfer capability of the higher voltage transmission system. Whereas an individual transmission line's *rating* is the ability of that single transmission line to accommodate electric power flow, the *transfer capability* is more specifically defined as a limit to maintain the reliability of the entire interconnected transmission network. These transfer values are called "capabilities" because they are highly dependent on the generation, customer demand, and transmission system conditions on the broader transmission system. It is the path transfer capability, not the individual capacity of a single lower or higher voltage transmission line that is used by transmission customers to schedule resources to load.

Q. Can transmission investments throughout the Company's system provide reliability benefits to Oregon customers?

A. Yes. In addition to meeting the Company's reliability obligations described above, the reliable performance of the transmission system in all areas—not just an area local to a single customer or group of customers—is critical to maintaining the ability to economically use the full transfer capability of the greater transmission system. Although electrically remote, a transmission line outage in Wyoming or Utah that results in a reduction in availability of a low cost energy resource, increased cost for transmission to move a resource across another transmission path, or increased cost for transmission to continue serving a network load affected by that transmission line outage raises the power cost for customers in Oregon. This occurs specifically because Oregon customers have been receiving the benefits of the transmission system in those states. Put another way, investments required to maintain reliable operation of all segments of the PacifiCorp transmission system benefit all customers of the transmission system, regardless of the state in which a specific customer resides.

Q. Does Staff agree that transmission facilities outside of Oregon provide reliability benefits to Oregon customers?

A. Yes. In response to a discovery request, Staff clarified that it defines "reliability to Oregon ratepayers" to mean that "loss of this facility, in simplest lay terms, would mean no transmission reliability event for the system (which is deemed a benefit to Oregon ratepayers). Part of the engineering review is to see what happens when a given resource is removed. In this case, the Company fails to show that loss of this resource will impair persons across state lines and across balancing authorities."[27] Importantly, the loss of transmission facilities that are less than 100 kV can create a "reliability event" that Staff appears to agree would impact Oregon customers. Staff's position that transmission facilities less than 100 kV presumptively do not benefit Oregon is entirely at odds with Staff's definition of reliability benefits.

Q. Does the way PacifiCorp plans and operates the transmission system provide system benefits that also benefit Oregon customers?

A. Yes. In addition to the broad reliability benefits described above, Oregon customers receive significant benefits from the increased flexibility to utilize the transmission

[27] PAC/4201 (Staff Response to PacifiCorp Data Request 62).

system transfer capability to economically dispatch or procure low-cost resources in order to reliably serve the energy needs of all customers, including the ability to dispatch resources into the Western Energy Imbalance Market. Oregon customers are not unique in receiving these benefits but instead receive the same benefits as the Company's customers in each of the six states in PacifiCorp's service territory.

2. Staff Adjustments to Specific Projects for Perceived Transmission Allocation Issues

Q. In light of the above context regarding PacifiCorp's integrated transmission system, do you have any comments concerning Staff's specific adjustments for perceived transmission allocation issues?

A. Yes. Staff repeatedly proposes to disallow the costs of customer-related projects, despite the fact that PacifiCorp remains obligated to serve these loads and to ensure that the transmission system accounts for the impacts of new load. As described in the surrebuttal testimonies of Ms. Lockey and Ms. McCoy, the Company uses a uniform categorization system for these types of projects to ensure fair ratemaking treatment across the Company's system, and does so consistent with FERC's required accounting methodology. While I discuss the specific projects identified by Staff, below, I disagree with the premise of Staff's proposed disallowances.

a. Goshen-Sugarmill-Rigby 161 kV Transmission Project

Q. Staff does not believe the Goshen-Sugarmill-Rigby project delivers system benefits to Oregon customers because the Company did not provide a load flow analysis or modeling to show that, absent this project, reliability for Oregon customers would be compromised.[28] How do you respond?

A. Once in-service, the new Goshen-Sugarmill-Rigby 161 kV line will become part of

[28] Staff 2100, Hanhan-Rashid-Mulddon/32.

PacifiCorp's integrated BES. The entire Goshen, Idaho area 161 kV system is operated as a looped system, and is part of the BES. The Company acknowledges that this line will provide benefits for load service in the southeast Idaho area, but it is also an integral part of the interconnected transmission *system,* which provides benefits system wide. The need for the project was identified as part of the annual NERC TPL-001-4 planning assessment as necessary to meet the Transmission System Planning Performance Requirements of the Standard. As described above, the NERC reliability standards apply to all BES components across the Western Interconnection as the integrity and reliability of the transmission system is reliant on all of these interrelated transmission components, regardless of the state where it is located. Staff's assertion that a load flow analysis demonstrating flow impacts to Oregon customers is necessary to show such benefits misunderstands and misrepresents the benefits of the integrated transmission system.

Moreover, as discussed above, Staff's definition of reliability benefits for Oregon customers appears to agree that, if a transmission facility is required to meet system-wide reliability requirements, then it provides benefits to Oregon customers. Applying this standard, the Goshen-Sugarmill-Rigby provides benefits to Oregon customers.

b. SW Wyoming Silver Creek Project

Q. Do you agree with Staff's conclusion that the SW Wyoming Silver Creek project does not deliver system benefits to Oregon customers?

A. No. The Southwest Wyoming Silver Creek project includes the Railroad to Silver Creek 138 kV line, which was placed in service in 2017. This line is part of the BES.

It is also part of the internal Evanston West transmission path, which moves power from resources in the generation rich Wyoming area to other major load centers in the system. The Evanston West path consists of the following lines:

- Naughton to Treasureton 230 kV
- Naughton to Ben Lomond 230 kV
- Birch Creek to Ben Lomond 230 kV
- Railroad to Silver Creek 138 kV

With completion of the Railroad to Silver Creek 138 kV line the transfer capability of the Evanston West path increased by approximately 137 MW from 1280 MW to 1417 MW. While the Company acknowledges that this project provides benefits for load service to the Park City, Utah area, it also is an integral part of the interconnected transmission *system,* which provides benefits system wide.

c. Transmission Upgrades Associated with Load Additions

Q. Staff does not believe the Lassen Substation or Utah State Prison at Salt Lake City projects deliver system benefits to Oregon customers because the Company did not provide a load flow analysis or modeling to show that, absent these projects, reliability for Oregon customers would be compromised. How do you respond?

A. These projects will benefit PacifiCorp's transmission and distribution system and its customers by (i) increasing the reliability of service to customers and (ii) ensuring that the system has adequate capacity to safely and reliably meet local and contractual system demand. The Lassen Substation project will support subsequent system conversions to 115 kV, as required, to address future needs. The Utah State Prison project furthers the transmission master plan by providing a 138 kV tie to an eventual 500/345/138 kV substation in the Tooele, Utah area. This tie will provide additional transmission path capacity and reliability to the bulk electric transmission system. As noted above, Staff's proposes a disallowance based on an inappropriately narrow definition of the type of transmission investment that benefits Oregon customers. PacifiCorp, however, now expects the Lassen Substation will not go into service in 2021, and has made a corresponding adjustment in this proceeding.[29]

C. <u>The Company's Other Pro Forma Projects are Verifiable and Beneficial.</u>

Q. In addition to the specific project adjustments and disallowances described above, Staff also proposes to disallow most of the Company's remaining pro forma projects on the basis that the Company has provided inadequate information. Please respond.

A. Staff's characterization of these projects as "unverifiable" is incorrect. PacifiCorp has provided explanations for each of the Company's pro forma projects over $1 million on a system-wide basis. The Company also supplemented this information with additional detail for those projects identified by Staff.

Q. Did the Company reasonably expect the detail of Staff's information requests in this proceeding?

A. No. For smaller projects, neither Staff nor other parties nor the Commission has previously required the level of detail sought in this case. Based on the findings in Staff's recent operational audit, the Company reasonably anticipated that a sampling approach would be used for smaller projects. In Staff's recent Audit Report issued on May 12, 2020, Staff specifically stated:

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[29] *See* PAC/4400.

> Rate Case staff should consider a stratified sampling approach across FERC accounts, especially for projects greater than $1 million, which are not explicitly discussed in the Company's testimony.[30]

Despite the effort expended by Staff and PacifiCorp for the pre-rate case audit, and this clear statement of the appropriate means of reviewing the Company's transmission investments as a result, Staff did not apply a sampling approach in this proceeding.[31]

Q. When did the Company understand that Staff was not satisfied with the Company's evidence supporting the pro forma projects?

A. The Company was made aware of the extent of Staff's dissatisfaction with the Company's supplemented information and explanation in Staff's rebuttal testimony. While Staff had initially asked a very broad, very high-level request for information related to all the pro forma transmission investments, Staff did not seek specific follow-up for many of the projects that Staff now seeks to disallow. PacifiCorp did not understand that Staff believed the materials provided were non-responsive.

Q. Can you provide an example of the disconnection regarding the materials sought by Staff?

A. Yes. Staff took specific issue with the one-line diagrams provided by PacifiCorp. PacifiCorp provided similar one-line diagrams in previous general rate cases, as they represent the type of information available to decision-makers when evaluating a potential investment project. This level of information has generally been appropriate

[30] Audit Report of PacifiCorp Audit Number 2019-01 (May 12, 2020). Note, while Staff's audit report states that sampling is appropriate for projects greater than $1 million, PacifiCorp understands that a similar approach would be at least as applicable for projects under $1 million.
[31] PacifiCorp is not suggesting a random sampling is dictated by the Audit Report, but requesting all underlying agreements, change orders, one-line diagrams, and other detailed documentation before conducting the higher level review is extremely difficult to accomplish within the time limitation of a general rate case proceeding.

for ratemaking purposes. Staff's data requests did not specify any particular criteria, and it was not until a meeting on July 15, 2020, that Staff indicated an interest in more detailed documents. The rationale behind that interest was not made clear until Staff filed its rebuttal testimony.

Through discovery, PacifiCorp sought to determine why Staff claimed the one-line diagrams were deficient, inquiring into the specific evaluation criteria used by Staff. In its responses, Staff cited to findings related to Portland General Electric Company in its recent request to reclassify transmission assets.[32] While PacifiCorp agrees a reclassification application would require more detailed system diagrams, reclassification was not requested by the Company and is well outside the scope of this proceeding.

Q. In light of Staff's rebuttal testimony, has the Company further expanded its evidence for and explanation of these pro forma projects?

A. Yes. In Exhibit PAC/4202, the Company lays out all of the Company's pro forma projects, including:

- further expanding the detail provided regarding the nature and benefit of these projects;
- identifying where in discovery the Company previously provided explanations of these projects;
- updating the projects' in-service dates, where necessary; and
- providing specific narrative explanations for all projects over $500,000 on a system-wide basis.

As demonstrated in this exhibit, the Company's pro forma projects reflect reasonable

[32] PAC/4203 (Staff Response to PacifiCorp Data Requests 55 and 63).

investments necessary to ensure the reliability of the Company's transmission system.

Q. Many pro forma projects refer to program level or "blanket" projects. What makes up program level or blanket projects in a capital plan?

A. Program level funding is used to allocate capital funds for a certain category of work that is made up of multiple projects. This is used to group smaller, similar projects in the capital plan or where specific scope is unknown during the planning process, either due to the timing of the project or immaterial project size compared to the overall plan. However, each specific project regardless of size must be approved through the appropriation request process prior to capital dollars being spent.

Q. Staff also proposed an across-the-board disallowance for any pro forma transmission investment in a facility that is less than 100 kV and located outside Oregon.[33] Is this a reasonable recommendation?

A. No. Staff's recommendation is based on the incorrect assumption that any facility that is less than 100 kV is properly classified as a *distribution* facility and not a *transmission* facility and therefore facilities that are less than 100 kV should be paid for exclusively by customers in the state where the facility is located.

Q. Why is Staff's recommendation unreasonable?

A. There are several reasons. First, this is a general rate case, not a docket to investigate the reclassification of transmission and distribution assets. Although Staff also recommends such an investigation, Staff's adjustment here essentially presupposes the outcome of that investigation and imposes a disallowance based on the presupposition, without providing PacifiCorp the opportunity to address the significant number of issues associated with any reclassification.

[33] Staff/2100, Hanhan-Rashid-Muldoon/49.

Staff's introduction of this new classification methodology in this rate case is particularly problematic because Staff waited until its rebuttal testimony to propose this far-reaching and fundamental change to transmission asset classifications. This required the Company to respond in a matter of weeks to a position that Staff could have raised in its opening testimony.

Q. Did Staff's pre-rate case audit indicate an intent to reclassify transmission assets are part of the rate case?

A. No. Staff's pre-rate case audit raised no concern with the Company's classification of all facilities that operate at 46 kV or above as transmission assets.

Q. Has the Commission ever disallowed PacifiCorp cost recovery of out-of-state transmission assets because the asset operates at less than 100 kV?

A. No. It is my understanding that Staff's proposal in this case has not been previously applied to PacifiCorp.

Q. Is it your understanding that Staff's proposed disallowance is also inconsistent with the Commission's rules?

A. Yes. It is my understanding that the Commission has adopted a specific rule for purposes of unbundling retail rates (OAR 860-038-0200(9)(a)(C)) that defines "Transmission Plant," as "both transmission lines and transmission substation equipment operating at voltages of at least 46 kilovolts, as well as transmission facilities and transmission substation equipment operating at voltages of at least 34.5 kilovolts if such facilities terminate within enclosed substations." The Company's classification of transmission assets is consistent with this definition. Staff's proposed disallowance is not.

Q. Staff refers to NERC's 100 kV bright line test as a basis for classifying all projects under 100 kV as distribution facilities.[34] Is this reasonable?

A. No. NERC has defined the BES as generally including all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. While this is often referred to as a bright line definition, the NERC BES does include criteria that allows facilities operated at less than 100 kV to be included as BES elements and some facilities operated at 100 kV or higher to be excluded.[35]

Q. Does FERC have a bright line test for transmission?

A. No. There is no such bright line test in the OATT, nor has FERC recognized the NERC BES Definition or 100 kV bright line as a basis for determining whether FERC has jurisdiction over a particular asset.

Q. Staff also suggests that the Company's classification of transmission assets for purposes of FERC-jurisdictional transmission rate may be improper.[36] Do you agree?

A. No. Staff's statement is directly contradicted by express language in PacifiCorp's FERC-approved OATT. Section 1.59 of the OATT defines PacifiCorp's "Transmission System" as:

> The facilities (for PacifiCorp that are generally operated at a voltage greater than 34.5 kV) that are owned, controlled or operated by the Transmission Provider; that are used to provide Transmission Service under Part II and Part III of the Tariff;

[34] Staff/2100, Hanhan-Rashid-Muldoon/50-51.
[35] *See e.g.* NERC Bulk Electric System Definition Reference Document, Version 3 (Aug. 2018) for discussion of the numerous inclusion and exclusion criteria, available at https://www.nerc.com/pa/Stand/2018%20Bulk%20Electric%20System%20Definition%20Reference/BES_Reference_Doc_08_08_2018_Clean_for_Posting.pdf.
[36] Staff/2100, Hanhan-Rashid-Muldoon/48.

> and that are included in the Transmission Provider's transmission revenue requirement periodically filed with the Commission.

PacifiCorp's OATT includes a formula rate, which adjusts the transmission charges annually based on PacifiCorp's transmission investments in assets of 46 kV and above. The annual update to the formula rate is filed with FERC and subject to a review process by transmission customers every year. More importantly, FERC completed an audit of PacifiCorp's compliance with its formula rate, including all accounting entries, in 2017, with no such finding.[37]

It is my understanding that FERC is authorized to determine what assets are included in what FERC accounts. Further, as explained by Ms. McCoy, FERC has approved the inclusion of all assets that operate at 46 kV or above into FERC Accounts 350-359, which are then used to calculate the Company's FERC formula rates. Staff appears to agree that assets providing a "system benefit" are those assets that are appropriately classified as transmission assets by FERC.[38]

Disallowing recovery of transmission assets in this case based on a different classification of assets than is currently used to set the Company's FERC OATT rate creates an improper inconsistency between rates. Any disallowance would result in an inappropriate subsidy to PacifiCorp's Oregon customers because they would receive a revenue credit from PacifiCorp's OATT, but would not be paying for all the facilities included in the formula rate.

[37] *Audit of PacifiCorp's Compliance with its Wholesale Formula Rate; the Accounting Requirements of the Uniform System of Accounts Prescribed for Public Utilities and Licensees; and the Reporting Requirements of the FERC Form No. 1, Annual Report*, FERC Docket No. FA16-4-000 (Aug. 29, 2017).
[38] PAC/4204 (Staff Response to PacifiCorp Data Request 53).

Q. Has Staff modified its proposed disallowance since filing rebuttal testimony?

A. Yes. When PacifiCorp questioned Staff about the implications of Staff's proposal to reclassify assets that are already included in FERC's formula rates, Staff conceded that its proposal was inappropriate in that respect. Staff modified its proposal such that it would not impact recovery "for those subset of transmission projects where the prudently-incurred costs at issue in this case are associated with plant already included in the Company's OATT, Staff was able to verify the costs, and where Staff's only objection was that the asset did not appear to be appropriately functionalized as transmission."[39]

Q. Are the implications of Staff's modified proposal clear?

A. No. It is unclear what transmission investments would be recoverable under Staff's modified proposal. Under PacifiCorp's OATT formula rate procedures, PacifiCorp's annual update includes a forecasted rate through the end of the year and first half of 2021. Accordingly, it is likely that all of the pro forma plant additions are already included in PacifiCorp's current transmission rate. It is also unclear whether Staff's modification to its position is intended to apply to the pro forma additions related to existing assets or upgrades to existing transmission assets, where the underlying assets are already included in the Company's OATT formula rates.

Regardless of how Staff's modification is applied, Staff's attempt to bifurcate investments based on whether the asset is already included in formula rates still ignores the OATT formula rate process. Under the formula rate process outlined in the OATT, all costs included in the FERC accounts linked to the formula rate are automatically included in the annual formula rate update. PacifiCorp cannot

[39] PAC/4205 (Staff Response to PacifiCorp Data Request 71).

unilaterally change the formula rate or its accounting practices.

Q. Does Staff propose alternative ratemaking treatment in addition to its modified disallowance?

A. Yes. As an alternative, Staff proposes deferring the Company's pro forma transmission investments, except those that Staff considers "verifiable" and which incurred cost overruns—seemingly recognizing the unprecedented nature of Staff's disallowance proposal.[40]

Q. Are there any other issues specific to PacifiCorp that further undermine Staff's proposed adjustment in this case?

A. Yes. PacifiCorp's status as a multi-state utility makes Staff's proposal to unilaterally reclassify assets particularly problematic. As discussed in detail in the surrebuttal testimony of Ms. Lockey, Staff's proposal for this Commission to develop a new allocation system for transmission investments would be wholly contrary to the recently agreed-upon and Commission-approved 2020 Protocol and would undermine the process used to allocate costs across PacifiCorp's six states. To effectuate the dramatic reclassification that Staff recommends would require approval by each of PacifiCorp's six state commissions. If the state commissions disagreed over the proper reclassification results, PacifiCorp would be forced to file its proposed reclassification with FERC for a final determination. This potential for inconsistent state classifications is one key reason that it is improper to use a rate case to effectuate a far-reaching reclassification scheme.

[40] Staff/2100, Hanhan-Rashid-Muldoon/50.

Q. Staff also proposes to open a new investigation into the allocation of the Company's transmission investments under the OATT. Is this necessary or appropriate?

A. No. As discussed above, this is an issue that should be addressed in PacifiCorp's Multi-State Process discussions.

IV. JIM BRIDGER AND AVOIDING TRANSMISSION INVESTMENT

Q. Sierra Club argues that if the Company had retired Jim Bridger Units 3 and 4 instead of installing SCRs, it would have freed up transmission capacity west of Jim Bridger that would have allowed the Company to avoid constructing the segment of Gateway West from Jim Bridger to Populous.[41] Is Sierra Club correct?

A. No. The need for and customer benefits associated with the Gateway West segment west of Jim Bridger is not related to the installation of the SCRs at Jim Bridger Units 3 and 4. Even if the Company had retired Units 3 and 4 instead of installing the SCRs, it would not have avoided the need for additional transmission investment in the Company's system.

Q. Does Sierra Club provide any evidence to support its assumption that not installing the SCRs would have allowed the Company to avoid certain transmission investments?

A. No. Sierra Club simply assumes this fact to be true and proceeds from there. But, to be clear, there is no basis for Sierra Club's assumption.

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[41] Sierra Club/400, Fisher/28.

Q. Sierra Club points to a Company data response that Dr. Fisher claims showed that the Company "agree[d] that retirement of the Jim Bridger 3 & 4 units could reduce the need for the Bridger to Populous segment of the Gateway West project."[42] Is Sierra Club's testimony accurate?

A. No. Sierra Club misrepresents what that data response says. Most importantly, the data response states clearly: "Retirement of Jim Bridger 3 and 4 would reduce the need to transport thermal resources westward between the proposed Anticline [Bridger] substation and existing Populous substations from Wyoming to the Company's load centers, *but it would not avoid the need for more transmission capacity out of Wyoming."*

Q. Sierra Club claims that the data response only identifies transmission constraints east of Jim Bridger and that those constraints are irrelevant to the potential for avoidable transmission.[43] Is that true?

A. No. Sierra Club's testimony simplistically assumes that constraints east of Jim Bridger have no impact on the need for transmission investment west of Jim Bridger. In fact, the identified transmission constraint east of Jim Bridger has a direct correlation to needing transmission west of Jim Bridger. As additional renewable generation is added in eastern Wyoming, the first transmission constraint identified is east of Jim Bridger that will be mitigated with the addition of Gateway West - Segment D.2 (Aeolus – Bridger/Anticline). By further increasing renewable generation in eastern Wyoming, the next transmission constraint identified is between Wyoming and Utah that will be mitigated with the addition of the Gateway South -

[42] Sierra Club/400, Fisher/28.
[43] Sierra Club/400, Fisher/29.

Segment F (Aeolus – Clover). During high transfer conditions from eastern Wyoming to central Utah, if the Gateway South (Aeolus – Clover) segment trips the remaining power will flow on the Aeolus West and Bridger West transmission paths, overloading the existing 345 kV lines west of Jim Bridger above their thermal ratings. This reliability violation will be mitigated with the addition of Energy Gateway Segment D.3 (Bridger/Anticline – Populus). These events would occur even if Units 3 and 4 at Jim Bridger were retired. Thus, as the data response correctly states: "Retirement of Bridger Units 3 and 4 would not avoid the need for Gateway West."

V. CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission:

- Approve full cost recovery for the Company's investments in Wallula-to-McNary, Vantage-to-Pomona Heights, Threemile Canyon Farm, and Q0542 Pryor Mountain. While cost overruns occurred, the Company's budgeting and project management process for these projects was nonetheless reasonable, and the Company's costs were therefore prudently incurred.
- Accept Staff's proposed adjustment of [redacted] to the Pavant Improve Transformer Protection project.
- Approve full cost recovery for the Company's investments in Goshen-Sugarmill-Rigby, SW Wyoming Silver Creek, and the Company's remaining pro forma projects. Staff's attempt to introduce reclassification issues into this proceeding is inappropriate, and the prudence of the Company's pro forma projects are fully supported by the record.

- Approve full cost recovery for the Company's investment in SCRs at Jim Bridger Units 3 and 4. Sierra Club's argument concerning the ability to avoid a substantial segment of the Gateway West transmission project through early retirement of these units is incorrect, as early retirement would not have avoided the need for these transmission investments.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/4201
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Richard A. Vail

Staff Response to PacifiCorp Data Request 62

August 2020

Issued: July 29, 2020 – Response Due By: **August 5, 2020**

TO:
DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 2000
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datarequest@pacificorp.com

FROM: Matt Muldoon – UE 374 Case Manager
Program Manager Energy Rates, Finance and Audit Division

Responding Staff: Hanhan, Rashid, and Muldoon

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 374- PacifiCorp Data Request filed July 29, 2020

PAC Data Request No 62:

62. Ms. Hanhan, Mr. Rashid, and Mr. Muldoon testify that "The Company did not provide any sort of load flow analysis or modeling that concluded that absent the project, reliability to Oregon rate payers would be compromised" (Staff/2100, Hanhan-Rashid-Muldoon/32:11-14 and 33:18-20). What specifically is meant by "reliability to Oregon ratepayers"? Please explain in detail.

OPUC Response No 62:

62. "Reliability to Oregon ratepayers" from a system perspective means that loss of this facility, in simplest lay terms, would mean no transmission reliability event for the system (which is deemed a benefit to Oregon ratepayers). Part of the engineering review is to see what happens when a given resource is removed. In this case, the Company fails to show that loss of this resource will impair persons across state lines and across balancing authorities.

REDACTED
Docket No. UE 374
Exhibit PAC/4202
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Richard A. Vail

Description of Pro Forma Transmission Plant Additions Over $500,000
(Total-Company)

August 2020

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Vantage Pomona Heights 230kV Line	May-20	[redacted]		Addressed in Vail Direct (PAC/1000, Vail/35) and Surrebuttal (PAC/4200) Testimony.
PP Trans New Connect	Various	[redacted]	OPUC 226-1	This category of projects represents system upgrades required to reliably serve customer requested new interconnections in California, Oregon, and Washington. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system.
Goshen-Sugarmill-Rigby 161kV Transm Line	Nov-20	[redacted]		Addressed in Vail Direct (PAC/1000, Vail/38) and Surrebuttal (PAC/4200) Testimony.
TMP Generation Interconnection Projects East	Various	[redacted]	OPUC 226-1	This category of projects represents system upgrades required to reliably serve customer generation interconnection requests on the PacifiCorp transmission system per the Open Access Transmission Tariff. This category pertains only to projects Idaho, Utah. and Wyoming with in-service dates planned in 2020. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects with in-service dates planned in 2020 used to determine costs.
Transmission Blankets	Various	[redacted]	OPUC 226-1	These 2019 projects provide functional upgrades and asset replacements to transmission substations and lines in Utah, Wyoming, and Idaho. These projects will add or enhance an existing operational function and replace assets that have failed or deteriorated and are deemed a risk to public safety and/or reliability.
Goshen #3 345/161 kV 700 MVA Trfrmr Inst	Nov-20	[redacted]	OPUC 226-1	This project involves the installation of a third 345/161 kV transformer at the Goshen substation located in southeast Idaho. This project is needed in order to resolve a potential overloading issue at the existing Goshen 345/161 kV transformers. Load in the Goshen area has continued to increase and as the load continues to grow, the risk of overloading the two existing Goshen 345/161 kV transformers increases. The 2016 Goshen area studies indicated that by 2021, loss of either one of the Goshen 345/161 kV transformers can overload the remaining Goshen 345/161 kV transformer above its emergency rating. Cost estimate included in rate case is for the installation of the third transformer being placed in-service in 2020. A replacement spare transformer is being ordered but will be received outside the dates of this rate case.
Wildfire Mitigation - Trans	Various	[redacted]	OPUC 226-1	These blanket projects will fund projects to decrease risk of transmission equipment failure during the wildfire season, which is increasing in length every year. Modern relaying will enable line patrols to quickly locate and fix any problems, restoring service to customers faster. Fiber optic communications between substations in Fire High Concern Areas will improve the clearing times for protective relaying schemes, which will reduce the time the fault is active. New wildfire safe designs on the transmission system will improve the survivability of the lines in the event that a wildfire does occur.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Jordanelle - Midway Construct 138 kV Line - Trans	2021	[redacted]	OPUC 226-1	This project has experienced major delays in obtaining a conditional use permit and is now projected to be placed in service sometime mid-2021. There will be $0.00 placed in service prior to 2021. This project will construct 9 miles of 138 kV transmission line with 795 ACSR conductor between Midway and Jordanelle substations. It will also construct a 138 kV three breaker ring bus at Midway substation, fiber optic communications between Silver Creek and Midway substations, and protection and control upgrades at all affected substations. Multiple outage scenarios on the 138 kV and 46 kV lines in the Summit and Wasatch County areas, and the outage of the Midway 75 MVA 138-46 kV transformer causes low voltage or voltage collapse conditions on the 138 kV and 46 kV systems in the area, which may result in load shedding. A 138 kV tie between Midway and Jordanelle substations mitigates this issue. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400)
Oregon New Large Load Network Upgrades	Dec-20	[redacted]	OPUC 226-1	This category of projects represents system upgrades required to reliably serve customer requested new large load interconnections in Oregon. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. The specific projects that make up this category are Network Upgrade needed to serve a 60 MW Load Addition project. The customer intends to add an additional 220 MW of load between 2020 and 2022 that the proposed improvements will also be able to service.
Q0542 Pryor Mountain	Dec-20	[redacted]	OPUC 226-1	Addressed in Vail Surrebuttal (PAC/4200) Testimony. This project is to interconnect 240 megawatts of new wind generation to PacifiCorp's Frannie - Yellowtail 230 kilovolt transmission line approximately 14.2 miles north of the Frannie substation located in Carbon County, Montana.
PP Trans	Various	[redacted]	OPUC 226-1; OPUC 745-2 2nd Supp CONF	These blanket projects will fund functional upgrades and asset replacements to transmission substations and lines in Oregon, Washington, and Idaho. These projects replace assets that have deteriorated, or add efficiency improvements and/or enhance productivity functions of an asset. An example of this activity is as follows: A breaker is in excellent working condition, however, the required fault interrupting capability is not high enough. You replace the breaker with one that meets the requirements and because you are enhancing the required functions of the breaker the "Modernize and Upgrade" activity would be used.
TMP Trans Main Grid East	Various	[redacted]	OPUC 226-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Utah, Wyoming, or Idaho to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. All project that fits description with estimated in-service in 2020 but are under $10m are rolled into this category. See tab 2 for projects included in this cost category.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Wildfire Mitigation Plan - CA T	Various	[redacted]	OPUC 226-1	This blanket project provides the means of allocating capital funds to mitigate operational risk within geographic regions that present the greatest risk of catastrophic wildfires. These investments are implemented consistent with the Company's 2020 Wildfire Mitigation Plan, including of 38 line miles of covered conductor, installation and commissioning of 31 system automation programs, replacement of 3 line miles of small diameter Cu conductor with aluminum stranded conductor, replacement of 189 in-service wooden poles with fiberglass for enhanced structural resilience, as well as evaluation of various pilot project results and continued implementation of enhanced inspection and correction programs.
TMP Gateway Projects	Various		OPUC 226-1	This 2019 blanket project provides the means of allocating capital funds for condemnation activities required on the Populus-Terminal 345 kV line placed in service in 2015. The settlement included the relocation of the line from customer's property to the adjacent Forest Service property.
TMP Transmission Major Projects - PP	Various		OPUC 226-1	This 2020 blanket project provides the means of allocating capital funds for improvements and reinforcements needed to support general load growth on transmission facilities located in Oregon, Washington, or California that arepart of the sub-transmission system. See tab 2 for the projects with in-service dates planned in 2020 included in this cost category.
TMP Trans Main Grid West	Various		OPUC 226-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Oregon, Washington, or California to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. All projects that fit the above description with estimated in-service in 2020, but are under $10M, are rolled into this category. See tab 2 for projects included in this cost category.
TMP Trans Customer Generated East	Various		OPUC 226-1	This category of projects represents system upgrades required in Utah, Wyoming, or Idaho to reliably serve transmission network customer requested loads as specified by the network customers in their OATT required load and resource submittals. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects with in-service dates planned in 2020 used to determine costs.
Replace Substation Switchgear, Breakers, Reclosers - UT	Various		OPUC 220-1	This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Utah when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Replace - Storm & Casualty - UT Trans	Various		OPUC 220-1	This 2020 blanket project will replace damaged transmission equipment in Utah due to a storm or external event (like a car hit pole).
TMP Trans Customer Generated East	Various		OPUC 220-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Oregon, Washington, or California to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects with in-service dates planned in 2019 used to determine costs.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Oregon - Rplc-OH Trans-Pole	Various	[redacted]	OPUC 220-1	This 2020 blanket project will replace transmission line assets other than poles in Oregon that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.
TMP Generation Interconnections West	Various	[redacted]	OPUC 220-1	This category of projects represents system upgrades required to reliably serve customer generation interconnection requests on the PacifiCorp transmission system in Oregon, Washington and California. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects used to determine costs.
U2 2-2 GSU Replacement	Oct-19	[redacted]	OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) The project will benefit our customers by maintaining the Huntington power plant by providing efficient and reliable electrical power. The replacement of the existing (40+) year old 2-2 GSUT with a new transformer will result in a reduced risk of an unscheduled outage at Huntington Plant. The project reduces the risk of failure of the existing 2-2 GSUT if it were replaced with a new one. The transformer is over 41 years old and the rate of failure in a transformer increases with age.
BIA - Fort Hall Grace - Goshen	Jun-20	[redacted]	OPUC 220-1	This project will renew the tribal authority permit for a portion of the Grace-Goshen transmission line. This permit is required in order to continue the operation of this line.
Replace Overhead Transmission Poles - UT	Various	[redacted]	OPUC 220-1	This 2020 blanket project will replace transmission poles in Utah that have deteriorated and are deemed a risk to public safety and/or system reliability.
U0 Spare GSU Transformer	Dec-20	[redacted]	OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) The project will benefit our customers by maintaining the Huntington power plant by providing efficient and reliable electrical power. Having a new universal spare will benefit PacifiCorp by reducing installation time (due to not having to manufacture bussing to tie into) in case of a GSUT failure. If the current spare GSUT is installed in an emergency, it will eventually need to be replaced, thus creating lost generation, restricted loads and unnecessary costs to perform the equipment change twice.
TMP Transmission Major Projects - PP	Various	[redacted]	OPUC 220-1	This 2019 blanket project provides the means of allocating capital funds for improvements and reinforcements needed to support general load growth on transmission facilities located in Oregon, Washington, or California that are part of the sub-transmission system. All project that fits description with estimated in-service in 2019 but are under $10m are rolled into this category. See tab 2 for projects behind cost estimate.
Replace Overhead Transmission Lines - Other - UT	Various	[redacted]	OPUC 220-1	This 2020 blanket project will replace transmission line assets other than poles in Utah that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.
TMP Gateway Projects	Various	[redacted]	OPUC 220-1	This 2020 blanket project provides the means of allocating capital funds for the final condemnation activities required on the Populus-Terminal 345 kV line placed in service in 2015. This The case involves a property owner who has contested valuation based on potential future mining and quarry activities and perceived profit potential from the area occupied by the project, and is still proceeding through the court. The Company anticipates resolution during the calendar year 2021.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Wildfire Mitigation - Trans	Various	[redacted]	OPUC 220-1	These 2019 projects will result in decreased risk of transmission equipment failure during the wildfire season, which is increasing in length every year. Modern relaying will enable line patrols to quickly locate and fix any problems, restoring service to customers faster. Fiber optic communications between substations in Fire High Concern Areas will improve the clearing times for protective relaying schemes, which will reduce the time the fault is active. New wildfire safe designs on the transmission system will improve the survivability of the lines in the event that a wildfire does occur.
Oregon - Transmission Improvements	Various		OPUC 220-1	The linescope reliability projects are being performed to enhance system visibility on the transmission system in strategic locations, enabling rapid response to faulted lines, ultimately enabling accurate fault location and quicker sectionalizing and restoration of customers.
Reroute JB Goshen 345kV line for Slide: IPC Shared	2021		OPUC 220-1	This project will not be placed in service until 2021 or later. There will be $0.00 placed in service prior to 2021. This project will relocate 2.5 miles of the Jim Bridger - Goshen 345kV transmission line out of a land slide area. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400).
Pavant - Improve Transformer Protection	Dec-20		OPUC 220-1	This project will allow for maintenance to be performed on either transformer without requiring an outage to the entire Pavant 46 kV system. This will increase reliability for customers served from the Pavant substation.
Replace Transmission Conductor / Armor Rod - ID	Various		OPUC 220-1	These projects are needed to maintain reliability of existing facilities by replacing deteriorated transmission line conductor and/or reinforcing existing conductor with armor rod. Damage has occurred mainly from Aeolian vibration so vibration dampeners are also installed.
Grid Resiliency Phase 1 - 230/69kV Xfmr Purchase	Dec-20		OPUC 220-1	A spare transformer analysis identified a spare transformer deficiency (or gap) in the Delta-Wye portion of the installed 230-69 kV transformer fleet. A new 230-69 kV, Delta-Wye, 150-MVA spare transformer is being purchased to serve as a ready-to-use spare backing up the six (6) three-phase Delta-Wye transformers in-service. The spare will provide timely customer service restoration should failure occur.
Idaho Power - Borah - Midpoint #1 replace wood w/ steel	Various		OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) This project will fund the PacifiCorp portion of the replacement of wood structures with steel structures on the Idaho Power operated Borah to Midpoint #1 line. This will reduce the need for future priority 2 replacements as well as improve the durability of the line by improving its resistance to fires and severe weather conditions.
Replace Substation Transformers - UT	Various		OPUC 220-1	This 2020 blanket project will rebuild or replace transmission level substation transformers in Utah when equipment has failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
Calif - Rplc- Trans Strm&Cas	Various		OPUC 220-1	This blanket project provides the means of allocating capital funds to replace damaged equipment due to a storm or external event (like a car hit pole).
Replace Substation Bushings, Glass & Other - ID	Various		OPUC 220-1	This 2020 blanket project will rebuild or replace transmission level substation bushings, brown glass and other equipment in Idaho that have failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
Oregon - Rplc-OH Trans-Othr	Various		OPUC 220-1	This blanket project provides the means of allocating capital funds to replace transmission line items other than poles that have deteriorated. Deteriorated Transmission cross arms, insulators, water passage culverts, easement access gates, are all examples of "other" items that fall into this category and are reported during annual field inspections.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
302 Spare GSU Replacement	Oct-19	[redacted]	OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) The project will benefit our customers by maintaining reliability and ensure Hunter Plant can continue to provide efficient electrical power at full unit rating. The purchase of a new spare GSU will result in a lower risk of an extended load restriction in the event of a failure of one of the in-service transformers. If a spare GSU transformer is onsite, the estimated time frame to remove a failed transformer from service and install the spare is 10–14 days. The best case scenario to purchase a GSU replacement is 18 months. The project reduces the risk of an extended half load restriction due to a GSU failure of an in-service transformer.
BIA Camp Williams 4 Corners: BIA ROW Renewal - Ute Mtn Tribal	Apr-20		OPUC 220-1	This project will renew the tribal authority permit for a portion of the Camp Williams-Four Corners transmission line. This permit is critical to continued operation of the line and the ability to meet firm transmission obligations from Four Corners into Utah. This line is part of the WECC rated TOT 2B1 transmission path.
State Prison at Salt Lake City - 8 MW Load	Sep-20		OPUC 220-1	This project will provide the customer a 138 kV connection in order to serve their requested load. This will also provide property for a future Rocky Mountain Power owned distribution substation to serve other projected load growth in the area.
Sams Valley 500-230kV New Substation	Nov-20		OPUC 220-1	The Sams Valley 500-230kV project is being placed in service in separate sequences. This is for upgrades at Grants Pass substation to reinforce the 230kV transmission system and resolve NERC reliability standard issues.
BLM Camp Williams 4 Corners: ROW Renewal PL#99001	Feb-20		OPUC 220-1	This project will renew the BLM permit for a portion of the Camp Williams-Four Corners transmission line. This permit is critical to continued operation of the line and the ability to meet firm transmission obligations from Four Corners into Utah. This line is part of the WECC rated TOT 2B1 transmission path.
Replace Substation Bushings, Glass & Other - UT	Various		OPUC 220-1	This 2020 blanket project will rebuild or replace transmission level substation bushings, brown glass and other equipment in Utah that has failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
TMP Trans Main Grid East	Various		OPUC 220-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Utah, Wyoming, or Idaho to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. All project that fits description with estimated in-service in 2019 but are under $10m are rolled into this category. See tab 2 for projects included in this cost estimate.
Replace - Storm & Casualty - ID Trans	Various		OPUC 220-1	This 2020 blanket project will replace damaged transmission equipment in Idaho due to a storm or external event (like a car hit pole). The pro forma amount is based on historical performance for this cost category.
Purchase One (1) 230-69kV 150 MVA 3 Phase Wye-Delta XFMR	Dec-20		OPUC 220-1	This is a second phase to Grid Resiliency Phase 1 - 230/69kV Xfmr Purchase project discussed above.
Replace Overhead Transmission Poles - ID	Various		OPUC 220-1	This 2020 blanket project will replace transmission poles in Idaho that have deteriorated and are deemed a risk to public safety and/or system reliability.
Replace Overhead Transmission Lines - Other - ID	Various		OPUC 220-1	This 2020 blanket project will replace transmission line assets other than poles in Idaho that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Upgrade Trans CB and Relays UT	Various	[redacted]	OPUC 220-1	This 2020 blanket project will fund functional upgrades to transmission substations in Utah. An upgrade would be the addition or enhancement to an existing operational function. For example, adding supervisory control and indication (SCADA) to an existing substation to allow remote operation and monitoring would be considered a functional upgrade.
Purchase One (1) 115-69 kV Wye-Delta 100 MVA 3 Phase XFMR Dedicated for Columbia	Dec-20	[redacted]	OPUC 220-1	A spare transformer analysis identified an aging spare transformer concern in the Delta-Wye portion of the installed 115-69 kV transformer fleet. A new 115-69 kV, Delta-Wye, 150-MVA spare transformer is being purchased to serve as a ready-to-use spare backing up the two (2) three-phase Delta-Wye transformers in-service. The spare will provide timely customer service restoration should failure occur.
Naples 138-12.5 kV New Substation TPL	Aug-2020	[redacted]		Transmission portion of new substation construction to address compliance with NERC Reliability Standards related to unacceptable voltage deviation and low voltage issues.
Parowan Valley Reg Replacement	Dec-20	[redacted]		This project was mis-classified as a transmission level project. This is a distribution level project in the state of Utah and should be removed from this filing. This project will replace the existing regulators at Parowan Valley substation that are projected to overload due to area load growth. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400).
Oregon Trans- Rplc Sub-Swgr,Brk,Rec	various	[redacted]		This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Oregon when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
BLM - Antelope Bannock Pass Anaconda -	May-20	[redacted]		This project will renew the BLM permit for a portion of the Antelope-Amps-Peterson Flat 230 kV transmission line. This permit is required in order to continue the operation of this line.
Replace Overhead Transmission Poles - WY	Various	[redacted]		This 2020 blanket project will replace transmission poles in Wyoming that have deteriorated and are deemed a risk to public safety and/or system reliability.
Oregon Trans - Repl Sub - Mtrs &	various	[redacted]		This 2020 blanket project will rebuild or replace existing transmission level substation meters and relays in Oregon when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Oregon - Rplc- Trans Strm&Cas	various	[redacted]		This 2020 blanket project will replace damaged transmission equipment in Oregon due to a storm or external event (like a car hit pole).
Asset Removal - UT	Various	[redacted]		This 2020 blanket project will remove transmission utility assets in Utah that have been abandoned for some length of time.
Wildfire Mitigation Plan - OR T	various	[redacted]		This 2020 blanket project provides the means of allocating capital funds to mitigate operational risk in Oregon that present the greatest risk of catastrophic wildfires.
Upgrade Trans CB and Relays WY	Various	[redacted]		This 2020 blanket project will fund functional upgrades to transmission substations in Wyoming. An upgrade would be the addition or enhancement to an existing operational function. For example, adding supervisory control and indication (SCADA) to an existing substation to allow remote operation and monitoring would be considered a functional upgrade.
Replace Substation Switchgear, Breakers, Reclosers - WY	Various	[redacted]		This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Wyoming when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Block 216 Tower Service Request	Oct-2020	[redacted]		This project was mis-classified as a transmission level project. This is a distribution level project in the state of Oregon and should be 100 percent assigned to Oregon from this filing. This project provides distribution service to a mixed use new customer load addition. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400)
Replace Substation Meters and Relays - UT	Various			This 2020 blanket project will rebuild or replace existing transmission level substation meters and relays in Utah when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Lassen Sub-New 69x115 kV sub to replace Mt Shasta Sub(Net 12.5 MVA) T	Jun-2020			Addressed in Vail Surrebuttal (PAC/4200) Testimony.
Targeted reliability Improvement, Trans - UT	Various			This 2020 blanket project will rebuild or replace existing transmission facilities, or install additional transmission facilities or functionality in Utah in order to improve customer reliability within a targeted area.
Replace Overhead Transmission Lines - Other - WY	Various			This 2020 blanket project will replace transmission line assets other than poles in Wyoming that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.
Upgrade Trans CB and Relays ID	Various			This 2020 blanket project will fund functional upgrades to transmission substations in Idaho An upgrade would be the addition or enhancement to an existing operational function. For example, adding supervisory control and indication (SCADA) to an existing substation to allow remote operation and monitoring would be considered a functional upgrade.
TMP Generation Interconnections West	Various			This category of projects represents system upgrades required to reliably serve customer generation interconnection requests on the PacifiCorp transmission system per the Open Access Transmission Tariff. This category pertains only to projects Oregon, Washington, and California with in-service dates planned in 2020. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system.
Replace - Storm & Casualty - WY Trans	Various			This 2020 blanket project will replace damaged transmission equipment in Wyoming due to a storm or external event (like a car hit pole).
Wash - Rplc-OH Trans-Pole	various			This 2020 blanket project provides the means of allocating capital funds to replace transmission poles in Washington that have deteriorated.
SF6 - Replace Naughton CB 235	5/1/2020			This project will replace the 1971 vintage, 230 kV circuit breaker at Naughton substation due to the ongoing failure of individual components and high rate of leaking SF6 gas. This will reduce SF6 emissions as well as reduce the risk of breaker failure that would result in added reliability risk.
SF6 - Replace Antelope CB 201 - shared IPC	10/1/2020			This project will replace the 1969 vintage, 230 kV circuit breaker at Antelope substation due to the ongoing failure of individual components and high rate of leaking SF6 gas. This will reduce SF6 emissions as well as reduce the risk of breaker failure that would result in added reliability risk.
Calif - Transmission Improvements	various			This 2020 blanket project will rebuild or replace existing transmission facilities, or install additional transmission facilities or functionality in California in order to improve customer reliability within a targeted area.

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Replace Substation Meters and Relays - ID	Various	[redacted]		This 2020 blanket project will rebuild or replace existing transmission level substation meters and relays in Idaho when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Replace Substation Switchgear, Breakers, Reclosers - ID	Various	[redacted]		This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Idaho when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
System Reinforcement - Local Transmission Projects	Various	[redacted]		This 2020 blanket project will fund transmission level system reinforcement projects in Utah in order to maintain acceptable reliability for the growing load. These projects typically consist of capacity increase projects such as replacing substation class transformers with larger ones.
Replace Substation Bushings, Glass & Other - WY	Various	[redacted]		This 2020 blanket project will rebuild or replace transmission level substation bushings, brown glass and other equipment in Wyoming that have failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
Projects Less Than $500 Thousand	Various	[redacted]		Of the 110 line items that make up the list of projects under $500k, 98 are program level funding which is based on historical experience. The Company forecasts a level of capital associated with unexpected events and smaller maintenance that requires capital replacement. The remaining line items are individual small projects or close-out costs on projects that enter service prior to the test period covered in this rate case.
Transmission Five Year Average Removals		[redacted]		
		[redacted]		

REDACTED

REDACTED

Projects By Budget Category

Category	Project Name	Planned Cost ($million)	Project Description
TMP Gen Interconnection East		**$ 21.4**	
	Q589 Sigurd Solar, LLC	[redacted]	This project interconnects 80 MW of new generation to PacifiCorp's Sigurd 230 kV substation located in Sevier County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes adding a new breaker, dead-end, switches, and other protection and control equipment at Sigurd substation. As well as updating communications at Salt Lake Control Center.
	Q0631 Milford Solar 1, LLC - Interconnection		This project interconnects 99 MW of new generation to PacifiCorp's Hickory 345 kV substation located in Beaver County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. Network upgrade work includes expanding Hickory substation and adding a new 345 kV position and related communication/relay equipment.
	Q737 Cove Mountain Solar 2, LLC		This project interconnects 122 MW of new generation to PacifiCorp's Enterprise Valley substation 138 kV bus located in Washington County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes new relaying and communications equipment at the Enterprise Valley substation. Communications and relaying to be installed at the Richfield service center and Holt, West Cedar, Clover, and Sigurd substations to support a Remedial Action Scheme (RAS).
	Q754 Steel Solar		The project interconnects 80 MW of new generation to PacifiCorp's 138 kV line east of Washakie substation located in Box Elder County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The Network upgrade work for this project includes installation of a new three breaker ring bus substation for the Point of Interconnection (POI), including all appurtenant metering and communication equipment and the loop in/out of the Wheelon-Nucor 138 kV transmission line at the new POI substation.
	Q764 Graphite Solar		The project interconnect 80 MW of new generation to PacifiCorp's Mathington 138 kV substation located in Carbon County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes: new RAS panel at Carbon substation; a new bay and RAS master at Mathington substation; and a new reactor and RAS panel at Spanish Fork substation.
	Q0781 Elektron Solar		This project interconnects 80 MW of new generation to PacifiCorp's Craner Flat 138 kV substation located in Tooele County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. Network upgrade work includes: a new circuit breaker at Craner Flat substation to tap to Homestead Knoll – Horseshoe transmission line; and modification of communications equipment and settings at Homestead and Horseshoe substations.
	Program level funding		
TMP Transmission Major Projects - PP		**$ 7.7**	

REDACTED

Projects By Budget Category

	Corvallis 115kV Loop - Reconductor 1 mile Fry - Circle Blvd	[redacted]	This project will reconductor a 1.1 mile section of the Fry – Circle Boulevard 115 kV line and replace the getaway conductor at Circle Boulevard substation. This project is needed to increase capacity on the Fry to Circle end of the 115 kV Corvallis loop and eliminates the need to shed up to 13 MW of load for an outage of the Hazelwood – Circle Tap 115 kV line during heavy summer loading.
	Dry Gulch Substation - Replace 115/69kV Transformer	[redacted]	This project replaces the existing 115/69 kV, 20 megavolt ampere (MVA) transformer, T-2210, with new 115/69 kV, 50 MVA transformer with on-load tap changer (LTC) at Dry Gulch substation located in Eastern Washington near Clarkston. Installation of a new 115/69 kV transformer at Dry Gulch with the ability to automatically control voltage on the 69 kV system will allow the 69 kV line to operate in a normal open configuration, with a sectionalizing point in the middle of the line. This will resolve a North American Electric Reliability Corporation (NERC) transmission planning (TPL) deficiency for a bus fault at the substation that results in low voltages. It will mitigate overloads for outages of heavily loaded parallel main grid lines. Also, by sectionalizing the line, customer outage exposure will be reduced.
	Yreka Sub 115/69 kV Tx addition - Install	[redacted]	This project will install a new 115/69 kV, 30/40/50 MVA LTC transformer at Yreka substation, relocate existing circuit breaker 3G85 to 69 kV breaker bay, and reroute Line 47 within Yreka substation so that 69 kV wire bus does not pass above new transformer bay. Transmission voltage in the Scott Valley is projected to fall below the 0.90 per unit guideline limit at summer peak during normal system operation, beyond the range of distribution substation regulators to maintain customer voltage within American National Standards Institute (ANSI) limits. The addition of an LTC transformer at Yreka will improve control of the 69 kV system voltage and will allow the use of load drop compensation feature to further improve the Scott Valley transmission voltage profile over the long term.
TMP Trans Main Grid East		**$ 12.2**	
	Siphon Tap - Pingree Junction 138 kV Reconductor	[redacted]	This project reconductored the 8.9-mile-long Siphon Tap to Pingree 138 kV line section of Idaho Power Company's (IPC) Don to Pingree to Blackfoot line, located in eastern Idaho. A construction agreement was signed with IPC outlining that all of the work for this project will be performed by IPC. IPC will own the completed project and all associated equipment. PacifiCorp will fund 100 percent of the actual project costs as agreed in the construction agreement. Results of the NERC TPL-001-4 Assessment, identified that the loss of the Goshen 345 kV source can cause the Don – Pingree 138 kV line to load up to 220 MVA. Thus, in order to eliminate the overload, preemptive load shedding of up to 150 MW would have been required in the Goshen area. By reconductoring the Don – Pingree line the rating will increase to at least 191.2 MVA continuous and emergency, and will reduce the preemptive load shedding requirement up to 65 MW.
	Spanish Fork 345/138 Transformer Upgrade TPL	[redacted]	This project upgrades the existing Spanish Fork substation transformer #3, installs backup bus differential relays, and replaces jumpers on the Spanish Fork – Tanner 138 kV line.. The project, based on the NERC TPL-001-4 and the Utah Valley 10-year study, will resolve thermal overload issues, eliminate voltage issues, and eliminate risk of load shedding or generation curtailment identified as NERC TPL-001-4 Category P1, P2, P3 and P6 issues impacting the system.
	TPL Backup Bus Differential Relays	[redacted]	Program level funding to mitigate NERC TPL-001-4 Category P5-5 contingency events for a failure of the relay to clear a bus fault. The backup bus differential relays monitors for bus faults and initiate tripping of circuit breakers thereby providing backup protection for the failure of the primary bus differential relays to operate. The failure of a bus differential relay during system peak load conditions could result in NERC TPL-001-4 performance violations resulting from thermal overloads or low voltage issues in the surrounding network.

REDACTED

Projects By Budget Category

	TPL Overdutied Circuit Breaker Replacements	[redacted]	Program level funding to replace overdutied circuit breakers with higher interrupt capability breakers. The failure of overdutied breakers during system peak load conditions could result in NERC TPL-001-4 deficiencies resulting from thermal overloads or low voltage issues in the surrounding area.
TMP Trans Main Grid West		**$ 7.1**	
	Hazelwood Sub- Expand Yard & Install Ring Bus	[redacted]	Treasureton 138 kV Sub Cap Bank Backup Protection ($0.1 million) - This project installs backup relays for two 49.5-MVAr capacitor banks providing backup protection for the failure of the primary relays at Treasureton 138 kV substation located in Preston, Idaho. The projects, based on the TPL-001-4 Category P5-4 analysis, which is a delayed fault clearing due to the failure of a non-redundant relay, will mitigate the issues impacting the system. Operating procedures cannot be implemented to mitigate the risk of P5-4 contingency events from occurring.
	Lone Pine Circuit Breaker Replacement	[redacted]	This project replaces four 115 kV circuit breakers with non-oil-filled units rated for 40,000 Amp RMS fault current capability to withstand and interrupt fault current at Lone Pine substation in Medford, Oregon. This project will resolve NERC Standard TPL-001-4 requirements that short circuit current interrupting ratings of circuit breakers be adequate to interrupt the available short circuit current. The momentary and interrupting capabilities of the existing 115 kV circuit breakers are not adequate to withstand the available fault current since the energization of Whetstone 230-115 kV substation.
	Meridian RAS Expansion	[redacted]	This project expands the existing Meridian RAS to cover three additional N-1-1 contingencies on the southern Oregon 500 kV system and trip additional load. The proposed RAS expansion will ensure compliance with the NERC PRC-014 Reliability Standard, Western Electricity Coordinating Council (WECC) PRC-(012-014)-WECC-CRT-2 Regional Criterion and NERC TPL-001-4 Reliability Standard. In addition, expanding the RAS will avoid relying on the Southern Oregon under Voltage Load Shedding scheme as the primary mitigation for double contingencies on the 500 kV system.
TMP Trans Customer Generated East- 2020		**$ 6.9**	
	Q2469 PacifiCorp ESM	[redacted]	This project is due to a PacifiCorp's energy supply management (ESM) request on PacifiCorp's Open Access, Same-time Information System (OASIS) for Designated Network Resource (DNR) status. The Construction Agreement was executed between PacifiCorp, on behalf of its merchant function (ESM), and PacifiCorp, on behalf of its transmission function on December 20, 2018. The project is associated with Generation Interconnection queue request Q0631. The network upgrade work includes: development and installation of new relay settings for the Spanish Fork – Timp transmission line at Spanish Fork substation, installation of new fiber and the decommissioning of the Spanish Fork – Lake Mountain microwave link; installation of a new 138 kV circuit breaker (and associated switches) at Timp substation; reconductoring of approximately 5.23 miles of the Spanish Fork- Timp transmission line; and installation of fiber in the shield wire position from Timp to Spanish Fork substation. Under the OATT, PacifiCorp is required to plan, construct, operate and maintain its transmission system in order to provide its network customers service over the transmission provider's transmission system.

	Q155 UAMPS	[redacted]	This project is in response to a transmission service request from UAMPS pursuant to its Transmission Service and Operating Agreement for a new point of delivery. The scope consists of constructing a new 138 kV substation with four circuit breakers, switches, etc., looping the Jordanelle – Midway 138 kV line in and out of the substation and two 138 kV delivery connections to UAMPS customer. Under the OATT, PacifiCorp is required to plan, construct, operate and maintain its transmission system in order to provide its network customers service over the transmission provider's transmission system.
TMP Trans Customer Generated East- 2019		**$ 4.3**	
	Bull River to Carter Substation 138 kV Conv - Trans	[redacted]	This project was required for increased load service for a UAMPS network customer. The project is to re-build 2.3 miles of the Lehi Bull River tap to Saratoga tap 46 kV line to 138 kV line.
	Program level funding	[redacted]	The close-out of several projects placed into service late 2018 and early 2019.
TMP Generation Interconnections West		[redacted]	
	Q729 Airport Solar, LLC - Airport Solar	[redacted]	This project interconnects a total of 47.25 MW of new generation to PacifiCorp's Chiloquin-Alturas 115 kV line at 42.178563°N, 120.357580°W located in Lake County, Oregon. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The Network upgrade work for this project includes: construction of a new 115 kV three-breaker ring bus substation.
TMP Transmission Major Projects - PP		**$ 2.6**	
	NE Portland Trans Upgrade	[redacted]	This project addressed electrical network deficiencies required to improve reliability within Northeast Portland. This project is a systemic solution to the operational and contingency related network issues in the Portland transmission and substation system. The dollars in 2019 were for the last phase of the project which was the installation of a second transformer at Albina substation.
	Program level funding	[redacted]	The close-out of several projects placed into service late 2018 and early 2019.
TMP Trans Main Grid East		[redacted]	
	90th South Bus Tie Breaker	[redacted]	The project, based on the 2017 TPL Assessment, identified that a fault on the 90th South 138 kV bus tie breaker results in a loss of the entire 90th South 138 kV substation. Once the project is completed, loss of the entire 90th South 138 kV substation will be prevented. Thermal overloads on the following 138 kV line segments will be resolved: Lone Peak – Lone Peak Tap, Travers Mtn. – South Mtn. South Tap, and South Mtn. South Tap – South Mountain. Low voltages on the 106th South, 108th South, Quarry, Dimple Dell and Dumas substations will not occur, and overloading of the Camp Williams transformer as seen in the 2022 TPL case will be prevented.

REDACTED

Docket No. UE 374
Exhibit PAC/4203
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Richard A. Vail

Staff Response to PacifiCorp Data Requests 55 and 63

August 2020

UE 374 –0PUC Response to PacifiCorp Data Request
Page 1

Issued: July 29, 2020 – Response Due By: **August 5, 2020**

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FROM: Matt Muldoon – UE 374 Case Manager
Program Manager Energy Rates, Finance and Audit Division

Responding Staff: Hanhan, Rashid, and Muldoon

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 374- PacifiCorp Data Request filed July 29, 2020

PAC Data Request No 55:

55. Please refer to Staff/2100, Hanhan-Rashid-Muldoon/16:3-12. Provide references to any and all Public Utility Commission of Oregon decisions relied on by Staff that "primary grid" benefits are required to include transmission projects in PacifiCorp's rate base.

OPUC Response No 55:

55. Please refer to Staff Response to PacifiCorp Data Request 54. In addition, please see docket number UM 2031, and the associated Commission Order No. 19-400.

Issued: July 29, 2020 – Response Due By: **August 5, 2020**

TO:
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FROM: Matt Muldoon – UE 374 Case Manager
Program Manager Energy Rates, Finance and Audit Division

Responding Staff: Hanhan, Rashid, and Muldoon

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 374- PacifiCorp Data Request filed July 29, 2020

PAC Data Request No 63:

63. Please refer to Staff/2100, Hanhan-Rashid-Muldoon/34:17-20. Does Staff admit that its concern is contrary to current regulatory approach adopted by the Public Utility Commission of Oregon? If the answer is no, explain in detail and provide reference to all supporting Commission decisions, regulations or applicable statutes.

OPUC Response No 63:

63. Staff objects to this request as vague, ambiguous, and argumentative. Without waiving these objections, Staff responds as follows: No, Staff does not admit that its concern is contrary to current regulatory approach adopted by the Public Utility Commission of Oregon. Rather, PacifiCorp's transmission assets are allocated to Oregon customers based on the 2020 Protocol. Whether an asset is a transmission asset is generally defined by the Company's OATT; however, the Commission retains discretion to determine which assets are considered distribution assets, and retains the ability to question or otherwise challenge, through appropriate regulatory proceedings, which assets the Company as classified as transmission and are included in its OATT. Please also refer to Order No. 19-400.

Docket No. UE 374
Exhibit PAC/4204
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Richard A. Vail

Staff Response to PacifiCorp Data Request 53

August 2020

Issued: July 29, 2020 – Response Due By: **August 5, 2020**

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FROM: Matt Muldoon – UE 374 Case Manager
Program Manager Energy Rates, Finance and Audit Division

Responding Staff: Hanhan, Rashid, and Muldoon

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 374- PacifiCorp Data Request filed July 29, 2020

PAC Data Request No 53:

53. Please refer to Staff/2100, Hanhan-Rashid-Muldoon/13:23-24. Provide any and all references to the definitions of "system benefit" and "local benefit" relied on by Staff. Specifically, identify where the Public Utility of Oregon has adopted such definitions.

OPUC Response No 53:

53. In the context of their testimony in this case, Ms. Hanhan, Mr. Rashid, and Mr. Muldoon generally consider a "system benefit" to be those assets that are appropriately classified as transmission assets under FERC; whereas "local benefit" refers to assets appropriately outside of FERC jurisdiction, which would include distribution assets.

Docket No. UE 374
Exhibit PAC/4205
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Richard A. Vail

Staff Response to PacifiCorp Data Request 71

August 2020

Issued: July 29, 2020 – Response Due By: **August 5, 2020.**

TO:
DATA REQUEST RESPONSE CENTER
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825 NE MULTNOMAH STREET STE 2000
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FROM: Matt Muldoon – UE 374 Case Manager
Program Manager Energy Rates, Finance and Audit Division

Responding Staff: Hanhan, Rashid, and Muldoon

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 374- PacifiCorp Data Request filed July 29, 2020

PAC Data Request No 71:

71. Was it Staff's understanding when it signed the 2020 PacifiCorp Inter- Jurisdictional Allocation Protocol that transmission assets included assets currently in the Company's Oregon rate base?
    a. If the answer is yes, was it Staff's intent to modify the approach in a subsequent general rate case while it was negotiating the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol?
    b. If the answer is no, explain how that complies with agreement to extend the terms of the 2017 Inter-Jurisdictional Protocol through the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol while the additional framework issues are negotiated.

OPUC Response No 71:

71. Yes. Staff understood, as of the date it signed the 2020 Protocol, that PacifiCorp's transmission assets included assets currently in PacifiCorp's Oregon rate base.
    a. Staff objects to this sub-part as argumentative, as it requires Staff to agree that its position that questioning the classification of assets as transmission is inconsistent with the 2020 Protocol or is otherwise a modification to the 2020 Protocol. Without waiving this objection, Staff responds as follows: Staff negotiated the 2020 Protocol in good faith, and in this case, seeks to implement the 2020 Protocol as agreed. Section 3.1.3 of the 2020 Protocol requires that transmission assets be allocated on a system basis, based on the SG factor. Staff agrees that transmission assets are generally defined in terms of PacifiCorp's OATT. However, this does not mean that Oregon Staff

(or other Oregon parties) have no ability to review and/or otherwise challenge PacifiCorp's classification of an asset as either transmission or distribution in an appropriate proceeding.

With this understanding, Staff modifies its recommendation in this case to remove disallowances for those subset of transmission projects where the prudently-incurred costs at issue in this case are associated with plant already included in the Company's OATT, Staff was able to verify the costs, and where Staff's only objection was that the asset did not appear to be appropriately functionalized as transmission. If PacifiCorp has classified an asset as transmission, but the asset has not yet been included in the OATT, Staff's recommendations remain consistent with its testimony position. Regardless of classification issues, Staff does not withdraw its recommendations regarding the prudence of cost-overruns or any other prudence disallowance unrelated to classification as transmission rather than distribution.

b. Not applicable.

REDACTED
Docket No. UE 374
Exhibit PAC/4300
Witness: Julie Lewis

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Julie Lewis

August 2020

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ATTACHED EXHIBIT

Exhibit PAC/4301—OPUC Staff Response to PacifiCorp Data Request 87

Confidential Exhibit PAC/4302—PacifiCorp's Full Response to OPUC Staff Data Request 179

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

A. My name is Julie Lewis. My business address is 825 NE Multnomah Street, Suite 1800, Portland, Oregon 97232. I am currently the Vice President of People for PacifiCorp.

Q. Please describe your education and professional experience.

A. I joined PacifiCorp in 1980 and have worked in human resources since 1985. I have taken on roles of increasing responsibility, including as Director of Compensation and Benefits for two years, before assuming my current role in 2018.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this case?

A. The purpose of my surrebuttal testimony is to explain the Company's compensation philosophy and why the Commission should reject certain labor related adjustments proposed by Public Utility Commission of Oregon (Commission) Staff witness Ms. Heather Cohen in her rebuttal testimony. Testimony concerning specific adjustments will be discussed in the testimony of Company witness Ms. Shelley E. McCoy.

Q. Please summarize your testimony.

A. In my testimony I demonstrate that:

- The proposed base wage expense is reasonable and consistent with the competitive market in which the Company competes for labor. The Company's union wage increases are based on actual union contracts, not the approximations used by Staff. The benchmarking studies used by the Company to determine annual wage escalation are more reasonable than the All Urban Consumer Price Index (CPI) proposed by Staff because they are specific to utility industry wages.

- Employee incentive compensation should not be disallowed. The Company's incentive program is not a "bonus." It is structured to provide benefits to customers consistent with Commission precedent and is part of the Company's total market-based compensation package. The removal of incentive expense would therefore result in below-market compensation.
- The Company's incentives are not "shrouded in secrecy."[1] The Company has provided complete responses to all discovery requests related to employee incentives, and Staff has not objected to any of the Company's responses.

Q. Please describe PacifiCorp's compensation philosophy.

A. The Company's primary objective in establishing employee compensation is to provide pay at the market average. Compensation at the market average (competitive level) is critical to attracting and retaining qualified employees to support the business and our customers. To encourage employee performance, a certain percentage of each employee's market compensation must be "at risk." The Company's Annual Incentive Plan (AIP) is structured so that each employee has the opportunity to receive total compensation at the market average, so long as the employee performs at an acceptable level. In exceptional performance years, an employee's at-risk incentive may be more than target and in low performance years it may be below target, but on average, the at-risk incentive is generally at the guideline level. If the

[1] Staff/2500, Cohen/16, line 17.

individual fails to earn the full guideline incentive, that individual will be paid less than the competitive total cash compensation in the marketplace for that year. Central to the Company's approach to total compensation is that, while certain employees may be paid more than or less than market in a given year as a result of the at-risk incentive portion of compensation, on an overall basis the base compensation and at-risk incentive will result in a level of compensation commensurate with the market. Stated another way, in the unlikely event every employee performed at exactly the same level, each employee would be paid only at the market average.

III. WAGE ESCALATION

Q. Please describe how the Company determines annual non-union wage increases.

A. The Company uses several surveys to determine the percentage by which base pay should be increased for non-union employees. The base pay increases are calculated based on actual employees and salary at the end of September and multiplied by the base pay increase percentage. The base pay increase percentages are determined using results from the following salary surveys: Willis Towers Watson – Energy Services Mid-Mgmt, Prof & Support; Willis Towers Watson – Energy Services Executive; Mercer – all surveys; and Aon Hewitt – all surveys. These surveys are specific to the utility industry and specific to the job classifications at the Company. This is in contrast to the surveys relied on by Northwest Natural Gas Company in its 1999 rate case, which was cited in Ms. Cohen's rebuttal testimony. In that case the Commission did not consider wage-specific surveys because the company had not "demonstrated that wages of its officers and nonunion employees" were related to the survey area (manufacturing).[2] The following tables are the result, in aggregate, of the base pay increases for all of the companies participating in the various surveys for years 2016 - 2019.

Table 1

	Base Salary Increase (Merit)	
Survey Title	**2019 Actual**	**2020 Projection**
World at Work 2019-2020 Salary Budget Survey:		
All Employees (Non0Union) National, Oregon and Utah	3.0%	3.0%
Mercer 2019-2020 US Compensation Planning:		
All Employees (Non-Union)	2.9%	3.0%
Willis Towers Watson 2019 General Industry Salary Budget Survey		
All Employees	3.1%	3.1%
Aon Energy Industry Compensation Planning Update for 2020		
All Employees (Non-Union)	3.0%	3.0%

Table 2

	Base Salary Increase (Merit)	
Survey Title	**2018 Actual**	**2019 Projection**
World at Work 2018-2019 Salary Budget Survey:		
National, Oregon and Utah	3.0%	3.0%
Aon Hewitt 2018-2019 Salary Increase Survey:		
Executive	3.1%	3.2%
Salaried Exempt	3.1%	3.1%
Salaried Non-exempt	3.0%	3.1%
Non-Union Hourly	3.0%	3.0%
2018 Milliman NW Management & Professional Salary Survey:		
All Industries (Oregon, Washington, Idaho)	3.0%	3.1%
Utilities (Oregon, Washington, Idaho)	3.1%	3.3%
Mercer 2018-2019 US Compensation Planning:		
All Employees (Non-Union)	2.8%	2.9%

[2] *In re the Application of Northwest Natural Gas Company*, Docket No. UG 132, Order No 99-697 (Nov. 12, 1999).

Table 3

	Base Salary Increase (Merit)	
Survey Title	**2017 Actual**	**2018 Projection**
World at Work 2017-2018 Salary Budget Survey:		
National, Oregon and Utah	3.0%	3.0%
Aon Hewitt 2017-2018 Salary Increase Survey:		
Executive	3.0%	3.0%
Salaried Exempt	2.9%	3.0%
Salaried Non-exempt	2.9%	3.0%
Non-Union Hourly	2.9%	3.0%
2017 Milliman NW Management & Professional Salary Survey:		
All Industries (Oregon, Washington, Idaho)	3.0%	3.0%
Utilities (Oregon, Washington, Idaho)	3.0%	3.0%
Mercer 2017-2018 US Compensation Planning:		
All Employees (Non-Union)	2.8%	2.9%

Table 4

	Base Salary Increase (Merit)	
Survey Title	**2016 Actual**	**2017 Projection**
World at Work 2016-2017 Salary Budget Survey:		
National, Oregon and Utah	3.0%	3.0%
Aon Hewitt 2016-2017 Salary Increase Survey:		
Executive	3.1%	3.1%
Salaried Exempt	3.0%	3.0%
Salaried Nonexempt	2.9%	2.9%
Nonunion Hourly	2.8%	2.8%
2016 Milliman NW Management & Professional Salary Survey:		
All Industries (Oregon, Washington, Idaho)	3.0%	3.0%
Utilities (Oregon, Washington, Idaho)	3.0%	3.0%
Western Management Group :		
Salt Lake Area	3.0%	Not

Q. Have the Company's wage increases been consistent with the actual and projected increases stated in the surveys?

A. No. As reflected in Table 2 – Non-Union Percentage Increases in the reply testimony of Ms. McCoy, the Company has consistently increased base pay at a lower rate than the surveys suggest.

Q. Does the Company consider the All Urban CPI to determine how much to increase base pay?

A. No. As explained in the rebuttal testimony of Ms. McCoy, the All Urban CPI is a measure of inflation over time, and includes goods and services. The Company uses wage-specific surveys that incorporate the market conditions influencing wages and salaries, which can vary from a more general CPI survey. Failing to take into account actual wages paid to employees in the marketplace, as Ms. Cohen failed to do,[3] results in undercompensating employees. It is important for the Company to utilize escalation factors that will result in a competitive salary structure. Using the All Urban CPI would not appropriately adjust salaries annually and would not result in a competitive salary structure to attract and retain qualified employees in a competitive market and would result in under recovery.

Q. Does the quarterly publication of All Urban-CPI data make it more reliable than the surveys relied on by the Company, which are released annually?

A. No. It is more reasonable to rely on surveys that relate to wages and salaries that are published annually than on CPI data that is not wage specific but has more frequent updates. The fact that the market is currently experiencing short-term volatility does not justify relying on a less specific escalation factor just because it is updated more frequently, particularly when it is not clear that the current volatility will continue for the duration of time that rates are in effect from this case.

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[3] PAC/4301 (OPUC Response to PacifiCorp Data Request 87).

Q. Has the Commission rejected the use of market surveys to determine wage escalation?

A. No. In one of the cases relied on by Ms. Cohen, docket UG 132, the Commission adopted Staff's recommendation to use the All-Urban CPI because the indices used by the utility were not applicable to the job classifications to which they were applied.[4] Specifically, the Commission rejected the utility's proposed indices because there was no evidence that the wages of its officers and nonunion employees were "related to manufacturing or governmental wages" and the company "admitted in testimony that utility wages are not closely related to service wage patterns."[5] As demonstrated by the breadth of surveys relied on by the Company, this concern is not applicable to the Company's proposed escalation factor.

IV. INCENTIVES

Q. Please describe how PacifiCorp determines AIP for employees.

A. The Company uses Company-wide and department goals, which are detailed in scorecards, to determine at-risk incentive payments. Each management-level employee has an individual scorecard by which their at-risk incentive payment is determined. Employees without an individual scorecard are judged based on the PacifiCorp scorecard and their department scorecard. An employee's individual at-risk incentive payment is then adjusted according to their manager's assessment of their performance of their contribution to the department and company scorecards.

Q. How are scorecard goals determined?

A. Individual department managers establish specific business unit goals consistent with

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[4] *In the Matter of Northwest Natural*, OPUC Docket UG 132, Order No. 99-697 at 43 (Nov. 12, 1999).
[5] *Id.*

the core principles of the Berkshire Hathaway Energy family of companies, which have direct customer benefits. The six core principles are: (1) customer service; (2) employee commitment; (3) environmental respect; (4) regulatory integrity; (5) operational excellence; and (6) financial strength. [redacted] AIP compensation. Performance against scorecard goals is measured with Key Performance Indicators (KPIs) that establish the measurable metric for success. KPIs are specific and measurable goals, such as achieving a certain reliability score or reducing the number of safety-incidents. Business unit goals must advance the business and demonstrate continuous improvement over previous year goals.

Q. Please explain the customer benefits associated with each core principle.

A. [redacted] incentive-based compensation.

Customer Service is based on delivering reliable and dependable service to customers at fair prices. This principle also includes providing exceptional service to customers. Customer satisfaction surveys comprise [redacted] of the total incentive-based compensation calculation, and approximately [redacted] of the Customer Service category. Keeping customer rates stable and as low as possible, while ensuring reliable service, provides a direct customer benefit.

Employee Commitment is based on preventing employee injury and workplace accidents, encouraging teamwork, and meeting goals related to employee engagement, training, and development plans. Ensuring that PacifiCorp's employees are safe, healthy, engaged with the company, and well-trained helps ensure that

PacifiCorp operates safely and well. This in turn benefits PacifiCorp's customers.

Environmental Respect focuses on increasing investment in renewable energy, improving emissions rates and efficiency of fossil-fueled generation, offering resources to help customers manage their energy use, and investing in new transmission and distribution equipment to reduce the loss of kilowatts and improve reliability. Reducing emissions, increasing renewable resources, offering demand-side resources, and improving reliability provides a direct benefit to PacifiCorp's customers.

Regulatory Integrity is based on minimizing rate increases by achieving balanced regulatory and legislative outcomes. Achieving favorable regulatory outcomes and legislation that do not have adverse impacts to the Company or its customers directly benefits customers.

Operational Excellence is based on achieving transmission and distribution reliability goals. Operational Excellence is also based on optimizing availability factors for PacifiCorp's thermal and renewables fleets, and on ensuring PacifiCorp's electronic and physical assets are safe and secure. A reliable transmission and distribution system, transmitting power produced by generating assets that are performing at optimal levels, and whose electronic and physical assets are safe and secure undeniably provides a direct benefit to PacifiCorp's customers.

Financial Strength is based on achieving strong credit ratings and maintaining a high-quality, diversified portfolio of regulated businesses. A financially healthy and well-capitalized utility is able to obtain lower interest rates, which translates to lower costs for customers.

Q. Is Ms. Cohen correct when she states that "PacifiCorp does not use other companies as benchmarks" when determining at-risk incentive payments to executives and employees?

A. No. The same survey data we use to benchmark base pay at the market average is also used to benchmark the appropriate at-risk incentive percent tied to each job at the market average.

Q. Is AIP considered a "bonus"?

A. No. It is critical to understand that the "at risk" portion of total compensation is not a bonus. A bonus is something unexpected. The "at risk" compensation is not unexpected—in fact, it is the opposite. The "at risk" portion of total compensation is expected by the employee, but only if the employee performs at or above an acceptable level. Any reduction beyond the competitive target incentive level would place the Company in a position of not being able to offer competitive pay levels and placing operational and customer objectives at risk.

Q. Have other jurisdictions approved recovery of the Company's AIP?

A. Yes. In docket UE-100749 Order 06, the Washington Utilities and Transportation Commission stated: "As we decided in the last litigated case, we conclude that the AIP is an appropriate method of implementing "incentive-based" compensation."[6] The Commission acknowledged that the "at risk" component of compensation was "not a bonus or a level of pay in excess of the maximum compensation for a position. It is simply motivation for an employee to strive for the total compensation for his or

[6] *Wash. Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-100749, Order 06, Final Order at 85 (Mar. 25, 2011).

her position by achieving certain individual and group goals."[7]

Q. Has the purpose or structure of the Company's AIP changed since the Washington decision issued?

A. No.

Q. Do you agree with Ms. Cohen's assertion that PacifiCorp's at-risk incentive payments to employees are "shrouded in secrecy"[8]?

A. No. The process is transparent, and the Company has provided extensive material to Staff through discovery, including the Company and department-level scorecards.[9] Staff did not object to the Company's discovery responses or indicate that they were insufficient or non-responsive. If Staff had, we would have addressed the issue before learning about it for the first time in Staff's rebuttal testimony.

Q. Do you believe that Ms. Cohen has presented a basis for disallowing any portion of the Company's at-risk incentive program?

A. No. Specifically, Ms. Cohen's testimony does not point to any aspect of incentive compensation that does not benefit customers. Her adjustments to incentive payments are unfounded, and the Commission should not adopt them.

V. CONCLUSION

Q. What is your recommendation?

A. I recommend the Commission reject Staff's labor related adjustments because the Company applied an appropriate wage escalation factor necessary to attract and retain talented employees; the Company's "at risk" AIP are not "bonus" payments and

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[7] *Id.* at 86.
[8] Staff/2500, Cohen/16, line 17.
[9] Confidential Exhibit PAC/4302 (Providing the complete response to Staff Data Request 179, partially included in Staff/2501).

benefit customers.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/4301
Witness: Julie Lewis

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Julie Lewis

OPUC Staff Response to PacifiCorp Data Request 87

August 2020

Issued: July 31, 2020 – Response Due By: **August 7, 2020**

TO:
DATA REQUEST RESPONSE CENTER
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FROM: Heather Cohen
Senior Utility Analyst

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 374 - PacifiCorp Data Request filed July 31, 2020

PAC Data Request No 87:

87. Please refer to Staff/2500, Cohen/17:12-14. Ms. Cohen testifies that "the Utility industry is one of the highest paying, mostly due to "supplements" or pensions, insurance plans, profit-sharing and retirement plans."
   a. Did Ms. Cohen compare PacifiCorp total compensation (i.e. salaries and incentives) to those of other public utilities in Oregon?
   b. Did Ms. Cohen compare PacifiCorp total compensation (i.e. salaries and incentives) to those of other public utilities in the Northwest region?
   c. Did Ms. Cohen compare PacifiCorp total compensation (i.e. salaries and incentives) to those of other public utilities nationally?
   d. If the answer to (a), (b), or (c) above is yes, provide a narrative explanation of the findings and provide any documents of that analysis.
   e. If the answer to (a), (b), and (c) above is no, provide a narrative explanation of why Ms. Cohen did not compare PacifiCorp's total compensation (i.e. salaries and incentives) to those of other public utilities in Oregon.
   f. Does Staff agree that total compensation must be considered if the goal is "eliminating any competitive disadvantage to one particular utility"(Staff/2500, Cohen/9-10)? If the answer is no, please explain in detail the basis for that answer.

OPUC Response No 87:

87. Staff replies below:
   a. No, the reference was for the utility industry in general.
   b. Please see response to subpart a, above.
   c. Please see response to subpart a, above.
   d. Please see response to subpart a, above.

e. Please refer to Staff's response to subpart a, above. Staff's statement was in reference to "the utility industry" in general. However, Staff relies on its Wage and Salary model, not industry benchmarks, to make adjustments.

f. No. Staff argues that: because all Oregon utilities are regulated by the Commission under the same Wage and Salary model, no one utility is at a competitive disadvantage.

REDACTED
Docket No. UE 374
Exhibit PAC/4302
Witness: Julie Lewis

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Julie Lewis

PacifiCorp's Full Response to OPUC Staff Data Request 179

August 2020

THIS ATTACHMENT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 374
Exhibit PAC/4400
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Shelley E. McCoy

August 2020

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ATTACHED EXHIBITS

Q. Are you the same Shelley E. McCoy who submitted direct and reply testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is to quantify the updates and revisions made to the Company's proposed revenue requirement in the current rate filing.

Q. Please summarize your testimony.

A. My testimony explains and supports the Company's revised overall revenue requirement increase of $47.5 million in this general rate case (GRC), based on the revised return on equity (ROE) of 9.80 percent as proposed in the testimony of Ms. Etta Lockey. This is a decrease of $30.5 million from the amount requested in the Company's initial filing and $24.4 million less than the amount proposed in the Company's reply filing. The $47.5 million GRC increase is offset with the proposed Tax Cuts and Jobs Act (TCJA) deferral amortization of $6.9 million and the decrease of $49.8 million in the Company's concurrent Transition Adjustment Mechanism (TAM) filing, for a net decrease of $9.2 million. My testimony discusses the revisions made to revenue requirement components in this modified request, as well as addressing several proposals made by Staff of the Public Utility Commission of Oregon (Staff), Alliance of Western Energy Consumers (AWEC) and the Oregon Citizens' Utility Board (CUB).

II. REVENUE REQUIREMENT

Q. Please describe the calculation of the revised overall revenue increase.

A. The Company's revised revenue requirement increase of $47.5 million is calculated using PacifiCorp's 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol) allocation methodology. As stated in my direct testimony, this rate filing was compiled using historical accounting information from the 12 months ended June 30, 2019 (Base Period), as a starting point. The historical information is then analyzed and adjusted to reflect known, measurable, and anticipated changes, and to include previous Public Utility Commission of Oregon (Commission or OPUC)-ordered adjustments. Since the Company's initial and reply filings, several changes have been made to modify the requested revenue increase. Exhibit PAC/4401 provides a summary of the Company's updated Oregon-allocated results of operations for the forecast period of the 12 months ending December 31, 2021 (Test Period). In support of the revised calculations, Exhibit PAC/4402 incorporates revisions and updates to certain adjustments and provides updated iterations of workpapers that support the Company's surrebuttal revenue requirement calculations.

Q. Please provide an overview of the revisions made to the Company's revenue requirement in this proceeding.

A. In addition to the adjustments reflected in the Company's initial and reply filings, several revisions or updates have been made to revenue requirement in the Company's surrebuttal filing. Each revision or update is described in more detail later in this testimony. Table 1 summarizes the impact of each change to the requested price change. Because of these revisions and updates, the Company's revenue requirement allocation model also automatically synchronized two other adjustments to account for cascaded changes in Interest Expense and Cash Working Capital calculations.

TABLE 1—Surrebuttal Revenue Requirement Increase

	GRC ($m)
Reply Revenue Requirement	$ 71.8
ROE Update to 9.80%	$ (12.3)
Depreciation Study Settlement in Principle	$ (10.7)
Depr Rate Update Impact on Other Adj	$ (0.3)
Depr Update Impact on Protected EDIT	$ 0.4
Cholla 4 Decommission Regulatory	$ (0.7)
Remove 2021 Wildfire Capital Projects	$ (0.7)
Other Updates	$ (0.1)
Total Changes	$ (24.4)
Surrebuttal Revenue Requirement	$ 47.5

Q. Please describe Exhibit No. PAC/4402.

A. Exhibit PAC/4402 is the Company's Oregon Results of Operations Report (Report), revised to incorporate changes and updates outlined in the table above. The Report is organized in a manner similar to Exhibit PAC/1302:

- Tab 1 (Summary) reflects the Oregon-allocated results based on the 2020 Protocol.
- Tab 2 (Results of Operations) details the Company's overall reply revenue requirement by Federal Energy Regulatory Commission (FERC) account and 2020 Protocol allocation factor.

- Tabs 4 through 8, Tab R and Tab SR provide supporting documentation for adjustments that have been revised in the calculation of the Company's surrebuttal revenue requirement.[1] New lead sheets are provided for those adjustments that are only being updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation.
- Tab 10 (Allocation Factors) reflects updates to allocation factors as a result of revisions made to the Company's revenue requirement in reply, primarily to plant-based factors.

III. DESCRIPTION OF REVISED ADJUSTMENTS

Q. Has the Company made an update to its proposed ROE in this case?

A. Yes. As discussed in the surrebuttal testimony of Ms. Lockey, the Company has updated the proposed ROE in this case to its currently authorized rate of 9.80 percent. This revision to the ROE decreases the Oregon revenue requirement by $12.3 million.

Q. Please describe the other revisions made in the Company's surrebuttal filing.

A. **Net Power Costs, Adjustment 5.1** – The Company has updated net power costs to the level included in the TAM settlement for purposes of showing the price changes related to both the TAM and GRC and for calculating the level of revenue sensitive items such as franchise taxes and bad debt expense.

Depreciation and Amortization Expense, Adjustment 6.1 – This adjustment has been updated to incorporate depreciation rates based on the settlement in principle parties have reached in the 2018 Depreciation Study, docket UM 1968.[2] New depreciation rates will be effective January 1, 2021. This adjustment has also been

[1] No revisions were made to the adjustments in Tab 3, Revenues.
[2] *In the matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates,* Docket No. UM 1968, Application filed Sept. 13, 2018.

updated to remove the incremental decommissioning costs related to the January 2020 Decommissioning Study for certain of the Company's coal generation plants. These incremental decommissioning costs have been incorporated in Adjustment 6.4, as described below.

Depreciation and Amortization Reserve, Adjustment 6.2 – This adjustment includes an incremental reserve amount associated with the updated depreciation expense due to proposed depreciation rates effective January 1, 2021. Consistent with the updates to Adjustment 6.1, Adjustment 6.2 has been updated to incorporate depreciation rates based on the settlement in principle parties have reached in the 2018 Depreciation Study, docket UM 1968, and to remove the reserve component of the incremental decommissioning costs.

Decommissioning and Other Plant Closure Costs, Adjustment 6.4 – This adjustment has been updated to include the incremental decommissioning costs related to the January 2020 Decommissioning Study. The incremental expense is accrued over Oregon's remaining life for each plant, with dollars accumulating in a regulatory liability that is reflected as a reduction to rate base in this case. The net impact of the updates to Adjustments 6.1, 6.2 and 6.4 is a decrease in Oregon revenue requirement of $10.7 million.

Tax Cuts and Jobs Act (TCJA), Adjustment 7.8 – This adjustment has been updated to reflect the impact of the 2018 Depreciation Study settlement in principle on the amortization of the protected excess deferred income taxes (EDIT) balances. Changes in average depreciable lives from the depreciation settlement in principle have been reflected in the amortization of the corresponding protected EDIT balances, resulting in a small increase of $0.4 million in Oregon revenue requirement.

Energy Vision 2020 Capital Additions, Adjustment 8.14 – The depreciation rates for transmission assets have been updated based on the settlement in principle that parties have reached for the 2018 Depreciation Study. Accordingly, the depreciation rate used to calculate the 2021 level of depreciation expense for transmission plant added in this adjustment has been updated, resulting in a $0.3 million decrease in Oregon revenue requirement.

Cholla Unit 4 Retirement, Adjustment 8.15 – This adjustment has been updated to reflect a portion of the TCJA balances being used to pay for Oregon's share of Cholla Unit 4 estimated decommissioning costs by establishing a regulatory liability for this balance and decreasing Oregon rate base. This change results in a $0.7 million decrease in Oregon revenue requirement.

Remove Cyber Security Capital Project, Adjustment R_1, and Remove Fish Passage Capital Project, Adjustment R_2 – Both of these adjustments have been updated to incorporate depreciation rates based on the settlement in principle parties have reached for the 2018 Depreciation Study, consistent with Adjustments 6.1 and 6.2 described above. These very minor updates are being made so that the removal of the depreciation on these projects is being made in the same amounts as the additions.

Remove 2021 Wildfire Mitigation Capital, Adjustment SR_1 – This new adjustment for surrebuttal removes the Wildfire Mitigation capital projects that are now projected to go into service after December 31, 2020. This adjustment is being presented individually for visibility and ease of calculation. Removal of these projects reduces the Oregon revenue requirement by $0.7 million.

Remove Lassen Substation, Adjustment SR_2 – This new adjustment removes the Lassen Substation transmission capital project, as it is now expected to go into service in 2021, rather than 2020. This adjustment is also being presented individually for visibility and ease of calculation. Removal of this small project reduces Oregon revenue requirement by approximately $22,000.

Q. Are there any additional revisions that did not get included in the updated revenue requirement?

A. Yes. As discussed by Mr. Richard A. Vail in PAC/4200, there are five additional adjustments that were not identified in time to be included in my update to the Company's revenue requirement. PacifiCorp will include the updates in its calculation following the Commission's issuance of its decision in this proceeding. The adjustments are a result of PacifiCorp's review of its pro forma transmission plant additions in response to Staff's recommendation of a wholesale disallowance. First, PacifiCorp identified that the revised forecast for the Pavant Transformer Protection project decreased project costs by $500,000. Two other projects, the Jordanelle - Midway 138 kilovolt (kV) transmission line project and Reroute of the Jim Bridger - Goshen 345kV transmission line, have been deferred and will not go into service until 2021, reducing PacifiCorp's requested total company rate base by approximately $16.5 million and $1.96 million, respectively. Finally, two items in the pro forma transmission plant were misclassified as transmission and were system allocated. One of the projects should have been situs assigned to Utah. The second should have been situs assigned to Oregon. The changes associated with these projects would decrease rate base from the system allocation of approximately $1.7 million, combined, to a 100 percent situs allocation of $768,748 to Oregon. PacifiCorp estimates the impact of these changes to be a reduction to Oregon revenue requirement of approximately $500,000.

Q. Does the Company have an update to the TCJA deferral balances and amortization schedule?

A. Yes. The Company has updated the interest calculation on the 2020 current tax deferral and updated the EDIT balance for final amortization amounts through 2020. These changes increased the combined TCJA balances by $2.3 million and the annual credit by $1.2 million. The Company is still proposing to use the TCJA balances to offset the unrecovered plant and closure costs associated with the early retirement of Cholla Unit 4, by first applying the remaining EDIT balance and then using a portion of the current tax deferral. The remaining TCJA balance, estimated to be $13.3 million, will be returned to customers over two years beginning January 1, 2021, resulting in a $6.9 million annual credit. Please refer to Exhibit PAC/4406 for the updated amortization schedule reflecting these changes.

IV. PROPOSED ADJUSTMENTS THE COMMISSION SHOULD REJECT

A. Advanced Metering Infrastructure (AMI)

Q. Have Parties made recommendations related to the Company's AMI rollout?

A. Yes. Both Staff witness Mr. John L. Fox and AWEC witness Dr. Lance D. Kaufman make recommendations related to the Company's AMI implementation. I will address each separately.

Q. Please describe Mr. Fox's recommendation.

A. In his opening testimony Mr. Fox proposed a $13.0 million reduction to the Company's operations and maintenance (O&M) expenses based on the total estimated financial benefits of the Oregon AMI implementation as provided in response to Staff Data Request 389. The $13.0 million is comprised of $4.1 million of additional revenue, $7.7 million net O&M savings and $1.2 million in avoided capital.

In my reply testimony, I clarified that the $1.2 million of avoided capital does not need to be removed, as this capital is not included in the Company's revenue requirement in the first place. Additionally, provided in response to Staff Data Request 592 and further detailed in my reply testimony and exhibit,[3] the Company achieved approximately 45 percent of the revenue and O&M benefits in the Base Period for this case. Included in the Company's reply revenue requirement was a decrease of $6.5 million for the remaining estimated revenue and expense benefits of AMI.

In his rebuttal testimony, Mr. Fox questions whether the $1.2 million of avoided capital was removed from the Company's case. He also states that in response to Staff Data Request 592, no detail was provided beyond the statement that approximately 45 percent of the benefits were achieved in the Base Period for this case. Based on the Company's responses to Staff Data Requests 389 and 592, Mr. Fox believes there is a level of uncertainty regarding the level of savings included in the Base Period. As a result, he recommends a reduction to O&M equal to two-

[3] PAC/3102, McCoy/74.

thirds of the total estimated benefits, or that $8.7 million be removed from revenue requirement rather than the Company's calculated $6.5 million reduction.

Q. How do you respond?

A. First, I will address Mr. Fox's concerns related to the $1.2 million of avoided capital as a result of the AMI implementation. When forecasting plant balances for this rate case, the Company started with actual plant balances as of June 30, 2019, and added in capital additions projected to be in service by December 31, 2020. As the Oregon AMI project began in 2017 and was nearing completion during the preparation of this case, the identified avoided capital was not included in Base Period balances or the pro forma capital additions. Therefore, there is nothing to remove in order to reflect the benefits of the capital savings as that capital is not included in the case in the first place.

As for the additional revenue and net O&M savings as a result of the Oregon AMI project, I agree with Mr. Fox that the response to Staff Data Request 592 did not provide any details supporting the 45 percent of benefits reflected in the Base Period for this case. However, on page McCoy/74 of my reply exhibit PAC/3102, I provided a breakdown of the projected annual benefits, the amounts reflected in the Base Period and the additional adjustment needed for the Test Period. While not including the additional benefits in the Company's initial filing was an oversight, this issue was corrected in reply and the full financial benefits of AMI are now included in the Company's requested revenue requirement. To include Mr. Fox's adjustment would inflate these benefits beyond the expected levels.

Q. What recommendation does Dr. Kaufman make related to AMI?

A. In his opening testimony and continuing in his rebuttal testimony, Dr. Kaufman proposes an adjustment related to the replaced meters as part of the Oregon AMI rollout. In his proposed adjustment, Dr. Kaufman recommends removing the net book value of the retired meters from rate base and moving them to a regulatory asset for recovery over 10 years with an interest rate equal to the current 10-year Treasury bond yield plus 100 basis points. He also proposes the recalculation of depreciation expense based on his recommended reduction to rate base.

Q. What support does Dr. Kaufman provide for his proposal?

A. Dr. Kaufman relies on ORS 757.355, Costs of property not presently providing utility service excluded from rate base, and the agreed upon treatment of replaced wind equipment in the settlement of the Company's 2019 wind repowering Renewable Adjustment Clause (RAC) filing, docket UE 352.[4] He also states that the Company treats retirement of generation and distribution assets differently even though both are depreciated using group depreciation.

Q. How do you respond to Dr. Kaufman's recommendations related to the retired meters?

A. I disagree with Dr. Kaufman's recommendations. First, the Company accounts for the retirement of all assets that fall under group depreciation, including generation and distribution assets, in the same manner. When an asset is retired through replacement, the gross plant value of the asset is transferred from electric plant in service to its corresponding depreciation reserve. The group depreciation

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[4] *In the matter of PacifiCorp dba Pacific Power, 2019 Renewable Adjustment Clause,* Docket No. 352, Order No. 19-304 (Sept. 16, 2019).

methodology does not require the maintenance of the net book value of individual assets, but rather the group in total. Therefore, when a replaced asset is retired it is assumed to be fully depreciated, but the remaining net book value is inherently included in the depreciation reserve and rate base.

There is a difference, however, when an entire generating facility, or unit, depending on how the depreciation group is defined, is retired early due to complete cessation of operation of that facility or unit. When this occurs, all of the assets in a particular location associated with that facility or unit, and thereby the depreciation group, are retired leaving a net book value for that group on the Company's accounting books. In this situation, as has been proposed with the early retirement of Cholla Unit 4, Oregon's allocation of the unrecovered plant balances, or net book value, is removed from Oregon's rate base, consistent with ORS 757.355.

In the case of distribution assets, because the depreciation reserve is grouped together by state, the equivalent of retiring a generating facility or unit would be the retirement of the entire Oregon distribution system. The Oregon Meter account 370 in question is only a subset of the overall Oregon distribution group; therefore, the group depreciation practice of transferring the gross plant value of the retired meters to the depreciation reserve is appropriate.

Dr. Kaufman emphasizes that 85 percent of assets in Oregon Meter account 370 were replaced.[5] It is not abnormal to upgrade or replace assets over time and in such cases, resulting retirements within a depreciation group would be treated in the manner of the replaced meters for the Oregon AMI rollout. Whether such upgrades

[5] AWEC/500, Kaufman/12:18-19.

or replacements occur within a short time frame or over a long period of time should not result in different treatment.

Dr. Kaufman points to the treatment of replaced wind assets in the Company's wind repowering projects as evidence that the Company accounts for the retirement of generation assets differently than it does distribution assets. However, Dr. Kaufman neglects to point out that the entries to immediately depreciate Oregon's share of the undepreciated balance of replaced wind assets were done in accordance with the stipulation agreed to by Parties and approved by the Commission in docket UE 352. In addition to the accelerated depreciation of the replaced assets, a corresponding amount of EDIT was also amortized to offset these entries. This stipulation was a compromise reached by Parties in the settlement of all issues in the Company's 2019 RAC and Stipulating Parties agreed "…that the return on the undepreciated replaced plant has been effectively offset from customer rates, regardless of whether this treatment is otherwise required under Oregon law."[6]

Dr. Kaufman further implies that similar to the wind repowering projects, the Company's AMI rollout in Oregon was undertaken for economic reasons.[7] However the Company implemented AMI in Oregon in order to upgrade metering technology and provide customer benefits as detailed in Mr. David M. Lucas' direct testimony and in response to Staff Data Request 389. While in the customers' benefit, it was not done for economic reasons and is more akin to an upgrade which, under the group method of depreciation, would result in retirement of the old equipment in the manner done by the Company for the Oregon AMI meters.

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[6] Order No. 19-304, page 6.
[7] AWEC/500, Kaufman/15:14-15.

For the reasons stated above and as articulated in my reply testimony, I believe that the Company has accounted for the replaced meters correctly and the Commission should reject Dr. Kaufman's proposal as contradictory to the group method of depreciation.

Q. If the Commission should agree with Dr. Kaufman's proposal, do you have recommendations or clarifications they should consider?

A. Yes. Should the Commission determine that an estimated amount of net book value should be placed in a regulatory asset for separate recovery, the Company's approved cost of debt in this proceeding is a more accurate interest rate to use for Dr. Kaufman's proposed long-term recovery of 10 years for this balance. The Company's cost of debt is a more accurate measure of its time value of money when looking at such a long-term recovery period.

Additionally, Dr. Kaufman states that the Company should recalculate depreciation expense to reflect the reduced rate base in his recommendation. There is no need to recalculate depreciation expense as depreciation is calculated on the gross plant balances utilizing Commission approved depreciation rates. It is not calculated on net book value as Dr. Kaufman implies in his recommendation.

B. <u>Emissions Control Retrofit Projects</u>

Q. Several Parties in this case make recommendations related to the Company's emissions control retrofit projects. Which of these proposals are you addressing in your testimony?

A. I will be addressing the issues related to depreciation of these assets raised by Staff witness Ms. Sabrinna Soldavini and CUB witness Mr. Bob Jenks. I will also clarify the date at which these balances are included in this rate case as raised by Ms. Soldavini.

Q. Which emissions control retrofit projects are subject to review for inclusion in customer rates as part of this GRC?

A. The following emissions control retrofit projects are subject to review for inclusion in customer rates: the selective catalytic reduction (SCR) systems installed at Jim Bridger Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2, as well as the Hunter Unit 1 low nitrogen oxide (NOx) burners and baghouse projects.

Q. Both Ms. Soldavini and Mr. Jenks believe the Company is depreciating these assets incorrectly. Please explain.

A. Mr. Jenks only addresses the SCRs at Jim Bridger Units 3 and 4, while Ms. Soldavini addresses all of the emissions control retrofit projects; however, they both believe the Company has used an incorrect depreciation rate on these assets, as the rates used do not equate to Oregon's remaining depreciable life for the respective generation plants. They both propose using a depreciation rate that is equivalent to straight-line depreciation from the in-service date of the assets to the end of the Oregon depreciable life for the each generation plant. However, their proposed rates are not the depreciation rates approved by the Commission in the Company's last depreciation study, nor does their approach reflect group depreciation.

Q. Please explain PacifiCorp's method for depreciating its assets as it pertains to the Jim Bridger, Craig and Hayden SCRs and Hunter low NOx burners and baghouse.

A. PacifiCorp utilizes the group depreciation method to depreciate its assets. This is the process of grouping like (similar) assets and applying a composite depreciation rate to each of the assets within a group. Prior to the Company's 2018 Depreciation Study, the assets at a steam plant were treated as one group. In the 2018 Depreciation Study, the steam plants were instead grouped by unit in anticipation of units within a plant having different lives. The environmental controls equipment in question is only a portion of the group of assets at the unit (formerly, the plant) that are defined as a depreciation group.

Composite rates are determined through depreciation studies and for the purposes of these studies, original cost, accumulated depreciation reserve, and net book balances are all maintained at a group level. As assets are continually being added through capital additions, an accumulation of different vintage years occur within a group. Retirement of assets within a group are charged in their entirety to the group's depreciation reserve along with any salvage and cost of removal.

During a depreciation study—which is based on the original cost, accumulated depreciation reserve, and net book balances at a specific point in time—an average cost recovery period (i.e., remaining life, which generally factors in the expected retirement date) is determined for each group of assets and an annual amount of depreciation is calculated on a straight-line basis over that average cost recovery period. The annual amount of depreciation for a group is then divided by the total original cost of that group to derive a composite depreciation rate. The resulting composite depreciation rate is applied to all the assets within the group from that point forward. Due to on-going additions and retirements and the fact that a depreciation study is based on balances at a specific point in time, depreciation studies are performed on a regular basis to update each group's composite depreciation rate to facilitate recovery of the Company's assets over the average remaining life of each group. As the end of an asset's operating life approaches and particularly if it occurs sooner than anticipated, this may result in higher depreciation in the remaining years. While the intent under this approach is for an asset to be fully depreciated by its end of life, it is possible for a residual unrecovered net book value to remain upon retirement due to the timing of additions, depreciation studies, and other factors.

Q. Please explain how regulatory lag affects depreciation recovery. How does this apply to the Jim Bridger, Craig, and Hayden SCRs and Hunter environmental assets?

A. The Company cannot spontaneously change its depreciation rates based on major additions or retirements; it is only allowed to utilize composite depreciation rates that are approved by the Commission through a depreciation study filing. While this inherently leads to regulatory lag, the approach described above to establishing these rates is accepted utility practice. It is only through the depreciation study filings that the Company is able to update its group composite depreciation rates to account for any new additions or retirements that have occurred since the last study.

The latest composite depreciation rates were implemented on January 1, 2014, as approved and ordered by the Commission. Absent additions and retirements since the December 31, 2013 date on which the last depreciation study was based, the approved composite depreciation rates would have fully depreciated the net book balances of the group of assets that the environmental controls equipment in question are a part of over their remaining lives. As the Jim Bridger, Craig and Hayden SCRs and Hunter environmental control assets were placed in service after December 31, 2013, they were assigned the approved composite depreciation rate for their respective depreciation group. These composite depreciation rates remain in effect until the Company's next depreciation study, which, if approved by the Commission, will be implemented on January 1, 2021, at which time new composite depreciation rates will be applied. Only then will the Company be allowed to update its composite depreciation rates to fully factor in additions, retirements and changes to remaining lives since the last depreciation study, including the noted SCRs and environmental control equipment.

Q. As of what date are plant balances and the associated depreciation reserves included in rate base in this rate case?

A. Both the plant balances and associated depreciation reserves are reflected at their projected December 31, 2020 balances. As stated in my direct testimony, the depreciation and amortization reserve balances were walked forward from June 30, 2019, to December 31, 2020, through Adjustment 6.2, Depreciation and Amortization Reserve.[8]

[8] PAC/1300, McCoy/22:12-17.

Q. Ms. Soldavini states in her rebuttal testimony that the net book value of the Hayden and Craig SCRs and the Hunter low NOx burner and baghouse are reflected in rate base at their June 30, 2019, balances. Please explain.

A. In Staff Data Request 750, Ms. Soldavini asked the Company to confirm the net book value it is seeking to recover in rates. In the Company's response, it was stated that PacifiCorp is seeking to recover the remaining net book value of the emission control projects as of December 31, 2020. However, the attachment included with the response inadvertently only provided the June 30, 2019 balances for the projects at these three generation plants. The Company apologizes for this error and sent out a supplemental response to Staff Data Request 750 as soon as it realized the mistake.

Q. For the Jim Bridger SCRs, Staff has proposed a 10 percent management disallowance as a possible adjustment. Can you please comment on this adjustment?

A. Yes. For the reasons stated in the testimony of Messrs. Link, Owen and Ralston, the Company disagrees that any adjustment is warranted. This is especially true given the fact that the Company has already absorbed $13.3 million in Oregon's share of depreciation related to these investments during the time that has passed since their installation. If the Commission decides to impose such an adjustment, however, the amount should be limited to a one-time disallowance of $4.3 million, which is 10 percent of the remaining $43.5 million balance of the Jim Bridger SCR investment as of December 31, 2020.

Q. In summary, how do you respond to the assertions related to depreciation made by Ms. Soldavini and Mr. Jenks?

A. The Company has applied the depreciation rates approved by the Commission to these assets. To do otherwise would go against the Commission order in the last depreciation study. In addition, while incorrect balances were mistakenly provided in response to Staff Data Request 750, the correct plant balances and their associated depreciation reserves are reflected in rate base for this case as of December 31, 2020. Therefore, no adjustment related to depreciation is necessary in the Company's filing.

C. <u>Deer Creek Mine</u>

Q. In his rebuttal testimony, Dr. Kaufman continues AWEC's recommendation that the Company's recovery of Deer Creek mine closure costs be limited to original estimates provided in the Company's application in docket UM 1712. How do you respond?

A. As with AWEC witness Mr. Bradley G. Mullins' opening testimony, Dr. Kaufman continues to focus on one aspect of the closure costs. As I stated in my reply testimony, while the mine closure costs are higher than originally estimated, the final royalty obligations are lower than forecast. In total, all closure costs are within range of the estimate provided in docket UM 1712.

Q. Dr. Kaufman also continues to recommend that abandonment royalties be excluded in this GRC as they have not yet been paid. Does the Company agree?

A. No. I addressed this issue in my reply testimony, explaining that the recovery-based methodology negotiated with the Department of Interior's Office of Natural Resources Revenue requires royalty payments on recoverable costs for coal production, mine closure and final reclamation activities. As the Company's rate cases are decided, recoverable costs will be known and PacifiCorp will be able to negotiate final payment. However, should the Commission determine that the abandonment royalties should not be included in rates at this time, the Company will continue to defer them as approved in docket UM 1712, and requests the ability to seek recovery in a future rate proceeding after they are paid.

Q. Are there any other issues related to the Deer Creek Mine that you would like to address?

A. Yes. In its reply filing, the Company made two updates related to retiree medical benefits and pension costs for the Deer Creek Mine that Staff has not reflected in its rebuttal calculation of revenue requirement.

First, in its initial filing the Company mistakenly included the United Mine Workers of America (UMWA) transfer of retiree medical benefits obligation in both Adjustment 4.2, Wage and Employee Benefits, and Adjustment 8.12, Deer Creek Mine Closure. Upon discovery of this error, the Company removed the UMWA transfer of $2,380,578 from Adjustment 4.2 in its reply filing, thereby removing the double treatment of this item. The impact is a reduction of approximately $447,000 of Oregon-allocated expenses.

Second, in alignment with its proposal in the TAM, Mr. Jenks proposed moving Deer Creek Mine legacy pension costs from the TAM to base rates in his opening testimony of this rate case. The Company appreciates Mr. Jenks raising this issue and agrees with his proposed treatment, which has also been included in settlement in principle of the Company's 2021 TAM. Therefore, the $3 million annual payment resulting from the Company's withdrawal from the 1974 Pension Trust was removed from the 2021 TAM and included in Adjustment 8.12, Deer Creek Mine, in the Company's reply filing. This change increased Oregon revenue requirement by $835,000, with a similar decrease reflected in the TAM.

Neither of these issues were addressed in Staff's rebuttal testimony or reflected in their calculation of revenue requirement. Given that the retiree medical correction reduces Oregon revenue requirement and the inclusion of the $3 million annual pension payment in base rates was agreed to in the TAM, I believe the exclusion of these updates is an oversight on Staff's part and should be properly reflected in the calculation of revenue requirement.

D. <u>Cholla Unit 4 Retirement</u>

Q. The Company has proposed using TCJA balances to offset Oregon's allocation of the Cholla Unit 4 unrecovered plant and closure costs, or approximately $64.5 million. Do any Parties provide rebuttal testimony on this proposal?

A. Yes. Both Staff witness Ms. Rose Anderson and AWEC witness Dr. Kaufman provide testimony on the Company's proposal. Ms. Anderson provided testimony in support of the Company's proposal as it allows for timely recovery while also removing the costs of the retired plant from customer rates. Dr. Kaufman filed testimony opposing this option, which allows Oregon customers to avoid an ongoing charge to pay off balances associated with a retired generation plant.

Q. Did Ms. Anderson make a request related to the Company's proposal?

A. Yes. Ms. Anderson requests the Company confirm that decommissioning costs are included in the closure costs requested to be offset with tax benefits.

Decommissioning costs are included in the closure costs. All costs associated with the retirement of Cholla Unit 4, which the Company is seeking to offset with TCJA balances, were provided in Exhibit PAC/3106. Amounts used to offset decommissioning costs will be recorded in a regulatory liability until actual costs are incurred. This regulatory liability will be reflected as a reduction to Oregon rate base and trued up upon completion of decommissioning work.

Q. What rationale does AWEC witness Dr. Kaufman give for opposing the use of TCJA balances to offset the costs related to the retirement of Cholla Unit 4?

A. Dr. Kaufman states the Company's proposal nets past benefits against future costs and enumerates the following reasons for his position.

- TCJA benefits should be returned to customers as soon as possible and the Cholla Unit 4 balances should continue to be recovered through 2025, matching the costs and benefits of the early retirement.
- The Commission loses the opportunity to review the actual costs for prudency.
- No final true up to actual costs.
- No adjustment for rate of return, giving the Company free use of benefits before incurring the costs.

Q. Do you agree with Dr. Kaufman's concerns?

A. No, I believe Dr. Kaufman's concerns are unfounded.

First, as explained by Ms. Etta Lockey, using TCJA balances to offset Cholla Unit 4 unrecovered balances and closure costs provides short- and long-term benefits to customers. Additionally, this proposal is very similar to the approach agreed to in the Company's 2019 RAC where Parties agreed to use TCJA balances to offset the immediate depreciation of replaced wind equipment.

Second, as to matching the costs and benefits of early retirement, the benefits are immediate. This rate case filing and the Company's simultaneous 2021 TAM filing remove all costs associated with Cholla Unit 4. Customers immediately benefit from lower rate base, net power costs, O&M and depreciation. Use of TCJA balances allows customer rates to reflect the full benefit of the retirement immediately, without an additional on-going cost.

Third, Dr. Kaufman is incorrect in stating that there will be no true up to actual costs and that the Commission loses the opportunity to review these costs for prudency. As with the retirement of the Carbon Plant, the Company will true up final decommissioning costs of Cholla Unit 4. Any difference between the Company's estimate and actual costs will be addressed in a future ratemaking proceeding. I point to this current case, which includes the return of Oregon's excess decommissioning reserve for the Carbon Plant as an example. At no point has the Company ever insinuated that the Commission should not have the opportunity to review the actual costs.

Fourth, as stated above, the Company will record a regulatory liability for the portion of TCJA balances used for Oregon's share of estimated decommissioning costs. This balance reduces rate base and provides a benefit to Oregon customers in the calculation of the Company's return on rate base.

Q. What proposal does Dr. Kaufman make for the liquidated damages that will be incurred as a result of the retirement of Cholla Unit 4?

A. Dr. Kaufman has adopted the testimony of Mr. Mullins and proposes that liquidated damages either be deferred or included in a power cost adjustment mechanism, as they are a future cost.

Q. Do you agree with Dr. Kaufman's assessment that liquidated damages are a future cost?

A. No. Per the terms of the coal supply agreement (CSA), liquidated damages will be incurred when Cholla Unit 4 is retired, as the Company will no longer be taking coal deliveries. The terms of the CSA define the conditions under which liquidated damages must be paid and the timing of those payments. The liquidated damages associated with the Cholla Unit 4 retirement will be payable in [redacted], well within the Test Period of this rate case, and hardly a future expense.

Q. How do you respond to Dr. Kaufman's proposal to include the liquidated damages in a power cost mechanism?

A. As stated in my reply testimony and further supported in the reply testimony of Mr. Michael G. Wilding, liquidated damages that are incurred while the plant is generating electricity have a direct relationship to power costs and are appropriate to include in a power cost mechanism. However, the liquidated damages in this instance are a direct result of the retirement of the plant and are more appropriately considered a closure cost and should be included in the buy down of the Cholla Unit 4 unrecovered plant and closure costs.

Q. Dr. Kaufman states that decommissioning is a future cost and that these costs should be deferred for future recovery. Are decommissioning costs collected through depreciation rates over the life of a plant?

A. Yes. Decommissioning costs, or negative salvage, are incorporated in approved depreciation rates and collected over the life of a plant. Amounts collected are recorded in the depreciation reserve for the plant and reflected as a reduction to rate base. This way the costs for decommissioning a plant are recovered from the customers who benefit from it. If a plant's depreciable life and operating life are equal, it is anticipated that a sufficient balance will have accumulated to cover the costs of decommissioning the retired plant.

Q. Have decommissioning costs been included in the depreciation rate for Cholla Unit 4?

A. Yes. It is estimated that approximately one-third of Oregon's allocation of Cholla Unit 4's decommissioning costs will have been collected by the time the plant is retired. The amounts collected are included in the accumulated depreciation balance shown in Exhibit PAC/3106.[9] However, since Cholla Unit 4 is retiring early these costs have not been fully collected from customers.

Q. How do you respond to Dr. Kaufman's proposal to defer decommissioning costs for later recovery?

A. As I described above, decommissioning costs are recovered through the Company's approved depreciation rates. This is by design so that the customers who benefit from a generation plant also pay the costs for that plant, including the decommissioning at

[9] It should be noted that the accumulated depreciation balance shown in Exhibit PAC/3106 is based on Oregon's approved depreciation rates for Cholla Unit 4 and is not applicable for evaluating the balance for any other state in the Company's jurisdiction.

the end of its operational life. Dr. Kaufman's proposal is an intergenerational issue. If the Company were to defer these costs and seek recovery at some point after decommissioning is complete, then customers who did not receive the benefits of Cholla Unit 4 will be paying for its decommissioning.

Q. In his testimony, Dr. Kaufman argues that Cholla Unit 4 property tax should be excluded from the Company's rates. Do you agree?

A. No. Dr. Kaufman argues that the Company should not be allowed to recover 2021 Cholla related property tax expense because that tax is associated with property that is no longer used or useful. This argument reflects an inadequate understanding of Arizona property tax assessment timelines. The amount of Cholla related property tax to be expensed in 2021 is based on the value of taxable property on January 1, 2020, a date when Cholla Unit 4 was still operating, and used and useful.

The Company should not be prevented from obtaining a recovery of property tax lawfully imposed on its Arizona operating property merely because Arizona has by law adopted an assessment timeline that results in the expensing and payment of tax in the year following the year of valuation.

Moreover, property taxes are a system-allocated cost and thus the amount of tax allocated to Oregon and included within the revenue requirement changes when system-wide property taxes change. The proposal to depart from this long used procedure by focusing on a single generation plant should be denied as it fails to consider the impact of other factors that are likely to lead to an overall increase in property tax expense.

Q. Dr. Kaufman has also adopted Mr. Mullins' position that EDIT will be "freed up" with the closure of Cholla Unit 4. In his rebuttal testimony, Dr. Kaufman states that PacifiCorp agrees.[10] Is this an accurate statement?

A. No. As provided in my reply testimony, under Internal Revenue Service normalization requirements, the protected EDIT associated with Cholla Unit 4 must amortize over the same time period as the regulatory life of the associated plant. The Company's proposal to offset the Cholla Unit 4 unrecovered plant and closure costs with a portion of the TCJA balances results in the associated EDIT balance being amortized as of December 31, 2020, along with the plant.

Q. Are there any other clarifications that need to be made related to the Cholla Unit 4 EDIT balance?

A. Yes. In the Company's reply filing, the Cholla Unit 4 EDIT balance was removed from the GRC revenue requirement and included in the TCJA balances to be returned to customers. The Cholla Unit 4 EDIT is currently included in the EDIT balance shown in Exhibit PAC/4406 based on the proposal to offset the Cholla Unit 4 balances with TCJA balances. This change has not been incorporated into Staff's revenue requirement calculation. As a result, they have it included in both the rate case revenue requirement and the TCJA amortization amount, essentially doubling up the benefit.

In the event the Commission does not approve the Company's proposed treatment, approximately $3.9 million will need to be removed from the TCJA amortization schedule and amortized over the approved recovery period for Cholla Unit 4.

[10] AWEC/500, Kaufman/20:3

E. TCJA Balances

Q. In his opening testimony Mr. Fox stated that the Company had calculated the gross up on the TCJA EDIT balances incorrectly and a greater benefit should be returned to customers. Has his position changed in his rebuttal testimony?

A. Yes. As Mr. Fox states in his testimony, Staff and the Company held an informal discussion on this topic on July 14, 2020. The Company appreciates the opportunity to talk through this issue with Mr. Fox and found the conversation productive. Following the meeting, Staff prepared several hypothetical examples and concluded that EDIT used to offset retired asset balances does not need to be adjusted.[11] As a result Staff has changed its position on this portion of EDIT.

Q. Does Mr. Fox still propose an adjustment to the remaining EDIT balances?

A. Yes. As discussed further in his testimony and shown in the table on Fox/25, Staff is including the additional gross up for revenue sensitive items on the remaining EDIT balances.

Q. Is there a clarification that needs to be made which impacts Staff's proposed adjustment to the EDIT balances?

A. Yes. As Mr. Fox shows in the table in his testimony, the TCJA balances are being used to offset the Oregon allocation of Cholla Unit 4 unrecovered plant and closure costs.[12] However, as Mr. Fox concludes earlier in his testimony, when EDIT is being used to offset balances, such as Cholla Unit 4, that would otherwise be collected in rates, the additional gross up is unnecessary. As stated previously, the EDIT associated with Cholla Unit 4 must amortize over the same period as the underlying

[11] Staff/1800, Fox/23:10-14.
[12] Staff/1800, Fox/25:1.

plant, necessitating the use of the EDIT to offset the Cholla Unit 4 balances. Since the EDIT balances are fully applied to offset Cholla Unit 4, no adjustment to the gross up is required.

Q. Is Staff agreeable to the two-year amortization and carrying charge on the remaining TCJA balance?

A. Yes. However as a point of clarification, Mr. Fox describes the carrying charge on the balance as "…the weighted average cost of capital plus 100 basis points…"[13] The Company interprets this to be the Modified Blended Treasury Rate as the applicable interest rate to apply to a deferral balance in amortization.

F. <u>Oregon Corporate Activity Tax (OCAT)</u>

Q. Has the rebuttal testimony of Mr. Fox changed the Company's proposal with respect to including the OCAT in base rates beginning with this GRC?

A. No. As I outlined in my reply testimony, the implementation of the OCAT is still a work-in-progress and much work still lays before both the Department of Revenue and taxpayers. The Company does support the eventual inclusion of the OCAT in base rates, but given the implementation status of the new tax, the Company's proposal remains the same.

The Company proposes the continued use of the balancing account and an automatic adjustment clause as approved in dockets UM 2036 and UE 367/Advice No. 19-015[14] and to revisit the inclusion of the OCAT in base rates in the Company's

[13] Staff/1800, Fox/24:15-16.

[14] *In the Matters of PacifiCorp, dba Pacific Power Application for Deferral of Costs and Revenues Related to the Payment and Collection of Oregon's Corporate Activity Tax (OCAT) and Application for Approval of Advice No. 19-015 – Schedule 104, Oregon Corporate Activity Tax Recovery Adjustment*, Docket Nos. 2035 and 367 (cons.), Order No. 20-028 (Jan. 29, 2020).

next filed GRC. This is the best means of providing a transition of this new tax into rates.

If the Commission decides the Company should include the OCAT in base rates in this case, the Company requests the ability to continue to defer and recover or return any incremental differences, similar to the settlement reached in the recent NW Natural rate case.[15]

Q. Should the Commission approve the inclusion of the OCAT in base rates, what amount does the Company propose?

A. The Company believes the amount estimated for the purposes of docket UM 2036, Application of Deferred Accounting for Oregon Corporate Activity Tax Expense, of $5.2 million is sufficient for the purposes of this GRC.

G. Wages and Incentives

Q. In her opening testimony, Staff witness Ms. Heather Cohen addressed the level of wages and incentives included in the Company's rate case filing. Briefly describe her proposed adjustments.

A. For wages and salaries, Ms. Cohen starts with calendar year 2018 data and then escalates this data to the 2021 Test Period. Non-union wages are escalated using the All Urban Consumer Price Index (CPI) and union wages are escalated using a simple average of contracted increases for the Company's multiple unions. Because the Company's and Staff's calculations are within 10 percent of each other for both union and non-union wages, Ms. Cohen then recommends removing 50 percent of the

[15] *In the matter of NW Natural Gas Company d/b/a NW Natural, Application for a General Rate Revision,* Docket No. UG 388, Comprehensive Stipulation, 7:7-16 (filed July 31, 2020).

difference. For incentives and bonuses, Ms. Cohen removes 100 percent of named executive officers (NEOs) and 50 percent of non-NEOs incentives.

Q. Ms. Cohen's rebuttal testimony continues with these proposed adjustments as well as calls into question the data the Company provided. How do you respond?

A. Ms. Julie Lewis addresses the Company's compensation policies and the reasonableness of wages and incentives, while I will respond to the adjustments themselves.

Q. In her rebuttal testimony, Ms. Cohen reflects that the Company's Base Period of June 2018 to June 2019 seems an odd choice given the Test Period of December 2020 to December 2021. Please describe the Company's Base Period, Test Period and the reason why they were chosen.

A. First, to clarify, the Company's Base Period is the 12 months ending June 2019, or July 2018 to June 2019. As stated in my direct testimony, this Base Period was chosen because it was the most recent total-company data available for inter-jurisdictional allocations to achieve a filing date of February 14, 2020. The Company could have used the 12 months ended December 31, 2018, but that would have utilized data that was six months older than the Company's chosen Base Period, further increasing the gap between Base Period and Test Period as Ms. Cohen has done in her calculations.

The Company's Test Period is the calendar year 2021, or January to December 2021. This Test Period was chosen because it aligns with the Company's concurrently filed 2021 TAM, allowing rates for both the GRC and TAM to go into effect at the same time. While separate dockets, the two are connected and it is key that they are in sync in order to simultaneously incorporate costs and benefits into customer rates.

Q. Ms. Cohen states in her testimony that when she requested Oregon union contracts and increases that the Company failed to provide the requested information. Do you agree?

A. No. In each instance when Ms. Cohen requested Oregon union information, the Company provided the information for all of its unions, including the Oregon-based unions, as labor expenses for all of the Company's unions are allocated to all of its state jurisdictions. I am not sure if Ms. Cohen meant she wanted the Oregon allocation of union increases or if she believes that only the costs of Oregon-based employees are included in Oregon customer rates, but the Company provided all relevant information based on what it believed she was requesting. There was no indication that she took issue with the provided information until the filing of her rebuttal testimony. Had the Company known, a meeting could have been scheduled to discuss and clarify the requested information.

Q. Ms. Cohen also states that Staff is open to an adjustment if the Company can provide an estimate of the Oregon-specific increases. Is the Company able to provide such an estimate?

A. It would be inappropriate to provide the Oregon-specific increases. As stated previously, labor is an allocated expense and Oregon revenue requirement includes an allocation of some portion of labor expenses from across the Company's operations. However, the Company is able to provide the Oregon allocation of union increases.

Between the Base Period and Test Period, all union base wages are expected to increase $16.3 million, or $4.6 million Oregon allocated. Union base pay increases are per the applicable union contracts for each of the PacifiCorp unions.

Q. The Company's reply filing included a correction to wages and incentives, both reducing the expense included in this GRC. Did Ms. Cohen include those updates in her rebuttal testimony and recommended adjustments?

A. No. Her calculations and analysis continue to be based off the Company's original filing. In fact she points to the Company's corrections as further support for the reasonableness of her reductions to the Company's union wages.

H. <u>Insurance Premiums</u>

Q. Please summarize Staff witness Mr. Brian Fjeldheim's adjustment for a property insurance "no claims bonus".

A. Mr. Fjeldheim proposes to include a $550,000 total-company, $150,000 Oregon-allocated, adjustment for a "no claim bonus" for the Test Period.

Q. Does the Company accept this adjustment?

A. No, the Company does not accept this adjustment. As stated in my reply testimony, Mr. Fjeldheim incorrectly assumes that the Company has not included a low claims bonus amount. The Company left the low claims bonus level for the Test Period as what was recorded during the Base Period. The Company has included $587,195 total-company for the low claims bonus in the Test Period.

Q. Please describe where the low claims bonus is included.

A. The low claims bonus amount is included in FERC Account 924 and has the System Overhead (SO) factor. The Total Company Normalized Results SO factor row on the

Report tab in the surrebuttal JAM has $3,117,669 as the amount. That amount is made up of the following items and includes the low claims bonus amount:

Table 2 - FERC Account 924, SO Factor Balance

	Total Company Amount	Oregon Allocated Amount
Test Period Property Insurance Premiums, Adj 4.4	$3,582,579	$ 974,924
Other Property Damage	$118,270	$32,185
Other Property Insurance Premium	$4,015	$1,092
Low Claims Bonus	$(587,195)	$(159,793)
Total FERC Account 924, SO Allocation Factor	$3,117,669	$ 848,408

Q. Mr. Fjeldheim also recommends an adjustment for insurance premiums. Please summarize this adjustment.

A. Mr. Fjeldheim proposes to exclude the adjustment the Company included in its reply filing to update insurance premiums to those expected during the Test Period.

Q. Does the Company agree with this adjustment?

A. No, the Company does not agree with this adjustment.

Q. Has Staff correctly modeled this adjustment in their revenue requirement calculation?

A. No, Staff has removed this amount from the Company's original filing amount. This amount was not included in the original filing. The change in premiums expected for the Test Period was only included in the Company's reply filing.[16]

[16] The update to insurance premiums included in the Company's initial filing was for August 2019 – July 2020, and was the best available information at the time.

Q. Mr. Fjeldheim states that "there was no opportunity to consider the $1.088 million increase in total insurance premiums with the Company or parties."[17] Did Mr. Fjeldheim have the opportunity to ask questions about this update after the Company filed reply testimony?

A. Yes. Mr. Fjeldheim could have issued data requests to the Company if he had questions. Additionally a call could have been scheduled to discuss this update or it could have been raised as an issue and discussed at the bi-weekly GRC calls with parties.

Q. Will the Company experience higher insurance premiums in 2020?

A. Yes.

Q. What are the reasons driving the increase in insurance premiums?

A. Two of the Company's insurers are contributing to the increase in premiums. The increase is due to the Company's loss history with them and the California wildfire exposure. One of the insurers believes they have not funded the California wildfire exposure adequately over the years and is looking for a minimum amount to continue offering it. These policies cover claims in any state, including for wildfires started in California, and are allocated to all states as the policies cover system-allocated assets.

[17] Staff/2600, Fjeldheim/4:7-9.

I. <u>Revenue Sensitive Items</u>

Q. In its reply testimony, the Company updated its Franchise Tax and Oregon Department of Energy (ODOE) fee percentages based on the three most recently completed calendar years (2017 - 2019). Why did the Company make this change?

A. In his opening testimony, Mr. Fjeldheim recommended an adjustment to these fees based on using a three-year average. The Company does not take issue with this approach, but believes the three most recently completed calendar years are more applicable to a 2021 Test Period.

Q. Did Mr. Fjeldheim agree with the Company's update?

A. No. While the Company was calculating a three-year average for these fees as proposed by Mr. Fjeldheim, he interpreted the use of the three most recent calendar years as the Company changing its Base Period.

Q. Did the Company change its Base Period in this rate case?

A. No. The Base Period remains the same, the 12 months ended June 2019. The Company has just used the most recent calendar year data to calculate a three-year average for these fees.

Q. How did Mr. Fjeldheim calculate his proposed three-year averages for these fees?

A. Mr. Fjeldheim used data from calendar years 2016 - 2018, which also does not correspond to the Company's Base Period.

Q. Has the Company made similar calculations, but using data from the 12 months ending June, consistent with the Base Period?

A. Yes. Below are updated three-year averages using the Base Period and the two previous 12 month periods ending June.

Table 3 - Franchise Tax Rate – Three-Year Average

	July 2016 –	July 2017 –	July 2018 –	3-YR
Franchise Tax Expense	30,288,016	30,470,804	30,080,115	
General Business Revenues	1,309,702,642	1,267,779,845	1,262,527,098	
Franchise Tax Rate	2.313%	2.403%	2.383%	**2.366%**

Table 4 - ODOE Fee Rate – Three-Year Average

	July 2016 –	July 2017 –	July 2018 –	3-YR
ODOE Fee Expense	1,494,919	1,734,036	1,723,510	
General Business Revenues	1,309,702,642	1,267,779,845	1,262,527,098	
ODOE Fee Rate	0.114%	0.137%	0.137%	**0.129%**

Q. How do these updated percentages compare to the ones used by the Company in its reply filing?

A. In its reply filing the Company used a Franchise Tax percentage of 2.354 percent compared to the 2.366 percent shown in the above table. The ODOE fee used in reply was 0.130 percent compared to the 0.129 percent above. As the Franchise Tax percentage used in reply is lower and the ODOE fee percentage is essentially unchanged, the Company has not updated these percentages from its reply filing.

Q. Are there other clarifications you would like to make regarding revenue sensitive items?

A. Yes. Ultimately the percentages authorized for the level of the OPUC fee, Franchise Tax, ODOE fee and uncollectible expense should be applied to the combined authorized revenue requirement for the TAM and GRC. It appears that Staff's revenue requirement model is still including adjustments to these expenses based on the Company's originally filed revenue requirement amount, rather than reflecting Staff's revenue requirement calculation.

J. <u>Other O&M Adjustments</u>

Q. Staff witnesses Ms. Cohen, Mr. Paul Rossow and Mr. Russ Beitzel all propose various adjustments to the Company's Test Period O&M expenses. Please describe.

A. Ms. Cohen proposes a $1.4 million adjustment to the Company's Customer Accounting and Customer Service FERC Account balances, excluding FERC 909, included in the Test Period. Her analysis does not appear to take into consideration amounts included in adjustments to bring the Base Period forward to the Test Period. Rather, her recommended adjustment is based on applying the All Urban CPI to the Company's Base Period amounts to arrive at a proposed Test Period amounts.

Mr. Rossow proposes $611,000 in adjustments to several O&M expenses based on his review of books, subscriptions, memberships, dues, licenses, meals and other miscellaneous expenses.

Mr. Beitzel proposes adjustments of $3.6 million to several O&M accounts, utilizing the All Urban CPI to escalate the balances from the Base Period to the Test Period, and reducing the Company's balances to his calculated amounts.

Q. Please address Ms. Cohen's proposed adjustment to Customer Accounts and Customer Service amounts in the Company's Test Period.

A. Ms. Cohen proposes to escalate the Company's Base Period balances to the Test Period utilizing the All Urban CPI. As Ms. Cohen utilizes the All Urban CPI to escalate both wages and salaries and the Customer Accounts and Customer Service balances to calculate her proposed adjustments, she is duplicating her adjustment to wages and salaries included in these two groups of FERC Account balances. Additionally, in her rebuttal testimony she fails to acknowledge that the Company made adjustments in its reply filing that reduced the Test Period balances for Customer Accounts and Customer Service by $2.5 million on an Oregon-allocated basis, making her proposed adjustment unnecessary. Included in the Company's reply adjustments is an update to the IHS Markit escalation factors applied to the Base Period. Ms. Lewis addresses wages and salaries in her testimony.

Q. Mr. Rossow continues to recommend adjustments to memberships, books, subscriptions, dues and licenses. Please discuss these adjustments.

A. In Mr. Rossow's opening testimony, he recommended a $197,678 reduction to memberships, books, subscriptions, dues and licenses. In my reply testimony, I pointed out that Mr. Rossow had duplicated a $182,052 adjustment the Company had already made. In rebuttal, Mr. Rossow updated this adjustment to remove the duplication, but also included some new amounts for disallowance, and is now recommending a reduction of $34,270 for these expenses.

Q. Does the Company agree with Mr. Rossow's adjustments to these expenses?

A. No. In reply, the Company had stated that Mr. Rossow was recommending a complete disallowance of some books, subscriptions, dues and licenses. Upon further review, it was determined that this is not the case. However, the Company continues to find Mr. Rossow's reductions inconsistent and not reflecting the Oregon-allocated amounts in this GRC. For example in the dues section of his review, he proposes no disallowance on some North American Electric Reliability Corporation (NERC) certifications, but then reduces the renewal of these certifications by 25 percent, even though certain NERC certifications are required to comply with mandatory federal reliability standards. Additionally Mr. Rossow's adjustment for these expenses is calculated on total-company amounts. While the Company does not agree with his proposal to reduce these expenses by $15,518, the correct amount on an Oregon-allocated basis is $4,424.

For memberships, Mr. Rossow has updated his recommended disallowance. He has removed his duplication of the Company's adjustment which already reduced Company memberships by 25 percent. However, now he is recommending a complete disallowance for memberships in community organizations, such as chambers of commerce, stating they are discretionary and not necessary in the delivery of electricity. The Company finds membership and participation in these community organizations a valuable tool for communicating and interacting with customers and recommends they be included at 75 percent as presented in the Company's filing. However, if the Commission determines these expenses should be removed, then Mr. Rossow has calculated the amount correctly at $18,753 as he utilized the Company's adjustment worksheet to do so.

Q. Mr. Rossow also made adjustments to meals and miscellaneous O&M expenses. Please discuss these adjustments.

A. Mr. Rossow continues to advocate for a reduction of approximately $590,000 of expenses related to meals and miscellaneous O&M expenses, although it is difficult to determine the exact number as his testimony, workpaper and Staff's revenue requirement workpaper all have different amounts. As stated in his opening testimony, Mr. Rossow continues to recommend a 50 percent reduction of the majority of the meals expenses based on a 2009 Commission order in a Portland General Electric Company (PGE) rate case. I addressed this topic in my reply testimony as the justification provided by PGE for inclusion of these costs is much different than PacifiCorp's Company policies related to these expenses. Additionally, Mr. Rossow continues to propose a 100 percent disallowance for meals purchased at any type of coffee shop, despite the very modest charge for a breakfast or lunch.

As with the books, subscriptions, dues and licenses, Mr. Rossow's calculated reduction is based on total-company expenses and not amounts allocated to Oregon for the purposes of this rate case. Utilizing Mr. Rossow's workpaper, the Company has calculated the Oregon allocation of these expenses as $136,475, should the Commission decide to remove them from the Company's GRC.

Q. Did Mr. Rossow issue any data requests specific to his proposed adjustments, requesting additional information or justification for the expenses?

A. No. While Mr. Rossow did issue some data requests, they centered on clarification around the Company's adjustment for membership expenses, and did not request additional details for the transactions which he felt did not include sufficient information. It was not until Mr. Rossow filed his opening testimony that the Company realized he questioned full inclusion of some transactions in the Base Period data.

Q. You state that the majority of Mr. Rossow's adjustments are calculated on a total-company basis, rather than Oregon allocated. Was Mr. Rossow aware that the transaction data provided in response to Standard Data Request OPUC 57 reflected total-company amounts, rather than Oregon allocated?

A. No. In my reply testimony I stated that Mr. Rossow did not calculate the Oregon allocation correctly. When he continued to include reductions of the same amounts in his rebuttal testimony, I suspected he was not aware the data he was reviewing reflected total-company amounts. His responses to PacifiCorp Data Requests 97 and 98, included as Exhibit PAC/4407, confirmed this to be the case.

Q. In communications with Staff did the Company discuss that the transactional data being requested in supplemental responses to OPUC 57 would be on a total-company basis?

A. Yes. As Mr. Rossow indicated, the amount of data was voluminous, with one set of data provided being approximately 12 million lines. As described in my reply testimony, the Company explained that state allocations are performed on summarized data and not at the transactional level. To calculate the Oregon allocation at this level would be extremely onerous and create numerous large files, as it would require the allocation to be calculated manually. Rather, the Company confirmed that it would provide the Oregon allocation on subsets of data as requested by Staff; however, no such requests were received. I believe there was a misunderstanding of the data provided as indicated in Mr. Rossow's responses to PacifiCorp's data requests. Therefore the Company has provided the Oregon-allocated amounts for Mr. Rossow's recommendations.

Q. Finally, Mr. Beitzel also continues to recommend adjustments to certain O&M accounts. What is the basis for Mr. Beitzel's proposed reductions?

A. Mr. Beitzel is recommending reductions based on data provided in response to Standard Data Request OPUC 58. This data request asked for the non-labor portions of O&M balances for the Test Period, Base Period and the previous two calendar years. As was explained in response to Staff Data Requests 571 - 591 and in my reply testimony, the Test Period data is not prepared at the same level of detail as the actual historical accounting records. The Company made a good faith effort to split the labor and non-labor expenses for the Test Period; however, it is still not a meaningful comparison to historical data.

Q. As the non-labor Test Period balances were not an apples-to-apples comparison of non-labor Base Period balances, did the Company provide alternate analysis in response to Staff Data Requests 571 - 591, in order to explain the changes from the Base Period to Test Period Balances?

A. Yes. In addition to the written response to Staff Data Request 571 that Mr. Beitzel provides as Exhibit Staff/3001, the Company provided an attachment which identified each change made to the requested FERC accounts to go from the Base Period to the Test Period amounts. This attachment, provided as Exhibit PAC/4408, references each adjustment in the Company's filing which impacts the FERC Accounts in question. Therefore, while the Company wasn't able to provide the exact analysis requested by Mr. Beitzel, it did provide an alternative which the Company believes answers the questions as to what changes are assumed to arrive at the Test Period O&M amounts included in this rate case.

Q. Several members of Staff have raised issues related to the data initially provided in response to Staff Data Requests 57 and 58. In her opening testimony Staff witness Marianne Gardner suggested a workshop be held in advance of the Company's next GRC. How do you respond?

A. I agree that a workshop well in advance of the Company's next GRC filing is a good idea. As the data for these two data requests is particularly time consuming to gather and assimilate in a useful manner for Staff, a workshop or meeting held four to six months in advance of the Company's next GRC filing would be useful. It seems from Ms. Gardner's testimony, that PacifiCorp is not the only utility that has not provided what Staff is looking for in response to these two data requests. The Company believes a thorough discussion to reach a mutual understanding of what is being requested in these two data requests will be helpful to all involved.

V. CLARIFICATIONS TO PARTIES' TESTIMONY

Q. In reviewing Staff's testimony and exhibits, are there additional items or issues you believe should be clarified or corrected related to revenue requirement?

A. Yes. The following updates from the Company's reply testimony have either not been incorporated in Staff's revenue requirement or have been reflected incorrectly.

Custody Fees - An update to Adjustment 4.1, Miscellaneous General Expense and Revenues, was included in the Company's reply filing. Staff and the Company agree that the reduction on an Oregon-allocated basis is approximately $60,000, however, Staff has incorrectly included $71,000 in its revenue requirement calculation.

Vegetation Management - The Company included an additional $8.8 million in Adjustment 4.7, Incremental O&M Expense, in its reply filing for increased vegetation management expenses. Staff witness Mr. Mitchell Moore has proposed setting the Test Period level of expense for vegetation management and wildfire mitigation at 80 percent of the total requested amount, with a deferral and recovery mechanism for any spending above that amount. The Company's initial filing included $19.6 million of vegetation management and $4.8 million of wildfire mitigation O&M for a total of $24.4 million. With the incremental vegetation management spending included in reply, this brought the amounts up to $28.4 million of vegetation management and $4.8 million of wildfire mitigation for a total of $33.2 million for these combined expenses. Mr. Moore's proposal would include $26.6 million in base rates, with the opportunity to defer and recover the next $6.6 million if certain conditions are met. When Staff modeled this change in their revenue requirement, they reduced the Company's initial request by $6.6 million, bringing the amount included in the Test Period down to $17.8 million. In order to properly model Mr. Moore's proposal, Staff needs to increase the level of expense in the Company's initial filing by $2.2 million, for a total of $26.6 million.

Carbon Plant Closure - In its reply filing, the Company made a correction to Adjustment 8.10, Carbon Plant Closure, to reflect the offset of Oregon's allocation of obsolete materials and supplies inventory against the excess decommissioning reserve being returned to customers in this GRC. The impact is an increase of approximately

$170,000 in revenue requirement, while still returning the remaining $8.1 million to Oregon customers over five years. As this update is not reflected in Staff's revenue requirement, nor is it addressed in testimony, the Company believes it to be an oversight.

Oregon Depreciation Deferral - The Company included in its reply filing the amortization of the Oregon depreciation deferral that resulted from the 2012 Depreciation Study. The amortization of this regulatory liability was added after the Commission issued Order No. 20-147, again authorizing the balance and making it possible for the Company to return this benefit to customers. This update, which reduces revenue requirement by $2.7 million, also has not been reflected in Staff's calculation.

Energy Vision 2020 Tax Correction - The Company's reply filing included a correction in the calculation of tax depreciation included in Adjustment 8.14, Energy Vision 2020 Capital Addition. This reduction of approximately $200,000 has not been added to Staff's revenue requirement calculation. As it is a benefit to customers, the Company believes it to be an oversight.

Cyber Security Project Removal - While the Company and Staff agree on the removal of this project, Staff has modeled it incorrectly by combining all of the tax items and treating them as expense when they are actually accumulated deferred income tax and Schedule M items. As a result, Staff has included a reduction in revenue requirement of $288,000 when the correct amount is $98,000.

Q. Are there any further issues you would like to clarify?

A. Yes. The testimony of Staff witnesses Ms. Nadine Hanhan, Mr. Yassir Rashid and

Mr. Matt Muldoon call into question how the Company accounts for its transmission costs and the pro forma transmission capital included in this GRC.

Q. How does the Company account for the assets, revenues and expenses related to its transmission system?

A. The Company accounts for its transmission system in accordance with FERC guidance as set forth in the Code of Federal Regulations, Title 18, Part 101 - Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. Assets that are identified as part of the Company's transmission system are recorded in FERC Plant Accounts 350 - 359.1, all part of Transmission Plant. Revenues from the transmission of electricity of others over the Company's transmission system are recorded in FERC Account 456.1, Revenues From Transmission of Electricity of Others. Finally, costs associated with the operations and maintenance of the Company's transmission system are recorded in FERC Accounts 560 - 573, as designated for the transmission function. In particular, the transmission maintenance FERC Accounts 569 - 572 specify that they are to be used for recording the maintenance expenses for plant recorded in the transmission FERC Plant Accounts.

Q. How did the Company forecast and incorporate pro forma capital additions in this rate case filing?

A. As stated in my direct testimony, the Company started with actual Base Period data as of the 12 months ending June 30, 2019. In the case of plant balances the Company starts with balances in its accounting system as of June 30, 2019. The Company then includes capital additions to plant expected to go into service between July 1, 2019, and December 31, 2020. The process of forecasting capital additions includes both specifically identified projects, as well as a level of routine capital, often referred to as "run-rate" capital. However, the largest dollar amounts are for specifically identified projects.

Q. How is "run-rate" capital forecasted?

A. Based on historical experience, the Company forecasts a level of capital associated with unexpected events and smaller maintenance projects that requires capital replacements. Conversely, the Company also includes a historical average of retirements to reflect both the additions and retirements of capital activity.

Q. How are costs in the FERC Accounts you identified above allocated?

A. Attachment B to PacifiCorp's 2020 Protocol identifies the agreed-upon allocation factors by FERC Account for all revenue requirement components. FERC Plant Accounts 350 - 359.1 (Transmission Plant) are allocated using the System Generation (SG) Factor, as are FERC Accounts 560 - 573 (Transmission O&M). FERC Account 456.1 (Revenues From Transmission of Electricity of Others) is also system-allocated, but the particular allocation factor depends on the source of the revenue (i.e. credit from revenues from non-firm wheeling under the OATT is allocated using the System Energy Factor, while credits from revenues from firm wheeling under the OATT or legacy transmission service agreements are allocated using the SG Factor).

VI. CONCLUSION

Q. What is your recommendation in this GRC filing?

A. I recommend the Commission approve a revenue requirement increase of $47.5 million and a return of the remaining TCJA benefits over two years for an annual credit of $6.9 million as proposed in this surrebuttal filing. Coupled with the $49.8 million decrease in the Company's concurrent TAM filing, these two filings result in a net decrease of $9.2 million for Oregon customers before the rate mitigation adjustment of $0.4 million.[18]

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[18] PAC/3300, Lockey/2

Docket No. UE 374
Exhibit PAC/4401
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Shelley E. McCoy

Revenue Requirement Summary

August 2020

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

		(1)	(2) (3) - (1)	(3) Ref. Page 1.2	(4) TAM	(5) GRC	(6) (3) + (4) + (5)
		NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1	Operating Revenues:						
2	General Business Revenues	341,185,758	967,698,957	1,308,884,715	(49,807,637)	47,451,000	1,306,528,079
3	Interdepartmental		-	-			-
4	Special Sales	66,064,455	-	66,064,455			66,064,455
5	Other Operating Revenues		52,332,890	52,332,890			52,332,890
6	Total Operating Revenues	407,250,213	1,020,031,847	1,427,282,060	(49,807,637)	47,451,000	1,424,925,424
7							
8	Operating Expenses:						
9	Steam Production	147,287,021	88,192,722	235,479,743			235,479,743
10	Nuclear Production		-	-			-
11	Hydro Production		11,417,028	11,417,028			11,417,028
12	Other Power Supply	238,616,648	19,665,622	258,282,269			258,282,269
13	Transmission	36,160,443	19,034,636	55,195,079			55,195,079
14	Distribution		76,239,883	76,239,883			76,239,883
15	Customer Accounting		26,274,504	26,274,504		(7,912)	26,266,591
16	Customer Service & Info		5,012,111	5,012,111			5,012,111
17	Sales		-	-			-
18	Administrative & General		42,687,596	42,687,596			42,687,596
19							
20	Total O&M Expenses	422,064,112	288,524,100	710,588,211	-	(7,912)	710,580,299
21							
22	Depreciation		286,994,006	286,994,006			286,994,006
23	Amortization		35,307,540	35,307,540			35,307,540
24	Taxes Other Than Income		86,350,580	86,350,580		(66,777)	86,283,803
25	Income Taxes - Federal	(51,702,980)	39,518,668	(12,184,312)	(9,984,738)	9,527,285	(12,641,765)
26	Income Taxes - State	(672,551)	8,950,908	8,278,357	(2,261,267)	2,157,666	8,174,756
27	Income Taxes - Def Net		(3,709,610)	(3,709,610)			(3,709,610)
28	Investment Tax Credit Adj.		-	-			-
29	Misc Revenue & Expense		546,879	546,879			546,879
30							
31	Total Operating Expenses:	369,688,581	742,483,071	1,112,171,651	(12,246,005)	11,610,262	1,111,535,909
32							
33	Operating Rev For Return:	37,561,633	277,548,776	315,110,409	(37,561,633)	35,840,738	313,389,515
34							
35	Rate Base:						
36	Electric Plant In Service		8,424,855,332	8,424,855,332			8,424,855,332
37	Plant Held for Future Use		-	-			-
38	Misc Deferred Debits		64,511,962	64,511,962			64,511,962
39	Elec Plant Acq Adj		1,749,820	1,749,820			1,749,820
40	Pension		-	-			-
41	Prepayments		8,804,564	8,804,564			8,804,564
42	Fuel Stock		42,986,611	42,986,611			42,986,611
43	Material & Supplies		73,657,782	73,657,782			73,657,782
44	Working Capital		(344,615)	(344,615)			(344,615)
45	Weatherization Loans		(1,363)	(1,363)			(1,363)
46	Misc Rate Base		-	-			-
47							
48	Total Electric Plant:	-	8,616,220,094	8,616,220,094			8,616,220,094
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec		(3,170,623,234)	(3,170,623,234)			(3,170,623,234)
52	Accum Prov For Amort		(190,424,211)	(190,424,211)			(190,424,211)
53	Accum Def Income Tax		(591,156,457)	(591,156,457)			(591,156,457)
54	Unamortized ITC		(46,670)	(46,670)			(46,670)
55	Customer Adv For Const		(13,802,322)	(13,802,322)			(13,802,322)
56	Customer Service Deposits		-	-			-
57	Misc Rate Base Deductions		(450,504,273)	(450,504,273)			(450,504,273)
58							
59	Total Rate Base Deductions	-	(4,416,557,167)	(4,416,557,167)			(4,416,557,167)
60							
61	Total Rate Base:	-	4,199,662,927	4,199,662,927			4,199,662,927
62							
63	Return on Rate Base			7.503%			7.462%
64							
65	Return on Equity			9.877%			9.800%

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

GENERAL RATE CASE RESULTS

		(1)	(2)	(3) (1) + (2)
		Total Adjusted Results	**GRC** Price Change	Total Normalized Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	967,698,957	47,451,000	1,015,149,958
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	52,332,890		52,332,890
6	Total Operating Revenues	1,020,031,847	47,451,000	1,067,482,847
7				
8	Operating Expenses:			
9	Steam Production	88,192,722		88,192,722
10	Nuclear Production	-		-
11	Hydro Production	11,417,028		11,417,028
12	Other Power Supply	19,665,622		19,665,622
13	Transmission	19,034,636		19,034,636
14	Distribution	76,239,883		76,239,883
15	Customer Accounting	26,274,504	(7,912)	26,266,591
16	Customer Service & Info	5,012,111		5,012,111
17	Sales	-		-
18	Administrative & General	42,687,596		42,687,596
19				
20	Total O&M Expenses	288,524,100	(7,912)	288,516,187
21				
22	Depreciation	286,994,006		286,994,006
23	Amortization	35,307,540		35,307,540
24	Taxes Other Than Income	86,350,580	(66,777)	86,283,803
25	Income Taxes - Federal	39,518,668	9,527,285	49,045,953
26	Income Taxes - State	8,950,908	2,157,666	11,108,574
27	Income Taxes - Def Net	(3,709,610)		(3,709,610)
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	546,879		546,879
30				
31	Total Operating Expenses:	742,483,071	11,610,262	754,093,333
32				
33	Operating Rev For Return:	277,548,776	35,840,738	313,389,515
34				
35	Rate Base:			
36	Electric Plant In Service	8,424,855,332		8,424,855,332
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	64,511,962		64,511,962
39	Elec Plant Acq Adj	1,749,820		1,749,820
40	Pension	-		-
41	Prepayments	8,804,564		8,804,564
42	Fuel Stock	42,986,611		42,986,611
43	Material & Supplies	73,657,782		73,657,782
44	Working Capital	(344,615)		(344,615)
45	Weatherization Loans	(1,363)		(1,363)
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	8,616,220,094		8,616,220,094
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,170,623,234)		(3,170,623,234)
52	Accum Prov For Amort	(190,424,211)		(190,424,211)
53	Accum Def Income Tax	(591,156,457)		(591,156,457)
54	Unamortized ITC	(46,670)		(46,670)
55	Customer Adv For Const	(13,802,322)		(13,802,322)
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	(450,504,273)		(450,504,273)
58				
59	Total Rate Base Deductions	(4,416,557,167)		(4,416,557,167)
60				
61	Total Rate Base:	4,199,662,927		4,199,662,927
62				
63	Return on Rate Base	6.609%		7.462%
64				
65	Return on Equity	8.205%		9.800%
66				

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

TRANSITION ADJUSTMENT MECHANISM RESULTS

		(1)	(2)	(3) (1) + (2)
		Total Adjusted Results	**TAM** Price Change	Total Normalized Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	341,185,758	(49,807,637)	291,378,121
3	Interdepartmental	-		-
4	Special Sales	66,064,455		66,064,455
5	Other Operating Revenues	-		-
6	Total Operating Revenues	407,250,213	(49,807,637)	357,442,576
7				
8	Operating Expenses:			
9	Steam Production	147,287,021		147,287,021
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	238,616,648		238,616,648
13	Transmission	36,160,443		36,160,443
14	Distribution	-		-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-		-
17	Sales	-		-
18	Administrative & General	-		-
19				
20	Total O&M Expenses	422,064,112	-	422,064,112
21				
22	Depreciation	-		-
23	Amortization	-		-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(51,702,980)	(9,984,738)	(61,687,718)
26	Income Taxes - State	(672,551)	(2,261,267)	(2,933,818)
27	Income Taxes - Def Net	-		-
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	-		-
30				
31	Total Operating Expenses:	369,688,581	(12,246,005)	357,442,576
32				
33	Operating Rev For Return:	37,561,633	(37,561,633)	-
34				
35	Rate Base:			
36	Electric Plant In Service	-		-
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	-		-
39	Elec Plant Acq Adj	-		-
40	Pension	-		-
41	Prepayments	-		-
42	Fuel Stock	-		-
43	Material & Supplies	-		-
44	Working Capital	-		-
45	Weatherization Loans	-		-
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	-		-
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-		-
52	Accum Prov For Amort	-		-
53	Accum Def Income Tax	-		-
54	Unamortized ITC	-		-
55	Customer Adv For Const	-		-
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	-		-
58				
59	Total Rate Base Deductions	-		-
60				
61	Total Rate Base:	-		-
62				
63	Return on Rate Base	N/A		N/A
64				
65	Return on Equity	N/A		N/A
66				

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,308,884,715	(2,356,637)	1,306,528,079
3	Interdepartmental	-		
4	Special Sales	66,064,455		
5	Other Operating Revenues	52,332,890		
6	Total Operating Revenues	1,427,282,060		
7				
8	Operating Expenses:			
9	Steam Production	235,479,743		
10	Nuclear Production	-		
11	Hydro Production	11,417,028		
12	Other Power Supply	258,282,269		
13	Transmission	55,195,079		
14	Distribution	76,239,883		
15	Customer Accounting	26,274,504	(7,912)	26,266,591
16	Customer Service & Info	5,012,111		
17	Sales	-		
18	Administrative & General	42,687,596		
19				
20	Total O&M Expenses	710,588,211		
21				
22	Depreciation	286,994,006		
23	Amortization	35,307,540		
24	Taxes Other Than Income	86,350,580	(66,777)	86,283,803
25	Income Taxes - Federal	(12,184,312)	(457,453)	(12,641,765)
26	Income Taxes - State	8,278,357	(103,600)	8,174,756
27	Income Taxes - Def Net	(3,709,610)		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	546,879		
30				
31	Total Operating Expenses:	1,112,171,651	(635,743)	1,111,535,909
32				
33	Operating Rev For Return:	315,110,409	(1,720,894)	313,389,515
34				
35	Rate Base:			
36	Electric Plant In Service	8,424,855,332		
37	Plant Held for Future Use	-		
38	Misc Deferred Debits	64,511,962		
39	Elec Plant Acq Adj	1,749,820		
40	Pensions	-		
41	Prepayments	8,804,564		
42	Fuel Stock	42,986,611		
43	Material & Supplies	73,657,782		
44	Working Capital	(344,615)		
45	Weatherization Loans	(1,363)		
46	Misc Rate Base	-		
47				
48	Total Electric Plant:	8,616,220,094	-	8,616,220,094
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,170,623,234)		
52	Accum Prov For Amort	(190,424,211)		
53	Accum Def Income Tax	(591,156,457)		
54	Unamortized ITC	(46,670)		
55	Customer Adv For Const	(13,802,322)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(450,504,273)		
58				
59	Total Rate Base Deductions	(4,416,557,167)	-	(4,416,557,167)
60				
61	Total Rate Base:	4,199,662,927	-	4,199,662,927
62				
63	Return on Rate Base	7.503%		7.462%
64				
65	Return on Equity	9.877%		9.800%
66				
67	TAX CALCULATION:			
68	Operating Revenue	307,494,843	(2,281,948)	305,212,896
69	Other Deductions			
70	Interest (AFUDC)	(18,882,996)	-	(18,882,996)
71	Interest	93,345,987	-	93,345,987
72	Schedule "M" Additions	378,241,136	-	378,241,136
73	Schedule "M" Deductions	428,930,329	-	428,930,329
74	Income Before Tax	182,342,659	(2,281,948)	180,060,711
75				
76	State Income Taxes	8,278,357	(103,600)	8,174,756
77	Taxable Income	174,064,302	(2,178,347)	171,885,955
78				
79	Federal Income Taxes + Other	(12,184,312)	(457,453)	(12,641,765)

Ref Page 2.1_SR, PAC/4402

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2021

	Exhibit PAC/4402		Exhibit PAC/4402			
			Tab 3	Tab 4	Tab 5	Tab 6
	TOTAL COMPANY UNADJUSTED RESULTS JUNE 2019	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2019	Revenue Adjustments	O&M Adjustments	Net Power Cost Adjustments	Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	4,738,801,365	1,262,527,098	44,630,291	1,727,327	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	243,934,081	59,812,893	-	-	6,251,562	-
5 Other Operating Revenues	177,063,148	45,048,066	1,703,647	950,885	-	-
6 Total Operating Revenues	5,159,798,594	1,367,388,056	46,333,938	2,678,212	6,251,562	-
7						
8 Operating Expenses:						
9 Steam Production	1,099,966,583	280,291,135	-	2,272,398	(44,408,808)	3,907,082
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	42,311,811	11,010,647	-	339,465	-	66,916
12 Other Power Supply	1,013,398,680	270,418,727	-	2,444,260	(18,667,337)	44,443
13 Transmission	212,793,850	55,389,954	-	977,903	(632,511)	35,286
14 Distribution	200,837,597	60,116,309	-	15,961,993	-	161,580
15 Customer Accounting	82,050,225	27,728,842	-	(1,516,429)	-	62,091
16 Customer Service & Info	99,292,578	5,678,204	-	(678,210)	-	12,117
17 Sales	-	-	-	-	-	-
18 Administrative & General	144,701,044	42,339,376	-	2,751,270	-	53,742
19						
20 Total O&M Expenses	2,895,352,368	752,973,193	-	22,552,649	(63,708,655)	4,343,255
21						
22 Depreciation	724,543,948	202,457,099	-	-	-	60,346,749
23 Amortization	53,602,343	14,431,102	-	-	45,829	25,119,185
24 Taxes Other Than Income	199,541,666	76,535,904	-	1,108,422	-	-
25 Income Taxes - Federal	207,219,463	52,798,852	9,287,901	(4,391,417)	13,952,791	(4,244,452)
26 Income Taxes - State	57,214,214	14,633,912	2,103,452	(994,534)	3,159,921	(961,251)
27 Income Taxes - Def Net	(183,345,084)	(18,174,689)	-	-	74,031	(15,804,465)
28 Investment Tax Credit Adj.	(2,943,987)	-	-	-	-	-
29 Misc Revenue & Expense	(3,327,067)	(372,479)	-	919,358	-	-
30						
31 Total Operating Expenses:	3,947,857,862	1,095,282,894	11,391,353	19,194,478	(46,476,084)	68,799,021
32						
33 Operating Rev For Return:	1,211,940,732	272,105,162	34,942,585	(16,516,265)	52,727,646	(68,799,021)
34						
35 Rate Base:						
36 Electric Plant In Service	28,210,093,332	7,705,344,751	-	-	1,040,905	-
37 Plant Held for Future Use	26,421,395	10,699,976	-	-	-	-
38 Misc Deferred Debits	852,539,521	185,631,435	-	-	-	-
39 Elec Plant Acq Adj	26,756,854	4,238,395	-	-	-	-
40 Pensions	2,485,363	676,340	-	-	-	-
41 Prepayments	46,540,395	8,804,564	-	-	-	-
42 Fuel Stock	184,750,079	46,375,019	-	-	-	-
43 Material & Supplies	249,437,716	75,381,055	-	-	-	-
44 Working Capital	49,571,514	16,224,528	107,671	172,736	(440,425)	(15,502,881)
45 Weatherization Loans	(8,425,958)	(1,363)	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	29,640,170,211	8,053,374,700	107,671	172,736	600,480	(15,502,881)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(10,032,916,685)	(2,903,744,108)	-	-	-	(176,284,105)
52 Accum Prov For Amort	(618,766,978)	(180,641,272)	-	-	-	(9,628,479)
53 Accum Def Income Tax	(4,311,827,079)	(1,121,912,270)	-	-	(81,517)	4,924,812
54 Unamortized ITC	(297,497)	(63,124)	-	-	-	-
55 Customer Adv For Const	(61,656,010)	(16,322,786)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(655,284,072)	(114,403,610)	-	-	-	-
58						
59 Total Rate Base Deductions	(15,680,748,321)	(4,337,087,171)	-	-	(81,517)	(180,987,772)
60						
61 Total Rate Base:	13,737,172,111	3,716,287,528	107,671	172,736	518,964	(196,490,653)
62						
63 Return on Rate Base		7.322%	0.940%	-0.445%	1.417%	-1.439%
64						
65 Return on Equity		9.538%	1.756%	-0.831%	2.648%	-2.688%
66						
67 TAX CALCULATION:						
68 Operating Revenue		321,363,237	46,333,938	(21,902,217)	69,914,389	(89,809,189)
69 Other Deductions		-				
70 Interest (AFUDC)		(13,015,300)	-	-	-	-
71 Interest		82,631,396	2,387	3,829	11,503	(4,355,449)
72 Schedule "M" Additions		306,952,346	-	-	45,829	64,280,812
73 Schedule "M" Deductions		236,366,619	-	-	346,934	-
74 Income Before Tax		322,332,867	46,331,551	(21,906,046)	69,601,781	(21,172,928)
75						
76 State Income Taxes		14,633,912	2,103,452	(994,534)	3,159,921	(961,251)
77 Taxable Income		307,698,955	44,228,099	(20,911,511)	66,441,860	(20,211,677)
78						
79 Federal Income Taxes + Other		52,798,852	9,287,901	(4,391,417)	13,952,791	(4,244,452)
APPROXIMATE PRICE CHANGE		7,142,000	(47,850,349)	22,643,238	(72,153,562)	74,135,764

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2021

		Exhibit PAC/4402				
		Tab 7	Tab 8	REPLY	SURREBUTTAL	OR Allocated
		Tax Adjustments	Rate Base Adjustments	Reply Adjustments	Surebuttal Adjustments - NEW	Results of Operations December 2021
1	Operating Revenues:					
2	General Business Revenues	-	-	-	-	1,308,884,715
3	Interdepartmental	-	-	-	-	-
4	Special Sales	-	-	-	-	66,064,455
5	Other Operating Revenues	-	4,630,292	-	-	52,332,890
6	Total Operating Revenues	-	4,630,292	-	-	1,427,282,060
7						
8	Operating Expenses:					
9	Steam Production	-	(6,582,064)	-	-	235,479,743
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	-	-	-	-	11,417,028
12	Other Power Supply	-	4,042,177	-	-	258,282,269
13	Transmission	-	-	(575,553)	-	55,195,079
14	Distribution	-	-	-	-	76,239,883
15	Customer Accounting	-	-	-	-	26,274,504
16	Customer Service & Info	-	-	-	-	5,012,111
17	Sales	-	-	-	-	-
18	Administrative & General	-	(2,456,792)	-	-	42,687,596
19						
20	Total O&M Expenses	-	(4,996,679)	(575,553)	-	710,588,211
21						
22	Depreciation	-	24,453,462	(151,034)	(112,269)	286,994,006
23	Amortization	-	(4,372,483)	83,908	-	35,307,540
24	Taxes Other Than Income	8,706,254	-	-	-	86,350,580
25	Income Taxes - Federal	(58,202,979)	(21,566,849)	92,694	89,149	(12,184,312)
26	Income Taxes - State	(4,820,031)	(4,884,294)	20,993	20,190	8,278,357
27	Income Taxes - Def Net	9,162,753	21,021,939	59,790	(48,969)	(3,709,610)
28	Investment Tax Credit Adj.	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	546,879
30						
31	Total Operating Expenses:	(45,154,003)	9,655,096	(469,203)	(51,900)	1,112,171,651
32						
33	Operating Rev For Return:	45,154,003	(5,024,804)	469,203	51,900	315,110,409
34						
35	Rate Base:					
36	Electric Plant In Service	-	727,351,260	(2,800,015)	(6,081,570)	8,424,855,332
37	Plant Held for Future Use	-	(10,699,976)	-	-	-
38	Misc Deferred Debits	-	(121,119,473)	-	-	64,511,962
39	Elec Plant Acq Adj	-	(2,488,575)	-	-	1,749,820
40	Pensions	-	(676,340)	-	-	-
41	Prepayments	-	-	-	-	8,804,564
42	Fuel Stock	-	(3,388,408)	-	-	42,986,611
43	Material & Supplies	-	(1,723,272)	-	-	73,657,782
44	Working Capital	(513,402)	(389,510)	(4,366)	1,033	(344,615)
45	Weatherization Loans	-	-	-	-	(1,363)
46	Misc Rate Base	-	-	-	-	-
47						
48	Total Electric Plant:	(513,402)	586,865,706	(2,804,381)	(6,080,536)	8,616,220,094
49						
50	Rate Base Deductions:					
51	Accum Prov For Deprec	-	(90,733,913)	126,132	12,760	(3,170,623,234)
52	Accum Prov For Amort	-	-	(154,459)	-	(190,424,211)
53	Accum Def Income Tax	501,974,114	23,887,309	(4,599)	55,695	(591,156,457)
54	Unamortized ITC	16,454	-	-	-	(46,670)
55	Customer Adv For Const	-	2,520,464	-	-	(13,802,322)
56	Customer Service Deposits	-	-	-	-	-
57	Misc Rate Base Deductions	(346,485,546)	10,384,883	-	-	(450,504,273)
58						
59	Total Rate Base Deductions	155,505,022	(53,941,258)	(32,926)	68,455	(4,416,557,167)
60						
61	Total Rate Base:	154,991,620	532,924,448	(2,837,307)	(6,012,081)	4,199,662,927
62						
63	Return on Rate Base	0.900%	-1.221%	0.016%	0.012%	7.503%
64						
65	Return on Equity	1.681%	-2.280%	0.030%	0.022%	9.877%
66						
67	TAX CALCULATION:					
68	Operating Revenue	(8,706,254)	(10,454,008)	642,679	112,269	307,494,843
69	Other Deductions					
70	Interest (AFUDC)	(5,867,696)	-	-	-	(18,882,996)
71	Interest	3,435,574	11,812,905	(62,892)	(133,265)	93,345,987
72	Schedule "M" Additions	(10,289,835)	17,431,380	(67,127)	(112,269)	378,241,136
73	Schedule "M" Deductions	89,604,124	102,748,040	176,053	(311,441)	428,930,329
74	Income Before Tax	(106,168,091)	(107,583,573)	462,392	444,706	182,342,659
75						
76	State Income Taxes	(4,820,031)	(4,884,294)	20,993	20,190	8,278,357
77	Taxable Income	(101,348,059)	(102,699,279)	441,399	424,517	174,064,302
78						
79	Federal Income Taxes + Other	(58,202,979)	(21,566,849)	92,694	89,149	(12,184,312)
	APPROXIMATE PRICE CHANGE	(45,996,456)	61,340,659	(932,483)	(685,447)	(2,356,637)

Docket No. UE 374
Exhibit PAC/4402
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Shelley E. McCoy

Oregon Results of Operations – December 2021

August 2020

Tab 1 - Results

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

(1)	Test Period 2020 Protocol Revenue Requirement	1,306,528,079	Page 1.1_SR
(2)	Normalized General Business Revenues	1,308,884,715	Page 1.1_SR
(3)	2020 Protocol Price Change	**(2,356,637)**	Page 1.1_SR

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

		(1)	(2)	(3)	(4)	(5)	(6)
			(3) - (1)	Ref. Page 1.2			(3) + (4) + (5)
					TAM	GRC	
		NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1	Operating Revenues:						
2	General Business Revenues	341,185,758	967,698,957	1,308,884,715	(49,807,637)	47,451,000	1,306,528,079
3	Interdepartmental		-	-			-
4	Special Sales	66,064,455	-	66,064,455			66,064,455
5	Other Operating Revenues		52,332,890	52,332,890			52,332,890
6	Total Operating Revenues	407,250,213	1,020,031,847	1,427,282,060	(49,807,637)	47,451,000	1,424,925,424
7							
8	Operating Expenses:						
9	Steam Production	147,287,021	88,192,722	235,479,743			235,479,743
10	Nuclear Production		-	-			-
11	Hydro Production		11,417,028	11,417,028			11,417,028
12	Other Power Supply	238,616,648	19,665,622	258,282,269			258,282,269
13	Transmission	36,160,443	19,034,636	55,195,079			55,195,079
14	Distribution		76,239,883	76,239,883			76,239,883
15	Customer Accounting		26,274,504	26,274,504		(7,912)	26,266,591
16	Customer Service & Info		5,012,111	5,012,111			5,012,111
17	Sales		-	-			-
18	Administrative & General		42,687,596	42,687,596			42,687,596
19							
20	Total O&M Expenses	422,064,112	288,524,100	710,588,211	-	(7,912)	710,580,299
21							
22	Depreciation		286,994,006	286,994,006			286,994,006
23	Amortization		35,307,540	35,307,540			35,307,540
24	Taxes Other Than Income		86,350,580	86,350,580		(66,777)	86,283,803
25	Income Taxes - Federal	(51,702,980)	39,518,668	(12,184,312)	(9,984,738)	9,527,285	(12,641,765)
26	Income Taxes - State	(672,551)	8,950,908	8,278,357	(2,261,267)	2,157,666	8,174,756
27	Income Taxes - Def Net		(3,709,610)	(3,709,610)			(3,709,610)
28	Investment Tax Credit Adj.		-	-			-
29	Misc Revenue & Expense		546,879	546,879			546,879
30							
31	Total Operating Expenses:	369,688,581	742,483,071	1,112,171,651	(12,246,005)	11,610,262	1,111,535,909
32							
33	Operating Rev For Return:	37,561,633	277,548,776	315,110,409	(37,561,633)	35,840,738	313,389,515
34							
35	Rate Base:						
36	Electric Plant In Service		8,424,855,332	8,424,855,332			8,424,855,332
37	Plant Held for Future Use		-	-			-
38	Misc Deferred Debits		64,511,962	64,511,962			64,511,962
39	Elec Plant Acq Adj		1,749,820	1,749,820			1,749,820
40	Pension		-	-			-
41	Prepayments		8,804,564	8,804,564			8,804,564
42	Fuel Stock		42,986,611	42,986,611			42,986,611
43	Material & Supplies		73,657,782	73,657,782			73,657,782
44	Working Capital		(344,615)	(344,615)			(344,615)
45	Weatherization Loans		(1,363)	(1,363)			(1,363)
46	Misc Rate Base		-	-			-
47							
48	Total Electric Plant:	-	8,616,220,094	8,616,220,094			8,616,220,094
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec		(3,170,623,234)	(3,170,623,234)			(3,170,623,234)
52	Accum Prov For Amort		(190,424,211)	(190,424,211)			(190,424,211)
53	Accum Def Income Tax		(591,156,457)	(591,156,457)			(591,156,457)
54	Unamortized ITC		(46,670)	(46,670)			(46,670)
55	Customer Adv For Const		(13,802,322)	(13,802,322)			(13,802,322)
56	Customer Service Deposits		-	-			-
57	Misc Rate Base Deductions		(450,504,273)	(450,504,273)			(450,504,273)
58							
59	Total Rate Base Deductions	-	(4,416,557,167)	(4,416,557,167)			(4,416,557,167)
60							
61	Total Rate Base:	-	4,199,662,927	4,199,662,927			4,199,662,927
62							
63	Return on Rate Base			7.503%			7.462%
64							
65	Return on Equity			9.877%			9.800%

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) GRC Price Change	(3) (1) + (2) Total Normalized Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	967,698,957	47,451,000	1,015,149,958
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	52,332,890		52,332,890
6	Total Operating Revenues	1,020,031,847	47,451,000	1,067,482,847
7				
8	Operating Expenses:			
9	Steam Production	88,192,722		88,192,722
10	Nuclear Production	-		-
11	Hydro Production	11,417,028		11,417,028
12	Other Power Supply	19,665,622		19,665,622
13	Transmission	19,034,636		19,034,636
14	Distribution	76,239,883		76,239,883
15	Customer Accounting	26,274,504	(7,912)	26,266,591
16	Customer Service & Info	5,012,111		5,012,111
17	Sales	-		-
18	Administrative & General	42,687,596		42,687,596
19				
20	Total O&M Expenses	288,524,100	(7,912)	288,516,187
21				
22	Depreciation	286,994,006		286,994,006
23	Amortization	35,307,540		35,307,540
24	Taxes Other Than Income	86,350,580	(66,777)	86,283,803
25	Income Taxes - Federal	39,518,668	9,527,285	49,045,953
26	Income Taxes - State	8,950,908	2,157,666	11,108,574
27	Income Taxes - Def Net	(3,709,610)		(3,709,610)
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	546,879		546,879
30				
31	Total Operating Expenses:	742,483,071	11,610,262	754,093,333
32				
33	Operating Rev For Return:	277,548,776	35,840,738	313,389,515
34				
35	Rate Base:			
36	Electric Plant In Service	8,424,855,332		8,424,855,332
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	64,511,962		64,511,962
39	Elec Plant Acq Adj	1,749,820		1,749,820
40	Pension	-		-
41	Prepayments	8,804,564		8,804,564
42	Fuel Stock	42,986,611		42,986,611
43	Material & Supplies	73,657,782		73,657,782
44	Working Capital	(344,615)		(344,615)
45	Weatherization Loans	(1,363)		(1,363)
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	8,616,220,094		8,616,220,094
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,170,623,234)		(3,170,623,234)
52	Accum Prov For Amort	(190,424,211)		(190,424,211)
53	Accum Def Income Tax	(591,156,457)		(591,156,457)
54	Unamortized ITC	(46,670)		(46,670)
55	Customer Adv For Const	(13,802,322)		(13,802,322)
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	(450,504,273)		(450,504,273)
58				
59	Total Rate Base Deductions	(4,416,557,167)		(4,416,557,167)
60				
61	Total Rate Base:	4,199,662,927		4,199,662,927
62				
63	Return on Rate Base	6.609%		7.462%
64				
65	Return on Equity	8.205%		9.800%
66				

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

TRANSITION ADJUSTMENT MECHANISM RESULTS

		(1)	(2)	(3) (1) + (2)
		Total Adjusted Results	**TAM** Price Change	Total Normalized Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	341,185,758	(49,807,637)	291,378,121
3	Interdepartmental	-		-
4	Special Sales	66,064,455		66,064,455
5	Other Operating Revenues	-		-
6	Total Operating Revenues	407,250,213	(49,807,637)	357,442,576
7				
8	Operating Expenses:			
9	Steam Production	147,287,021		147,287,021
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	238,616,648		238,616,648
13	Transmission	36,160,443		36,160,443
14	Distribution	-		-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-		-
17	Sales	-		-
18	Administrative & General	-		-
19				
20	Total O&M Expenses	422,064,112	-	422,064,112
21				
22	Depreciation	-		-
23	Amortization	-		-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(51,702,980)	(9,984,738)	(61,687,718)
26	Income Taxes - State	(672,551)	(2,261,267)	(2,933,818)
27	Income Taxes - Def Net	-		-
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	-		-
30				
31	Total Operating Expenses:	369,688,581	(12,246,005)	357,442,576
32				
33	Operating Rev For Return:	37,561,633	(37,561,633)	-
34				
35	Rate Base:			
36	Electric Plant In Service	-		-
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	-		-
39	Elec Plant Acq Adj	-		-
40	Pension	-		-
41	Prepayments	-		-
42	Fuel Stock	-		-
43	Material & Supplies	-		-
44	Working Capital	-		-
45	Weatherization Loans	-		-
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	-		-
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-		-
52	Accum Prov For Amort	-		-
53	Accum Def Income Tax	-		-
54	Unamortized ITC	-		-
55	Customer Adv For Const	-		-
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	-		-
58				
59	Total Rate Base Deductions	-		-
60				
61	Total Rate Base:	-		-
62				
63	Return on Rate Base	N/A		N/A
64				
65	Return on Equity	N/A		N/A
66				

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,308,884,715	(2,356,637)	1,306,528,079
3	Interdepartmental	-		
4	Special Sales	66,064,455		
5	Other Operating Revenues	52,332,890		
6	Total Operating Revenues	1,427,282,060		
7				
8	Operating Expenses:			
9	Steam Production	235,479,743		
10	Nuclear Production	-		
11	Hydro Production	11,417,028		
12	Other Power Supply	258,282,269		
13	Transmission	55,195,079		
14	Distribution	76,239,883		
15	Customer Accounting	26,274,504	(7,912)	26,266,591
16	Customer Service & Info	5,012,111		
17	Sales	-		
18	Administrative & General	42,687,596		
19				
20	Total O&M Expenses	710,588,211		
21				
22	Depreciation	286,994,006		
23	Amortization	35,307,540		
24	Taxes Other Than Income	86,350,580	(66,777)	86,283,803
25	Income Taxes - Federal	(12,184,312)	(457,453)	(12,641,765)
26	Income Taxes - State	8,278,357	(103,600)	8,174,756
27	Income Taxes - Def Net	(3,709,610)		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	546,879		
30				
31	Total Operating Expenses:	1,112,171,651	(635,743)	1,111,535,909
32				
33	Operating Rev For Return:	315,110,409	(1,720,894)	313,389,515
34				
35	Rate Base:			
36	Electric Plant In Service	8,424,855,332		
37	Plant Held for Future Use	-		
38	Misc Deferred Debits	64,511,962		
39	Elec Plant Acq Adj	1,749,820		
40	Pensions	-		
41	Prepayments	8,804,564		
42	Fuel Stock	42,986,611		
43	Material & Supplies	73,657,782		
44	Working Capital	(344,615)		
45	Weatherization Loans	(1,363)		
46	Misc Rate Base	-		
47				
48	Total Electric Plant:	8,616,220,094	-	8,616,220,094
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,170,623,234)		
52	Accum Prov For Amort	(190,424,211)		
53	Accum Def Income Tax	(591,156,457)		
54	Unamortized ITC	(46,670)		
55	Customer Adv For Const	(13,802,322)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(450,504,273)		
58				
59	Total Rate Base Deductions	(4,416,557,167)	-	(4,416,557,167)
60				
61	Total Rate Base:	4,199,662,927	-	4,199,662,927
62				
63	Return on Rate Base	7.503%		7.462%
64				
65	Return on Equity	9.877%		9.800%
66				
67	TAX CALCULATION:			
68	Operating Revenue	307,494,843	(2,281,948)	305,212,896
69	Other Deductions			
70	Interest (AFUDC)	(18,882,996)	-	(18,882,996)
71	Interest	93,345,987	-	93,345,987
72	Schedule "M" Additions	378,241,136	-	378,241,136
73	Schedule "M" Deductions	428,930,329	-	428,930,329
74	Income Before Tax	182,342,659	(2,281,948)	180,060,711
75				
76	State Income Taxes	8,278,357	(103,600)	8,174,756
77	Taxable Income	174,064,302	(2,178,347)	171,885,955
78				
79	Federal Income Taxes + Other	(12,184,312)	(457,453)	(12,641,765)

Ref. Page 2.2_SR

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

Net Rate Base	$	4,199,662,927	Ref. Page 1.1_SR
Return on Rate Base Requested		7.46%	Ref. Page 2.1_SR
Revenues Required to Earn Requested Return		313,389,515	
Less Current Operating Revenues		(315,110,409)	
Increase to Current Revenues		(1,720,894)	
Net to Gross Bump-up		136.94%	
Price Change Required for Requested Return	$	(2,356,637)	
Requested Price Change	$	(2,356,637)	
Uncollectible Percent		0.336%	Ref. Page 1.6_SR
Increased Uncollectible Expense	$	(7,912)	
Requested Price Change	$	(2,356,637)	
Franchise Tax		2.354%	Ref. Page 1.6_SR
Revenue Tax		0.000%	Ref. Page 1.6_SR
Resource Supplier Tax		0.130%	Ref. Page 1.6_SR
PUC Fees Based on General Business Revenues		0.350%	Ref. Page 1.6_SR
Increase Taxes Other Than Income	$	(66,777)	
Requested Price Change	$	(2,356,637)	
Uncollectible Expense		7,912	
Taxes Other Than Income		66,777	
Income Before Taxes	$	(2,281,948)	
State Effective Tax Rate		4.54%	Ref. Page 2.1_SR
State Income Taxes	$	(103,600)	
Taxable Income	$	(2,178,347)	
Federal Income Tax Rate		21.00%	Ref. Page 2.1_SR
Federal Income Taxes	$	(457,453)	
Operating Income		100.000%	
Net Operating Income		73.023%	Ref. Page 1.6_SR
Net to Gross Bump-Up		136.94%	

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.336%	See Note (1) Below
Taxes Other - Franchise Tax	2.354%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.130%	
PUC Fees Based on General Business Revenues	0.350%	
Sub-Total	96.831%	
State Income Tax @ 4.54%	4.396%	
Sub-Total	92.435%	
Federal Income Tax @ 21.00%	19.411%	
Net Operating Income	73.023%	

(1) Uncollectible Accounts =	4,394,621	Pg 2.11_SR, OREGON Situs from Account 904
	1,308,884,715	Pg. 2.2_SR, General Business Revenues

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2021

	TOTAL COMPANY UNADJUSTED RESULTS JUNE 2019	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2019	Tab 3 Revenue Adjustments	Tab 4 O&M Adjustments	Tab 5 Net Power Cost Adjustments	Tab 6 Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	4,738,801,365	1,262,527,098	44,630,291	1,727,327	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	243,934,081	59,812,893	-	-	6,251,562	-
5 Other Operating Revenues	177,063,148	45,048,066	1,703,647	950,885	-	-
6 Total Operating Revenues	5,159,798,594	1,367,388,056	46,333,938	2,678,212	6,251,562	-
7						
8 Operating Expenses:						
9 Steam Production	1,099,966,583	280,291,135	-	2,272,398	(44,408,808)	3,907,082
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	42,311,811	11,010,647	-	339,465	-	66,916
12 Other Power Supply	1,013,398,680	270,418,727	-	2,444,260	(18,667,337)	44,443
13 Transmission	212,793,850	55,389,954	-	977,903	(632,511)	35,286
14 Distribution	200,837,597	60,116,309	-	15,961,993	-	161,580
15 Customer Accounting	82,050,225	27,728,842	-	(1,516,429)	-	62,091
16 Customer Service & Info	99,292,578	5,678,204	-	(678,210)	-	12,117
17 Sales	-	-	-	-	-	-
18 Administrative & General	144,701,044	42,339,376	-	2,751,270	-	53,742
19						
20 Total O&M Expenses	2,895,352,368	752,973,193	-	22,552,649	(63,708,655)	4,343,255
21						
22 Depreciation	724,543,948	202,457,099	-	-	-	60,346,749
23 Amortization	53,602,343	14,431,102	-	-	45,829	25,119,185
24 Taxes Other Than Income	199,541,666	76,535,904	-	1,108,422	-	-
25 Income Taxes - Federal	207,219,463	52,798,852	9,287,901	(4,391,417)	13,952,791	(4,244,452)
26 Income Taxes - State	57,214,214	14,633,912	2,103,452	(994,534)	3,159,921	(961,251)
27 Income Taxes - Def Net	(183,345,084)	(18,174,689)	-	-	74,031	(15,804,465)
28 Investment Tax Credit Adj.	(2,943,987)	-	-	-	-	-
29 Misc Revenue & Expense	(3,327,067)	(372,479)	-	919,358	-	-
30						
31 Total Operating Expenses:	3,947,857,862	1,095,282,894	11,391,353	19,194,478	(46,476,084)	68,799,021
32						
33 Operating Rev For Return:	1,211,940,732	272,105,162	34,942,585	(16,516,265)	52,727,646	(68,799,021)
34						
35 Rate Base:						
36 Electric Plant In Service	28,210,093,332	7,705,344,751	-	-	1,040,905	-
37 Plant Held for Future Use	26,421,395	10,699,976	-	-	-	-
38 Misc Deferred Debits	852,539,521	185,631,435	-	-	-	-
39 Elec Plant Acq Adj	26,756,854	4,238,395	-	-	-	-
40 Pensions	2,485,363	676,340	-	-	-	-
41 Prepayments	46,540,395	8,804,564	-	-	-	-
42 Fuel Stock	184,750,079	46,375,019	-	-	-	-
43 Material & Supplies	249,437,716	75,381,055	-	-	-	-
44 Working Capital	49,571,514	16,224,528	107,671	172,736	(440,425)	(15,502,881)
45 Weatherization Loans	(8,425,958)	(1,363)	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	29,640,170,211	8,053,374,700	107,671	172,736	600,480	(15,502,881)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(10,032,916,685)	(2,903,744,108)	-	-	-	(176,284,105)
52 Accum Prov For Amort	(618,766,978)	(180,641,272)	-	-	-	(9,628,479)
53 Accum Def Income Tax	(4,311,827,079)	(1,121,912,270)	-	-	(81,517)	4,924,812
54 Unamortized ITC	(297,497)	(63,124)	-	-	-	-
55 Customer Adv For Const	(61,656,010)	(16,322,786)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(655,284,072)	(114,403,610)	-	-	-	-
58						
59 Total Rate Base Deductions	(15,680,748,321)	(4,337,087,171)	-	-	(81,517)	(180,987,772)
60						
61 Total Rate Base:	13,737,172,111	3,716,287,528	107,671	172,736	518,964	(196,490,653)
62						
63 Return on Rate Base		7.322%	0.940%	-0.445%	1.417%	-1.439%
64						
65 Return on Equity		9.538%	1.756%	-0.831%	2.648%	-2.688%
66						
67 TAX CALCULATION:						
68 Operating Revenue		321,363,237	46,333,938	(21,902,217)	69,914,389	(89,809,189)
69 Other Deductions		-				
70 Interest (AFUDC)		(13,015,300)	-	-	-	-
71 Interest		82,631,396	2,387	3,829	11,503	(4,355,449)
72 Schedule "M" Additions		306,952,346	-	-	45,829	64,280,812
73 Schedule "M" Deductions		236,366,619	-	-	346,934	-
74 Income Before Tax		322,332,867	46,331,551	(21,906,046)	69,601,781	(21,172,928)
75						
76 State Income Taxes		14,633,912	2,103,452	(994,534)	3,159,921	(961,251)
77 Taxable Income		307,698,955	44,228,099	(20,911,511)	66,441,860	(20,211,677)
78						
79 Federal Income Taxes + Other		52,798,852	9,287,901	(4,391,417)	13,952,791	(4,244,452)
APPROXIMATE PRICE CHANGE		7,142,000	(47,850,349)	22,643,238	(72,153,562)	74,135,764

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2021

	Tab 7	Tab 8	REPLY	SURREBUTTAL	OR Allocated
	Tax Adjustments	Rate Base Adjustments	Reply Adjustments	Surebuttal Adjustments - NEW	Results of Operations December 2021
1 Operating Revenues:					
2 General Business Revenues	-	-	-	-	1,308,884,715
3 Interdepartmental	-	-	-	-	-
4 Special Sales	-	-	-	-	66,064,455
5 Other Operating Revenues	-	4,630,292	-	-	52,332,890
6 Total Operating Revenues	-	4,630,292	-	-	1,427,282,060
7					
8 Operating Expenses:					
9 Steam Production	-	(6,582,064)	-	-	235,479,743
10 Nuclear Production	-	-	-	-	-
11 Hydro Production	-	-	-	-	11,417,028
12 Other Power Supply	-	4,042,177	-	-	258,282,269
13 Transmission	-	-	(575,553)	-	55,195,079
14 Distribution	-	-	-	-	76,239,883
15 Customer Accounting	-	-	-	-	26,274,504
16 Customer Service & Info	-	-	-	-	5,012,111
17 Sales	-	-	-	-	-
18 Administrative & General	-	(2,456,792)	-	-	42,687,596
19					
20 Total O&M Expenses	-	(4,996,679)	(575,553)	-	710,588,211
21					
22 Depreciation	-	24,453,462	(151,034)	(112,269)	286,994,006
23 Amortization	-	(4,372,483)	83,908	-	35,307,540
24 Taxes Other Than Income	8,706,254	-	-	-	86,350,580
25 Income Taxes - Federal	(58,202,979)	(21,566,849)	92,694	89,149	(12,184,312)
26 Income Taxes - State	(4,820,031)	(4,884,294)	20,993	20,190	8,278,357
27 Income Taxes - Def Net	9,162,753	21,021,939	59,790	(48,969)	(3,709,610)
28 Investment Tax Credit Adj.	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	546,879
30					
31 Total Operating Expenses:	(45,154,003)	9,655,096	(469,203)	(51,900)	1,112,171,651
32					
33 Operating Rev For Return:	45,154,003	(5,024,804)	469,203	51,900	315,110,409
34					
35 Rate Base:					
36 Electric Plant In Service	-	727,351,260	(2,800,015)	(6,081,570)	8,424,855,332
37 Plant Held for Future Use	-	(10,699,976)	-	-	-
38 Misc Deferred Debits	-	(121,119,473)	-	-	64,511,962
39 Elec Plant Acq Adj	-	(2,488,575)	-	-	1,749,820
40 Pensions	-	(676,340)	-	-	-
41 Prepayments	-	-	-	-	8,804,564
42 Fuel Stock	-	(3,388,408)	-	-	42,986,611
43 Material & Supplies	-	(1,723,272)	-	-	73,657,782
44 Working Capital	(513,402)	(389,510)	(4,366)	1,033	(344,615)
45 Weatherization Loans	-	-	-	-	(1,363)
46 Misc Rate Base	-	-	-	-	-
47					
48 Total Electric Plant:	(513,402)	586,865,706	(2,804,381)	(6,080,536)	8,616,220,094
49					
50 Rate Base Deductions:					
51 Accum Prov For Deprec	-	(90,733,913)	126,132	12,760	(3,170,623,234)
52 Accum Prov For Amort	-	-	(154,459)	-	(190,424,211)
53 Accum Def Income Tax	501,974,114	23,887,309	(4,599)	55,695	(591,156,457)
54 Unamortized ITC	16,454	-	-	-	(46,670)
55 Customer Adv For Const	-	2,520,464	-	-	(13,802,322)
56 Customer Service Deposits	-	-	-	-	-
57 Misc Rate Base Deductions	(346,485,546)	10,384,883	-	-	(450,504,273)
58					
59 Total Rate Base Deductions	155,505,022	(53,941,258)	(32,926)	68,455	(4,416,557,167)
60					
61 Total Rate Base:	154,991,620	532,924,448	(2,837,307)	(6,012,081)	4,199,662,927
62					
63 Return on Rate Base	0.900%	-1.221%	0.016%	0.012%	7.503%
64					
65 Return on Equity	1.681%	-2.280%	0.030%	0.022%	9.877%
66					
67 TAX CALCULATION:					
68 Operating Revenue	(8,706,254)	(10,454,008)	642,679	112,269	307,494,843
69 Other Deductions					
70 Interest (AFUDC)	(5,867,696)	-	-	-	(18,882,996)
71 Interest	3,435,574	11,812,905	(62,892)	(133,265)	93,345,987
72 Schedule "M" Additions	(10,289,835)	17,431,380	(67,127)	(112,269)	378,241,136
73 Schedule "M" Deductions	89,604,124	102,748,040	176,053	(311,441)	428,930,329
74 Income Before Tax	(106,168,091)	(107,583,573)	462,392	444,706	182,342,659
75					
76 State Income Taxes	(4,820,031)	(4,884,294)	20,993	20,190	8,278,357
77 Taxable Income	(101,348,059)	(102,699,279)	441,399	424,517	174,064,302
78					
79 Federal Income Taxes + Other	(58,202,979)	(21,566,849)	92,694	89,149	(12,184,312)
APPROXIMATE PRICE CHANGE	(45,996,456)	61,340,659	(932,483)	(685,447)	(2,356,637)

Tab 2 - Report

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	TWELVE MONTHS ENDING DECEMBER 31, 2021
FILE:	OR JAM Dec 2021 GRC_SR
PREPARED BY:	Revenue Requirement Department
DATE:	8/6/2020
TIME:	1:59:18 PM
TYPE OF RATE BASE:	Year End
ALLOCATION METHOD:	**2020 PROTOCOL**
FERC JURISDICTION:	Separate Jurisdiction
8 OR 12 CP:	12 Coincident Peaks
DEMAND %	75% Demand
ENERGY %	25% Energy

TAX INFORMATION

TAX RATE ASSUMPTIONS:	TAX RATE
FEDERAL RATE	21.00%
STATE EFFECTIVE RATE	4.54%
TAX GROSS UP FACTOR	1.369
FEDERAL/STATE COMBINED RATE	24.587%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	46.47%	4.77%	2.22%
PREFERRED	0.01%	6.75%	0.00%
COMMON	53.52%	9.80%	5.24%
	100.00%		7.46%

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see testimony of Ms. Nikki L. Kobliha.
For information and support regarding return on common equity, see testimony of Ms. Ann E. Bulkley.

2020 PROTOCOL
Year End

RESULTS OF OPERATIONS SUMMARY

			JUNE 2019 UNADJUSTED RESULTS		DECEMBER 2021 NORMALIZED RESULTS	
	Description of Account Summary:	**Ref**	**TOTAL**	**OREGON**	**TOTAL**	**OREGON**
1	Operating Revenues					
2	General Business Revenues	2.2	4,738,801,365	1,262,527,098	4,785,158,983	1,308,884,715
3	Interdepartmental	2.2	0	0	0	0
4	Special Sales	2.2	243,934,081	59,812,893	267,957,662	66,064,455
5	Other Operating Revenues	2.3	177,063,148	45,048,066	189,191,114	52,332,890
6	Total Operating Revenues	2.3	5,159,798,594	1,367,388,056	5,242,307,759	1,427,282,060
7						
8	Operating Expenses:					
9	Steam Production	2.5	1,099,966,583	280,291,135	927,530,187	235,479,743
10	Nuclear Production	2.5	0	0	0	0
11	Hydro Production	2.6	42,311,811	11,010,647	43,873,454	11,417,028
12	Other Power Supply	2.7, .8	1,013,398,680	270,418,727	968,833,667	258,282,269
13	Transmission	2.9	212,793,850	55,389,954	212,199,503	55,195,079
14	Distribution	2.10	200,837,597	60,116,309	225,314,308	76,239,883
15	Customer Accounting	2.11	82,050,225	27,728,842	84,086,846	26,274,504
16	Customer Service & Infor	2.12	99,292,578	5,678,204	99,640,113	5,012,111
17	Sales	2.12	0	0	0	0
18	Administrative & General	2.13	144,701,044	42,339,376	148,547,103	42,687,596
19						
20	Total O & M Expenses	2.13	2,895,352,368	752,973,193	2,710,025,181	710,588,211
21						
22	Depreciation	2.14	724,543,948	202,457,099	1,092,104,741	286,994,006
23	Amortization	2.15	53,602,343	14,431,102	146,032,212	35,307,540
24	Taxes Other Than Income	2.15	199,541,666	76,535,904	232,644,663	86,350,580
25	Income Taxes - Federal	2.18	207,219,463	52,798,852	(60,421,131)	(12,184,312)
26	Income Taxes - State	2.18	57,214,214	14,633,912	28,732,455	8,278,357
27	Income Taxes - Def Net	2.16	(183,345,084)	(18,174,689)	(57,076,292)	(3,709,610)
28	Investment Tax Credit Adj.	2.15	(2,943,987)	0	(2,943,987)	0
29	Misc Revenue & Expense	2.3	(3,327,067)	(372,479)	(80,922)	546,879
30						
31	Total Operating Expenses	2.18	3,947,857,862	1,095,282,894	4,089,016,919	1,112,171,651
32						
33	Operating Revenue for Return		1,211,940,732	272,105,162	1,153,290,840	315,110,409
34						
35	Rate Base:					
36	Electric Plant in Service	2.26	28,210,093,332	7,705,344,751	30,959,041,472	8,424,855,332
37	Plant Held for Future Use	2.26	26,421,395	10,699,976	0	0
38	Misc Deferred Debits	2.28	852,539,521	185,631,435	399,114,706	64,511,962
39	Elec Plant Acq Adj	2.26,.27	26,756,854	4,238,395	17,193,735	1,749,820
40	Pensions	2.27	2,485,363	676,340	0	0
41	Prepayments	2.28	46,540,395	8,804,564	46,540,395	8,804,564
42	Fuel Stock	2.27	184,750,079	46,375,019	171,251,246	42,986,611
43	Material & Supplies	2.28	249,437,716	75,381,055	242,815,511	73,657,782
44	Working Capital	2.28	49,571,514	16,224,528	(14,816,485)	(344,615)
45	Weatherization Loans	2.27	(8,425,958)	(1,363)	(8,425,958)	(1,363)
46	Miscellaneous Rate Base	2.29	0	0	0	0
47						
48	Total Electric Plant		29,640,170,211	8,053,374,700	31,812,714,622	8,616,220,094
49						
50	Rate Base Deductions:					
51	Accum Prov For Depr	2.32	(10,032,916,685)	(2,903,744,108)	(11,068,333,557)	(3,170,623,234)
52	Accum Prov For Amort	2.33	(618,766,978)	(180,641,272)	(647,024,287)	(190,424,211)
53	Accum Def Income Taxes	2.30	(4,311,827,079)	(1,121,912,270)	(2,763,679,386)	(591,156,457)
54	Unamortized ITC	2.30	(297,497)	(63,124)	(205,518)	(46,670)
55	Customer Adv for Const	2.29	(61,656,010)	(16,322,786)	(61,656,010)	(13,802,322)
56	Customer Service Deposits	2.29	0	0	0	0
57	Misc. Rate Base Deductions	2.29	(655,284,072)	(114,403,610)	(869,707,771)	(450,504,273)
58						
59	Total Rate Base Deductions		(15,680,748,321)	(4,337,087,171)	(15,410,606,529)	(4,416,557,167)
60						
61	Total Rate Base		13,959,421,890	3,716,287,528	16,402,108,093	4,199,662,927
62						
63	Return on Rate Base		8.682%	7.322%	7.031%	7.503%
64						
65	Return on Equity		12.079%	9.538%	8.995%	9.877%
66	Net Power Costs		1,678,049,950	426,089,987	1,404,232,351	355,999,656
67	100 Basis Points in Equity:		74,710,826	19,889,571	87,784,083	22,476,596
68	Revenue Requirement Impact		99,068,370	26,374,054	116,403,825	29,804,512
69	Rate Base Decrease		(810,569,056)	(253,139,375)	(1,160,158,814)	(279,614,219)

2020 PROTOCOL
Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
70	Sales to Ultimate Customers								
71	440	Residential Sales							
72			0	S		1,808,805,075	629,272,437	1,825,391,907	645,859,269
73									
74					B1	1,808,805,075	629,272,437	1,825,391,907	645,859,269
75									
76	442	Commercial & Industrial Sales							
77			0	S		2,911,591,589	627,285,353	2,943,266,555	658,960,319
78			P	SE		-	-	-	-
79			PT	SG		-	-	-	-
80									
81									
82					B1	2,911,591,589	627,285,353	2,943,266,555	658,960,319
83									
84	444	Public Street & Highway Lighting							
85			0	S		18,404,701	5,969,307	16,500,521	4,065,127
86			0	SO		-	-	-	-
87					B1	18,404,701	5,969,307	16,500,521	4,065,127
88									
89	445	Other Sales to Public Authority							
90			0	S		-	-	-	-
91									
92					B1	-	-	-	-
93									
94	448	Interdepartmental							
95			DPW	S		-	-	-	-
96			GP	SO		-	-	-	-
97					B1	-	-	-	-
98									
99	**Total Sales to Ultimate Customers**				**B1**	**4,738,801,365**	**1,262,527,098**	**4,785,158,983**	**1,308,884,715**
100									
101									
102									
103	447	Sales for Resale-Non NPC							
104			P	S		14,084,596	-	14,084,596	-
105					B1	14,084,596	-	14,084,596	-
106									
107	447NPC	Sales for Resale-NPC							
108			P	SG		229,850,101	59,813,047	253,873,066	66,064,455
109			P	SE		(616)	(155)	-	-
110			P	SG		-	-	-	-
111					B1	229,849,485	59,812,893	253,873,066	66,064,455
112									
113		Total Sales for Resale			B1	243,934,081	59,812,893	267,957,662	66,064,455
114									
115	449	Provision for Rate Refund							
116			P	S		-	-	-	-
117			P	SG		-	-	-	-
118									
119									
120					B1	-	-	-	-
121									
122	**Total Sales from Electricity**				**B1**	**4,982,735,447**	**1,322,339,990**	**5,053,116,645**	**1,374,949,171**
123	450	Forfeited Discounts & Interest							
124			CUST	S		9,589,380	4,242,722	9,589,380	4,242,722
125			CUST	SO		-	-	-	-
126					B1	9,589,380	4,242,722	9,589,380	4,242,722
127									
128	451	Misc Electric Revenue							
129			CUST	S		7,215,463	2,461,735	8,166,349	3,412,620
130			GP	SG		-	-	-	-
131			GP	SO		34,932	9,506	34,932	9,506
132					B1	7,250,396	2,471,241	8,201,281	3,422,126
133									
134	453	Water Sales							
135			P	SG		58,210	15,148	58,210	15,148
136					B1	58,210	15,148	58,210	15,148
137									
138	454	Rent of Electric Property							
139			DPW	S		9,513,442	3,723,611	9,513,442	3,723,611
140			T	SG		5,900,441	1,535,450	5,900,441	1,535,450
141			T	SG		-	-	-	-
142			GP	SO		1,699,946	462,605	1,699,946	462,605
143					B1	17,113,829	5,721,666	17,113,829	5,721,666

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
456	Other Electric Revenue							
		DMSC	S		1,952,244	(4,012,252)	6,582,536	618,040
		CUST	CN		-	-	-	-
		OTHSE	SE		17,028,845	4,274,493	17,028,845	4,274,493
		OTHSO	SO		4,091,872	1,113,517	4,091,872	1,113,517
		OTHSGR	SG		119,978,372	31,221,531	126,525,161	32,925,178
				B1	143,051,333	32,597,290	154,228,414	38,931,228
Total Other Electric Revenues				**B1**	**177,063,148**	**45,048,066**	**189,191,114**	**52,332,890**
Total Electric Operating Revenues				**B1**	**5,159,798,594**	**1,367,388,056**	**5,242,307,759**	**1,427,282,060**
Summary of Revenues by Factor								
	S				4,781,156,490	1,268,942,913	4,833,095,285	1,320,881,708
	CN				-	-	-	-
	SE				17,028,229	4,274,339	17,028,845	4,274,493
	SO				5,826,750	1,585,628	5,826,750	1,585,628
	SG				355,787,125	92,585,176	386,356,879	100,540,231
	DGP				-	-	-	-
Total Electric Operating Revenues					5,159,798,594	1,367,388,056	5,242,307,759	1,427,282,060
Miscellaneous Revenues								
41160	Gain on Sale of Utility Plant - CR							
		DPW	S		-	-	-	-
		T	SG		-	-	-	-
		G	SO		-	-	-	-
		T	SG		-	-	-	-
		P	SG		-	-	-	-
				B1	-	-	-	-
41170	Loss on Sale of Utility Plant							
		DPW	S		-	-	-	-
		T	SG		-	-	-	-
				B1	-	-	-	-
4118	Gain from Emission Allowances							
		P	S		-	-	-	-
		P	SE		(173)	(44)	(173)	(44)
				B1	(173)	(44)	(173)	(44)
41181	Gain from Disposition of NOX Credits							
		P	SE		-	-	-	-
				B1	-	-	-	-
4194	Impact Housing Interest Income							
		P	SG		-	-	-	-
				B1	-	-	-	-
421	(Gain) / Loss on Sale of Utility Plant							
		DPW	S		734,943	731,594	629,490	731,675
		T	SG		26,718	6,953	26,718	6,953
		T	SG		(137,165)	(35,694)	(137,165)	(35,694)
		P	CN		-	-	-	-
		PTD	SO		(3,951,390)	(1,075,288)	5,942	1,617
		P	SG		-	-	(605,734)	(157,628)
				B1	(3,326,894)	(372,436)	(80,749)	546,923
Total Miscellaneous Revenues				**B1**	**(3,327,067)**	**(372,479)**	**(80,922)**	**546,879**
Miscellaneous Expenses								
4311	Interest on Customer Deposits							
		CUST	S		-	-	-	-
					-	-	-	-
Total Miscellaneous Expenses				B1	**-**	**-**	**-**	**-**
Net Misc Revenue and Expense				**B1**	**(3,327,067)**	**(372,479)**	**(80,922)**	**546,879**

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
500	Operation Supervision & Engineering							
		P	SG		15,596,765	4,058,689	15,596,765	4,058,689
		P	SG		2,462,779	640,880	2,462,779	640,880
		P	SG		-	-	5,740,684	1,493,877
				B2	18,059,545	4,699,569	23,800,228	6,193,446
501	Fuel Related-Non NPC							
		P	S		1,746,531	1,881,937	(133,922)	1,484
		P	SE		23,055,537	5,787,283	53,565,531	13,445,745
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SE		2,819,582	707,757	2,819,582	707,757
				B2	27,621,649	8,376,977	56,251,190	14,154,986
501NPC	Fuel Related-NPC							
		P	S		398,108	-	-	-
		P	SE		714,777,401	179,419,763	537,923,023	135,026,683
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SE		44,335,052	11,128,758	44,335,052	11,128,758
				B2	759,510,561	190,548,521	582,258,075	~~146,155,441~~
	Total Fuel Related			B2	787,132,210	198,925,498	638,509,266	160,310,427
502	Steam Expenses							
		P	SG		74,510,141	19,389,500	74,510,141	19,389,500
		P	SG		7,737,962	2,013,621	7,737,962	2,013,621
		P	SG		-	-	(691,988)	(180,073)
				B2	82,248,103	21,403,122	81,556,115	21,223,048
503	Steam From Other Sources-Non-NPC							
		P	SE		-	-	1,224	307
				B2	-	-	1,224	307
503NPC	Steam From Other Sources-NPC							
		P	SE		4,570,678	1,147,308	4,508,022	1,131,580
				B2	4,570,678	1,147,308	4,508,022	1,131,580
505	Electric Expenses							
		P	SG		1,268,962	330,217	1,268,962	330,217
		P	SG		298,020	77,553	298,020	77,553
		P	SG		-	-	(17,148)	(4,462)
				B2	1,566,982	407,770	1,549,834	403,308
506	Misc. Steam Expense							
		P	SG		27,210,000	7,080,758	27,210,000	7,080,758
		P	SG		-	-	(33,074,267)	(8,606,795)
		P	SG		2,037,857	530,304	2,037,857	530,304
				B2	29,247,857	7,611,062	(3,826,410)	(995,732)
507	Rents							
		P	SG		515,835	134,234	515,835	134,234
		P	SG		-	-	(5,654)	(1,471)
		P	SG		-	-	-	-
				B2	515,835	134,234	510,182	132,763
510	Maint Supervision & Engineering							
		P	SG		5,371,531	1,397,814	5,371,531	1,397,814
		P	SG		2,718,835	707,512	2,718,835	707,512
		P	SG		-	-	(1,524,954)	(396,833)
				B2	8,090,366	2,105,326	6,565,412	1,708,493
511	Maintenance of Structures							
		P	SG		23,079,914	6,006,001	23,079,914	6,006,001
		P	SG		3,709,903	965,415	3,709,903	965,415
		P	SG		-	-	99,449	25,879
				B2	26,789,817	6,971,416	26,889,267	6,997,295
512	Maintenance of Boiler Plant							
		P	SG		89,358,403	23,253,409	89,358,403	23,253,409
		P	SG		6,140,690	1,597,969	6,140,690	1,597,969
		P	SG		-	-	5,549,235	1,444,057
				B2	95,499,093	24,851,378	101,048,328	26,295,435
513	Maintenance of Electric Plant							
		P	SG		34,988,575	9,104,948	34,988,575	9,104,948
		P	SG		891,759	232,059	891,759	232,059
		P	SG		-	-	129,288	33,644
				B2	35,880,333	9,337,007	36,009,621	9,370,651

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
514	Maintenance of Misc. Steam Plant							
		P	SG		8,781,068	2,285,065	8,781,068	2,285,065
		P	SG		1,584,696	412,380	1,584,696	412,380
		P	SG		-	-	43,335	11,277
				B2	10,365,764	2,697,445	10,409,099	2,708,722
Total Steam Power Generation				**B2**	**1,099,966,583**	**280,291,135**	**927,530,187**	**235,479,743**
517	Operation Super & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
518	Nuclear Fuel Expense							
		P	SE		-	-	-	-
				B2	-	-	-	-
519	Coolants and Water							
		P	SG		-	-	-	-
				B2	-	-	-	-
520	Steam Expenses							
		P	SG		-	-	-	-
				B2	-	-	-	-
523	Electric Expenses							
		P	SG		-	-	-	-
				B2	-	-	-	-
524	Misc. Nuclear Expenses							
		P	SG		-	-	-	-
				B2	-	-	-	-
528	Maintenance Super & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
529	Maintenance of Structures							
		P	SG		-	-	-	-
				B2	-	-	-	-
530	Maintenance of Reactor Plant							
		P	SG		-	-	-	-
				B2	-	-	-	-
531	Maintenance of Electric Plant							
		P	SG		-	-	-	-
				B2	-	-	-	-
532	Maintenance of Misc Nuclear							
		P	SG		-	-	-	-
				B2	-	-	-	-
Total Nuclear Power Generation				**B2**	**-**	**-**	**-**	**-**
535	Operation Super & Engineering							
		P	SG		-	-	1,273,793	331,475
		P	SG		-	-	688,929	179,277
		P	SG		-	-	(122,585)	(31,900)
		P	SG		7,989,309	2,079,029	7,989,309	2,079,029
		P	SG		823,116	214,196	823,116	214,196
				B2	8,812,425	2,293,225	10,652,562	2,772,077
536	Water For Power							
		P	SG		-	-	(328)	(85)
		P	SG		39,247	10,213	39,247	10,213
		P	SG		-	-	-	-
				B2	39,247	10,213	38,918	10,128
537	Hydraulic Expenses							
		P	SG		-	-	(184,707)	(48,066)
		P	SG		4,073,258	1,059,969	4,073,258	1,059,969
		P	SG		368,745	95,957	368,745	95,957
				B2	4,442,003	1,155,926	4,257,295	1,107,860

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
538	Electric Expenses							
		P	DGP		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B2	-	-	-	-
539	Misc. Hydro Expenses							
		P	SG		-	-	(379,461)	(98,746)
		P	SG		12,329,988	3,208,588	12,329,988	3,208,588
		P	SG		7,222,447	1,879,471	7,222,447	1,879,471
				B2	19,552,436	5,088,058	19,172,974	4,989,313
540	Rents (Hydro Generation)							
		P	SG		-	-	(65,214)	(16,971)
		P	SG		1,260,371	327,982	1,260,371	327,982
		P	SG		53,740	13,985	53,740	13,985
				B2	1,314,111	341,966	1,248,897	324,996
541	Maint Supervision & Engineering							
		P	SG		-	-	0	0
		P	SG		470	122	470	122
		P	SG		-	-	-	-
				B2	470	122	470	122
542	Maintenance of Structures							
		P	SG		-	-	71	18
		P	SG		487,433	126,843	487,433	126,843
		P	SG		26,209	6,820	26,209	6,820
				B2	513,642	133,663	513,713	133,682
543	Maintenance of Dams & Waterways							
		P	SG		-	-	250	65
		P	SG		941,650	245,042	941,650	245,042
		P	SG		629,929	163,924	629,929	163,924
				B2	1,571,579	408,966	1,571,830	409,031
544	Maintenance of Electric Plant							
		P	SG		-	-	183	48
		P	SG		1,701,465	442,766	1,701,465	442,766
		P	SG		292,333	76,073	292,333	76,073
				B2	1,993,798	518,839	1,993,981	518,886
545	Maintenance of Misc. Hydro Plant							
		P	SG		-	-	282,110	73,412
		P	SG		-	-	67,561	17,581
		P	SG		-	-	1,042	271
		P	SG		3,365,693	875,842	3,365,693	875,842
		P	SG		706,408	183,826	706,408	183,826
				B2	4,072,101	1,059,668	4,422,814	1,150,933
Total Hydraulic Power Generation				**B2**	**42,311,811**	**11,010,647**	**43,873,454**	**11,417,028**
546	Operation Super & Engineering							
		P	SG		280,415	72,971	280,415	72,971
		P	SG		-	-	-	-
		P	SG		-	-	(9,784)	(2,546)
				B2	280,415	72,971	270,631	70,425
547	Fuel-Non-NPC							
		P	SE		-	-	-	-
		P	SE		-	-	-	-
				B2	-	-	-	-
547NPC	Fuel-NPC							
		P	SE		268,434,763	67,381,120	304,231,364	76,366,599
		P	SE		1,064,775	267,274	1,064,775	267,274
				B2	269,499,538	67,648,394	305,296,140	76,633,874

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
548	Generation Expense							
		P	SG		17,053,590	4,437,793	17,053,590	4,437,793
		P	SG		717,121	186,614	717,121	186,614
		P	SG		-	-	675,862	175,877
				B2	17,770,711	4,624,407	18,446,573	4,800,284
549	Miscellaneous Other							
		P	S		96,122	96,122	99,036	99,036
		P	SG		3,633,672	945,577	3,633,672	945,577
		P	SG		1,479,164	384,917	1,479,164	384,917
		P	SG		-	-	20,009,069	5,206,887
		P	SG		-	-	-	-
				B2	5,208,958	1,426,617	25,220,942	6,636,417
550	Rents							
		P	S		288,047	288,047	281,031	281,031
		P	SG		-	-	(88,812)	(23,111)
		P	SG		39,499	10,279	39,499	10,279
		P	SG		3,606,840	938,595	3,606,840	938,595
				B2	3,934,386	1,236,920	3,838,558	1,206,793
551	Maint Supervision & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
552	Maintenance of Structures							
		P	SG		2,826,932	735,642	2,826,932	735,642
		P	SG		103,131	26,837	103,131	26,837
		P	SG		-	-	18,824	4,899
				B2	2,930,062	762,479	2,948,886	767,378
553	Maint of Generation & Electric Plant							
		P	SG		4,560,215	1,186,688	4,560,215	1,186,688
		P	SG		9,767,154	2,541,671	9,767,154	2,541,671
		P	SG		368,894	95,996	368,894	95,996
		P	SG		-	-	1,159,851	301,824
				B2	14,696,262	3,824,354	15,856,113	4,126,178
554	Maintenance of Misc. Other							
		P	SG		1,937,065	504,075	1,937,065	504,075
		P	SG		968,293	251,975	968,293	251,975
		P	SG		163,067	42,434	163,067	42,434
		P	SG		-	-	29,563	7,693
				B2	3,068,425	798,485	3,097,988	806,178
Total Other Power Generation				**B2**	**317,388,758**	**80,394,628**	**374,975,830**	**95,047,527**
555	Purchased Power-Non NPC							
		DMSC	S		(69,142,527)	-	(69,142,527)	-
					(69,142,527)	-	(69,142,527)	-
555NPC	Purchased Power-NPC							
		P	S		3,755,804	-	(1,403,107)	(1,403,107)
		P	SE		11,756	2,951	15,044,970	3,776,511
	Seasonal Cont	P	SG		729,221,964	189,762,752	613,348,281	159,609,369
		P	DGP		-	-	-	-
					732,989,524	189,765,703	626,990,144	161,982,774
	Total Purchased Power			B2	663,846,997	189,765,703	557,847,616	161,982,774
556	System Control & Load Dispatch							
		P	SG		909,957	236,795	900,160	234,245
				B2	909,957	236,795	900,160	234,245
557	Other Expenses							
		P	S		5,529,036	1,682,582	5,400,745	1,641,600
		P	SG		35,879,207	9,336,714	39,864,813	10,373,874
		P	SGCT		-	-	-	-
		P	SE		9,184	2,305	8,960	2,249
		P	SG		-	-	-	-
		P	TROJP		-	-	-	-
				B2	41,417,427	11,021,601	45,274,518	12,017,723

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
Embedded Cost Differentials								
Company Owned Hydro		P	DGP		-	-	-	-
Company Owned Hydro		P	SG		-	-	-	-
Mid-C Contract		P	MC		-	-	-	-
Mid-C Contract		P	SG		-	-	-	-
Existing QF Contracts		P	S		-	-	-	-
Existing QF Contracts		P	SG		-	-	-	-
					-	-	-	-
2020 Protocol Adjustment								
Baseline ECD		P	S		(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
		P	S		-	-	-	-
2020 Protocol Adjustment					(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
Total Other Power Supply				**B2**	**696,009,922**	**190,024,099**	**593,857,837**	**163,234,742**
Total Production Expense				**B2**	**2,155,677,074**	**561,720,509**	**1,940,237,308**	**505,179,040**
Summary of Production Expense by Factor								
	S				(67,493,336)	(7,051,312)	(75,063,201)	(10,379,955)
	SG				1,164,091,683	302,927,302	1,051,798,007	273,705,531
	SE				1,059,078,727	265,844,519	963,502,502	241,853,465
	SNPPH				-	-	-	-
	TROJP				-	-	-	-
	SGCT				-	-	-	-
	DGP				-	-	-	-
	DEU				-	-	-	-
	DEP				-	-	-	-
	SNPPS				-	-	-	-
	SNPPO				-	-	-	-
	DGU				-	-	-	-
	MC				-	-	-	-
	SSGCT				-	-	-	-
	SSECT				-	-	-	-
	SSGC				-	-	-	-
	SSGCH				-	-	-	-
	SSECH				-	-	-	-
Total Production Expense by Factor					2,155,677,074	561,720,509	1,940,237,308	505,179,040
560	Operation Supervision & Engineering							
		T	SG		7,289,449	1,896,906	7,289,449	1,896,906
		T	SG		-	-	(347,470)	(90,421)
				B2	7,289,449	1,896,906	6,941,979	1,806,486
561	Load Dispatching							
		T	SG		19,997,379	5,203,844	19,997,379	5,203,844
		T	SG		-	-	73,806	19,206
				B2	19,997,379	5,203,844	20,071,185	5,223,051
562	Station Expense							
		T	SG		2,788,755	725,707	2,788,755	725,707
		T	SG		-	-	7,784	2,026
				B2	2,788,755	725,707	2,796,539	727,733
563	Overhead Line Expense							
		T	SG		1,038,410	270,222	1,038,410	270,222
		T	SG		-	-	3,479	905
				B2	1,038,410	270,222	1,041,888	271,127
564	Underground Line Expense							
		T	SG		-	-	-	-
				B2	-	-	-	-
565	Transmission of Electricity by Others							
		T	SG		-	-	-	-
		T	SE		-	-	-	-
					-	-	-	-
565NPC	Transmission of Electricity by Others-NPC							
		T	SG		143,000,130	37,212,398	136,358,778	35,484,144
		T	SE		(1,670,995)	(419,445)	2,694,259	676,299
					141,329,135	36,792,954	139,053,037	36,160,443
	Total Transmission of Electricity by Others			B2	141,329,135	36,792,954	139,053,037	36,160,443

2020 PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
566	Misc. Transmission Expense							
		T	SG		2,871,698	747,291	2,871,698	747,291
		T	SG		-	-	21,482	5,590
				B2	2,871,698	747,291	2,893,180	752,882
567	Rents - Transmission							
		T	SG		2,121,266	552,009	2,121,266	552,009
		T	SG		-	-	15,106	3,931
				B2	2,121,266	552,009	2,136,371	555,940
568	Maint Supervision & Engineering							
		T	SG		1,350,447	351,422	1,350,447	351,422
		T	SG		-	-	(1,255)	(327)
				B2	1,350,447	351,422	1,349,192	351,095
569	Maintenance of Structures							
		T	SG		5,806,560	1,511,020	5,806,560	1,511,020
		T	SG		-	-	(30,197)	(7,858)
				B2	5,806,560	1,511,020	5,776,363	1,503,162
570	Maintenance of Station Equipment							
		T	SG		11,856,292	3,085,319	11,856,292	3,085,319
		T	SG		-	-	(54,869)	(14,278)
				B2	11,856,292	3,085,319	11,801,423	3,071,041
571	Maintenance of Overhead Lines							
		T	SG		16,155,917	4,204,195	16,155,917	4,204,195
		T	SG		-	-	1,995,766	519,351
				B2	16,155,917	4,204,195	18,151,683	4,723,546
572	Maintenance of Underground Lines							
		T	SG		37,745	9,822	37,745	9,822
		T	SG		-	-	(111)	(29)
				B2	37,745	9,822	37,634	9,793
573	Maint of Misc. Transmission Plant							
		T	SG		150,799	39,242	150,799	39,242
		T	SG		-	-	(1,772)	(461)
				B2	150,799	39,242	149,027	38,781
Total Transmission Expense				**B2**	**212,793,850**	**55,389,954**	**212,199,503**	**55,195,079**
Summary of Transmission Expense by Factor								
		SE			(1,670,995)	(419,445)	2,694,259	676,299
		SG			214,464,845	55,809,399	209,505,244	54,518,780
		SNPT			-	-	-	-
Total Transmission Expense by Factor					212,793,850	55,389,954	212,199,503	55,195,079
580	Operation Supervision & Engineering							
		DPW	S		1,049,359	308,795	3,299,663	958,882
		DPW	SNPD		7,995,339	2,146,977	10,136,604	2,721,968
				B2	9,044,698	2,455,772	13,436,266	3,680,851
581	Load Dispatching							
		DPW	S		-	-	-	-
		DPW	SNPD		12,174,853	3,269,297	12,174,198	3,269,121
				B2	12,174,853	3,269,297	12,174,198	3,269,121
582	Station Expense							
		DPW	S		4,674,701	1,050,441	4,682,360	1,052,708
		DPW	SNPD		3,667	985	3,668	985
				B2	4,678,369	1,051,426	4,686,028	1,053,693
583	Overhead Line Expenses							
		DPW	S		9,086,257	1,649,556	9,093,760	1,650,658
		DPW	SNPD		163	44	163	44
				B2	9,086,420	1,649,600	9,093,923	1,650,702
584	Underground Line Expense							
		DPW	S		1,746	483	1,751	489
		DPW	SNPD		-	-	-	-
				B2	1,746	483	1,751	489
585	Street Lighting & Signal Systems							
		DPW	S		-	-	-	-
		DPW	SNPD		212,694	57,114	212,709	57,118
				B2	212,694	57,114	212,709	57,118

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
586	Meter Expenses							
		DPW	S		2,624,679	741,264	2,031,512	147,039
		DPW	SNPD		-	-	-	-
				B2	2,624,679	741,264	2,031,512	147,039
587	Customer Installation Expenses							
		DPW	S		14,776,621	5,498,261	14,787,154	5,502,068
		DPW	SNPD		-	-	-	-
				B2	14,776,621	5,498,261	14,787,154	5,502,068
588	Misc. Distribution Expenses							
		DPW	S		(183,942)	78,056	(402,345)	(139,891)
		DPW	SNPD		871,343	233,981	864,730	232,205
				B2	687,402	312,037	462,386	92,314
589	Rents							
		DPW	S		2,846,644	1,590,360	2,854,181	1,595,180
		DPW	SNPD		12,973	3,484	13,015	3,495
				B2	2,859,617	1,593,844	2,867,196	1,598,675
590	Maint Supervision & Engineering							
		DPW	S		3,451,251	948,653	3,446,616	947,176
		DPW	SNPD		2,489,002	668,368	2,488,347	668,192
				B2	5,940,253	1,617,021	5,934,963	1,615,368
591	Maintenance of Structures							
		DPW	S		2,149,515	438,530	2,117,458	431,990
		DPW	SNPD		180,852	48,564	178,154	47,840
				B2	2,330,367	487,094	2,295,612	479,830
592	Maintenance of Station Equipment							
		DPW	S		7,841,238	2,644,907	7,805,808	2,633,434
		DPW	SNPD		1,853,390	497,688	1,851,535	497,190
				B2	9,694,628	3,142,596	9,657,343	3,130,624
593	Maintenance of Overhead Lines							
		DPW	S		87,107,242	27,978,322	107,681,378	43,587,666
		DPW	SNPD		2,197,739	590,156	2,870,552	770,825
				B2	89,304,980	28,568,477	110,551,930	44,358,491
594	Maintenance of Underground Lines							
		DPW	S		25,749,537	6,234,963	25,565,732	6,196,700
		DPW	SNPD		24,641	6,617	24,574	6,599
				B2	25,774,177	6,241,580	25,590,306	6,203,299
595	Maintenance of Line Transformers							
		DPW	S		-	-	-	-
		DPW	SNPD		957,891	257,221	955,357	256,541
				B2	957,891	257,221	955,357	256,541
596	Maint of Street Lighting & Signal Sys.							
		DPW	S		2,907,881	849,569	2,884,624	846,121
		DPW	SNPD		-	-	-	-
				B2	2,907,881	849,569	2,884,624	846,121
597	Maintenance of Meters							
		DPW	S		641,735	258,545	639,711	257,676
		DPW	SNPD		(265,353)	(71,255)	(264,841)	(71,117)
				B2	376,382	187,291	374,871	186,559
598	Maint of Misc. Distribution Plant							
		DPW	S		1,755,437	619,578	1,730,174	610,979
		DPW	SNPD		5,648,503	1,516,785	5,586,005	1,500,002
				B2	7,403,940	2,136,363	7,316,179	2,110,981
Total Distribution Expense				**B2**	**200,837,597**	**60,116,309**	**225,314,308**	**76,239,883**
Summary of Distribution Expense by Factor								
	S				166,479,901	50,890,284	188,219,538	66,278,875
	SNPD				34,357,696	9,226,025	37,094,771	9,961,008
Total Distribution Expense by Factor					200,837,597	60,116,309	225,314,308	76,239,883
901	Supervision							
		CUST	S		178	-	181	-
		CUST	CN		2,689,357	839,538	2,702,268	843,568
				B2	2,689,535	839,538	2,702,449	843,568

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
902	Meter Reading Expense							
		CUST	S		16,478,688	7,223,864	15,511,315	6,215,573
		CUST	CN		743,635	232,141	748,862	233,773
				B2	17,222,323	7,456,005	16,260,177	6,449,346
903	Customer Receipts & Collections							
		CUST	S		6,621,316	1,745,123	6,479,983	538,860
		CUST	CN		41,740,807	13,030,252	44,913,234	14,020,591
				B2	48,362,122	14,775,376	51,393,217	14,559,451
904	Uncollectible Accounts							
		CUST	S		13,273,070	4,630,969	13,217,315	4,394,621
		P	SG		-	-	-	-
		CUST	CN		64,325	20,080	65,669	20,500
				B2	13,337,395	4,651,050	13,282,984	4,415,121
905	Misc. Customer Accounts Expense							
		CUST	S		416,830	-	425,540	-
		CUST	CN		22,019	6,874	22,479	7,017
				B2	438,849	6,874	448,020	7,017
Total Customer Accounts Expense				**B2**	**82,050,225**	**27,728,842**	**84,086,846**	**26,274,504**
Summary of Customer Accts Exp by Factor								
	S				36,790,081	13,599,956	35,634,334	11,149,055
	CN				45,260,144	14,128,886	48,452,512	15,125,449
	SG				-	-	-	-
Total Customer Accounts Expense by Factor					82,050,225	27,728,842	84,086,846	26,274,504
907	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		165	51	206	64
				B2	165	51	206	64
908	Customer Assistance							
		CUST	S		89,487,408	2,096,459	90,420,657	2,288,433
		CUST	CN		2,701,624	843,367	3,027,758	945,177
				B2	92,189,031	2,939,827	93,448,416	3,233,610
909	Informational & Instructional Adv							
		CUST	S		4,400,114	1,894,445	3,609,210	972,324
		CUST	CN		2,687,097	838,833	2,565,811	800,971
				B2	7,087,211	2,733,277	6,175,020	1,773,295
910	Misc. Customer Service							
		CUST	S		-	-	-	-
		CUST	CN		16,171	5,048	16,471	5,142
				B2	16,171	5,048	16,471	5,142
Total Customer Service Expense				**B2**	**99,292,578**	**5,678,204**	**99,640,113**	**5,012,111**
Summary of Customer Service Exp by Factor								
	S				93,887,521	3,990,904	94,029,867	3,260,757
	CN				5,405,056	1,687,300	5,610,246	1,751,354
Total Customer Service Expense by Factor				B2	99,292,578	5,678,204	99,640,113	5,012,111
911	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
912	Demonstration & Selling Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
913	Advertising Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
916	Misc. Sales Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
Total Sales Expense				**B2**	**-**	**-**	**-**	**-**
Total Sales Expense by Factor								
	S				-	-	-	-
	CN				-	-	-	-
Total Sales Expense by Factor					-	-	-	-
Total Customer Service Exp Including Sales				**B2**	**99,292,578**	**5,678,204**	**99,640,113**	**5,012,111**
920	Administrative & General Salaries							
		PTD	S		(38)	(39)	41,832	8,055
		CUST	CN		-	-	-	-
		PTD	SO		73,780,564	20,077,837	78,198,391	21,280,056
				B2	73,780,526	20,077,798	78,240,224	21,288,111
921	Office Supplies & expenses							
		PTD	S		270,856	56,778	278,207	58,319
		CUST	CN		89,293	27,875	91,716	28,631
		PTD	SO		9,148,245	2,489,504	10,627,569	2,892,070
				B2	9,508,394	2,574,156	10,997,492	2,979,020
922	A&G Expenses Transferred							
		PTD	S		-	-	-	-
		CUST	CN		-	-	-	-
		PTD	SO		(33,020,274)	(8,985,777)	(33,268,968)	(9,053,453)
				B2	(33,020,274)	(8,985,777)	(33,268,968)	(9,053,453)
923	Outside Services							
		PTD	S		1,550,477	123,975	1,593,952	127,451
		CUST	CN		-	-	-	-
		PTD	SO		21,001,084	5,715,006	21,574,614	5,871,080
				B2	22,551,561	5,838,981	23,168,566	5,998,531
924	Property Insurance							
		PT	S		10,379,773	6,295,833	11,913,743	7,829,803
		PT	SG		-	-	-	-
		PTD	SO		4,722,691	1,285,182	3,117,669	848,408
				B2	15,102,464	7,581,015	15,031,412	8,678,211
925	Injuries & Damages							
		PTD	S		(21,503)	(21,503)	1,096,675	1,096,675
		PTD	SO		17,313,348	4,711,465	10,778,438	2,933,126
				B2	17,291,845	4,689,962	11,875,114	4,029,802
926	Employee Pensions & Benefits							
		LABOR	S		(68,187)	(407,236)	(3,715,385)	(4,115,651)
		CUST	CN		-	-	-	-
		LABOR	SO		118,045,638	32,123,650	131,507,730	35,787,077
				B2	117,977,451	31,716,415	127,792,345	31,671,426
927	Franchise Requirements							
		DMSC	S		-	-	-	-
		DMSC	SO		-	-	-	-
				B2	-	-	-	-
928	Regulatory Commission Expense							
		DMSC	S		14,733,573	4,070,427	15,061,574	4,276,092
		P	SE		8,083	2,029	8,083	2,029
		DMSC	SO		3,155,077	858,588	3,221,435	876,646
		FERC	SG		5,233,705	1,361,948	5,306,516	1,380,895
				B2	23,130,437	6,292,992	23,597,608	6,535,662
929	Duplicate Charges							
		LABOR	S		-	-	-	-
		LABOR	SO		(130,126,920)	(35,411,318)	(137,265,074)	(37,353,818)
				B2	(130,126,920)	(35,411,318)	(137,265,074)	(37,353,818)
930	Misc General Expenses							
		PTD	S		42,496	33,354	9,285	(665)
		CUST	CN		-	-	-	-
		P	SG		-	-	-	-
		LABOR	SO		2,160,475	587,928	1,662,583	452,437
				B2	2,202,972	621,282	1,671,868	451,772

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
938									
939	931	Rents							
940			PTD	S		420,480	259,287	442,404	272,806
941			PTD	SO		2,138,243	581,878	2,249,732	612,218
942					B2	2,558,723	841,165	2,692,136	885,024
943									
944	935	Maintenance of General Plant							
945			G	S		471,629	167,285	474,620	169,079
946			CUST	CN		59,158	18,467	59,316	18,517
947			G	SO		23,213,078	6,316,954	23,480,445	6,389,712
948					B2	23,743,865	6,502,706	24,014,381	6,577,307
949									
950	**Total Administrative & General Expense**				**B2**	**144,701,044**	**42,339,376**	**148,547,103**	**42,687,596**
951									
952	Summary of A&G Expense by Factor								
953		S				27,779,556	10,578,161	27,196,908	9,721,965
954		SE				8,083	2,029	8,083	2,029
955		SO				111,531,250	30,350,896	115,884,564	31,535,559
956		SG				5,233,705	1,361,948	5,306,516	1,380,895
957		CN				148,451	46,342	151,032	47,148
958	Total A&G Expense by Factor					144,701,044	42,339,376	148,547,103	42,687,596
959									
960	**Total O&M Expense**				**B2**	**2,895,352,368**	**752,973,193**	**2,710,025,181**	**710,588,211**
961	403SP	Steam Depreciation							
962			P	SG		30,169,736	7,850,960	30,169,736	7,850,960
963			P	SG		30,130,900	7,840,853	30,130,900	7,840,853
964			P	SG		170,224,168	44,296,810	381,806,215	99,356,028
965			P	SG		15,145,184	3,941,176	15,145,184	3,941,176
966					B3	245,669,987	63,929,798	457,252,035	118,989,017
967									
968	403NP	Nuclear Depreciation							
969			P	SG		-	-	-	-
970					B3	-	-	-	-
971									
972	403HP	Hydro Depreciation							
973			P	SG		(74,556)	(19,402)	(74,556)	(19,402)
974			P	SG		1,386,317	360,756	1,386,317	360,756
975			P	SG		32,698,277	8,508,952	17,994,642	4,682,680
976			P	SG		5,919,818	1,540,493	7,578,991	1,972,253
977			P	SG		-	-	4,052,542	1,054,578
978					B3	39,929,856	10,390,800	30,937,935	8,050,865
979									
980	403OP	Other Production Depreciation							
981			p	S		-	-	5,998	5,998
982			P	SG		-	-	-	-
983			P	SG		57,519,990	14,968,216	180,372,811	46,937,754
984			P	SG		3,259,020	848,083	3,259,020	848,083
985			P	SG		67,675,190	17,610,866	50,049,597	13,024,223
986					B3	128,454,199	33,427,164	233,687,426	60,816,057
987									
988	403TP	Transmission Depreciation							
989			T	SG		8,665,935	2,255,104	8,665,935	2,255,104
990			T	SG		10,823,573	2,816,579	10,823,573	2,816,579
991			T	SG		91,403,582	23,785,618	110,183,951	28,672,765
992					B3	110,893,089	28,857,301	129,673,458	33,744,448
993									
994									
995									
996	403	Distribution Depreciation							
997	360	Land & Land Rights	DPW	S		428,924	61,992	751,261	45,507
998	361	Structures	DPW	S		2,085,151	572,195	2,702,702	540,611
999	362	Station Equipment	DPW	S		(4,092,588)	5,417,172	1,092,529	5,151,985
1000	363	Storage Battery Equip	DPW	S		-	-	-	-
1001	364	Poles & Towers	DPW	S		43,265,700	12,836,209	49,474,039	12,484,839
1002	365	OH Conductors	DPW	S		20,500,784	7,071,868	24,470,783	6,868,827
1003	366	UG Conduit	DPW	S		9,409,489	1,906,326	11,378,523	1,805,622
1004	367	UG Conductor	DPW	S		22,043,207	3,968,159	26,640,163	3,733,053
1005	368	Line Trans	DPW	S		34,230,814	11,126,561	41,310,956	10,764,455
1006	369	Services	DPW	S		18,920,122	6,776,031	23,159,791	6,559,198
1007	370	Meters	DPW	S		8,681,662	3,046,879	9,881,385	2,985,521
1008	371	Inst Cust Prem	DPW	S		496,701	126,330	541,219	124,053
1009	372	Leased Property	DPW	S		-	-	-	-
1010	373	Street Lighting	DPW	S		2,235,385	698,542	2,552,210	682,338
1011					B3	158,205,353	53,608,264	193,955,562	51,746,009

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1012									
1013	403GP	General Depreciation							
1014			G-SITUS	S		14,773,471	5,078,614	17,386,302	5,791,053
1015			G-DGP	SG		23,762	6,183	23,762	6,183
1016			G-DGU	SG		73,045	19,008	73,045	19,008
1017			P	SE		95,328	23,929	117,402	29,470
1018			CUST	CN		1,040,345	324,765	846,011	264,100
1019			G-SG	SG		9,665,735	2,515,279	10,191,963	2,652,217
1020			PTD	SO		15,567,254	4,236,302	17,807,317	4,845,889
1021			G-SG	SG		8,187	2,130	8,187	2,130
1022			G-SG	SG		144,337	37,560	144,337	37,560
1023					B3	41,391,464	12,243,772	46,598,325	13,647,610
1024									
1025	403GV0	General Vehicles							
1026			G-SG	SG		-	-	-	-
1027					B3	-	-	-	-
1028									
1029	403MP	Mining Depreciation							
1030			P	SE		-	-	-	-
1031					B3	-	-	-	-
1032									
1033	403EP	Experimental Plant Depreciation							
1034			P	SG		-	-	-	-
1035			P	SG		-	-	-	-
1036					B3	-	-	-	-
1037	4031	ARO Depreciation							
1038			P	S		-	-	-	-
1039					B3	-	-	-	-
1040									
1041									
1042	**Total Depreciation Expense**				**B3**	**724,543,948**	**202,457,099**	**1,092,104,741**	**286,994,006**
1043									
1044	Summary	S				172,978,823	58,686,878	211,347,862	57,543,060
1045		DGP				-	-	-	-
1046		DGU				-	-	-	-
1047		SG				534,862,197	139,185,224	861,986,150	224,311,489
1048		SO				15,567,254	4,236,302	17,807,317	4,845,889
1049		CN				1,040,345	324,765	846,011	264,100
1050		SE				95,328	23,929	117,402	29,470
1051		SSGCH				-	-	-	-
1052		SSGCT				-	-	-	-
1053	Total Depreciation Expense By Factor					724,543,948	202,457,099	1,092,104,741	286,994,006
1054									
1055	404GP	Amort of LT Plant - Leasehold Improvements							
1056			I-SITUS	S		576,525	308,163	407,271	249,902
1057			I-SG	SG		-	-	-	-
1058			PTD	SO		289,934	78,899	284,353	77,381
1059			I-DGU	SG		-	-	-	-
1060			CUST	CN		-	-	-	-
1061			I-DGP	SG		-	-	-	-
1062					B4	866,459	387,063	691,624	327,282
1063									
1064	404SP	Amort of LT Plant - Cap Lease Steam							
1065			P	SG		-	-	-	-
1066			P	SG		-	-	-	-
1067					B4	-	-	-	-
1068									
1069	404IP	Amort of LT Plant - Intangible Plant							
1070			I-SITUS	S		821,777	10,341	985,326	13,738
1071			P	SE		1,239	311	-	-
1072			I-SG	SG		14,326,925	3,728,243	8,050,212	2,094,877
1073			PTD	SO		10,992,229	2,991,305	16,358,935	4,451,742
1074			CUST	CN		9,726,915	3,036,457	10,650,150	3,324,664
1075			I-SG	SG		10,915,568	2,840,518	2,616,793	680,958
1076			I-SG	SG		315,841	82,190	314,803	81,920
1077			I-DGP	SG		78,646	20,466	78,646	20,466
1078			I-SG	SG		-	-	-	-
1079			I-SG	SG		21,649	5,634	21,649	5,634
1080			I-DGU	SG		16,485	4,290	16,485	4,290
1081					B4	47,217,274	12,719,754	39,092,998	10,678,289
1082									
1083	404MP	Amort of LT Plant - Mining Plant							
1084			P	SE		-	-	-	-
1085					B4	-	-	-	-
1086									
1087	404OP	Amort of LT Plant - Other Plant							
1088			P	SG		-	-	-	-
1089					B4	-	-	-	-
1090									
1091									

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
404HP	Amortization of Other Electric Plant							
		P	SG		311,125	80,963	311,696	81,111
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B4	311,125	80,963	311,696	81,111
Total Amortization of Limited Term Plant				**B4**	**48,394,858**	**13,187,780**	**40,096,318**	**11,086,682**
405	Amortization of Other Electric Plant							
		GP	S		-	-	-	-
				B4	-	-	-	-
406	Amortization of Plant Acquisition Adj							
		P	S		301,635	-	301,635	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		4,781,559	1,244,288	4,781,559	1,244,288
		P	SO		-	-	-	-
				B4	5,083,195	1,244,288	5,083,195	1,244,288
407	Amort of Prop Losses, Unrec Plant, etc							
		DPW	S		124,290	(966)	(4,248,193)	(4,373,449)
		GP	SO		-	-	-	-
		P	SG-P		-	-	-	-
		P	SE		-	-	-	-
		P	SG		-	-	105,100,892	27,350,019
		P	TROJP		-	-	-	-
				B4	124,290	(966)	100,852,699	22,976,570
Total Amortization Expense				**B4**	**53,602,343**	**14,431,102**	**146,032,212**	**35,307,540**
Summary of Amortization Expense by Factor								
	S				1,824,227	317,539	(2,553,960)	(4,109,809)
	SE				1,239	311	-	-
	TROJP				-	-	-	-
	DGP				-	-	-	-
	DGU				-	-	-	-
	SO				11,282,163	3,070,205	16,643,288	4,529,123
	SSGCT				-	-	-	-
	SSGCH				-	-	-	-
	CN				9,726,915	3,036,457	10,650,150	3,324,664
	SG				30,767,798	8,006,591	121,292,734	31,563,563
Total Amortization Expense by Factor					53,602,343	14,431,102	146,032,212	35,307,540
408	Taxes Other Than Income							
		DMSC	S		35,011,797	31,803,625	36,120,219	32,912,046
		GP	GPS		149,370,144	40,647,959	181,331,121	49,345,470
		GP	SO		12,360,904	3,363,761	12,360,904	3,363,761
		P	SE		843,248	211,668	843,248	211,668
		P	SG		1,955,572	508,891	1,989,171	517,635
		DMSC	OPRV-ID		-	-	-	-
		GP	EXCTAX		-	-	-	-
		GP	SG		-	-	-	-
Total Taxes Other Than Income				**B5**	**199,541,666**	**76,535,904**	**232,644,663**	**86,350,580**
41140	Deferred Investment Tax Credit - Fed							
		PTD	DGU		(2,943,987)	-	(2,943,987)	-
				B7	(2,943,987)	-	(2,943,987)	-
41141	Deferred Investment Tax Credit - Idaho							
		PTD	DGU		-	-	-	-
				B7	-	-	-	-
Total Deferred ITC				**B7**	**(2,943,987)**	**-**	**(2,943,987)**	**-**
427	Interest on Long-Term Debt							
		GP	S		309,427,198	82,375,935	363,572,244	93,090,526
		GP	SNP		-	-	-	-
				B6	309,427,198	82,375,935	363,572,244	93,090,526

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
428	Amortization of Debt Disc & Exp							
		GP	SNP		4,460,171	1,173,655	4,460,171	1,173,655
				B6	4,460,171	1,173,655	4,460,171	1,173,655
429	Amortization of Premium on Debt							
		GP	SNP		(11,026)	(2,901)	(11,026)	(2,901)
				B6	(11,026)	(2,901)	(11,026)	(2,901)
431	Other Interest Expense							
		NUTIL	OTH		-	-	-	-
		GP	SO		-	-	-	-
		GP	SNP		21,988,458	5,786,071	21,988,458	5,786,071
				B6	21,988,458	5,786,071	21,988,458	5,786,071
432	AFUDC - Borrowed							
		GP	SNP		(25,466,792)	(6,701,365)	(25,466,792)	(6,701,365)
					(25,466,792)	(6,701,365)	(25,466,792)	(6,701,365)
	Total Elec. Interest Deductions for Tax			B6	310,398,010	82,631,396	364,543,056	93,345,987
	Non-Regulated Portion of Interest							
	427	NUTIL	NUTIL		-	-	-	-
	428	NUTIL	NUTIL		-	-	-	-
	429	NUTIL	NUTIL		-	-	-	-
	431	NUTIL	NUTIL		-	-	-	-
	Total Non-Regulated Interest				-	-	-	-
	Total Interest Deductions for Tax			B6	310,398,010	82,631,396	364,543,056	93,345,987
419	Interest & Dividends							
		GP	S		-	-	-	-
		GP	SNP		(49,461,258)	(13,015,300)	(71,759,910)	(18,882,996)
	Total Operating Deductions for Tax			B6	(49,461,258)	(13,015,300)	(71,759,910)	(18,882,996)
41010	Deferred Income Tax - Federal-DR							
		GP	S		17,770,795	(312,672)	(2,270,823)	2,434,509
		P	TROJD		-	-	-	-
		PT	SG		83,511	21,732	83,511	21,732
		LABOR	SO		5,670,881	1,543,212	5,789,362	1,575,454
		GP	SNP		18,367,499	4,833,248	24,895,341	6,550,992
		P	SE		(288,054)	(72,306)	(4,951,776)	(1,242,969)
		PT	SG		35,663,554	9,280,596	120,908,117	31,463,475
		GP	GPS		16,739,227	4,555,230	11,085,507	3,016,689
		DITEXP	DITEXP		-	-	-	-
		CUST	BADDEBT		-	-	-	-
		CUST	CN		-	-	-	-
		IBT	IBT		-	-	-	-
		DPW	CIAC		-	-	-	-
		GP	SCHMDEXP		-	-	-	-
		TAXDEPR	TAXDEPR		145,237,384	38,159,076	231,359,927	60,786,561
		DPW	SNPD		375,210	100,755	1	0
				B7	239,620,007	58,108,870	386,899,167	104,606,442
41110	Deferred Income Tax - Federal-CR							
		GP	S		(130,056,939)	800,425	(72,165,579)	(10,838,244)
		P	SE		(8,667,169)	(2,175,588)	(8,209,435)	(2,060,690)
		PT	SG		(344,503)	(89,649)	(344,503)	(89,649)
		GP	SNP		(10,288,673)	(2,707,375)	(14,672,252)	(3,860,875)
		PT	SG		100,670	26,197	(102,984,304)	(26,799,227)
		GP	GPS		145,317	39,545	-	-
		LABOR	SO		(5,993,991)	(1,631,139)	(2,355,335)	(640,955)
		PT	SNPD		(516,039)	(138,571)	2,008	539
		CUST	BADDEBT		(97,689)	(32,471)	(0)	(0)
		P	SG		-	-	7,370	1,918
		DITEXP	SG		-	-	820	213
		P	TROJD		12,532	3,241	(1)	(0)
		IBT	CN		-	-	431	135
		DPW	CIAC		(25,324,501)	(6,800,353)	(18,185,604)	(4,883,355)
		GP	SCHMDEXP		(241,934,106)	(63,577,820)	(225,069,075)	(59,145,861)
		TAXDEPR	TAXDEPR		-	-	-	-
				B7	(422,965,091)	(76,283,559)	(443,975,459)	(108,316,052)
Total Deferred Income Taxes				**B7**	**(183,345,084)**	**(18,174,689)**	**(57,076,292)**	**(3,709,610)**

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1249	SCHMAF	Additions - Flow Through							
1250			SCHMAF	S		-	-	-	-
1251			SCHMAF	SNP		-	-	-	-
1252			SCHMAF	SO		-	-	-	-
1253			SCHMAF	SE		-	-	-	-
1254			SCHMAF	TROJP		-	-	-	-
1255			SCHMAF	SG		-	-	-	-
1256					B6	-	-	-	-
1257									
1258	SCHMAP	Additions - Permanent							
1259			P	S		-	-	-	-
1260			P	SE		58,125	14,590	18,000	4,518
1261			LABOR	SNP		-	-	-	-
1262			SCHMAP-SO	SO		2,371,219	645,278	3,718,000	1,011,776
1263			SCHMAP	SG		-	-	-	-
1264			DPW	SCHMDEXP		129,290	33,976	143,074	37,598
1265					B6	2,558,634	693,844	3,879,074	1,053,892
1266									
1267	SCHMAT	Additions - Temporary							
1268			SCHMAT-SITUS	S		13,263,811	(6,898,690)	(73,501,691)	(21,521,142)
1269			P	SG		-	-	(29,975)	(7,800)
1270			DPW	CIAC		103,001,232	27,658,779	73,965,511	19,861,857
1271			SCHMAT-SNP	SNP		41,846,673	11,011,588	59,675,808	15,703,169
1272			P	TROJD		(50,974)	(13,181)	0	0
1273			P	SG		-	-	(3,334)	(868)
1274			SCHMAT-SE	SE		35,251,596	8,848,675	33,389,901	8,381,362
1275			P	SG		(403,666)	(105,045)	428,992,724	111,635,200
1276			SCHMAT-GPS	GPS		(591,042)	(160,840)	0	0
1277			SCHMAT-SO	SO		24,379,109	6,634,265	9,469,168	2,576,836
1278			SCHMAT-SNP	SNPD		2,098,862	563,605	(8,166)	(2,193)
1279			CUST	BADDEBT		397,328	132,068	(0)	(0)
1280			P	CN		-	-	(1,755)	(548)
1281			BOOKDEPR	SCHMDEXP		984,007,982	258,587,279	915,413,585	240,561,370
1282					B6	1,203,200,912	306,258,502	1,447,361,776	377,187,243
1283									
1284	TOTAL SCHEDULE - M ADDITIONS				B6	1,205,759,546	306,952,346	1,451,240,850	378,241,136
1285									
1286	SCHMDF	Deductions - Flow Through							
1287			SCHMDF	S		-	-	-	-
1288			SCHMDF	DGP		-	-	-	-
1289			SCHMDF	DGU		-	-	-	-
1290					B6	-	-	-	-
1291	SCHMDP	Deductions - Permanent							
1292			SCHMDP	S		-	-	-	-
1293			P	SE		-	-	3,545,057	889,862
1294			PTD	SNP		106,610	28,054	0	0
1295			BOOKDEPR	SCHMDEXP		(19,357)	(5,087)	525,184	138,013
1296			P	SG		-	-	-	-
1297			SCHMDP-SO	SO		-	-	-	-
1298					B6	87,253	22,967	4,070,241	1,027,875
1299									
1300	SCHMDT	Deductions - Temporary							
1301			GP	S		72,278,358	(1,271,716)	(9,268,244)	9,869,568
1302			CUST	BADDEBT		-	-	-	-
1303			SCHMDT-SNP	SNP		74,705,322	19,658,055	101,255,730	26,644,564
1304			CUST	CN		-	-	-	-
1305			SCHMDT	SG		339,662	88,389	339,662	88,389
1306			CUST	DGP		-	-	-	-
1307			P	SE		(1,171,589)	(294,086)	(20,140,135)	(5,055,474)
1308			SCHMDT-SG	SG		145,052,807	37,746,559	501,384,985	130,473,572
1309			SCHMDT-GPS	GPS		68,082,721	18,527,288	45,087,598	12,269,646
1310			SCHMDT-SO	SO		23,064,917	6,276,635	23,436,216	6,377,676
1311			TAXDEPR	TAXDEPR		590,717,641	155,202,736	941,000,086	247,234,512
1312			DPW	SNPD		1,526,070	409,793	(0)	(0)
1313					B6	974,595,908	236,343,652	1,583,095,897	427,902,454
1314									
1315	TOTAL SCHEDULE - M DEDUCTIONS				B6	974,683,161	236,366,619	1,587,166,139	428,930,329
1316									
1317	**TOTAL SCHEDULE - M ADJUSTMENTS**				**B6**	**231,076,385**	**70,585,727**	**(135,925,289)**	**(50,689,193)**
1318									
1319									
1320									
1321	40911	State Income Taxes							
1322			IBT			57,214,214	14,633,912	28,732,455	8,278,357
1323			IBT	IBT		-	-	-	-
1324		PTC	P	SG		-	-	-	-
1325			IBT	IBT		-	-	-	-
1326	**Total State Tax Expense**					**57,214,214**	**14,633,912**	**28,732,455**	**8,278,357**
1327									
1328									

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
Calculation of Taxable Income:								
	Operating Revenues				5,159,798,594	1,367,388,056	5,242,307,759	1,427,282,060
	Operating Deductions:							
	O & M Expenses				2,895,352,368	752,973,193	2,710,025,181	710,588,211
	Depreciation Expense				724,543,948	202,457,099	1,092,104,741	286,994,006
	Amortization Expense				53,602,343	14,431,102	146,032,212	35,307,540
	Taxes Other Than Income				199,541,666	76,535,904	232,644,663	86,350,580
	Interest & Dividends (AFUDC-Equity)				(49,461,258)	(13,015,300)	(71,759,910)	(18,882,996)
	Misc Revenue & Expense				(3,327,067)	(372,479)	(80,922)	546,879
	Total Operating Deductions				3,820,251,999	1,033,009,519	4,108,965,965	1,100,904,221
	Other Deductions:							
	Interest Deductions				310,398,010	82,631,396	364,543,056	93,345,987
	Interest on PCRBS				-	-	-	-
	Schedule M Adjustments				231,076,385	70,585,727	(135,925,289)	(50,689,193)
	Income Before State Taxes				1,260,224,970	322,332,867	632,873,449	182,342,659
	State Income Taxes				57,214,214	14,633,912	28,732,455	8,278,357
Total Taxable Income					1,203,010,757	307,698,955	604,140,994	174,064,302
Tax Rate					21.0%	21.0%	21.0%	21.0%
Federal Income Tax - Calculated					252,632,259	64,616,781	126,869,609	36,553,503
Adjustments to Calculated Tax:								
40910		P	SE		(18,519)	(4,649)	(18,000)	(4,518)
40910	PTC	P	SG		(45,352,770)	(11,801,985)	(187,272,740)	(48,733,297)
40910		P	SO		(41,507)	(11,295)	-	-
40910	IRS Settle	LABOR	S		-	-	-	-
Federal Income Tax Expense					**207,219,463**	**52,798,852**	**(60,421,131)**	**(12,184,312)**
Total Operating Expenses					**3,947,857,862**	**1,095,282,894**	**4,089,016,919**	**1,112,171,651**
310	Land and Land Rights							
		P	SG		2,328,177	605,853	2,328,177	605,853
		P	SG		33,837,468	8,805,400	33,837,468	8,805,400
		P	SG		54,188,889	14,101,375	54,188,889	14,101,375
		P	S		-	-	-	-
		P	SG		2,635,317	685,779	2,635,317	685,779
				B8	92,989,851	24,198,407	92,989,851	24,198,407
311	Structures and Improvements							
		P	SG		227,138,030	59,107,295	227,138,030	59,107,295
		P	SG		314,032,398	81,719,497	314,032,398	81,719,497
		P	SG		429,854,817	111,859,540	429,854,817	111,859,540
		P	SG		65,501,187	17,045,133	65,501,187	17,045,133
				B8	1,036,526,432	269,731,465	1,036,526,432	269,731,465
312	Boiler Plant Equipment							
		P	SG		591,094,231	153,818,280	591,094,231	153,818,280
		P	SG		468,246,188	121,849,985	468,246,188	121,849,985
		P	SG		3,210,660,584	835,498,407	2,757,133,558	717,478,735
		P	SG		341,888,910	88,968,495	341,888,910	88,968,495
				B8	4,611,889,914	1,200,135,167	4,158,362,888	1,082,115,495
314	Turbogenerator Units							
		P	SG		109,569,676	28,512,914	109,569,676	28,512,914
		P	SG		109,731,202	28,554,947	109,731,202	28,554,947
		P	SG		713,024,372	185,547,712	713,024,372	185,547,712
		P	SG		69,096,130	17,980,632	69,096,130	17,980,632
				B8	1,001,421,379	260,596,206	1,001,421,379	260,596,206
315	Accessory Electric Equipment							
		P	SG		86,091,816	22,403,357	86,091,816	22,403,357
		P	SG		133,452,442	34,727,839	133,452,442	34,727,839
		P	SG		199,968,303	52,037,017	199,968,303	52,037,017
		P	SG		68,681,644	17,872,772	68,681,644	17,872,772
				B8	488,194,205	127,040,984	488,194,205	127,040,984
316	Misc Power Plant Equipment							
		P	SG		2,593,134	674,802	2,593,134	674,802
		P	SG		4,977,072	1,295,165	4,977,072	1,295,165
		P	SG		21,305,517	5,544,256	21,305,517	5,544,256
		P	SG		4,159,337	1,082,369	4,159,337	1,082,369
				B8	33,035,060	8,596,592	33,035,060	8,596,592

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1406									
1407	317	Steam Plant ARO							
1408			P	S		-	-	-	-
1409					B8	-	-	-	-
1410									
1411	SP	Unclassified Steam Plant - Account 300							
1412			P	SG		56,210,192	14,627,372	56,210,192	14,627,372
1413					B8	56,210,192	14,627,372	56,210,192	14,627,372
1414									
1415									
1416	**Total Steam Production Plant**				**B8**	**7,320,267,032**	**1,904,926,193**	**6,866,740,006**	**1,786,906,522**
1417									
1418									
1419	Summary of Steam Production Plant by Factor								
1420		S				-	-	-	-
1421		DGP				-	-	-	-
1422		DGU				-	-	-	-
1423		SG				7,320,267,032	1,904,926,193	6,866,740,006	1,786,906,522
1424		SSGCH				-	-	-	-
1425	Total Steam Production Plant by Factor					7,320,267,032	1,904,926,193	6,866,740,006	1,786,906,522
1426	320	Land and Land Rights							
1427			P	SG		-	-	-	-
1428			P	SG		-	-	-	-
1429					B8	-	-	-	-
1430									
1431	321	Structures and Improvements							
1432			P	SG		-	-	-	-
1433			P	SG	B8	-	-	-	-
1434						-	-	-	-
1435									
1436	322	Reactor Plant Equipment							
1437			P	SG		-	-	-	-
1438			P	SG		-	-	-	-
1439					B8	-	-	-	-
1440									
1441	323	Turbogenerator Units							
1442			P	SG		-	-	-	-
1443			P	SG		-	-	-	-
1444					B8	-	-	-	-
1445									
1446	324	Land and Land Rights							
1447			P	SG		-	-	-	-
1448			P	SG		-	-	-	-
1449					B8	-	-	-	-
1450									
1451	325	Misc. Power Plant Equipment							
1452			P	SG		-	-	-	-
1453			P	SG		-	-	-	-
1454					B8	-	-	-	-
1455									
1456									
1457	NP	Unclassified Nuclear Plant - Acct 300							
1458			P	SG		-	-	-	-
1459					B8	-	-	-	-
1460									
1461									
1462	**Total Nuclear Production Plant**				**B8**	**-**	**-**	**-**	**-**
1463									
1464									
1465									
1466	Summary of Nuclear Production Plant by Factor								
1467		DGP				-	-	-	-
1468		DGU				-	-	-	-
1469		SG				-	-	-	-
1470									
1471	Total Nuclear Plant by Factor					-	-	-	-
1472									
1473	330	Land and Land Rights							
1474			P	SG		10,332,372	2,688,755	10,332,372	2,688,755
1475			P	SG		5,268,322	1,370,956	5,268,322	1,370,956
1476			P	SG		19,440,549	5,058,943	19,440,549	5,058,943
1477			P	SG		1,278,861	332,793	1,278,861	332,793
1478					B8	36,320,104	9,451,447	36,320,104	9,451,447
1479									
1480	331	Structures and Improvements							
1481			P	SG		19,715,170	5,130,406	19,715,170	5,130,406
1482			P	SG		4,896,038	1,274,078	4,896,038	1,274,078
1483			P	SG		241,524,977	62,851,157	241,524,977	62,851,157
1484			P	SG		12,056,480	3,137,413	12,056,480	3,137,413
1485					B8	278,192,664	72,393,055	278,192,664	72,393,055

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
332	Reservoirs, Dams & Waterways							
		P	SG		145,549,115	37,875,711	145,549,115	37,875,711
		P	SG		18,827,062	4,899,297	18,827,062	4,899,297
		P	SG		269,730,914	70,191,085	329,829,647	85,830,357
		P	SG		76,753,070	19,973,169	91,687,595	23,859,526
		0	SG		-	-	(30,273,855)	(7,878,054)
				B8	510,860,161	132,939,263	555,619,564	144,586,838
333	Water Wheel, Turbines, & Generators							
		P	SG		28,896,674	7,519,675	28,896,674	7,519,675
		P	SG		7,509,110	1,954,068	7,509,110	1,954,068
		P	SG		64,147,858	16,692,961	64,147,858	16,692,961
		P	SG		38,559,755	10,034,263	38,559,755	10,034,263
				B8	139,113,397	36,200,968	139,113,397	36,200,968
334	Accessory Electric Equipment							
		P	SG		3,692,063	960,772	3,692,063	960,772
		P	SG		3,374,907	878,240	3,374,907	878,240
		P	SG		67,020,116	17,440,399	67,020,116	17,440,399
		P	SG		10,835,756	2,819,749	10,835,756	2,819,749
				B8	84,922,843	22,099,159	84,922,843	22,099,159
335	Misc. Power Plant Equipment							
		P	SG		1,129,697	293,977	1,129,697	293,977
		P	SG		154,522	40,211	154,522	40,211
		P	SG		1,165,880	303,393	1,165,880	303,393
		P	SG		18,279	4,757	18,279	4,757
				B8	2,468,378	642,337	2,468,378	642,337
336	Roads, Railroads & Bridges							
		P	SG		4,370,270	1,137,259	4,370,270	1,137,259
		P	SG		765,090	199,097	765,090	199,097
		P	SG		18,375,816	4,781,871	18,375,816	4,781,871
		P	SG		1,450,471	377,451	1,450,471	377,451
				B8	24,961,647	6,495,678	24,961,647	6,495,678
337	Hydro Plant ARO							
		P	S		-	-	-	-
				B8	-	-	-	-
HP	Unclassified Hydro Plant - Acct 300							
		P	S		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
Total Hydraulic Production Plant				**B8**	**1,076,839,193**	**280,221,907**	**1,121,598,596**	**291,869,482**
Summary of Hydraulic Plant by Factor								
	S				-	-	-	-
	SG				1,076,839,193	280,221,907	1,121,598,596	291,869,482
	DGP				-	-	-	-
	DGU				-	-	-	-
Total Hydraulic Plant by Factor					1,076,839,193	280,221,907	1,121,598,596	291,869,482
340	Land and Land Rights							
		P	S		74,986	74,986	74,986	74,986
		P	SG		39,022,504	10,154,683	39,022,504	10,154,683
		P	SG		6,100,269	1,587,451	6,100,269	1,587,451
		P	SG		235,129	61,187	235,129	61,187
				B8	45,432,889	11,878,306	45,432,889	11,878,306
341	Structures and Improvements							
		P	SG		170,247,300	44,302,829	166,769,047	43,397,696
		P	SG		-	-	-	-
		P	SG		53,823,433	14,006,274	53,823,433	14,006,274
		P	SG		4,273,000	1,111,947	4,273,000	1,111,947
				B8	228,343,732	59,421,051	224,865,480	58,515,918
342	Fuel Holders, Producers & Accessories							
		P	SG		13,428,889	3,494,550	13,428,889	3,494,550
		P	SG		-	-	-	-
		P	SG		2,759,334	718,051	2,759,334	718,051
				B8	16,188,223	4,212,602	16,188,223	4,212,602

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1564									
1565	343	Prime Movers							
1566			P	S		-	-	129,823	129,823
1567			P	SG		-	-	-	-
1568			P	SG		1,792,108,861	466,353,904	1,003,136,418	261,042,504
1569			P	SG		1,074,511,952	279,616,297	3,218,958,184	837,657,661
1570			P	SG		57,923,631	15,073,254	57,923,631	15,073,254
1571					B8	2,924,544,444	761,043,455	4,280,148,057	1,113,903,242
1572									
1573	344	Generators							
1574			P	S		-	-	-	-
1575			P	SG		56,865,366	14,797,865	56,865,366	14,797,865
1576			P	SG		400,761,809	104,288,773	394,911,436	102,766,352
1577			P	SG		17,782,763	4,627,543	17,782,763	4,627,543
1578					B8	475,409,937	123,714,181	469,559,564	122,191,760
1579									
1580	345	Accessory Electric Plant							
1581			P	SG		211,261,475	54,975,797	198,936,993	51,768,643
1582			P	SG		113,374,163	29,502,942	113,374,163	29,502,942
1583			P	SG		-	-	-	-
1584			P	SG		2,901,493	755,045	2,901,493	755,045
1585					B8	327,537,131	85,233,784	315,212,649	82,026,629
1586									
1587									
1588									
1589	346	Misc. Power Plant Equipment							
1590			P	SG		12,586,673	3,275,384	11,927,176	3,103,765
1591			P	SG		3,337,649	868,544	3,337,649	868,544
1592			P	SG		-	-	-	-
1593					B8	15,924,321	4,143,928	15,264,824	3,972,309
1594									
1595	347	Other Production ARO							
1596			P	S		-	-	-	-
1597					B8	-	-	-	-
1598									
1599	OP	Unclassified Other Prod Plant-Acct 300							
1600			P	S		-	-	-	-
1601			P	SG		(553,173)	(143,950)	(553,173)	(143,950)
1602						(553,173)	(143,950)	(553,173)	(143,950)
1603									
1604	**Total Other Production Plant**				**B8**	**4,032,827,505**	**1,049,503,356**	**5,366,118,513**	**1,396,556,816**
1605									
1606	Summary of Other Production Plant by Factor								
1607		S				74,986	74,986	204,809	204,809
1608		DGU				-	-	-	-
1609		SG				4,032,752,519	1,049,428,371	5,365,913,703	1,396,352,007
1610		SSGCT				-	-	-	-
1611	Total of Other Production Plant by Factor					4,032,827,505	1,049,503,356	5,366,118,513	1,396,556,816
1612									
1613	Experimental Plant								
1614	103	Experimental Plant							
1615			P	SG		-	-	-	-
1616	**Total Experimental Production Plant**				**B8**	**-**	**-**	**-**	**-**
1617									
1618	**Total Production Plant**				**B8**	**12,429,933,730**	**3,234,651,456**	**13,354,457,115**	**3,475,332,820**
1619	350	Land and Land Rights							
1620			T	SG		21,061,510	5,480,759	21,061,510	5,480,759
1621			T	SG		48,203,820	12,543,903	48,203,820	12,543,903
1622			T	SG		202,173,533	52,610,876	202,173,533	52,610,876
1623					B8	271,438,863	70,635,538	271,438,863	70,635,538
1624									
1625	352	Structures and Improvements							
1626			T	S		-	-	-	-
1627			T	SG		7,026,134	1,828,385	7,026,134	1,828,385
1628			T	SG		17,682,315	4,601,404	17,682,315	4,601,404
1629			T	SG		253,240,919	65,899,954	253,240,919	65,899,954
1630					B8	277,949,368	72,329,743	277,949,368	72,329,743
1631									
1632	353	Station Equipment							
1633			T	SG		106,317,064	27,666,499	106,317,064	27,666,499
1634			T	SG		154,018,190	40,079,588	154,018,190	40,079,588
1635			T	SG		1,938,735,944	504,510,131	1,938,735,944	504,510,131
1636					B8	2,199,071,199	572,256,218	2,199,071,199	572,256,218
1637									
1638	354	Towers and Fixtures							
1639			T	SG		128,108,873	33,337,301	128,108,873	33,337,301
1640			T	SG		131,291,848	34,165,595	131,291,848	34,165,595
1641			T	SG		1,044,149,057	271,715,073	1,044,149,057	271,715,073
1642					B8	1,303,549,778	339,217,969	1,303,549,778	339,217,969
1643									

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1644	355	Poles and Fixtures							
1645			T	SG		61,226,901	15,932,852	61,226,901	15,932,852
1646			T	SG		114,992,728	29,924,135	114,992,728	29,924,135
1647			T	SG		815,456,440	212,203,233	1,932,844,035	502,976,901
1648					B8	991,676,069	258,060,220	2,109,063,664	548,833,888
1649									
1650	356	Clearing and Grading							
1651			T	SG		158,450,690	41,233,041	158,450,690	41,233,041
1652			T	SG		157,758,213	41,052,840	157,758,213	41,052,840
1653			T	SG		954,283,677	248,329,735	954,283,677	248,329,735
1654					B8	1,270,492,579	330,615,616	1,270,492,579	330,615,616
1655									
1656	357	Underground Conduit							
1657			T	SG		6,371	1,658	6,371	1,658
1658			T	SG		91,651	23,850	91,651	23,850
1659			T	SG		3,689,299	960,053	3,689,299	960,053
1660					B8	3,787,321	985,561	3,787,321	985,561
1661									
1662	358	Underground Conductors							
1663			T	SG		-	-	-	-
1664			T	SG		1,087,552	283,010	1,087,552	283,010
1665			T	SG		6,947,802	1,808,001	6,947,802	1,808,001
1666					B8	8,035,354	2,091,011	8,035,354	2,091,011
1667									
1668	359	Roads and Trails							
1669			T	SG		1,863,032	484,810	1,863,032	484,810
1670			T	SG		440,513	114,633	440,513	114,633
1671			T	SG		9,633,656	2,506,931	9,633,656	2,506,931
1672					B8	11,937,200	3,106,374	11,937,200	3,106,374
1673									
1674	TP	Unclassified Trans Plant - Acct 300							
1675			T	SG		108,436,132	28,217,936	108,436,132	28,217,936
1676					B8	108,436,132	28,217,936	108,436,132	28,217,936
1677									
1678	TS0	Unclassified Trans Sub Plant - Acct 300							
1679			T	SG		-	-	-	-
1680					B8	-	-	-	-
1681									
1682	**Total Transmission Plant**				**B8**	**6,446,373,863**	**1,677,516,185**	**7,563,761,458**	**1,968,289,853**
1683	Summary of Transmission Plant by Factor								
1684			DGP			-	-	-	-
1685			DGU			-	-	-	-
1686			SG			6,446,373,863	1,677,516,185	7,563,761,458	1,968,289,853
1687	Total Transmission Plant by Factor					6,446,373,863	1,677,516,185	7,563,761,458	1,968,289,853
1688	360	Land and Land Rights							
1689			DPW	S		63,752,760	14,190,626	68,285,023	15,425,674
1690					B8	63,752,760	14,190,626	68,285,023	15,425,674
1691									
1692	361	Structures and Improvements							
1693			DPW	S		122,141,315	32,577,502	130,824,493	34,943,680
1694					B8	122,141,315	32,577,502	130,824,493	34,943,680
1695									
1696	362	Station Equipment							
1697			DPW	S		1,025,529,740	258,312,285	1,098,435,924	278,179,324
1698					B8	1,025,529,740	258,312,285	1,098,435,924	278,179,324
1699									
1700	363	Storage Battery Equipment							
1701			DPW	S		-	-	-	-
1702					B8	-	-	-	-
1703									
1704	364	Poles, Towers & Fixtures							
1705			DPW	S		1,234,275,701	395,746,642	1,320,597,038	418,232,748
1706					B8	1,234,275,701	395,746,642	1,320,597,038	418,232,748
1707									
1708	365	Overhead Conductors							
1709			DPW	S		785,199,742	272,505,215	841,020,569	287,716,469
1710					B8	785,199,742	272,505,215	841,020,569	287,716,469
1711									
1712	366	Underground Conduit							
1713			DPW	S		389,442,059	97,778,526	417,127,980	105,322,979
1714					B8	389,442,059	97,778,526	417,127,980	105,322,979
1715									
1716									
1717									
1718									
1719	367	Underground Conductors							
1720			DPW	S		909,201,308	190,342,123	973,837,560	207,955,594
1721					B8	909,201,308	190,342,123	973,837,560	207,955,594

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1722									
1723	368	Line Transformers							
1724			DPW	S		1,400,334,104	460,558,670	1,499,885,597	487,686,594
1725					B8	1,400,334,104	460,558,670	1,499,885,597	487,686,594
1726									
1727	369	Services							
1728			DPW	S		838,536,076	298,209,521	898,148,649	314,454,032
1729					B8	838,536,076	298,209,521	898,148,649	314,454,032
1730									
1731	370	Meters							
1732			DPW	S		237,285,260	91,508,919	254,154,164	96,105,719
1733					B8	237,285,260	91,508,919	254,154,164	96,105,719
1734									
1735	371	Installations on Customers' Premises							
1736			DPW	S		8,805,090	2,639,353	9,431,055	2,809,929
1737					B8	8,805,090	2,639,353	9,431,055	2,809,929
1738									
1739	372	Leased Property							
1740			DPW	S		-	-	-	-
1741					B8	-	-	-	-
1742									
1743	373	Street Lights							
1744			DPW	S		62,662,687	24,072,918	67,117,455	25,286,848
1745					B8	62,662,687	24,072,918	67,117,455	25,286,848
1746									
1747	DP	Unclassified Dist Plant - Acct 300							
1748			DPW	S		61,420,721	15,304,313	61,420,721	15,304,313
1749					B8	61,420,721	15,304,313	61,420,721	15,304,313
1750									
1751	DS0	Unclassified Dist Sub Plant - Acct 300							
1752			DPW	S		-	-	-	-
1753					B8	-	-	-	-
1754									
1755									
1756	**Total Distribution Plant**				**B8**	**7,138,586,565**	**2,153,746,612**	**7,640,286,229**	**2,289,423,905**
1757									
1758	Summary of Distribution Plant by Factor								
1759		S				7,138,586,565	2,153,746,612	7,640,286,229	2,289,423,905
1760									
1761	Total Distribution Plant by Factor					7,138,586,565	2,153,746,612	7,640,286,229	2,289,423,905
1762	389	Land and Land Rights							
1763			G-SITUS	S		14,969,289	6,114,113	14,969,289	6,114,113
1764			CUST	CN		1,128,506	352,286	1,128,506	352,286
1765			G-DGU	SG		332	86	332	86
1766			G-SG	SG		1,228	319	1,228	319
1767			PTD	SO		7,516,302	2,045,404	7,516,302	2,045,404
1768					B8	23,615,657	8,512,210	23,615,657	8,512,210
1769									
1770	390	Structures and Improvements							
1771			G-SITUS	S		132,298,513	39,510,644	132,298,513	39,510,644
1772			G-DGP	SG		335,238	87,238	335,238	87,238
1773			G-DGU	SG		1,487,359	387,050	1,487,359	387,050
1774			CUST	CN		8,207,715	2,562,207	8,207,715	2,562,207
1775			G-SG	SG		5,786,797	1,505,877	5,786,797	1,505,877
1776			P	SE		1,235,588	310,151	1,235,588	310,151
1777			PTD	SO		96,548,451	26,273,641	96,548,451	26,273,641
1778					B8	245,899,661	70,636,808	245,899,661	70,636,808
1779									
1780	391	Office Furniture & Equipment							
1781			G-SITUS	S		6,522,746	2,191,143	6,522,746	2,191,143
1782			G-DGP	SG		-	-	-	-
1783			G-DGU	SG		-	-	-	-
1784			CUST	CN		4,040,675	1,261,380	4,040,675	1,261,380
1785			G-SG	SG		3,183,296	828,377	3,183,296	828,377
1786			P	SE		10,034	2,519	10,034	2,519
1787			PTD	SO		51,456,014	14,002,678	51,456,014	14,002,678
1788			G-SG	SG		-	-	-	-
1789			G-SG	SG		4,039	1,051	4,039	1,051
1790					B8	65,216,804	18,287,147	65,216,804	18,287,147

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1791									
1792	392	Transportation Equipment							
1793			G-SITUS	S		88,138,177	24,809,266	88,138,177	24,809,266
1794			PTD	SO		6,893,825	1,876,010	6,893,825	1,876,010
1795			G-SG	SG		21,029,810	5,472,510	21,029,810	5,472,510
1796			CUST	CN		-	-	-	-
1797			G-DGU	SG		455,094	118,427	455,094	118,427
1798			P	SE		488,092	122,518	488,092	122,518
1799			G-DGP	SG		70,616	18,376	70,616	18,376
1800			G-SG	SG		299,519	77,943	299,519	77,943
1801			G-DGU	SG		44,655	11,620	44,655	11,620
1802					B8	117,419,788	32,506,671	117,419,788	32,506,671
1803									
1804	393	Stores Equipment							
1805			G-SITUS	S		8,440,223	2,635,106	8,440,223	2,635,106
1806			G-DGP	SG		-	-	-	-
1807			G-DGU	SG		-	-	-	-
1808			PTD	SO		255,085	69,416	255,085	69,416
1809			G-SG	SG		5,860,195	1,524,977	5,860,195	1,524,977
1810			G-DGU	SG		53,971	14,045	53,971	14,045
1811					B8	14,609,473	4,243,544	14,609,473	4,243,544
1812									
1813	394	Tools, Shop & Garage Equipment							
1814			G-SITUS	S		34,364,049	10,475,442	34,364,049	10,475,442
1815			G-DGP	SG		93,384	24,301	93,384	24,301
1816			G-SG	SG		22,341,758	5,813,914	22,341,758	5,813,914
1817			PTD	SO		2,127,184	578,868	2,127,184	578,868
1818			P	SE		109,044	27,372	109,044	27,372
1819			G-DGU	SG		-	-	-	-
1820			G-SG	SG		1,716,843	446,768	1,716,843	446,768
1821			G-SG	SG		89,913	23,398	89,913	23,398
1822					B8	60,842,175	17,390,063	60,842,175	17,390,063
1823									
1824	395	Laboratory Equipment							
1825			G-SITUS	S		21,189,900	7,887,804	21,189,900	7,887,804
1826			G-DGP	SG		-	-	-	-
1827			G-DGU	SG		-	-	-	-
1828			PTD	SO		4,973,535	1,353,444	4,973,535	1,353,444
1829			P	SE		1,257,984	315,773	1,257,984	315,773
1830			G-SG	SG		6,377,729	1,659,653	6,377,729	1,659,653
1831			G-SG	SG		223,587	58,183	223,587	58,183
1832			G-SG	SG		14,022	3,649	14,022	3,649
1833					B8	34,036,757	11,278,505	34,036,757	11,278,505
1834									
1835	396	Power Operated Equipment							
1836			G-SITUS	S		136,639,519	40,611,944	136,639,519	40,611,944
1837			G-DGP	SG		262,000	68,179	262,000	68,179
1838			G-SG	SG		43,994,098	11,448,423	43,994,098	11,448,423
1839			PTD	SO		6,093,193	1,658,135	6,093,193	1,658,135
1840			G-DGU	SG		1,057,504	275,190	1,057,504	275,190
1841			P	SE		236,686	59,412	236,686	59,412
1842			P	SG		-	-	-	-
1843			G-SG	SG		1,378,336	358,679	1,378,336	358,679
1844					B8	189,661,336	54,479,962	189,661,336	54,479,962
1845	397	Communication Equipment							
1846			G-SITUS	S		203,501,421	76,477,521	278,077,094	94,814,269
1847			G-DGP	SG		412,544	107,355	412,544	107,355
1848			G-DGU	SG		1,136,750	295,812	1,136,750	295,812
1849			PTD	SO		93,060,474	25,324,461	110,752,978	30,139,105
1850			CUST	CN		3,848,526	1,201,397	1,036,506	323,567
1851			G-SG	SG		175,128,628	45,573,079	186,276,393	48,474,021
1852			P	SE		341,558	85,736	289,707	72,721
1853			G-SG	SG		1,285,815	334,603	1,285,815	334,603
1854			G-SG	SG		16,633	4,328	16,633	4,328
1855					B8	478,732,348	149,404,292	579,284,420	174,565,782
1856									
1857	398	Misc. Equipment							
1858			G-SITUS	S		2,966,638	1,107,524	2,966,638	1,107,524
1859			G-DGP	SG		-	-	-	-
1860			G-DGU	SG		-	-	-	-
1861			CUST	CN		82,497	25,753	82,497	25,753
1862			PTD	SO		2,205,144	600,084	2,205,144	600,084
1863			P	SE		3,966	995	3,966	995
1864			G-SG	SG		2,713,930	706,236	2,713,930	706,236
1865			G-SG	SG		-	-	-	-
1866					B8	7,972,175	2,440,593	7,972,175	2,440,593

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1867									
1868	399	Coal Mine							
1869			P	SE		1,854,828	465,589	84,739,827	21,270,957
1870	MP		P	SE		-	-	-	-
1871					B8	1,854,828	465,589	84,739,827	21,270,957
1872									
1873	399L	WIDCO Capital Lease							
1874			P	SE		-	-	-	-
1875						-	-	-	-
1876									
1877		Remove Capital Leases				-	-	-	-
1878						-	-	-	-
1879									
1880	1011390	General Capital Leases							
1881			G-SITUS	S		6,010,764	2,257,880	6,010,764	2,257,880
1882			P	SG		11,703,570	3,045,577	11,703,570	3,045,577
1883			PTD	SO		1,887,427	513,624	1,887,427	513,624
1884					B9	19,601,761	5,817,080	19,601,761	5,817,080
1885									
1886		Remove Capital Leases				(19,601,761)	(5,817,080)	(19,601,761)	(5,817,080)
1887						-	-	-	-
1888									
1889	1011346	General Gas Line Capital Leases							
1890			P	SG		-	-	-	-
1891					B9	-	-	-	-
1892									
1893		Remove Capital Leases				-	-	-	-
1894						-	-	-	-
1895									
1896	GP	Unclassified Gen Plant - Acct 300							
1897			G-SITUS	S		-	-	-	-
1898			PTD	SO		39,436,687	10,731,869	39,436,687	10,731,869
1899			CUST	CN		-	-	-	-
1900			G-SG	SG		-	-	-	-
1901			G-DGP	SG		-	-	-	-
1902			G-DGU	SG		-	-	-	-
1903					B8	39,436,687	10,731,869	39,436,687	10,731,869
1904									
1905	399G	Unclassified Gen Plant - Acct 300							
1906			G-SITUS	S		-	-	-	-
1907			PTD	SO		-	-	-	-
1908			G-SG	SG		-	-	-	-
1909			G-DGP	SG		-	-	-	-
1910			G-DGU	SG		-	-	-	-
1911					B8	-	-	-	-
1912									
1913	**Total General Plant**				**B8**	**1,279,297,689**	**380,377,252**	**1,462,734,760**	**426,344,109**
1914									
1915	Summary of General Plant by Factor								
1916		S				655,041,239	214,078,386	729,616,912	232,415,134
1917		DGP				-	-	-	-
1918		DGU				-	-	-	-
1919		SG				308,559,192	80,295,225	319,706,957	83,196,167
1920		SO				312,453,319	85,027,633	330,145,823	89,842,278
1921		SE				5,537,780	1,390,065	88,370,928	22,182,418
1922		CN				17,307,919	5,403,023	14,495,900	4,525,194
1923		DEU				-	-	-	-
1924		SSGCT				-	-	-	-
1925		SSGCH				-	-	-	-
1926		Less Capital Leases				(19,601,761)	(5,817,080)	(19,601,761)	(5,817,080)
1927	Total General Plant by Factor					1,279,297,689	380,377,252	1,462,734,760	426,344,109
1928	301	Organization							
1929			I-SITUS	S		-	-	-	-
1930			PTD	SO		-	-	-	-
1931			I-SG	SG		-	-	-	-
1932					B8	-	-	-	-
1933	302	Franchise & Consent							
1934			I-SITUS	S		(31,081,215)	-	(31,081,215)	-
1935			I-SG	SG		10,337,588	2,690,113	4,228,422	1,100,347
1936			I-SG	SG		175,244,590	45,603,256	175,004,296	45,540,725
1937			I-SG	SG		9,350,399	2,433,220	9,350,399	2,433,220
1938			I-DGP	SG		-	-	-	-
1939			I-DGU	SG		600,993	156,394	600,993	156,394
1940					B8	164,452,355	50,882,982	158,102,895	49,230,686

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
1941									
1942	303	Miscellaneous Intangible Plant							
1943			I-SITUS	S		22,022,344	4,615,241	23,265,327	5,489,081
1944			I-SG	SG		167,592,259	43,611,918	180,893,159	47,073,162
1945			PTD	SO		385,727,443	104,967,652	401,152,776	109,165,334
1946			P	SE		-	-	(1,106,269)	(277,690)
1947			CUST	CN		176,107,084	54,975,452	175,494,022	54,784,072
1948			P	SG		-	-	-	-
1949			I-DGP	SG		-	-	-	-
1950					B8	751,449,130	208,170,263	779,699,015	216,233,959
1951	303	Less Non-Regulated Plant							
1952			I-SITUS	S		-	-	-	-
1953						751,449,130	208,170,263	779,699,015	216,233,959
1954	IP	Unclassified Intangible Plant - Acct 300							
1955			I-SITUS	S		-	-	-	-
1956			I-SG	SG		-	-	-	-
1957			I-DGU	SG		-	-	-	-
1958			PTD	SO		-	-	-	-
1959						-	-	-	-
1960									
1961	**Total Intangible Plant**				**B8**	**915,901,485**	**259,053,246**	**937,801,910**	**265,464,645**
1962									
1963	Summary of Intangible Plant by Factor								
1964		S				(9,058,871)	4,615,241	(7,815,888)	5,489,081
1965		DGP				-	-	-	-
1966		DGU				-	-	-	-
1967		SG				363,125,829	94,494,900	370,077,269	96,303,848
1968		SO				385,727,443	104,967,652	401,152,776	109,165,334
1969		CN				176,107,084	54,975,452	175,494,022	54,784,072
1970		SSGCT				-	-	-	-
1971		SSGCH				-	-	-	-
1972		SE				-	-	(1,106,269)	(277,690)
1973	Total Intangible Plant by Factor					915,901,485	259,053,246	937,801,910	265,464,645
1974	Summary of Unclassified Plant (Account 106)								
1975		DP				61,420,721	15,304,313	61,420,721	15,304,313
1976		DS0				-	-	-	-
1977		GP				39,436,687	10,731,869	39,436,687	10,731,869
1978		HP				-	-	-	-
1979		NP				-	-	-	-
1980		OP				(553,173)	(143,950)	(553,173)	(143,950)
1981		TP				108,436,132	28,217,936	108,436,132	28,217,936
1982		TS0				-	-	-	-
1983		IP				-	-	-	-
1984		MP				-	-	-	-
1985		SP				56,210,192	14,627,372	56,210,192	14,627,372
1986	Total Unclassified Plant by Factor					264,950,558	68,737,539	264,950,558	68,737,539
1987									
1988	**Total Electric Plant In Service**				**B8**	**28,210,093,332**	**7,705,344,751**	**30,959,041,472**	**8,424,855,332**
1989	Summary of Electric Plant by Factor								
1990		S				7,784,643,920	2,372,515,226	8,362,292,062	2,527,532,929
1991		SE				5,537,780	1,390,065	87,264,660	21,904,728
1992		DGU				-	-	-	-
1993		DGP				-	-	-	-
1994		SG				19,547,917,628	5,086,882,780	21,607,797,990	5,622,917,878
1995		SO				698,180,762	189,995,285	731,298,599	199,007,612
1996		CN				193,415,003	60,378,475	189,989,922	59,309,266
1997		DEU				-	-	-	-
1998		SSGCH				-	-	-	-
1999		SSGCT				-	-	-	-
2000		Less Capital Leases				(19,601,761)	(5,817,080)	(19,601,761)	(5,817,080)
2001						28,210,093,332	7,705,344,751	30,959,041,472	8,424,855,332
2002	105	Plant Held For Future Use							
2003			DPW	S		13,840,559	7,426,112	-	-
2004			P	SG		-	-	-	-
2005			T	SG		3,657,534	951,787	3,657,534	951,787
2006			P	SG		8,923,302	2,322,078	8,923,302	2,322,078
2007			P	SE		-	-	-	-
2008			G	SG		-	-	(12,580,836)	(3,273,865)
2009									
2010									
2011	**Total Plant Held For Future Use**				**B10**	**26,421,395**	**10,699,976**	**-**	**-**
2012									
2013	114	Electric Plant Acquisition Adjustments							
2014			P	S		11,763,784	-	11,763,784	-
2015			P	SG		144,704,699	37,655,972	144,704,699	37,655,972
2016			P	SG		-	-	-	-
2017	**Total Electric Plant Acquisition Adjustment**				**B15**	**156,468,483**	**37,655,972**	**156,468,483**	**37,655,972**

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
115	Accum Provision for Asset Acquisition Adjustments							
		P	S		(1,294,270)	-	(1,294,270)	-
		P	SG		(128,417,358)	(33,417,577)	(137,980,477)	(35,906,153)
		P	SG		-	-	-	-
				B15	(129,711,629)	(33,417,577)	(139,274,748)	(35,906,153)
128	Pensions							
		LABOR	SO		2,485,363	676,340	-	-
Total Pensions				**B15**	**2,485,363**	**676,340**	**-**	**-**
124	Weatherization							
		DMSC	S		795,098	0	795,098	0
		DMSC	SO		(5,008)	(1,363)	(5,008)	(1,363)
				B16	790,090	(1,363)	790,090	(1,363)
182W	Weatherization							
		DMSC	S		(9,216,048)	-	(9,216,048)	-
		DMSC	SG		-	-	-	-
		DMSC	SGCT		-	-	-	-
		DMSC	SO		-	-	-	-
				B16	(9,216,048)	-	(9,216,048)	-
186W	Weatherization							
		DMSC	S		-	-	-	-
		DMSC	CN		-	-	-	-
		DMSC	CNP		-	-	-	-
		DMSC	SG		-	-	-	-
		DMSC	SO		-	-	-	-
				B16	-	-	-	-
Total Weatherization				**B16**	**(8,425,958)**	**(1,363)**	**(8,425,958)**	**(1,363)**
151	Fuel Stock							
		P	DEU		-	-	-	-
		P	SE		174,905,762	43,903,949	161,077,156	40,432,763
		P	SE		-	-	-	-
		P	SE		14,945,408	3,751,520	14,945,408	3,751,520
				B13	189,851,170	47,655,469	176,022,564	44,184,283
152	Fuel Stock - Undistributed							
		P	SE		-	-	-	-
					-	-	-	-
25316	UAMPS Working Capital Deposit							
		P	SE		(2,479,000)	(622,266)	(2,063,462)	(517,960)
				B13	(2,479,000)	(622,266)	(2,063,462)	(517,960)
25317	DG&T Working Capital Deposit							
		P	SE		(2,622,091)	(658,184)	(2,707,856)	(679,712)
				B13	(2,622,091)	(658,184)	(2,707,856)	(679,712)
25319	Provo Working Capital Deposit							
		P	SE		-	-	-	-
					-	-	-	-
Total Fuel Stock				**B13**	**184,750,079**	**46,375,019**	**171,251,246**	**42,986,611**
154	Materials and Supplies							
		MSS	S		120,236,546	41,769,971	120,236,546	41,769,971
		MSS	SG		5,020,695	1,306,517	(1,601,510)	(416,755)
		MSS	SE		-	-	-	-
		MSS	SO		336,188	91,486	336,188	91,486
		MSS	SG		116,359,013	30,279,678	116,359,013	30,279,678
		MSS	SG		7,954	2,070	7,954	2,070
		MSS	SNPD		(1,742,112)	(467,807)	(1,742,112)	(467,807)
		MSS	SG		-	-	-	-
		MSS	SG		-	-	-	-
		MSS	SG		-	-	-	-
		MSS	SG		-	-	-	-
		MSS	SG		9,492,432	2,470,181	9,492,432	2,470,181
		MSS	SG		-	-	-	-
				B13	249,710,716	75,452,096	243,088,511	73,728,824
163	Stores Expense Undistributed							
		MSS	SO		-	-	-	-
				B13	-	-	-	-

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
25318	Provo Working Capital Deposit							
		MSS	SG		(273,000)	(71,042)	(273,000)	(71,042)
				B13	(273,000)	(71,042)	(273,000)	(71,042)
Total Materials and Supplies				**B13**	**249,437,716**	**75,381,055**	**242,815,511**	**73,657,782**
165	Prepayments							
		DMSC	S		25,224,552	3,030,864	25,224,552	3,030,864
		GP	GPS		181,209	49,312	181,209	49,312
		PT	SG		2,258,700	587,773	2,258,700	587,773
		P	SE		3,590	901	3,590	901
		PTD	SO		18,872,344	5,135,714	18,872,344	5,135,714
Total Prepayments				**B15**	**46,540,395**	**8,804,564**	**46,540,395**	**8,804,564**
182M	Misc Regulatory Assets							
		DDS2	S		105,288,567	(11,751,160)	107,835,611	(9,204,116)
		DEFSG	SG		3,448,669	897,435	-	-
		P	SGCT		-	-	-	-
		DEFSG	SG-P		-	-	-	-
		P	SE		185,628,278	46,595,460	165,945,770	41,654,857
		P	SG		-	-	-	-
		DDSO2	SO		472,555,803	128,596,174	36,359,142	9,894,380
				B16	766,921,317	164,337,908	310,140,523	42,345,121
186M	Misc Deferred Debits							
		LABOR	S		3,746,439	-	3,746,439	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		DEFSG	SG		80,227,740	20,877,370	83,583,719	21,750,684
		LABOR	SO		164,900	44,874	164,900	44,874
		P	SE		1,479,125	371,282	1,479,125	371,282
		P	SG		-	-	-	-
		GP	EXCTAX		-	-	-	-
Total Misc. Deferred Debits				**B11**	**85,618,204**	**21,293,526**	**88,974,183**	**22,166,841**
Working Capital								
CWC	Cash Working Capital							
		CWC	S		30,507,253	8,581,870	26,286,717	7,599,721
		CWC	SO		-	-	-	-
		CWC	SE		-	-	-	-
				B14	30,507,253	8,581,870	26,286,717	7,599,721
OWC	Other Work. Cap.							
131	Cash	GP	SNP		-	-	-	-
135	Working Funds	GP	SG		-	-	-	-
141	Notes Receivable	GP	SO		-	-	-	-
143	Other A/R	GP	SO		44,856,675	12,206,805	44,856,675	12,206,805
232	A/P	PTD	S		(16,765)	-	(16,765)	-
232	A/P	PTD	SO		(7,127,991)	(1,939,734)	(7,127,991)	(1,939,734)
232	A/P	P	SE		(1,813,806)	(455,292)	(1,813,806)	(455,292)
232	A/P	T	SG		(2,053,168)	(534,288)	(2,053,168)	(534,288)
2533	Other Msc. Df. Crd.	P	S		-	-	-	-
2533	Other Msc. Df. Crd.	P	SE		(6,512,893)	(1,634,833)	(6,880,463)	(1,727,099)
230	Asset Retir. Oblig.	P	SG		-	-	-	-
230	Asset Retir. Oblig.	P	S		(8,267,790)	-	(8,267,790)	-
254	Decom. Reg Liability	P	SG		-	-	(52,550,446)	(13,675,009)
254	Reclam. Reg Liability	P	SE		-	-	(7,249,448)	(1,819,719)
2533	Cholla Reclamation	P	SE		-	-	-	-
				B14	19,064,261	7,642,658	(41,103,203)	(7,944,336)
Total Working Capital				**B14**	**49,571,514**	**16,224,528**	**(14,816,485)**	**(344,615)**
Miscellaneous Rate Base								
18221	Unrec Plant & Reg Study Costs							
		P	S		-	-	-	-
					-	-	-	-
18222	Nuclear Plant - Trojan							
		P	S		-	-	-	-
		P	TROJP		-	-	-	-
		P	TROJD		-	-	-	-
				B16	-	-	-	-

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	 OREGON
2169									
2170									
2171									
2172	1869	Misc Deferred Debits-Trojan							
2173			P	S		-	-	-	-
2174			P	SG		-	-	-	-
2175						-	-	-	-
2176									
2177	**Total Miscellaneous Rate Base**				**B15**	**-**	**-**	**-**	**-**
2178									
2179	**Total Rate Base Additions**					**1,430,076,879**	**348,029,948**	**853,673,150**	**191,364,762**
2180	235	Customer Service Deposits							
2181			CUST	S		-	-	-	-
2182			CUST	CN		-	-	-	-
2183	**Total Customer Service Deposits**				B15	-	-	-	-
2184									
2185	2281	Prop Ins	PTD	S		(8,955,526)	11,606,109	(8,955,526)	11,606,109
2186	2282	Inj & Dam	PTD	SO		(16,281,344)	(4,430,627)	(16,281,344)	(4,430,627)
2187	2283	Pen & Ben	PTD	SO		(100,000,003)	(27,212,908)	(1,650,782)	(449,226)
2188	2282	Prov for Injurie	PTD	S		(8,767,623)	(8,767,623)	(8,767,623)	(8,767,623)
2189	25335	Reg Liabilities	PTD	SE		(115,119,099)	(28,896,607)	(115,119,099)	(28,896,607)
2190					B15	(249,123,595)	(57,701,656)	(150,774,374)	(30,937,973)
2191									
2192	22841	Accum Misc. Operating Provisions							
2193			P	S		-	-	-	-
2194			P	SG		(512,398)	(133,339)	(512,398)	(133,339)
2195					B15	(512,398)	(133,339)	(512,398)	(133,339)
2196									
2197	254105	ARO	P	S		258,730	-	258,730	-
2198	230	ARO	P	TROJD		(2,743,652)	(709,453)	(2,743,652)	(709,453)
2199	254105	ARO	P	TROJD		(2,639,042)	(682,403)	(2,639,042)	(682,403)
2200	254		P	S		(308,256,823)	(30,478,104)	(621,029,743)	(393,342,450)
2201					B15	(313,380,787)	(31,869,961)	(626,153,708)	(394,734,306)
2202									
2203	252	Customer Advances for Construction							
2204			DPW	S		(2,462,507)	(919,079)	(18,762,474)	(2,640,295)
2205			DPW	SE		-	-	-	-
2206			T	SG		(59,193,503)	(15,403,708)	(42,893,536)	(11,162,027)
2207			DPW	SO		-	-	-	-
2208			CUST	CN		-	-	-	-
2209	**Total Customer Advances for Construction**				**B20**	**(61,656,010)**	**(16,322,786)**	**(61,656,010)**	**(13,802,322)**
2210									
2211	25398	SO2 Emissions							
2212			P	SE		-	-	-	-
2213						-	-	-	-
2214									
2215	25399	Other Deferred Credits							
2216			P	S		(322,520)	(150,115)	(322,520)	(150,115)
2217			LABOR	SO		(58,098,162)	(15,810,199)	(58,098,162)	(15,810,199)
2218			P	SG		(26,308,326)	(6,846,119)	(26,308,326)	(6,846,119)
2219			P	SE		(7,538,284)	(1,892,222)	(7,538,284)	(1,892,222)
2220					B15	(92,267,292)	(24,698,654)	(92,267,292)	(24,698,654)
2221									
2222	190	Accumulated Deferred Income Taxes							
2223			P	S		79,883,162	9,583,796	194,469,726	103,267,970
2224			CUST	CN		-	-	-	-
2225			LABOR	SO		110,574,221	30,090,461	76,650,267	20,858,766
2226			P	DGP		-	-	-	-
2227			IBT	IBT		-	-	-	-
2228			P	SG		-	-	-	-
2229			P	SG		-	-	-	-
2230			CUST	BADDEBT		2,719,261	903,853	2,754,659	915,619
2231			P	TROJD		1,323,421	342,210	1,314,030	339,782
2232			P	SG		26,606,986	6,923,838	14,369,559	3,739,338
2233			P	SE		21,618,853	5,426,654	(4,111,127)	(1,031,954)
2234			PTD	SNP		-	-	-	-
2235			DPW	SNPD		794,940	213,464	1,932,611	518,961
2236			P	SG		-	-	-	-
2237					B19	243,520,844	53,484,276	287,379,725	128,608,482
2238									
2239	281	Accumulated Deferred Income Taxes							
2240			P	S		-	-	-	-
2241			PT	SG		(177,049,368)	(46,072,906)	0	0
2242			T	SG		-	-	-	-
2243					B19	(177,049,368)	(46,072,906)	0	0

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
2244									
2245	282	Accumulated Deferred Income Taxes							
2246			GP	S		(170,620,898)	(93,279,909)	(2,851,806,683)	(687,502,731)
2247			ACCMDIT	DITBAL		(3,983,914,217)	(983,169,895)	(383,928)	(94,748)
2248			PT	SNP		-	-	-	-
2249			LABOR	SO		(1,047,616)	(285,087)	(1,090,424)	(296,736)
2250			PTD	GPS		-	-	-	-
2251			DPW	CIAC		-	-	-	-
2252			P	SNPD		-	-	(615)	(165)
2253			GP	SCHMDEXP		-	-	-	-
2254			TAXDEPR	TAXDEPR		-	-	-	-
2255			P	SG		-	-	(2,261)	(588)
2256			PT	IBT		-	-	-	-
2257			PT	SG		-	-	(250)	(65)
2258			P	CN		-	-	(134)	(42)
2259			P	SE		(6,997,593)	(1,756,500)	(2,507,257)	(629,359)
2260			P	SG		(841,696)	(219,032)	(71,117,171)	(18,506,560)
2261					B19	(4,163,422,021)	(1,078,710,422)	(2,926,908,724)	(707,030,994)
2262									
2263	283	Accumulated Deferred Income Taxes							
2264			GP	S		(31,598,310)	(1,660,055)	(79,285,404)	(857,569)
2265			P	SG		(1,699,725)	(442,313)	(801,560)	(208,587)
2266			P	SE		(42,271,091)	(10,610,673)	(14,979,435)	(3,760,061)
2267			LABOR	SO		(131,569,480)	(35,803,881)	(21,498,251)	(5,850,299)
2268			GP	GPS		(6,689,945)	(1,820,529)	(6,821,149)	(1,856,233)
2269			PTD	SNP		(1,047,982)	(275,767)	(764,589)	(201,195)
2270			P	TROJD		-	-	-	-
2271			P	SG		-	-	-	-
2272			P	SG		-	-	-	-
2273			P	SG		-	-	-	-
2274					B19	(214,876,533)	(50,613,218)	(124,150,388)	(12,733,944)
2275									
2276	**Total Accum Deferred Income Tax**				**B19**	**(4,311,827,079)**	**(1,121,912,270)**	**(2,763,679,386)**	**(591,156,457)**
2277	255	Accumulated Investment Tax Credit							
2278			PTD	S		(38,436)	-	(26,173)	-
2279			PTD	ITC84		-	-	-	-
2280			PTD	ITC85		-	-	-	-
2281			PTD	ITC86		-	-	-	-
2282			PTD	ITC88		-	-	-	-
2283			PTD	ITC89		-	-	-	-
2284			PTD	ITC90		(42,534)	(6,778)	-	-
2285			PTD	SG		(216,528)	(56,346)	(179,345)	(46,670)
2286	**Total Accumulated ITC**				**B19**	**(297,497)**	**(63,124)**	**(205,518)**	**(46,670)**
2287									
2288	**Total Rate Base Deductions**					**(5,029,064,657)**	**(1,252,701,791)**	**(3,695,248,685)**	**(1,055,509,722)**
2289									
2290									
2291									
2292	108SP	Steam Prod Plant Accumulated Depr							
2293			P	S		10,702,263	-	10,702,263	-
2294			P	SG		(759,016,718)	(197,516,132)	(759,016,718)	(197,516,132)
2295			P	SG		(726,882,090)	(189,153,855)	(726,882,090)	(189,153,855)
2296			P	SG		(1,488,197,425)	(387,268,148)	(2,465,497,627)	(641,587,388)
2297			P	SG		-	-	-	-
2298			P	SG		(246,321,600)	(64,099,365)	(246,321,600)	(64,099,365)
2299					B17	(3,209,715,569)	(838,037,500)	(4,187,015,771)	(1,092,356,740)
2300									
2301	108NP	Nuclear Prod Plant Accumulated Depr							
2302			P	SG		-	-	-	-
2303			P	SG		-	-	-	-
2304			P	SG		-	-	-	-
2305					B17	-	-	-	-
2306									
2307									
2308	108HP	Hydraulic Prod Plant Accum Depr							
2309			P	S		3,575,830	-	3,575,830	-
2310			P	SG		(175,334,101)	(45,626,549)	(175,334,101)	(45,626,549)
2311			P	SG		(30,353,650)	(7,898,819)	(30,353,650)	(7,898,819)
2312			P	SG		(189,513,434)	(49,316,384)	(251,826,176)	(65,531,800)
2313			P	SG		(51,987,503)	(13,528,517)	(60,898,122)	(15,847,295)
2314			p	SG		-	-	27,894,346	7,258,843
2315					B17	(443,612,856)	(116,370,269)	(486,941,872)	(127,645,619)
2316									
2317	108OP	Other Production Plant - Accum Depr							
2318			P	S		-	-	(4,278)	(4,278)
2319			P	SG		-	-	-	-
2320			P	SG		(752,142,958)	(195,727,398)	376,504,462	97,976,373
2321			P	SG		(418,175,116)	(108,820,174)	(1,194,313,760)	(310,791,882)
2322			P	SG		(36,871,542)	(9,594,946)	(36,871,542)	(9,594,946)
2323					B17	(1,207,189,615)	(314,142,518)	(854,685,118)	(222,414,733)
2324									

Line	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
2325	108EP	Experimental Plant - Accum Depr							
2326			P	SG		-	-	-	-
2327			P	SG		-	-	-	-
2328						-	-	-	-
2330	**Total Production Plant Accum Depreciation**				**B17**	**(4,860,518,041)**	**(1,268,550,287)**	**(5,528,642,760)**	**(1,442,417,092)**
2332	Summary of Prod Plant Depreciation by Factor								
2333			S			14,278,093	-	14,273,815	(4,278)
2334			DGP			-	-	-	-
2335			DGU			-	-	-	-
2336			SG			(4,874,796,134)	(1,268,550,287)	(5,542,916,575)	(1,442,412,814)
2337			SSGCH			-	-	-	-
2338			SSGCT			-	-	-	-
2339	Total of Prod Plant Depreciation by Factor					(4,860,518,041)	(1,268,550,287)	(5,528,642,760)	(1,442,417,092)
2342	108TP	Transmission Plant Accumulated Depr							
2343			T	SG		(351,699,893)	(91,521,571)	(351,699,893)	(91,521,571)
2344			T	SG		(418,414,202)	(108,882,391)	(418,414,202)	(108,882,391)
2345			T	SG		(1,043,195,644)	(271,466,970)	(1,181,074,399)	(307,346,651)
2346	**Total Trans Plant Accum Depreciation**				**B17**	**(1,813,309,739)**	**(471,870,931)**	**(1,951,188,494)**	**(507,750,613)**
2347	108360	Land and Land Rights							
2348			DPW	S		(10,233,509)	(2,963,365)	(11,981,468)	(3,380,175)
2349					B17	(10,233,509)	(2,963,365)	(11,981,468)	(3,380,175)
2351	108361	Structures and Improvements							
2352			DPW	S		(28,147,776)	(7,888,962)	(31,496,619)	(8,687,512)
2353					B17	(28,147,776)	(7,888,962)	(31,496,619)	(8,687,512)
2355	108362	Station Equipment							
2356			DPW	S		(291,777,869)	(83,881,742)	(319,895,613)	(90,586,573)
2357					B17	(291,777,869)	(83,881,742)	(319,895,613)	(90,586,573)
2359	108363	Storage Battery Equipment							
2360			DPW	S		-	-	-	-
2361					B17	-	-	-	-
2363	108364	Poles, Towers & Fixtures							
2364			DPW	S		(659,772,406)	(264,470,557)	(693,612,399)	(272,539,052)
2365					B17	(659,772,406)	(264,470,557)	(693,612,399)	(272,539,052)
2367	108365	Overhead Conductors							
2368			DPW	S		(334,433,698)	(133,533,467)	(355,962,128)	(138,667,040)
2369					B17	(334,433,698)	(133,533,467)	(355,962,128)	(138,667,040)
2371	108366	Underground Conduit							
2372			DPW	S		(170,989,343)	(45,983,562)	(181,666,978)	(48,529,704)
2373					B17	(170,989,343)	(45,983,562)	(181,666,978)	(48,529,704)
2375	108367	Underground Conductors							
2376			DPW	S		(403,012,479)	(88,409,472)	(427,940,756)	(94,353,757)
2377					B17	(403,012,479)	(88,409,472)	(427,940,756)	(94,353,757)
2379	108368	Line Transformers							
2380			DPW	S		(543,787,041)	(237,387,679)	(582,181,086)	(246,542,952)
2381					B17	(543,787,041)	(237,387,679)	(582,181,086)	(246,542,952)
2383	108369	Services							
2384			DPW	S		(326,285,972)	(131,146,354)	(349,276,766)	(136,628,636)
2385					B17	(326,285,972)	(131,146,354)	(349,276,766)	(136,628,636)
2387	108370	Meters							
2388			DPW	S		(77,394,282)	(9,285,875)	(83,900,116)	(10,837,227)
2389					B17	(77,394,282)	(9,285,875)	(83,900,116)	(10,837,227)
2393	108371	Installations on Customers' Premises							
2394			DPW	S		(7,198,645)	(2,109,957)	(7,440,061)	(2,167,524)
2395					B17	(7,198,645)	(2,109,957)	(7,440,061)	(2,167,524)
2397	108372	Leased Property							
2398			DPW	S		-	-	-	-
2399					B17	-	-	-	-
2401	108373	Street Lights							
2402			DPW	S		(31,527,544)	(11,198,218)	(33,245,615)	(11,607,902)
2403					B17	(31,527,544)	(11,198,218)	(33,245,615)	(11,607,902)

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
2404									
2405	108D00	Unclassified Dist Plant - Acct 300							
2406			DPW	S		-	-	-	-
2407					B17	-	-	-	-
2408									
2409	108DS	Unclassified Dist Sub Plant - Acct 300							
2410			DPW	S		-	-	-	-
2411					B17	-	-	-	-
2412									
2413	108DP	Unclassified Dist Sub Plant - Acct 300							
2414			DPW	S		3,574,567	1,007,451	3,574,567	1,007,451
2415					B17	3,574,567	1,007,451	3,574,567	1,007,451
2416									
2417									
2418	**Total Distribution Plant Accum Depreciation**				**B17**	**(2,880,985,998)**	**(1,017,251,759)**	**(3,075,025,038)**	**(1,063,520,605)**
2419									
2420	Summary of Distribution Plant Depr by Factor								
2421		S				(2,880,985,998)	(1,017,251,759)	(3,075,025,038)	(1,063,520,605)
2422									
2423	Total Distribution Depreciation by Factor					(2,880,985,998)	(1,017,251,759)	(3,075,025,038)	(1,063,520,605)
2424	108GP	General Plant Accumulated Depr							
2425			G-SITUS	S		(247,578,241)	(84,544,724)	(269,066,423)	(91,828,418)
2426			G-DGP	SG		(843,233)	(219,431)	(843,233)	(219,431)
2427			G-DGU	SG		(2,907,693)	(756,658)	(2,907,693)	(756,658)
2428			G-SG	SG		(113,184,624)	(29,453,619)	(124,639,316)	(32,434,431)
2429			CUST	CN		(6,314,416)	(1,971,175)	(4,849,240)	(1,513,790)
2430			PTD	SO		(102,867,839)	(27,993,330)	(106,588,178)	(29,005,742)
2431			P	SE		(1,583,569)	(397,499)	(1,759,892)	(441,759)
2432			G-SG	SG		(110,482)	(28,750)	(110,482)	(28,750)
2433			G-SG	SG		(2,712,809)	(705,944)	(2,712,809)	(705,944)
2434					B17	(478,102,906)	(146,071,132)	(513,477,265)	(156,934,924)
2435									
2436									
2437	108MP	Mining Plant Accumulated Depr.							
2438			P	S		-	-	-	-
2439			P	SE		-	-	-	-
2440					B17	-	-	-	-
2441	108MP	Less Centralia Situs Depreciation							
2442			P	S		-	-	-	-
2443					B17	-	-	-	-
2444									
2445	1081390	Accum Depr - Capital Lease							
2446			PTD	SO	B17	-	-	-	-
2447						-	-	-	-
2448									
2449		Remove Capital Leases				-	-	-	-
2450					B17	-	-	-	-
2451									
2452	1081399	Accum Depr - Capital Lease							
2453			P	S		-	-	-	-
2454			P	SE	B17	-	-	-	-
2455						-	-	-	-
2456									
2457		Remove Capital Leases				-	-	-	-
2458					B17	-	-	-	-
2459									
2460									
2461	**Total General Plant Accum Depreciation**				**B17**	**(478,102,906)**	**(146,071,132)**	**(513,477,265)**	**(156,934,924)**
2462									
2463									
2464									
2465	Summary of General Depreciation by Factor								
2466		S				(247,578,241)	(84,544,724)	(269,066,423)	(91,828,418)
2467		DGP				-	-	-	-
2468		DGU				-	-	-	-
2469		SE				(1,583,569)	(397,499)	(1,759,892)	(441,759)
2470		SO				(102,867,839)	(27,993,330)	(106,588,178)	(29,005,742)
2471		CN				(6,314,416)	(1,971,175)	(4,849,240)	(1,513,790)
2472		SG				(119,758,841)	(31,164,403)	(131,213,533)	(34,145,215)
2473		DEU				-	-	-	-
2474		SSGCT				-	-	-	-
2475		SSGCH				-	-	-	-
2476		Remove Capital Leases				-	-	-	-
2477	Total General Depreciation by Factor					(478,102,906)	(146,071,132)	(513,477,265)	(156,934,924)
2478									
2479									
2480	**Total Accum Depreciation - Plant In Service**				**B17**	**(10,032,916,685)**	**(2,903,744,108)**	**(11,068,333,557)**	**(3,170,623,234)**

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
2481	111SP	Accum Prov for Amort-Steam							
2482			P	SG		-	-	-	-
2483			P	SG		-	-	-	-
2484					B18	-	-	-	-
2485									
2486									
2487	111GP	Accum Prov for Amort-General							
2488			G-SITUS	S		(11,076,917)	(4,176,900)	(11,687,824)	(4,551,753)
2489			CUST	CN		-	-	-	-
2490			I-SG	SG		-	-	-	-
2491			PTD	SO		(3,442,703)	(936,860)	(3,869,233)	(1,052,931)
2492			P	SE		-	-	-	-
2493					B18	(14,519,621)	(5,113,760)	(15,557,057)	(5,604,684)
2494									
2495									
2496	111HP	Accum Prov for Amort-Hydro							
2497			P	SG		-	-	-	-
2498			P	SG		-	-	-	-
2499			P	SG		(2,515,843)	(654,689)	(2,983,387)	(776,356)
2500			P	SG		-	-	-	-
2501					B18	(2,515,843)	(654,689)	(2,983,387)	(776,356)
2502									
2503									
2504	111IP	Accum Prov for Amort-Intangible Plant							
2505			I-SITUS	S		29,199,040	(105,941)	34,376,581	(114,464)
2506			I-DGP	SG		-	-	-	-
2507			I-DGU	SG		(489,827)	(127,466)	(489,827)	(127,466)
2508			P	SE		-	-	1,106,269	277,690
2509			I-SG	SG		(91,016,089)	(23,684,783)	(97,077,910)	(25,262,228)
2510			I-SG	SG		(105,420,483)	(27,433,185)	(112,901,800)	(29,380,021)
2511			I-SG	SG		(6,044,246)	(1,572,872)	(6,516,451)	(1,695,752)
2512			CUST	CN		(137,070,357)	(42,789,334)	(152,460,423)	(47,593,660)
2513			P	SG		-	-	-	-
2514			P	SG		(21,945)	(5,711)	(21,945)	(5,711)
2515			PTD	SO		(290,867,606)	(79,153,533)	(294,498,335)	(80,141,560)
2516					B18	(601,731,514)	(174,872,824)	(628,483,843)	(184,043,171)
2517	111IP	Less Non-Regulated Plant							
2518			NUTIL	OTH		-	-	-	-
2519						(601,731,514)	(174,872,824)	(628,483,843)	(184,043,171)
2520									
2521	111390	Accum Amtr - Capital Lease							
2522			G-SITUS	S		-	-	-	-
2523			P	SG		-	-	-	-
2524			PTD	SO		-	-	-	-
2525					B9	-	-	-	-
2526									
2527		Remove Capital Lease Amtr				-	-	-	-
2528									
2529	**Total Accum Provision for Amortization**				**B18**	**(618,766,978)**	**(180,641,272)**	**(647,024,287)**	**(190,424,211)**
2530									
2531									
2532									
2533									
2534	Summary of Amortization by Factor								
2535		S				18,122,122	(4,282,841)	22,688,757	(4,666,217)
2536		DGP				-	-	-	-
2537		DGU				-	-	-	-
2538		SE				-	-	1,106,269	277,690
2539		SO				(294,310,310)	(80,090,392)	(298,367,568)	(81,194,491)
2540		CN				(137,070,357)	(42,789,334)	(152,460,423)	(47,593,660)
2541		SSGCT				-	-	-	-
2542		SSGCH				-	-	-	-
2543		SG				(205,508,434)	(53,478,705)	(219,991,321)	(57,247,533)
2544		Less Capital Lease				-	-	-	-
2545	Total Provision For Amortization by Factor					(618,766,978)	(180,641,272)	(647,024,287)	(190,424,211)

Tab 3 - Revenues

Pacificorp
Oregon General Rate Case - December 2021
Tab 3 Adjustment Summary

	Total Adjustments	3.1 Pro Forma Revenue	3.2 Wheeling Revenue	3.3 REC Revenue	3.4 Ancillary Revenue
1 Operating Revenues:					
2 General Business Revenues	44,630,291	44,630,291	-	-	-
3 Interdepartmental	-	-	-	-	-
4 Special Sales	-	-	-	-	-
5 Other Operating Revenues	1,703,647	-	2,320,564	(946,387)	329,471
6 Total Operating Revenues	46,333,938	44,630,291	2,320,564	(946,387)	329,471
7					
8 Operating Expenses:					
9 Steam Production	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-
11 Hydro Production	-	-	-	-	-
12 Other Power Supply	-	-	-	-	-
13 Transmission	-	-	-	-	-
14 Distribution	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-
17 Sales	-	-	-	-	-
18 Administrative & General	-	-	-	-	-
19					
20 Total O&M Expenses	-	-	-	-	-
21		-	-	-	-
22 Depreciation	-	-	-	-	-
23 Amortization	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-
25 Income Taxes - Federal	9,287,901	8,946,395	465,170	(189,709)	66,044
26 Income Taxes - State	2,103,452	2,026,111	105,348	(42,964)	14,957
27 Income Taxes - Def Net	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-
30					
31 Total Operating Expenses:	11,391,353	10,972,506	570,518	(232,672)	81,001
32					
33 Operating Rev For Return:	34,942,585	33,657,785	1,750,045	(713,715)	248,469
34					
35 Rate Base:					
36 Electric Plant In Service	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-
41 Prepayments	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-
44 Working Capital	107,671	103,712	5,393	(2,199)	766
45 Weatherization Loans	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-
47					
48 Total Electric Plant:	107,671	103,712	5,393	(2,199)	766
49		-	-	-	-
50 Rate Base Deductions:		-	-	-	-
51 Accum Prov For Deprec	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-
53 Accum Def Income Tax	-	-	-	-	-
54 Unamortized ITC	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-
58		-	-	-	-
59 Total Rate Base Deductions	-	-	-	-	-
60		-	-	-	-
61 Total Rate Base:	107,671	103,712	5,393	(2,199)	766
62					
63 Return on Rate Base	0.940%	0.905%	0.047%	-0.019%	0.007%
64					
65 Return on Equity	1.756%	1.692%	0.088%	-0.036%	0.012%
66					
67 TAX CALCULATION:					
68 Operating Revenue	46,333,938	44,630,291	2,320,564	(946,387)	329,471
69 Other Deductions		-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-
71 Interest	2,387	2,299	120	(49)	17
72 Schedule "M" Additions	-	-	-	-	-
73 Schedule "M" Deductions	-	-	-	-	-
74 Income Before Tax	46,331,551	44,627,992	2,320,444	(946,339)	329,454
75					
76 State Income Taxes	2,103,452	2,026,111	105,348	(42,964)	14,957
77 Taxable Income	44,228,099	42,601,881	2,215,096	(903,375)	314,496
78					
79 Federal Income Taxes + Other	9,287,901	8,946,395	465,170	(189,709)	66,044
APPROXIMATE PRICE CHANGE	(47,850,349)	(46,090,980)	(2,396,464)	977,342	(340,247)

Tab 4 - Operations & Maintenance Expenses

Pacificorp
Oregon General Rate Case - December 2021
Tab 4 Adjustment Summary

		Total Adjustments	4.1_SR Miscellaneous General Expenses & Revenues	4.2_SR Wage & Employee Benefits Adjustment	4.3_R Revenue Sensitive Items & Uncollectible Expense	4.4_SR Insurance Expense	4.5 Generation Overhaul Expense	4.6_SR Memberships and Subscriptions
1	Operating Revenues:							
2	General Business Revenues	1,727,327	1,727,327	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-
5	Other Operating Revenues	950,885	-	-	-	-	-	-
6	Total Operating Revenues	2,678,212	1,727,327	-	-	-	-	-
7								
8	Operating Expenses:							
9	Steam Production	2,272,398	-	2,738,664	-	-	(400,846)	-
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	339,465	-	534,830	-	-	-	-
12	Other Power Supply	2,444,260	(1,344)	1,035,509	-	-	273,811	-
13	Transmission	977,903	-	822,148	-	-	-	-
14	Distribution	15,961,993	(161,609)	3,764,795	-	-	-	-
15	Customer Accounting	(1,516,429)	(23,549)	1,446,708	163,705	-	-	-
16	Customer Service & Info	(678,210)	(966,188)	280,647	-	-	-	-
17	Sales	-	-	-	-	-	-	-
18	Administrative & General	2,751,270	(91,407)	1,252,174	156,206	437,036	-	(182,039)
19								
20	Total O&M Expenses	22,552,649	(1,244,097)	11,875,475	319,911	437,036	(127,035)	(182,039)
21			-	-	-	-	-	-
22	Depreciation	-	-	-	-	-	-	-
23	Amortization	-	-	-	-	-	-	-
24	Taxes Other Than Income	1,108,422	-	-	1,108,422	-	-	-
25	Income Taxes - Federal	(4,391,417)	411,400	(2,381,005)	(286,377)	(87,625)	25,470	36,498
26	Income Taxes - State	(994,534)	93,171	(539,232)	(64,857)	(19,845)	5,768	8,266
27	Income Taxes - Def Net	-	-	-	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc Revenue & Expense	919,358	919,358	-	-	-	-	-
30								
31	Total Operating Expenses:	19,194,478	179,832	8,955,238	1,077,098	329,567	(95,796)	(137,275)
32								
33	Operating Rev For Return:	(16,516,265)	1,547,494	(8,955,238)	(1,077,098)	(329,567)	95,796	137,275
34								
35	Rate Base:							
36	Electric Plant In Service	-	-	-	-	-	-	-
37	Plant Held for Future Use	-	-	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-	-	-
44	Working Capital	172,736	(6,990)	84,645	10,181	3,115	(905)	(1,298)
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	172,736	(6,990)	84,645	10,181	3,115	(905)	(1,298)
49			-	-	-	-	-	-
50	Rate Base Deductions:		-	-	-	-	-	-
51	Accum Prov For Deprec	-	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	-	-	-	-	-	-	-
54	Unamortized ITC	-	-	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-	-	-
58			-	-	-	-	-	-
59	Total Rate Base Deductions	-	-	-	-	-	-	-
60			-	-	-	-	-	-
61	Total Rate Base:	172,736	(6,990)	84,645	10,181	3,115	(905)	(1,298)
62								
63	Return on Rate Base	-0.445%	0.042%	-0.241%	-0.029%	-0.009%	0.003%	0.004%
64								
65	Return on Equity	-0.831%	0.078%	-0.451%	-0.054%	-0.017%	0.005%	0.007%
66								
67	TAX CALCULATION:							
68	Operating Revenue	(21,902,217)	2,052,066	(11,875,475)	(1,428,332)	(437,036)	127,035	182,039
69	Other Deductions		-	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-	-
71	Interest	3,829	(155)	1,876	226	69	(20)	(29)
72	Schedule "M" Additions	-	-	-	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-	-	-
74	Income Before Tax	(21,906,046)	2,052,221	(11,877,351)	(1,428,558)	(437,105)	127,055	182,068
75								
76	State Income Taxes	(994,534)	93,171	(539,232)	(64,857)	(19,845)	5,768	8,266
77	Taxable Income	(20,911,511)	1,959,050	(11,338,119)	(1,363,701)	(417,260)	121,287	173,802
78								
79	Federal Income Taxes + Other	(4,391,417)	411,400	(2,381,005)	(286,377)	(87,625)	25,470	36,498
	APPROXIMATE PRICE CHANGE	22,643,238	(2,120,092)	12,274,472	1,472,565	451,778	(131,320)	(188,180)

Pacificorp
Oregon General Rate Case - December 202
Tab 4 Adjustment Summary

		4.7_R	4.8	4.9_SR	4.10	4.11_SR
		Incremental O&M Expense	Paperless Bill Credits Adjustment	Credit Facility Fees Adjustment	Remove Non-Recurring Entries	O&M Expense Escalation
1	Operating Revenues:					
2	General Business Revenues	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-
4	Special Sales	-	-	-	-	-
5	Other Operating Revenues	2,324,747	(1,373,862)	-	-	-
6	Total Operating Revenues	2,324,747	(1,373,862)	-	-	-
7						
8	Operating Expenses:					
9	Steam Production	-	-	-	-	(65,419)
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	-	-	-	-	(195,365)
12	Other Power Supply	1,093,227	-	-	192,438	(149,382)
13	Transmission	184,741	-	-	-	(28,987)
14	Distribution	12,566,249	-	-	-	(207,441)
15	Customer Accounting	(3,351,584)	-	-	-	248,291
16	Customer Service & Info	-	-	-	-	7,331
17	Sales	-	-	-	-	-
18	Administrative & General	-	-	412,657	-	766,643
19						
20	Total O&M Expenses	10,492,632	-	412,657	192,438	375,672
21		-	-	-	-	-
22	Depreciation	-	-	-	-	-
23	Amortization	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-
25	Income Taxes - Federal	(1,637,740)	(275,398)	(82,737)	(38,583)	(75,321)
26	Income Taxes - State	(370,903)	(62,370)	(18,738)	(8,738)	(17,058)
27	Income Taxes - Def Net	-	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-
30						
31	Total Operating Expenses:	8,483,990	(337,769)	311,183	145,117	283,292
32						
33	Operating Rev For Return:	(6,159,243)	(1,036,093)	(311,183)	(145,117)	(283,292)
34						
35	Rate Base:					
36	Electric Plant In Service	-	-	-	-	-
37	Plant Held for Future Use	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-
41	Prepayments	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-
44	Working Capital	80,191	(3,193)	2,941	1,372	2,678
45	Weatherization Loans	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-
47						
48	Total Electric Plant:	80,191	(3,193)	2,941	1,372	2,678
49		-	-	-	-	-
50	Rate Base Deductions:	-	-	-	-	-
51	Accum Prov For Deprec	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-
53	Accum Def Income Tax	-	-	-	-	-
54	Unamortized ITC	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-
58		-	-	-	-	-
59	Total Rate Base Deductions	-	-	-	-	-
60		-	-	-	-	-
61	Total Rate Base:	80,191	(3,193)	2,941	1,372	2,678
62						
63	Return on Rate Base	-0.166%	-0.028%	-0.008%	-0.004%	-0.008%
64						
65	Return on Equity	-0.310%	-0.052%	-0.016%	-0.007%	-0.014%
66						
67	TAX CALCULATION:					
68	Operating Revenue	(8,167,885)	(1,373,862)	(412,657)	(192,438)	(375,672)
69	Other Deductions	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-
71	Interest	1,778	(71)	65	30	59
72	Schedule "M" Additions	-	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-
74	Income Before Tax	(8,169,662)	(1,373,791)	(412,722)	(192,469)	(375,731)
75						
76	State Income Taxes	(370,903)	(62,370)	(18,738)	(8,738)	(17,058)
77	Taxable Income	(7,798,760)	(1,311,421)	(393,985)	(183,731)	(358,673)
78						
79	Federal Income Taxes + Other	(1,637,740)	(275,398)	(82,737)	(38,583)	(75,321)
	APPROXIMATE PRICE CHANGE	8,453,578	1,418,415	426,409	198,851	386,762

PacifiCorp PAGE 4.1_SR
Oregon General Rate Case - December 2021
Miscellaneous General Expense & Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Gain on Property Sales	421	1	(613,406)	SG	26.023%	(159,624)	
Gain on Property Sales	421	1	(105,668)	UT	Situs	-	
Gain on Property Sales	421	1	(62)	WA	Situs	-	
Gain on Property Sales	***421***	***1***	***3,965,281***	***SO***	***27.213%***	***1,079,068***	
Loss on Property Sales	421	1	7,672	SG	26.023%	1,996	
Loss on Property Sales	421	1	196	WYP	Situs	-	
Loss on Property Sales	421	1	81	OR	Situs	81	
Loss on Property Sales	421	1	(7,949)	SO	27.213%	(2,163)	
			3,246,145			919,358	4.1.1_R
Commercial and Industrial	442	1	1,727,327	OR	Situs	1,727,327	4.1.2
Adjustment to Expense:							
Other Expenses	557	1	(5,165)	SG	26.023%	(1,344)	
Distribution Expense	593	1	(161,609)	OR	Situs	(161,609)	
Customer Records	903	1	(4,389)	CN	31.217%	(1,370)	
Customer Records	903	1	(22,179)	OR	Situs	(22,179)	
Informational Advertising	909	1	(127,051)	CN	31.217%	(39,662)	
Informational Advertising	909	1	26,576	CA	Situs	-	
Informational Advertising	909	1	(926,526)	OR	Situs	(926,526)	
Informational Advertising	909	1	10,877	ID	Situs	-	
Informational Advertising	909	1	79,266	UT	Situs	-	
Informational Advertising	909	1	3,512	WA	Situs	-	
Informational Advertising	909	1	(962)	WY	Situs	-	
Administrative & General Salaries	920	1	(1,916)	SO	27.213%	(521)	
Office Supplies and Expense	***921***	***1***	***(263,662)***	***SO***	***27.213%***	***(71,750)***	
Outside Services	***923***	***1***	***(14,920)***	***SO***	***27.213%***	***(4,060)***	
Employee Pensions & Benefits	***926***	***1***	***(36,529)***	***SO***	***27.213%***	***(9,941)***	
Employee Pensions & Benefits	926	1	36,529	WA	Situs	-	
Regulatory Commission Expense	928	1	(10,940)	WY	Situs	-	
Regulatory Commission Expense	928	1	(8,037)	OR	Situs	(8,037)	
Regulatory Commission Expense	928	1	(9,536)	UT	Situs	-	
Regulatory Commission Expense	928	1	(268)	WA	Situs	-	
Regulatory Commission Expense	***928***	***1***	***28,780***	***SO***	***27.213%***	***7,832***	
Duplicate Charges	929	1	(18,115)	SO	27.213%	(4,930)	
Advertising	930	1	531	UT	Situs	-	
Total Miscellaneous General Expense Removal			(1,425,733)			(1,244,097)	4.1.1_R

Description of Adjustment:

This adjustment removes certain miscellaneous expenses that should have been charged below-the-line to non-regulated expenses. It also reallocates certain items such as gains and losses on property sales and regulatory commission expense to reflect the appropriate allocation among the Company's jurisdictions. In addition, it recognizes revenues from the Oregon Direct Access Opt Out amortization.

This adjustment has been updated to correct advertising allocations based on SDR 104 Supplemental update filed by the Company. It has also been updated based on Staff Testimony Exhibit 400, Cohen, Issue 3 - Category "A" Advertising expenses over limit authorized. Added an adjustment to custody fees recommended in Staff Testimony Exhibit 700, Soldavini, Issue 2 Affiliate Allocations, UI435 and OPUC 416.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Wages & Employee Benefits Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	5,552,763	SG	26.023%	1,444,975	
Fuel Related-Non NPC	501	3	10,102	SE	25.101%	2,536	
Steam Maintenance	512	3	4,961,655	SG	26.023%	1,291,153	
Hydro Operations	535	3	1,104,619	SG-P	26.023%	287,451	
Hydro Operations	535	3	615,347	SG-U	26.023%	160,130	
Hydro Maintenance	545	3	270,501	SG-P	26.023%	70,391	
Hydro Maintenance	545	3	64,781	SG-U	26.023%	16,858	
Other Operations	548	3	919,692	SG	26.023%	239,328	
Other Operations	549	3	4,005	OR	Situs	4,005	
Other Maintenance	553	3	258,204	SG	26.023%	67,191	
Other Power Supply Expenses	557	3	2,785,975	SG	26.023%	724,984	
Other Power Supply Expenses	557	3	4,860	ID	Situs	-	
Transmission Operations	560	3	1,783,884	SG	26.023%	464,214	
Transmission Maintenance	571	3	1,375,475	SG	26.023%	357,935	
Distribution Operations	***580***	***3***	***2,050,484***	***SNPD***	***26.853%***	***550,614***	
Distribution Operations	580	3	2,157,027	OR	Situs	623,181	
Distribution Maintenance	***593***	***3***	***660,904***	***SNPD***	***26.853%***	***177,472***	
Distribution Maintenance	593	3	7,460,649	OR	Situs	2,413,529	
Customer Accounts	903	3	2,772,261	CN	31.217%	865,418	
Customer Accounts	903	3	1,579,519	OR	Situs	581,290	
Customer Services	908	3	310,276	CN	31.217%	96,859	
Customer Services	908	3	5,531	OTHER	0.000%	-	
Customer Services	908	3	524,301	OR	Situs	183,787	
Administrative & General	***920***	***3***	***4,365,113***	***SO***	***27.213%***	***1,187,874***	
Administrative & General	920	3	40,149	OR	Situs	7,763	
Administrative & General	***935***	***3***	***202,869***	***SO***	***27.213%***	***55,207***	
Administrative & General	935	3	1,714	OR	Situs	1,331	
			41,842,660			11,875,475	4.2.2_R

Description of Adjustment:

This adjustment recognizes wage and benefit increases that have occurred, or are projected to occur during the twelve month period ending December 2021 for labor charged to operation & maintenance accounts. See page 4.2.1_R for more information on how this adjustment was calculated.

This adjustment has been updated in rebuttal for various corrections to underlying data.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
2020 Protocol FERC Spread

2020P Indicator	Actual 12 Months Ended June 2019	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2021	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2021 Oregon Allocated
500SG	13,461,410	1.917%	1,218,142	14,679,552	26.023%	316,993	3,820,006
502SG	19,112,019	2.721%	1,729,473	20,841,493	26.023%	450,054	5,423,505
503SE	111,639	0.016%	10,102	121,741	25.101%	2,536	30,559
505SG	2,437	0.000%	221	2,658	26.023%	57	692
506SG	28,786,463	4.099%	2,604,927	31,391,391	26.023%	677,871	8,168,866
510SG	3,748,990	0.534%	339,251	4,088,241	26.023%	88,282	1,063,868
511SG	8,727,910	1.243%	789,801	9,517,711	26.023%	205,527	2,476,759
512SG	27,458,737	3.910%	2,484,780	29,943,516	26.023%	646,605	7,792,091
513SG	12,399,234	1.765%	1,122,024	13,521,258	26.023%	291,980	3,518,587
514SG	2,495,258	0.355%	225,799	2,721,057	26.023%	58,759	708,091
535SG-P	4,682,667	0.667%	423,741	5,106,408	26.023%	110,269	1,328,822
535SG-U	1,660,557	0.236%	150,266	1,810,823	26.023%	39,103	471,224
536SG-P	32,637	0.005%	2,953	35,591	26.023%	769	9,262
537SG-P	662,490	0.094%	59,950	722,440	26.023%	15,600	187,998
537SG-U	58,994	0.008%	5,338	64,332	26.023%	1,389	16,741
539SG-P	6,828,515	0.972%	617,922	7,446,437	26.023%	160,800	1,937,759
539SG-U	5,080,514	0.723%	459,743	5,540,257	26.023%	119,637	1,441,721
540SG-P	512	0.000%	46	559	26.023%	12	145
541SG-P	73	0.000%	7	80	26.023%	2	21
542SG-P	295,994	0.042%	26,785	322,779	26.023%	6,970	83,996
542SG-U	13,861	0.002%	1,254	15,115	26.023%	326	3,933
543SG-P	470,039	0.067%	42,534	512,573	26.023%	11,069	133,385
543SG-U	381,043	0.054%	34,481	415,524	26.023%	8,973	108,130
544SG-P	1,250,686	0.178%	113,176	1,363,862	26.023%	29,451	354,913
544SG-U	217,636	0.031%	19,694	237,330	26.023%	5,125	61,760
545SG-P	972,521	0.138%	88,005	1,060,526	26.023%	22,901	275,977
545SG-U	103,342	0.015%	9,352	112,693	26.023%	2,434	29,326
546SG	(121,280)	-0.017%	(10,975)	(132,254)	26.023%	(2,856)	(34,416)
548SG	6,139,285	0.874%	555,552	6,694,837	26.023%	144,569	1,742,173
549OR	44,262	0.006%	4,005	48,267	100.000%	4,005	48,267
549SG	4,145,301	0.590%	375,114	4,520,415	26.023%	97,615	1,176,331
552SG	1,037,918	0.148%	93,923	1,131,841	26.023%	24,441	294,535
553SG	1,718,541	0.245%	155,513	1,874,055	26.023%	40,469	487,678
554SG	96,895	0.014%	8,768	105,663	26.023%	2,282	27,496
556SG	507,745	0.072%	45,947	553,691	26.023%	11,957	144,085
557ID	53,712	0.008%	4,860	58,572	0.000%	-	-
557SG	30,279,431	4.311%	2,740,028	33,019,459	26.023%	713,027	8,592,532
560SG	6,789,975	0.967%	614,434	7,404,409	26.023%	159,892	1,926,822
561SG	10,354,725	1.474%	937,014	11,291,738	26.023%	243,836	2,938,408
562SG	1,771,816	0.252%	160,334	1,932,150	26.023%	41,723	502,796
563SG	583,916	0.083%	52,839	636,755	26.023%	13,750	165,700
566SG	65,140	0.009%	5,895	71,035	26.023%	1,534	18,485
567SG	147,727	0.021%	13,368	161,095	26.023%	3,479	41,921
568SG	1,243,672	0.177%	112,542	1,356,213	26.023%	29,286	352,922
569SG	3,236,813	0.461%	292,904	3,529,716	26.023%	76,221	918,525
570SG	7,186,959	1.023%	650,358	7,837,317	26.023%	169,240	2,039,476
571SG	3,504,357	0.499%	317,114	3,821,471	26.023%	82,521	994,447
572SG	28,267	0.004%	2,558	30,825	26.023%	666	8,022
580ID	1,202	0.000%	109	1,310	0.000%	-	-
580OR	258,359	0.037%	23,379	281,738	100.000%	23,379	281,738
580SNPD	***7,125,836***	***1.015%***	***644,827***	***7,770,663***	***26.853%***	***173,154***	***2,086,646***
580UT	374,658	0.053%	33,903	408,561	0.000%	-	-
580WA	101,964	0.015%	9,227	111,191	0.000%	-	-
580WYP	93,887	0.013%	8,496	102,383	0.000%	-	-
581SNPD	***12,379,980***	***1.763%***	***1,120,282***	***13,500,262***	***26.853%***	***300,828***	***3,625,207***
582CA	32,559	0.005%	2,946	35,506	0.000%	-	-
582ID	398,191	0.057%	36,033	434,224	0.000%	-	-
582OR	340,494	0.048%	30,812	371,306	100.000%	30,812	371,306
582SNPD	***3,277***	***0.000%***	***297***	***3,574***	***26.853%***	***80***	***960***
582UT	970,520	0.138%	87,824	1,058,344	0.000%	-	-
582WA	98,366	0.014%	8,901	107,267	0.000%	-	-
582WYP	436,380	0.062%	39,489	475,869	0.000%	-	-
583CA	196,788	0.028%	17,808	214,596	0.000%	-	-
583ID	260,045	0.037%	23,532	283,577	0.000%	-	-
583OR	1,304,513	0.186%	118,047	1,422,560	100.000%	118,047	1,422,560
583SNPD	***165***	***0.000%***	***15***	***180***	***26.853%***	***4***	***48***
583UT	4,336,793	0.617%	392,442	4,729,235	0.000%	-	-
583WA	184,683	0.026%	16,712	201,395	0.000%	-	-
583WYP	349,085	0.050%	31,589	380,674	0.000%	-	-
583WYU	104,858	0.015%	9,489	114,347	0.000%	-	-
585SNPD	***208,034***	***0.030%***	***18,825***	***226,859***	***26.853%***	***5,055***	***60,918***
586CA	66,432	0.009%	6,011	72,443	0.000%	-	-
586ID	161,401	0.023%	14,605	176,006	0.000%	-	-
586OR	579,652	0.083%	52,454	632,106	100.000%	52,454	632,106

PacifiCorp
Oregon General Rate Case - December 2021
2020 Protocol FERC Spread

2020P Indicator	Actual 12 Months Ended June 2019	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2021	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2021 Oregon Allocated
586UT	700,794	0.100%	63,416	764,210	0.000%	-	-
586WA	248,559	0.035%	22,492	271,051	0.000%	-	-
586WYP	285,093	0.041%	25,798	310,891	0.000%	-	-
586WYU	89,734	0.013%	8,120	97,855	0.000%	-	-
587CA	472,414	0.067%	42,749	515,164	0.000%	-	-
587ID	710,539	0.101%	64,298	774,837	0.000%	-	-
587OR	4,306,255	0.613%	389,679	4,695,934	100.000%	389,679	4,695,934
587UT	3,994,768	0.569%	361,492	4,356,261	0.000%	-	-
587WA	1,021,229	0.145%	92,412	1,113,641	0.000%	-	-
587WYP	867,257	0.123%	78,479	945,737	0.000%	-	-
587WYU	105,851	0.015%	9,579	115,430	0.000%	-	-
588CA	18,519	0.003%	1,676	20,195	0.000%	-	-
588ID	(3,752)	-0.001%	(340)	(4,092)	0.000%	-	-
588OR	16,192	0.002%	1,465	17,657	100.000%	1,465	17,657
588SNPD	***2,942,138***	***0.419%***	***266,238***	***3,208,376***	***26.853%***	***71,493***	***861,541***
588UT	(91,697)	-0.013%	(8,298)	(99,995)	0.000%	-	-
588WA	(2,896)	0.000%	(262)	(3,158)	0.000%	-	-
588WYP	2,419	0.000%	219	2,638	0.000%	-	-
588WYU	(41,930)	-0.006%	(3,794)	(45,724)	0.000%	-	-
589CA	8,786	0.001%	795	9,581	0.000%	-	-
589ID	11,232	0.002%	1,016	12,249	0.000%	-	-
589OR	81,164	0.012%	7,345	88,509	100.000%	7,345	88,509
589UT	272,483	0.039%	24,657	297,140	0.000%	-	-
589WA	14,361	0.002%	1,300	15,661	0.000%	-	-
589WYP	93,248	0.013%	8,438	101,686	0.000%	-	-
589WYU	5,362	0.001%	485	5,848	0.000%	-	-
590CA	105,593	0.015%	9,555	115,148	0.000%	-	-
590ID	134,688	0.019%	12,188	146,876	0.000%	-	-
590OR	849,596	0.121%	76,881	926,477	100.000%	76,881	926,477
590SNPD	***2,445,065***	***0.348%***	***221,257***	***2,666,322***	***26.853%***	***59,414***	***715,984***
590UT	1,376,780	0.196%	124,587	1,501,366	0.000%	-	-
590WA	189,439	0.027%	17,143	206,582	0.000%	-	-
590WYP	484,395	0.069%	43,834	528,229	0.000%	-	-
592CA	190,045	0.027%	17,197	207,243	0.000%	-	-
592ID	203,012	0.029%	18,371	221,382	0.000%	-	-
592OR	1,875,579	0.267%	169,724	2,045,303	100.000%	169,724	2,045,303
592SNPD	***1,729,019***	***0.246%***	***156,461***	***1,885,480***	***26.853%***	***42,014***	***506,305***
592UT	2,250,004	0.320%	203,606	2,453,610	0.000%	-	-
592WA	206,992	0.029%	18,731	225,723	0.000%	-	-
592WYP	709,888	0.101%	64,239	774,127	0.000%	-	-
592WYU	30,006	0.004%	2,715	32,721	0.000%	-	-
593CA	3,448,003	0.491%	312,015	3,760,017	0.000%	-	-
593ID	3,367,055	0.479%	304,690	3,671,745	0.000%	-	-
593OR	19,415,268	2.764%	1,756,915	21,172,183	100.000%	1,756,915	21,172,183
593SNPD	***1,094,385***	***0.156%***	***99,032***	***1,193,417***	***26.853%***	***26,593***	***320,467***
593UT	22,147,383	3.153%	2,004,148	24,151,531	0.000%	-	-
593WA	3,211,435	0.457%	290,607	3,502,042	0.000%	-	-
593WYP	6,283,331	0.895%	568,587	6,851,918	0.000%	-	-
593WYU	626,614	0.089%	56,703	683,317	0.000%	-	-
594CA	331,646	0.047%	30,011	361,657	0.000%	-	-
594ID	418,411	0.060%	37,863	456,274	0.000%	-	-
594OR	3,669,311	0.522%	332,041	4,001,352	100.000%	332,041	4,001,352
594SNPD	***20,194***	***0.003%***	***1,827***	***22,021***	***26.853%***	***491***	***5,913***
594UT	7,472,596	1.064%	676,206	8,148,801	0.000%	-	-
594WA	808,165	0.115%	73,132	881,298	0.000%	-	-
594WYP	623,949	0.089%	56,462	680,411	0.000%	-	-
594WYU	100,809	0.014%	9,122	109,931	0.000%	-	-
595SNPD	***787,964***	***0.112%***	***71,304***	***859,267***	***26.853%***	***19,147***	***230,738***
596CA	66,093	0.009%	5,981	72,074	0.000%	-	-
596ID	73,179	0.010%	6,622	79,802	0.000%	-	-
596OR	618,374	0.088%	55,958	674,332	100.000%	55,958	674,332
596UT	200,415	0.029%	18,136	218,551	0.000%	-	-
596WA	108,699	0.015%	9,836	118,536	0.000%	-	-
596WYP	241,754	0.034%	21,877	263,631	0.000%	-	-
596WYU	39,898	0.006%	3,610	43,508	0.000%	-	-
597CA	16,483	0.002%	1,492	17,975	0.000%	-	-
597ID	33,478	0.005%	3,029	36,507	0.000%	-	-
597OR	200,267	0.029%	18,122	218,389	100.000%	18,122	218,389
597SNPD	***(231,006)***	***-0.033%***	***(20,904)***	***(251,911)***	***26.853%***	***(5,613)***	***(67,645)***
597UT	188,362	0.027%	17,045	205,407	0.000%	-	-
597WA	25,868	0.004%	2,341	28,209	0.000%	-	-
597WYP	29,749	0.004%	2,692	32,441	0.000%	-	-
597WYU	11,854	0.002%	1,073	12,927	0.000%	-	-
598CA	7,656	0.001%	693	8,349	0.000%	-	-

PacifiCorp
Oregon General Rate Case - December 2021
2020 Protocol FERC Spread

2020P Indicator	Actual 12 Months Ended June 2019	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2021	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2021 Oregon Allocated
598OR	42,966	0.006%	3,888	46,854	100.000%	3,888	46,854
598SNPD	***1,457,878***	***0.208%***	***131,925***	***1,589,803***	***26.853%***	***35,426***	***426,908***
598WA	10,859	0.002%	983	11,842	0.000%	-	-
901CN	2,071,551	0.295%	187,458	2,259,008	31.217%	58,519	705,196
902CA	529,531	0.075%	47,918	577,449	0.000%	-	-
902CN	493,516	0.070%	44,659	538,175	31.217%	13,941	168,002
902ID	1,778,805	0.253%	160,967	1,939,772	0.000%	-	-
902OR	5,378,245	0.766%	486,685	5,864,930	100.000%	486,685	5,864,930
902UT	3,504,392	0.499%	317,117	3,821,509	0.000%	-	-
902WA	483,624	0.069%	43,764	527,388	0.000%	-	-
902WYP	823,511	0.117%	74,521	898,032	0.000%	-	-
902WYU	176,923	0.025%	16,010	192,933	0.000%	-	-
903CA	139,957	0.020%	12,665	152,622	0.000%	-	-
903CN	28,070,562	3.997%	2,540,144	30,610,707	31.217%	792,958	9,555,762
903ID	270,827	0.039%	24,508	295,335	0.000%	-	-
903OR	1,045,460	0.149%	94,605	1,140,066	100.000%	94,605	1,140,066
903UT	2,537,235	0.361%	229,598	2,766,833	0.000%	-	-
903WA	355,965	0.051%	32,212	388,176	0.000%	-	-
903WYP	360,029	0.051%	32,579	392,608	0.000%	-	-
903WYU	70,400	0.010%	6,371	76,771	0.000%	-	-
907CN	(8,828)	-0.001%	(799)	(9,627)	31.217%	(249)	(3,005)
908CA	42,192	0.006%	3,818	46,010	0.000%	-	-
908CN	2,143,251	0.305%	193,946	2,337,197	31.217%	60,544	729,604
908ID	(456)	0.000%	(41)	(497)	0.000%	-	-
908OR	2,030,993	0.289%	183,787	2,214,780	100.000%	183,787	2,214,780
908OTHER	61,125	0.009%	5,531	66,657	0.000%	-	-
908UT	2,429,917	0.346%	219,887	2,649,803	0.000%	-	-
908WA	337,255	0.048%	30,519	367,773	0.000%	-	-
908WYP	954,027	0.136%	86,331	1,040,358	0.000%	-	-
909CN	1,293,631	0.184%	117,063	1,410,694	31.217%	36,543	440,377
910CN	740	0.000%	67	807	31.217%	21	252
920OR	0.48	0.000%	0.04	0.52	100.000%	0	0.52
920SO	***76,668,180***	***10.916%***	***6,937,811***	***83,605,990***	***27.213%***	***1,887,980***	***22,751,621***
921SO	***2,052,875***	***0.292%***	***185,768***	***2,238,642***	***27.213%***	***50,553***	***609,200***
922SO	***(27,605,572)***	***-3.931%***	***(2,498,067)***	***(30,103,639)***	***27.213%***	***(679,797)***	***(8,192,075)***
925SO	***1,195***	***0.000%***	***108***	***1,303***	***27.213%***	***29***	***355***
928CA	165,614	0.024%	14,987	180,601	0.000%	-	-
928ID	35,586	0.005%	3,220	38,806	0.000%	-	-
928OR	85,782	0.012%	7,763	93,545	100.000%	7,763	93,545
928SO	***490,819***	***0.070%***	***44,415***	***535,234***	***27.213%***	***12,087***	***145,653***
928UT	66,659	0.009%	6,032	72,691	0.000%	-	-
928WA	3,640	0.001%	329	3,969	0.000%	-	-
928WYP	86,394	0.012%	7,818	94,212	0.000%	-	-
929SO	***(3,369,621)***	***-0.480%***	***(304,922)***	***(3,674,542)***	***27.213%***	***(82,978)***	***(999,950)***
935CA	4,037	0.001%	365	4,403	0.000%	-	-
935OR	14,708	0.002%	1,331	16,039	100.000%	1,331	16,039
935SO	***2,241,864***	***0.319%***	***202,869***	***2,444,733***	***27.213%***	***55,207***	***665,283***
935WA	33	0.000%	3	36	0.000%	-	-
935WYP	164	0.000%	15	179	0.000%	-	-
Utility Labor	**462,393,780**	**65.83603%**	**41,842,660**	**504,236,441**		***11,875,475***	***143,108,664***
						Ref 4.2_SR	
Capital/Non Utility	239,947,739	34.16397%	21,713,207	261,660,946			
Total Labor	**702,341,520**	**100.00%**	**63,555,867**	**765,897,386**			
	Ref 4.2.2_R		**Ref 4.2.2_R**	**Ref 4.2.2_R**			

PacifiCorp
Oregon General Rate Case - December 2021
Insurance Expense

	ACCOUNT	TYPE	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Base Pd. Inj & Damage	***925***	***1***	***(13,822,515)***	***SO***	***27.213%***	***(3,761,508)***	***4.4.1***
Remove Base Pd. Inj & Damage	925	1	21,503	OR	Situs	21,503	4.4.1
Adj. Inj & Damage to 5-yr avg.	***925***	***3***	***1,096,675***	***OR***	***Situs***	***1,096,675***	***4.4.2_SR***
Adjust property damage expense to 10-year average							
Property Insurance - Transmission	924	3	96,958	OR	Situs	96,958	4.4.3
Property Insurance - OR Dist.	924	3	1,697,875	OR	Situs	1,697,875	4.4.3
Property Insurance - Non-T&D	924	3	(260,864)	OR	Situs	(260,864)	4.4.3
Adj. Liability Insurance Prem.	***925***	***3***	***7,287,606***	***SO***	***27.213%***	***1,983,169***	***4.4.4_R***
Adj. Property Insurance Prem.	***924***	***3***	***(1,605,022)***	***SO***	***27.213%***	***(436,773)***	***4.4.4_R***

Description

This adjustment removes the accrued level of injuries and damages from the base period and recalculates the Oregon-allocated five-year average, using the most recent five-year time period. The adjustment also recalculates the historical 10-year average Oregon-allocated property damage amount using the most recent 10-year time period. The insurance premiums in the base period have been adjusted to those in the Company's the most current renewal.

The Company's rebuttal position updates the Company's premium renewal amounts to levels expected in the Test Period.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Insurance Expense
Provision for Injuries & Damages
5-Year Average

	Accruals to Injuries & Damages Reserve				Accruals for Insurance Recovery			
	Accruals to Expense	Amount not Seeking Recovery	5 - Year Avg to Recover		Accrual for Ins Recovery	Amount not Seeking Recovery	5 - Year Avg to Recovery	
12 Months Ended June 2015	18,507,160	16,228,767			(15,719,453)	(15,417,329)		
12 Months Ended June 2016	2,674,843	2,456,033			(10,586,667)	(3,586,667)		
12 Months Ended June 2017	1,321,158	(6,783,392)			1,262,587	5,762,587		
12 Months Ended June 2018	4,700,124	(1,234,110)			2,496,412	846,412		
12 Months Ended June 2019	13,729,796	(36,250)			36,750	36,750		
Average Accrual	8,186,616	2,126,210	6,060,407	Below	(4,502,074)	(2,471,649)	(2,030,425)	Below

5 Year Average of Accruals to Injuries & Damages Reserve	6,060,407	Above
5 Year Average of Accruals for Insurance Recovery	(2,030,425)	Above
5 Year Normalized Average	4,029,982	
Oregon SO Allocation %	***27.213%***	
Oregon Allocated Annual Accrual	***1,096,675***	
	Ref 4.4_SR	

PacifiCorp
Oregon General Rate Case - December 2021
Memberships & Subscriptions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Total Memberships and Subscriptions							
	930	***1***	***(1,665,097)***	***SO***	***27.213%***	***(453,121)***	
	930	1	(34,000)	OR	Situs	(34,000)	
Total			(1,699,097)			(487,121)	4.6.1
Add Back 75% of National & Regional Memberships							
Various	***930***	***1***	***1,121,094***	***SO***	***27.213%***	***305,082***	***4.6.2***
Total			1,121,094			305,082	

Description of Adjustment:

This adjustment removes expenses in excess of Commission policy allowances as stated in the Commission order in UE-94. National and regional trade organizations are recognized at 75%. Western Electricity Coordinating Council and Northern Tier Transmission Group fees are included at 100%. These fees are no longer included in FERC account 930 and are not shown in this adjustment. The fees for these two organizations are now being booked to FERC account 561.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Credit Facility Fee Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Credit facility fee expense	***921***	***1***	***1,516,402***	***SO***	***27.213%***	***412,657***	***4.9.1***

Description of Adjustment:

This adjustment adds the credit facilities and associated commitment fees which are a requirement for the company to have access to short-term borrowing or commercial paper to administrative and general expenses.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	(23,404)	SG	26.023%	(6,090)	
Steam Operations	500	3	(26,993)	SG	26.023%	(7,024)	
Steam Operations	501	3	(161,510)	SE	25.101%	(40,541)	
Steam Operations	501	3	(30,903)	SE	25.101%	(7,757)	
Steam Operations	501	3	1,484	OR	Situs	-	
Steam Operations	502	3	(607,178)	SG	26.023%	(158,004)	
Steam Operations	502	3	(84,810)	SG	26.023%	(22,070)	
Steam Operations	503	3	1,224	SE	25.101%	307	
Steam Operations	505	3	-	SG	26.023%	-	
Steam Operations	505	3	(13,881)	SG	26.023%	(3,612)	
Steam Operations	505	3	(3,266)	SG	26.023%	(850)	
Steam Operations	506	3	35,440	SG	26.023%	9,223	
Steam Operations	506	3	17,278	SG	26.023%	4,496	
Steam Operations	506	3	(22,335)	SG	26.023%	(5,812)	
Steam Operations	507	3	-	SG	26.023%	-	
Steam Operations	507	3	(5,654)	SG	26.023%	(1,471)	
Steam Operations	507	3	-	SG	26.023%	-	
Steam Maintenance	510	3	(8,481)	SG	26.023%	(2,207)	
Steam Maintenance	510	3	8,934	SG	26.023%	2,325	
Steam Maintenance	510	3	14,970	SG	26.023%	3,896	
Steam Maintenance	511	3	79,023	SG	26.023%	20,564	
Steam Maintenance	511	3	20,427	SG	26.023%	5,316	
Steam Maintenance	512	3	-	SG	26.023%	-	
Steam Maintenance	512	3	340,822	SG	26.023%	88,691	
Steam Maintenance	512	3	33,811	SG	26.023%	8,798	
Steam Maintenance	513	3	-	SG	26.023%	-	
Steam Maintenance	513	3	124,378	SG	26.023%	32,366	
Steam Maintenance	513	3	4,910	SG	26.023%	1,278	
Steam Maintenance	514	3	34,610	SG	26.023%	9,006	
Steam Maintenance	514	3	8,725	SG	26.023%	2,271	
Hydro Operations	535	3	(164,160)	SG	26.023%	(42,719)	
Hydro Operations	535	3	41,575	SG	26.023%	10,819	
Hydro Operations	536	3	(328)	SG	26.023%	(85)	
Hydro Operations	536	3	-	SG	26.023%	-	
Hydro Operations	537	3	(169,330)	SG	26.023%	(44,064)	
Hydro Operations	537	3	(15,378)	SG	26.023%	(4,002)	
Hydro Operations	539	3	(273,124)	SG	26.023%	(71,074)	
Hydro Operations	539	3	(106,338)	SG	26.023%	(27,672)	
Hydro Operations	540	3	(62,546)	SG	26.023%	(16,276)	
Hydro Operations	540	3	(2,668)	SG	26.023%	(694)	
			(1,014,677)			(262,671)	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2019 to December 2021 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2019 actual data was separated into labor and non-labor components and costs that should not be included in December 2021 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

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PacifiCorp
Oregon General Rate Case - December 2021
(cont.) O&M Expense Escalation

PAGE 4.11.1_SR

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Hydro Maintenance	541	3	0	SG	26.023%	0	
Hydro Maintenance	541	3	-	SG	26.023%	-	
Hydro Maintenance	542	3	67	SG	26.023%	17	
Hydro Maintenance	542	3	4	SG	26.023%	1	
Hydro Maintenance	543	3	164	SG	26.023%	43	
Hydro Maintenance	543	3	87	SG	26.023%	23	
Hydro Maintenance	544	3	157	SG	26.023%	41	
Hydro Maintenance	544	3	26	SG	26.023%	7	
Hydro Maintenance	545	3	832	SG	26.023%	216	
Hydro Maintenance	545	3	210	SG	26.023%	55	
Other Operations	546	3	(9,784)	SG	26.023%	(2,546)	
Other Operations	546	3	-	SG	26.023%	-	
Other Operations	547	3	-	SE	25.101%	-	
Other Operations	547	3	-	SE	25.101%	-	
Other Operations	548	3	(278,733)	SG	26.023%	(72,534)	
Other Operations	548	3	-	SG	26.023%	-	
Other Operations	548	3	(4,569)	SG	26.023%	(1,189)	
Other Operations	549	3	(1,263)	OR	Situs	(1,263)	
Other Operations	549	3	9	SG	26.023%	2	
Other Operations	549	3	1,174	SG	26.023%	305	
Other Operations	549	3	(24,739)	SG	26.023%	(6,438)	
Other Operations	550	3	(7,016)	OR	Situs	(7,016)	
Other Operations	550	3	-	SG	26.023%	-	
Other Operations	550	3	(962)	SG	26.023%	(250)	
Other Operations	550	3	(87,850)	SG	26.023%	(22,861)	
Other Operations	550	3	-	SG	26.023%	-	
Other Maintenance	552	3	-	SG	26.023%	-	
Other Maintenance	552	3	18,373	SG	26.023%	4,781	
Other Maintenance	552	3	452	SG	26.023%	118	
Other Maintenance	553	3	7,501	SG	26.023%	1,952	
Other Maintenance	553	3	97,043	SG	26.023%	25,253	
Other Maintenance	553	3	29,677	SG	26.023%	7,723	
Other Maintenance	553	3	2,391	SG	26.023%	622	
Other Maintenance	554	3	-	SG	26.023%	-	
Other Maintenance	554	3	9,593	SG	26.023%	2,496	
Other Maintenance	554	3	19,001	SG	26.023%	4,944	
Other Maintenance	554	3	969	SG	26.023%	252	
Other Operations	556	3	(9,797)	SG	26.023%	(2,549)	
			(236,985)			(67,794)	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2019 to December 2021 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2019 actual data was separated into labor and non-labor components and costs that should not be included in December 2021 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

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PacifiCorp
Oregon General Rate Case - December 2021
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Other Operations	557	3	(133,360)	OR	Situs	(40,982)	
Other Operations	557	3	(154,278)	SG	26.023%	(40,147)	
Other Operations	557	3	(224)	SE	25.101%	(56)	
Other Operations	557	3	-	SG	26.023%	-	
Transmission Operations	560	3	3,823	SG	26.023%	995	
Transmission Operations	561	3	73,806	SG	26.023%	19,206	
Transmission Operations	562	3	7,784	SG	26.023%	2,026	
Transmission Operations	563	3	3,479	SG	26.023%	905	
Transmission Operations	566	3	21,482	SG	26.023%	5,590	
Transmission Operations	567	3	15,106	SG	26.023%	3,931	
Transmission Maintenance	568	3	(1,255)	SG	26.023%	(327)	
Transmission Maintenance	569	3	(30,197)	SG	26.023%	(7,858)	
Transmission Maintenance	570	3	(54,869)	SG	26.023%	(14,278)	
Transmission Maintenance	571	3	(148,666)	SG	26.023%	(38,687)	
Transmission Maintenance	572	3	(111)	SG	26.023%	(29)	
Transmission Maintenance	573	3	(1,772)	SG	26.023%	(461)	
Distribution Operations	580	3	700	OR	Situs	161	
Distribution Operations	***580***	***3***	***2,777***	***SNPD***	***26.853%***	***746***	
Distribution Operations	581	3	-	OR	Situs	-	
Distribution Operations	***581***	***3***	***(655)***	***SNPD***	***26.853%***	***(176)***	
Distribution Operations	582	3	7,659	OR	Situs	2,267	
Distribution Operations	582	3	1	SNPD	26.853%	0	
Distribution Operations	583	3	7,503	OR	Situs	1,102	
Distribution Operations	583	3	(0)	SNPD	26.853%	(0)	
Distribution Operations	584	3	6	OR	Situs	2	
Distribution Operations	584	3	-	SNPD	26.853%	-	
Distribution Operations	585	3	15	SNPD	26.853%	4	
Distribution Operations	586	3	1,574	OR	Situs	516	
Distribution Operations	586	3	-	SNPD	26.853%	-	
Distribution Operations	587	3	10,533	OR	Situs	3,807	
Distribution Operations	587	3	-	SNPD	26.853%	-	
Distribution Operations	588	3	(258)	OR	Situs	198	
Distribution Operations	***588***	***3***	***(6,613)***	***SNPD***	***26.853%***	***(1,776)***	
Distribution Operations	589	3	7,537	OR	Situs	4,820	
Distribution Operations	589	3	41	SNPD	26.853%	11	
Distribution Maintenance	590	3	(4,635)	OR	Situs	(1,477)	
Distribution Maintenance	***590***	***3***	***(655)***	***SNPD***	***26.853%***	***(176)***	
Distribution Maintenance	591	3	(32,057)	OR	Situs	(6,540)	
Distribution Maintenance	***591***	***3***	***(2,697)***	***SNPD***	***26.853%***	***(724)***	
Distribution Maintenance	592	3	(35,430)	OR	Situs	(11,473)	
Distribution Maintenance	***592***	***3***	***(1,855)***	***SNPD***	***26.853%***	***(498)***	
			(445,761)			(119,380)	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2019 to December 2021 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2019 actual data was separated into labor and non-labor components and costs that should not be included in December 2021 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

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PacifiCorp
Oregon General Rate Case - December 2021
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Distribution Maintenance	593	3	(424,241)	OR	Situs	(125,296)	
Distribution Maintenance	***593***	***3***	***(16,455)***	***SNPD***	***26.853%***	***(4,419)***	
Distribution Maintenance	594	3	(183,805)	OR	Situs	(38,263)	
Distribution Maintenance	594	3	(66)	SNPD	26.853%	(18)	
Distribution Maintenance	595	3	-	OR	Situs	-	
Distribution Maintenance	***595***	***3***	***(2,534)***	***SNPD***	***26.853%***	***(681)***	
Distribution Maintenance	596	3	(23,257)	OR	Situs	(3,448)	
Distribution Maintenance	597	3	(2,023)	OR	Situs	(869)	
Distribution Maintenance	597	3	512	SNPD	26.853%	138	
Distribution Maintenance	598	3	(25,263)	OR	Situs	(8,599)	
Distribution Maintenance	***598***	***3***	***(62,497)***	***SNPD***	***26.853%***	***(16,782)***	
Customer Accounts Operations	901	3	4	OR	Situs	-	
Customer Accounts Operations	901	3	12,910	CN	31.217%	4,030	
Customer Accounts Operations	902	3	79,484	OR	Situs	38,568	
Customer Accounts Operations	902	3	5,227	CN	31.217%	1,632	
Customer Accounts Operations	903	3	38,017	OR	Situs	14,157	
Customer Accounts Operations	903	3	285,573	CN	31.217%	89,148	
Customer Accounts Operations	904	3	280,786	OR	Situs	100,194	
Customer Accounts Operations	904	3	1,344	CN	31.217%	420	
Customer Accounts Operations	905	3	8,710	OR	Situs	-	
Customer Accounts Operations	905	3	460	CN	31.217%	144	
Customer Service Operations	907	3	41	CN	31.217%	13	
Customer Service Operations	908	3	1,527	OR	Situs	298	
Customer Service Operations	908	3	2,542	CN	31.217%	793	
Customer Service Operations	908	3	379,151	OTHER	0.000%	-	
Customer Service Operations	909	3	16,354	OR	Situs	4,406	
Customer Service Operations	909	3	5,764	CN	31.217%	1,799	
Customer Service Operations	910	3	-	OR	Situs	-	
Customer Service Operations	910	3	70	CN	31.217%	22	
A&G Operations	920	3	(2)	OR	Situs	(2)	
A&G Operations	***920***	***3***	***(132,714)***	***SO***	***27.213%***	***(36,115)***	
A&G Operations	921	3	2,424	CN	31.217%	757	
A&G Operations	921	3	7,352	OR	Situs	1,541	
A&G Operations	***921***	***3***	***226,583***	***SO***	***27.213%***	***61,660***	
A&G Operations	***922***	***3***	***(248,693)***	***SO***	***27.213%***	***(67,677)***	
A&G Operations	923	3	43,475	OR	Situs	3,476	
A&G Operations	***923***	***3***	***588,450***	***SO***	***27.213%***	***160,134***	
A&G Operations	924	3	-	SO	27.213%	-	
A&G Operations	925	3	-	SO	27.213%	-	
A&G Operations	***926***	***3***	***7,757,250***	***SO***	***27.213%***	***2,110,973***	
A&G Operations	926	3	(2,081)	OR	Situs	(26,769)	
			8,620,379			2,265,363	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2019 to December 2021 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2019 actual data was separated into labor and non-labor components and costs that should not be included in December 2021 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

This adjustment has been updated to reflect the latest IHS Global Insights Indices released for Q1 of 2020.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
A&G Operations	928	3	72,812	SG	26.023%	18,947	
A&G Operations	928	3	112	SO	27.213%	31	
A&G Operations	***928***	***3***	***37,466***	***SO***	***27.213%***	***10,196***	
A&G Operations	928	3	200,575	OR	Situs	57,496	
A&G Operations	***929***	***3***	***(5,879,674)***	***SO***	***27.213%***	***(1,600,030)***	
A&G Operations	930	3	258	OR	Situs	(18)	
A&G Operations	930	3	-	CN	31.217%	-	
A&G Operations	930	3	-	SG	26.023%	-	
A&G Operations	***930***	***3***	***46,111***	***SO***	***27.213%***	***12,548***	
A&G Operations	931	3	21,924	OR	Situs	13,519	
A&G Operations	***931***	***3***	***111,489***	***SO***	***27.213%***	***30,340***	
A&G Operations	935	3	1,204	OR	Situs	406	
A&G Operations	935	3	157	CN	31.217%	49	
A&G Operations	***935***	***3***	***55,790***	***SO***	***27.213%***	***15,182***	
			(5,331,775)			(1,441,335)	
			(1,014,677)			(262,671)	4.11_SR
			(236,985)			(67,794)	4.11.1_SR
			(445,761)			***(119,380)***	4.11.2_SR
			8,620,379			***2,265,363***	4.11.3_SR
			(5,331,775)			***(1,441,335)***	4.11.4_SR
Total Adjustment			1,591,180			374,183	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2019 to December 2021 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2019 actual data was separated into labor and non-labor components and costs that should not be included in December 2021 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

This adjustment has been updated to reflect the latest IHS Global Insights Indices released for Q1 of 2020.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

Tab 5 - Net Power Costs

Pacificorp
Oregon General Rate Case - December 2021
Tab 5 Adjustment Summary

	Total Adjustments	5.1_SR Net Power Costs	5.2 Nodal Pricing Model
1 Operating Revenues:			
2 General Business Revenues	-	-	-
3 Interdepartmental	-	-	-
4 Special Sales	6,251,562	6,251,562	-
5 Other Operating Revenues	-	-	-
6 Total Operating Revenues	6,251,562	6,251,562	-
7			
8 Operating Expenses:			
9 Steam Production	(44,408,808)	(44,408,808)	-
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	-
12 Other Power Supply	(18,667,337)	(18,797,450)	130,113
13 Transmission	(632,511)	(632,511)	-
14 Distribution	-	-	-
15 Customer Accounting	-	-	-
16 Customer Service & Info	-	-	-
17 Sales	-	-	-
18 Administrative & General	-	-	-
19			
20 Total O&M Expenses	(63,708,655)	(63,838,768)	130,113
21		-	-
22 Depreciation	-	-	-
23 Amortization	45,829	-	45,829
24 Taxes Other Than Income	-	-	-
25 Income Taxes - Federal	13,952,791	14,052,686	(99,895)
26 Income Taxes - State	3,159,921	3,182,544	(22,623)
27 Income Taxes - Def Net	74,031	-	74,031
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	-
30			
31 Total Operating Expenses:	(46,476,084)	(46,603,539)	127,455
32			
33 Operating Rev For Return:	52,727,646	52,855,101	(127,455)
34			
35 Rate Base:			
36 Electric Plant In Service	1,040,905	-	1,040,905
37 Plant Held for Future Use	-	-	-
38 Misc Deferred Debits	-	-	-
39 Elec Plant Acq Adj	-	-	-
40 Nuclear Fuel	-	-	-
41 Prepayments	-	-	-
42 Fuel Stock	-	-	-
43 Material & Supplies	-	-	-
44 Working Capital	(440,425)	(440,497)	72
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	600,480	(440,497)	1,040,977
49	-	-	-
50 Rate Base Deductions:	-	-	-
51 Accum Prov For Deprec	-	-	-
52 Accum Prov For Amort	-	-	-
53 Accum Def Income Tax	(81,517)	-	(81,517)
54 Unamortized ITC	-	-	-
55 Customer Adv For Const	-	-	-
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	-	-	-
58		-	-
59 Total Rate Base Deductions	(81,517)	-	(81,517)
60			
61 Total Rate Base:	518,964	(440,497)	959,461
62			
63 Return on Rate Base	1.417%	1.423%	-0.006%
64			
65 Return on Equity	2.648%	2.659%	-0.011%
66			
67 TAX CALCULATION:			
68 Operating Revenue	69,914,389	70,090,331	(175,942)
69 Other Deductions	-	-	-
70 Interest (AFUDC)	-	-	-
71 Interest	11,503	(9,764)	21,268
72 Schedule "M" Additions	45,829	-	45,829
73 Schedule "M" Deductions	346,934	-	346,934
74 Income Before Tax	69,601,781	70,100,095	(498,314)
75			
76 State Income Taxes	3,159,921	3,182,544	(22,623)
77 Taxable Income	66,441,860	66,917,551	(475,691)
78			
79 Federal Income Taxes + Other	13,952,791	14,052,686	(99,895)
APPROXIMATE PRICE CHANGE	(72,153,562)	(72,426,149)	272,587

PacifiCorp
Oregon General Rate Case - December 2021
Net Power Cost Adjustment

PAGE 5.1_SR

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Existing Firm PPL	447NPC	3	7,364,161	SG	26.023%	1,916,348	5.1.1_SR
Existing Firm UPL	447NPC	3	-	SG	26.023%	-	5.1.1_SR
Post-Merger Firm	447NPC	3	16,658,804	SG	26.023%	4,335,059	5.1.1_SR
Non-Firm	447NPC	3	616	SE	25.101%	155	5.1.1_SR
Total Sales for Resale			24,023,581			6,251,562	
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555NPC	3	2,847,480	SG	26.023%	740,989	5.1.1_SR
Existing Firm Demand UPL	555NPC	3	2,484,823	SG	26.023%	646,616	5.1.1_SR
Existing Firm Energy	555NPC	3	15,044,970	SE	25.101%	3,776,511	5.1.1_SR
Post-merger Firm	***555NPC***	***3***	***(72,466,539)***	***SG***	***26.023%***	***(18,857,701)***	***5.1.1_SR***
Post-merger Firm - Situs	555NPC	3	(3,755,804)	UT	0.000%	-	5.1.1_SR
Secondary Purchases	555NPC	3	(11,756)	SE	25.101%	(2,951)	5.1.1_SR
Seasonal Contracts	555NPC	3	-	SG	26.023%	-	5.1.1_SR
Other Generation	555NPC	3	-	SG	26.023%	-	5.1.1_SR
Total Purchased Power Adjustments:			(55,856,826)			(13,696,535)	
Wheeling Expense (Account 565)							
Existing Firm PPL	565NPC	3	21,615,814	SG	26.023%	5,625,004	5.1.1_SR
Existing Firm UPL	565NPC	3	-	SG	26.023%	-	5.1.1_SR
Post-merger Firm	565NPC	3	(28,257,165)	SG	26.023%	(7,353,258)	5.1.1_SR
Non-Firm	565NPC	3	4,365,254	SE	25.101%	1,095,744	5.1.1_SR
Total Wheeling Expense Adjustments:			(2,276,097)			(632,511)	
Fuel Expense (Accounts 501, 503, 547)							
Fuel - Overburden Amortization - Idaho	501NPC	3	(104,388)	IDU	Situs	-	5.1.1_SR
Fuel - Overburden Amortization - Wyoming	501NPC	3	(293,720)	WYP	Situs	-	5.1.1_SR
Fuel Consumed - Coal	501NPC	3	(134,133,202)	SE	25.101%	(33,669,429)	5.1.1_SR
Fuel Consumed - Gas	501NPC	3	1,613,876	SE	25.101%	405,107	5.1.1_SR
Steam from Other Sources	503NPC	3	(62,656)	SE	25.101%	(15,728)	5.1.1_SR
Natural Gas Consumed	547NPC	3	33,516,927	SE	25.101%	8,413,247	5.1.1_SR
Simple Cycle Combustion Turbines	547NPC	3	2,279,675	SE	25.101%	572,232	5.1.1_SR
Cholla / APS Exchange	501NPC	3	(44,335,052)	SE	25.101%	(11,128,758)	5.1.1_SR
Total Fuel Expense Adjustments:			(141,518,541)			(35,423,329)	
Total Power Cost Adjustment			(223,675,045)			(56,003,937)	
Post-merger Firm Type 1	555NPC	1	(48,739,448)	SG	26.023%	(12,683,287)	5.1.1_SR
Oregon Situs NPC Adjustments	555NPC	3	846,893	OR	Situs	846,893	5.1.4_SR
TAM Settlement Docket UE 375	***555NPC***	***3***	***(2,250,000)***	***OR***	***Situs***	***(2,250,000)***	

Description of Adjustment:

This net power cost adjustment normalizes power costs by adjusting sales for resale, purchased power, wheeling and fuel in a manner consistent with the contractual terms of sales and purchase agreements, and normal hydro and temperature conditions for the 12 month period ending December 2021. The GRID study for this adjustment is based on forecast loads for the period.

As described in the testimony of Shelley E. McCoy, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC as part of the general rate case.

This adjustment was updated with the latest NPC data used in the Company's Settlement testimony in Docket UE 375.

PacifiCorp
Oregon General Rate Case - December 2021
Net Power Cost Adjustment

Description	FERC Account	(1) Total Account (B Tabs)	(2) Remove Non-NPC / NPC Mechanism Accruals	(3) Unadjusted NPC (1) + (2)	(4) Type 1 Adjustments	(5) Type 1 Normalized NPC (3) + (4)	(6) Type 3 Pro Forma NPC	(7) Type 3 Adjustment (6) - (5)
Sales for Resale (Account 447)								
Existing Firm Sales PPL	447.12	-	-	-	-	-	7,364,161	7,364,161
Existing Firm Sales UPL	447.122	-	-	-	-	-	-	-
Post-merger Firm Sales	447.13, .14, .20, .61, .62	229,850,101.48	-	229,850,101	-	229,850,101	246,508,905	16,658,804
Non-firm Sales	447.5	(616)	-	(616)	-	(616)	-	616
Transmission Services	447.9	82,889	(82,889)	-	-	-	-	-
On-system Wholesale Sales	447.1	14,001,706	(14,001,706)	-	-	-	-	-
Total Revenue Adjustments		243,934,081	(14,084,596)	229,849,485	-	229,849,485	253,873,066	24,023,581
Purchased Power (Account 555)								
Existing Firm Demand PPL	555.66	-	-	-	-	-	2,847,480	2,847,480
Existing Firm Demand UPL	555.68	-	-	-	-	-	2,484,823	2,484,823
Existing Firm Energy	555.65, 555.69	-	-	-	-	-	15,044,970	15,044,970
Post-merger Firm	555.26, .55, .59, .61, .62, .63, .64, .67, .8	729,221,964	-	729,221,964	-	729,221,964	608,015,977	(121,205,987)
Post-merger Firm - Situs	555.27	3,755,804	-	3,755,804	-	3,755,804	-	(3,755,804)
Secondary Purchases	555.7, 555.25	11,756	-	11,756	-	11,756	-	(11,756)
NPC Deferral Mechanism	555.57	(69,933,370)	69,933,370	-	-	-	-	-
Seasonal Contracts		-	-	-	-	-	-	-
Wind Integration Charge		-	-	-	-	-	-	-
RPS Compliance Purchases	555.22,555.23,555.24	790,843	(790,843)	-	-	-	-	-
BPA Regional Adjustments	555.11, 555.12, 555.133	-	-	-	-	-	-	-
Post-merger Firm Type 1		-	-	-	(48,739,448)	(48,739,448)	-	48,739,448
Total Purchased Power Adjustment		663,846,997	69,142,527	732,989,524	(48,739,448)	684,250,076	628,393,250	(55,856,826)
Wheeling (Account 565)								
Existing Firm PPL	565.26	-	-	-	-	-	21,615,814	21,615,814
Existing Firm UPL	565.27	-	-	-	-	-	-	-
Post-merger Firm	565.0, 565.46, 565.1	143,000,130	-	143,000,130	-	143,000,130	114,742,965	(28,257,165)
Non-firm	565.25	(1,670,995)	-	(1,670,995)	-	(1,670,995)	2,694,259	4,365,254
Total Wheeling Expense Adjustment		141,329,135	-	141,329,135	-	141,329,135	139,053,037	(2,276,097)
Fuel Expense (Accounts 501, 503 and 547)								
Fuel - Overburden Amortization - Idaho	501.12	104,388	-	104,388	-	104,388	-	(104,388)
Fuel - Overburden Amortization - Wyoming	501.12	293,720	-	293,720	-	293,720	-	(293,720)
Fuel Consumed - Coal	501.1	710,194,823	-	710,194,823	-	710,194,823	576,061,622	(134,133,202)
Fuel Consumed - Gas	501.35	4,582,577	-	4,582,577	-	4,582,577	6,196,453	1,613,876
Steam From Other Sources	503	4,570,678	-	4,570,678	-	4,570,678	4,508,022	(62,656)
Natural Gas Consumed	547.1	268,434,763	-	268,434,763	-	268,434,763	301,951,689	33,516,927
Simple Cycle Combustion Turbines	547.1	1,064,775	-	1,064,775	-	1,064,775	3,344,450	2,279,675
Cholla/APS Exchange	501.1	44,335,052	-	44,335,052	-	44,335,052	-	(44,335,052)
Fuel Regulatory Costs Deferral and Amort	501.15	1,746,531	(1,746,531)	-	-	-	-	-
Fuel Regulatory Costs Deferral and Amort	501.15	7,095,072	(7,095,072)	-	-	-	-	-
Miscellaneous Fuel Costs	501.0, .2, .3, .4, .45, .5, .51	15,960,465	(15,960,465)	-	-	-	-	-
Miscellaneous Fuel Costs - Cholla	501.2,501.45	2,819,582	(2,819,582)	-	-	-	-	-
Total Fuel Expense		1,061,202,426	(27,621,649)	1,033,580,777	-	1,033,580,777	892,062,236	(141,518,541)
Net Power Cost		**1,622,444,476**	**55,605,474**	**1,678,049,950**	**(48,739,448)**	**1,629,310,503**	**1,405,635,458**	**(223,675,045)**
					Ref 5.1_SR		**Ref 5.1.3_SR**	**Ref 5.1_SR**

PacifiCorp
Oregon General Rate Case - December 2021
Net Power Cost Study

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 01/21-12/21	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	7,364,161	7,364,161			
Post Merger	246,508,905				246,508,905
Utah Pre Merger	-	-			
NonFirm Sub Total	-			-	
TOTAL SPECIAL SALES	253,873,066	7,364,161	-	-	246,508,905
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	-	-			
Pacific Capacity	-	-	-		
Mid Columbia	2,134,076	640,223	1,493,853		
Misc/Pacific	-	-	-		
Q.F. Contracts/PPL	159,016,552	2,207,257	10,754,080		146,055,215
Small Purchases west	-		-		
Pacific Sub Total	161,150,629	2,847,480	12,247,933	-	146,055,215
Gemstate	1,717,824		1,717,824		
GSLM	-		-		
QF Contracts/UPL	178,500,589	2,484,823	1,064,924		174,950,842
IPP Layoff	-	-	-		
Small Purchases east	14,288		14,288		
UP&L to PP&L	-	-	-		
Utah Sub Total	180,232,702	2,484,823	2,797,036	-	174,950,842
APS Supplemental	-				-
Avoided Cost Resource	-				-
BPA Reserve Purchase					
Cedar Springs Wind	11,723,273				11,723,273
Cedar Springs Wind III	8,908,095				8,908,095
Combine Hills Wind	5,369,183				5,369,183
Cove Mountain Solar	3,863,906				3,863,906
Cove Mountain Solar II	343,571				343,571
Deseret Purchase	32,584,476				32,584,476
Eagle Mountain - UAMPS/UMPA	2,615,653				2,615,653
Georgia-Pacific Camas	-				-
Hermiston Purchase	-				-
Hunter Solar	7,122,324				7,122,324
Hurricane Purchase	157,969				157,969
MagCorp	-				-
MagCorp Reserves	5,084,680				5,084,680
Milican Solar	2,646,179				2,646,179
Milford Solar	7,081,219				7,081,219
Nucor	7,129,800				7,129,800
Monsanto Reserves	19,999,999				19,999,999
PGE Cove	154,785				154,785
Rock River Wind	3,946,224				3,946,224
Prineville Solar	1,795,505				1,795,505
Sigurd Solar	2,839,304				2,839,304
Three Buttes Wind	20,590,359				20,590,359
Top of the World Wind	40,561,724				40,561,724
Tri-State Purchase	-				-
Wolverine Creek Wind	10,280,610				10,280,610
BPA So. Idaho	-				-
PSCo Exchange	5,400,000				5,400,000
West Valley Toll	-				-

	Merged 01/21-12/21	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	7,364,161	7,364,161			
Seasonal Purchased Power					
Constellation 2013-2016	-				-
Short Term Firm Purchases	86,811,080				86,811,080
New Firm Sub Total	287,009,920	-	-	-	287,009,920
Integration Charge	-				-
Non Firm Sub Total	-			-	
TOTAL PURCHASED PW & NET INT.	628,393,250	5,332,304	15,044,970	-	608,015,977
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Facilities	21,615,814	21,615,814			
Utah Firm Wheeling and Use of Facilities	-	-			
Post Merger	114,742,965				114,742,965
Nonfirm Wheeling	2,694,259			2,694,259	
TOTAL WHEELING & U. OF F. EXPENSE	139,053,037	21,615,814	-	2,694,259	114,742,965
THERMAL FUEL BURN EXPENSE					
Carbon	-			-	
Cholla	-			-	
Colstrip	15,366,792			15,366,792	
Craig	17,156,599			17,156,599	
Chehalis	58,124,540			58,124,540	
Currant Creek	60,328,362			60,328,362	
Dave Johnston	50,983,383			50,983,383	
Gadsby	6,196,453			6,196,453	
Gadsby CT	3,344,450			3,344,450	
Hayden	14,731,538			14,731,538	
Hermiston	23,682,380			23,682,380	
Hunter	80,527,897			80,527,897	
Huntington	94,265,675			94,265,675	
Jim Bridger	199,771,850			199,771,850	
Lake Side 1	70,913,854			70,913,854	
Lake Side 2	63,629,938			63,629,938	
Naughton - Gas	25,272,616			25,272,616	
Naughton	77,109,926			77,109,926	
Wyodak	26,147,961			26,147,961	
TOTAL FUEL BURN EXPENSE	887,554,215	-	-	887,554,215	-
OTHER GENERATION EXPENSE					
Blundell	4,508,022			4,508,022	
TOTAL OTHER GEN. EXPENSE	4,508,022	-	-	4,508,022	-
TOTAL NET POWER COST BEFORE SETTLEMENT	**1,405,635,458** **Ref 5.1.1_SR**	19,583,957	15,044,970	894,756,495	476,250,036
TAM Settlement Adjustment	(8,802,107)				(8,802,107)
NET POWER COST	1,396,833,350	19,583,957	15,044,970	894,756,495	467,447,929

PacifiCorp
Oregon General Rate Case - December 2021
Net Power Cost Adjustment
Oregon Situs Adjustments

	Total	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Total Energy Impact	**846,893**	47,577	57,160	69,234	92,653	110,566	124,754	67,840	53,105	58,835	66,003	52,808	46,358
	Ref 5.1_SR												

Tab 6 - Depreciation & Amortization

Pacificorp
Oregon General Rate Case - December 2021
Tab 6 Adjustment Summary

		Total Adjustments	6.1_SR Depreciation & Amortiation Expense	6.2_SR Depreciation & Amortization Reserve	6.3 Depreciation Allocation Correction	6.4_SR Decommissioning & Other Plant Closure Costs
1	Operating Revenues:					
2	General Business Revenues	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-
4	Special Sales	-	-	-	-	-
5	Other Operating Revenues	-	-	-	-	-
6	Total Operating Revenues	-	-	-	-	-
7						
8	Operating Expenses:					
9	Steam Production	3,907,082	267,643	-	-	3,639,439
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	66,916	66,916	-	-	-
12	Other Power Supply	44,443	44,443	-	-	-
13	Transmission	35,286	35,286	-	-	-
14	Distribution	161,580	161,580	-	-	-
15	Customer Accounting	62,091	62,091	-	-	-
16	Customer Service & Info	12,117	12,117	-	-	-
17	Sales	-	-	-	-	-
18	Administrative & General	53,742	53,742	-	-	-
19						
20	Total O&M Expenses	4,343,255	703,817	-	-	3,639,439
21		-	-	-	-	-
22	Depreciation	60,346,749	61,061,144	-	(714,395)	-
23	Amortization	25,119,185	(2,230,834)	-	-	27,350,019
24	Taxes Other Than Income	-	-	-	-	-
25	Income Taxes - Federal	(4,244,452)	(5,265,497)	826,073	143,204	51,768
26	Income Taxes - State	(961,251)	(1,192,489)	187,083	32,432	11,724
27	Income Taxes - Def Net	(15,804,465)	(8,185,212)	-	-	(7,619,254)
28	Investment Tax Credit Adj.	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-
30						
31	Total Operating Expenses:	68,799,021	44,890,928	1,013,155	(538,758)	23,433,696
32						
33	Operating Rev For Return:	(68,799,021)	(44,890,928)	(1,013,155)	538,758	(23,433,696)
34		-				
35	Rate Base:	-				
36	Electric Plant In Service	-	-	-	-	-
37	Plant Held for Future Use	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-
41	Prepayments	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-
44	Working Capital	(15,502,881)	(54,388)	9,576	1,660	(15,459,729)
45	Weatherization Loans	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-
47						
48	Total Electric Plant:	(15,502,881)	(54,388)	9,576	1,660	(15,459,729)
49		-	-	-	-	-
50	Rate Base Deductions:	-	-	-	-	-
51	Accum Prov For Deprec	(176,284,105)	-	(176,284,105)	-	-
52	Accum Prov For Amort	(9,628,479)	-	(9,628,479)	-	-
53	Accum Def Income Tax	4,924,812	1,115,185	-	-	3,809,627
54	Unamortized ITC	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-
58			-	-	-	-
59	Total Rate Base Deductions	(180,987,772)	1,115,185	(185,912,585)	-	3,809,627
60						
61	Total Rate Base:	(196,490,653)	1,060,797	(185,903,008)	1,660	(11,650,102)
62						
63	Return on Rate Base	-1.439%	-1.210%	0.394%	0.015%	-0.638%
64						
65	Return on Equity	-2.688%	-2.261%	0.736%	0.028%	-1.192%
66						
67	TAX CALCULATION:					
68	Operating Revenue	(89,809,189)	(59,534,126)	-	714,395	(30,989,458)
69	Other Deductions	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-
71	Interest	(4,355,449)	23,514	(4,120,761)	37	(258,238)
72	Schedule "M" Additions	64,280,812	33,291,354	-	-	30,989,458
73	Schedule "M" Deductions	-	-	-	-	-
74	Income Before Tax	(21,172,928)	(26,266,286)	4,120,761	714,358	258,238
75						
76	State Income Taxes	(961,251)	(1,192,489)	187,083	32,432	11,724
77	Taxable Income	(20,211,677)	(25,073,797)	3,933,679	681,926	246,514
78						
79	Federal Income Taxes + Other	(4,244,452)	(5,265,497)	826,073	143,204	51,768
	APPROXIMATE PRICE CHANGE	74,135,764	61,583,194	(17,609,993)	(737,620)	30,900,182

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation & Amortization Expense
Adjustment to Test Period Levels

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Depreciation Expense	403SP	3	16,315,142	SG	26.023%	4,245,629	
Steam Depreciation Expense	403SP	3	8,936,043	SG	26.023%	2,325,394	
Steam Depreciation Expense	403SP	3	83,750,971	SG	26.023%	21,794,208	
Steam Depreciation Expense	403SP	3	10,563,821	SG	26.023%	2,748,984	
Hydro Depreciation Expense	403HP	3	4,314,203	SG	26.023%	1,122,669	
Hydro Depreciation Expense	403HP	3	(77,499)	SG	26.023%	(20,167)	
Hydro Depreciation Expense	403HP	3	(16,253,032)	SG-P	26.023%	(4,229,467)	
Hydro Depreciation Expense	403HP	3	1,307,840	SG-U	26.023%	340,334	
Other Depreciation Expense	403OP	3	-	SG	26.023%	-	
Other Depreciation Expense	403OP	3	(7,833)	SG	26.023%	(2,038)	
Other Depreciation Expense	403OP	3	(33,483,336)	SG-W	26.023%	(8,713,245)	
Other Depreciation Expense	403OP	3	4,752	OR	Situs	4,752	
Other Depreciation Expense	403OP	3	8,056	SG	26.023%	2,096	
Transmission Depreciation Expense	403TP	3	(239,396)	SG	26.023%	(62,297)	
Transmission Depreciation Expense	403TP	3	(213,443)	SG	26.023%	(55,544)	
Transmission Depreciation Expense	403TP	3	8,601,817	SG	26.023%	2,238,419	
Distribution Depreciation Expense	403360	3	391,766	Situs	Situs	38,818	
Distribution Depreciation Expense	403361	3	750,568	Situs	Situs	74,370	
Distribution Depreciation Expense	403362	3	6,301,963	Situs	Situs	624,431	
Distribution Depreciation Expense	403364	3	7,584,724	Situs	Situs	751,534	
Distribution Depreciation Expense	403365	3	4,825,116	Situs	Situs	478,098	
Distribution Depreciation Expense	403366	3	2,393,153	Situs	Situs	237,126	
Distribution Depreciation Expense	403367	3	5,587,115	Situs	Situs	553,600	
Distribution Depreciation Expense	403368	3	8,605,166	Situs	Situs	852,645	
Distribution Depreciation Expense	403369	3	5,152,872	Situs	Situs	510,573	
Distribution Depreciation Expense	403370	3	1,458,137	Situs	Situs	144,480	
Distribution Depreciation Expense	403371	3	54,108	Situs	Situs	5,361	
Distribution Depreciation Expense	403373	3	385,067	Situs	Situs	38,154	
General Depreciation Expense	403GP	3	117,937	CA	Situs	-	
General Depreciation Expense	403GP	3	634,299	OR	Situs	634,299	
General Depreciation Expense	403GP	3	57,846	WA	Situs	-	
General Depreciation Expense	403GP	3	180,533	WYP	Situs	-	
General Depreciation Expense	403GP	3	819,963	UT	Situs	-	
General Depreciation Expense	403GP	3	146,862	ID	Situs	-	
General Depreciation Expense	403GP	3	(25,897)	WYU	Situs	-	
General Depreciation Expense	403GP	3	1,585	SG	26.023%	412	
General Depreciation Expense	403GP	3	(3,584)	SG	26.023%	(933)	
General Depreciation Expense	403GP	3	779,781	SG	26.023%	202,919	
General Depreciation Expense	***403GP***	***3***	***1,355,444***	***SO***	***27.213%***	***368,856***	
General Depreciation Expense	403GP	3	(7,051)	SG	26.023%	(1,835)	
General Depreciation Expense	403GP	3	692	SG	26.023%	180	
General Depreciation Expense	403GP	3	(264,451)	CN	31.217%	(82,554)	
General Depreciation Expense	403GP	3	9,648	SE	25.101%	2,422	
Total Depreciation Expense			130,821,463			27,172,684	6.1.6_SR

Description of Adjustment:

This adjustment reflects the incremental depreciation expense that is calculated on the plant additions included in this filing in adjustment 8.5. The annualized 2020 depreciation and amortization expense for the test period is calculated by applying the currrent composite depreciation and amortization rates to the December 2020 projected plant balances.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated in Surrebuttal to reflect Settlement details in the Oregon Depreciation Study, Docket No. UM 1968. Allocation factor changes as a result of revisions made the the Company's revenue requirement in Surrebuttal have also been incorporated.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation & Amortization Expense
Adjustment to Test Period Levels

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Intangible Amortization	404IP	3	2,337	CA	Situs	-	
Intangible Amortization	404IP	3	923,235	CN	31.217%	288,207	
Intangible Amortization	404IP	3	(0)	SG	26.023%	(0)	
Intangible Amortization	404IP	3	(78,646)	SG	26.023%	(20,466)	
Intangible Amortization	404IP	3	(8)	ID	Situs	-	
Intangible Amortization	404IP	3	3,397	OR	Situs	3,397	
Intangible Amortization	404IP	3	(1,239)	SE	25.101%	(311)	
Intangible Amortization	404IP	3	(6,762,029)	SG	26.023%	(1,759,658)	
Intangible Amortization	404IP	3	(8,298,775)	SG-P	26.023%	(2,159,560)	
Intangible Amortization	404IP	3	(1,038)	SG-U	26.023%	(270)	
Intangible Amortization	404IP	3	(21,649)	SG	26.023%	(5,634)	
Intangible Amortization	***404IP***	***3***	***5,449,956***	***SO***	***27.213%***	***1,483,091***	
Intangible Amortization	404IP	3	159,758	UT	Situs	-	
Intangible Amortization	404IP	3	-	WA	Situs	-	
Intangible Amortization	404IP	3	(1,935)	WYP	Situs	-	
Intangible Amortization	404IP	3	-	WYU	Situs	-	
Hydro Amortization	404HP	3	-	SG	26.023%	-	
Hydro Amortization	404HP	3	571	SG-P	26.023%	148	
Hydro Amortization	404HP	3	-	SG-U	26.023%	-	
Other Amortization	404OP	3	-	SG	26.023%	-	
General Amortization	404GP	3	(39,046)	CA	Situs	-	
General Amortization	404GP	3	-	CN	31.217%	-	
General Amortization	404GP	3	(58,262)	OR	Situs	(58,262)	
General Amortization	***404GP***	***3***	***(5,581)***	***SO***	***27.213%***	***(1,519)***	
General Amortization	404GP	3	(0)	UT	Situs	-	
General Amortization	404GP	3	(1,526)	WA	Situs	-	
General Amortization	404GP	3	(70,419)	WYP	Situs	-	
General Amortization	404GP	3	-	WYU	Situs	-	
			(8,800,899)			(2,230,834)	6.1.7_SR

Description of Adjustment:

This adjustment reflects the incremental depreciation expense that is calculated on the plant additions included in this filing in adjustment 8.5. The annualized 2020 depreciation and amortization expense for the test period is calculated by applying the currrent composite depreciation and amortization rates to the December 2020 projected plant balances.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated in Surrebuttal to reflect Settlement details in the Oregon Depreciation Study, Docket No. UM 1968. Allocation factor changes as a result of revisions made the the Company's revenue requirement in Surrebuttal have also been incorporated.

PacifiCorp
Oregon General Rate Case - December 2021
Adjustment to Proposed Depreciation Study Rates

PAGE 6.1.2_SR

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Depreciation Expense	***403SP***	***3***	***21,194,885***	***SG***	***26.023%***	***5,515,467***	
Steam Depreciation Expense	***403SP***	***3***	***13,725,646***	***SG***	***26.023%***	***3,571,774***	
Steam Depreciation Expense	***403SP***	***3***	***91,110,950***	***SG***	***26.023%***	***23,709,468***	
Steam Depreciation Expense	403SP	3	-	SG	26.023%	-	
Hydro Depreciation Expense	***403HP***	***3***	***(177,958)***	***SG***	***26.023%***	***(46,309)***	
Hydro Depreciation Expense	***403HP***	***3***	***(6,204)***	***SG***	***26.023%***	***(1,615)***	
Hydro Depreciation Expense	***403HP***	***3***	***1,127,651***	***SG-P***	***26.023%***	***293,445***	
Hydro Depreciation Expense	***403HP***	***3***	***351,333***	***SG-U***	***26.023%***	***91,426***	
Other Depreciation Expense	403OP	3	-	SG	26.023%	-	
Other Depreciation Expense	403OP	3	10,908,511	SG	26.023%	2,838,682	
Other Depreciation Expense	403OP	3	15,857,743	SG-W	26.023%	4,126,602	
Other Depreciation Expense	403OP	3	1,246	OR	Situs	1,246	
Other Depreciation Expense	***403OP***	***3***	***869,963***	***SG***	***26.023%***	***226,387***	
Transmission Depreciation Expense	***403TP***	***3***	***(245,677)***	***SG***	***26.023%***	***(63,932)***	
Transmission Depreciation Expense	***403TP***	***3***	***(258,005)***	***SG***	***26.023%***	***(67,140)***	
Transmission Depreciation Expense	***403TP***	***3***	***(1,749,690)***	***SG***	***26.023%***	***(455,315)***	
Distribution Depreciation Expense	***403360***	***3***	***(69,430)***	***Situs***	***Situs***	***(55,304)***	
Distribution Depreciation Expense	***403361***	***3***	***(133,017)***	***Situs***	***Situs***	***(105,954)***	
Distribution Depreciation Expense	***403362***	***3***	***(1,116,846)***	***Situs***	***Situs***	***(889,618)***	
Distribution Depreciation Expense	***403364***	***3***	***(1,344,180)***	***Situs***	***Situs***	***(1,070,699)***	
Distribution Depreciation Expense	***403365***	***3***	***(855,117)***	***Situs***	***Situs***	***(681,139)***	
Distribution Depreciation Expense	***403366***	***3***	***(424,119)***	***Situs***	***Situs***	***(337,830)***	
Distribution Depreciation Expense	***403367***	***3***	***(990,160)***	***Situs***	***Situs***	***(788,706)***	
Distribution Depreciation Expense	***403368***	***3***	***(1,525,025)***	***Situs***	***Situs***	***(1,214,750)***	
Distribution Depreciation Expense	***403369***	***3***	***(913,202)***	***Situs***	***Situs***	***(727,406)***	
Distribution Depreciation Expense	***403370***	***3***	***(258,414)***	***Situs***	***Situs***	***(205,838)***	
Distribution Depreciation Expense	***403371***	***3***	***(9,589)***	***Situs***	***Situs***	***(7,638)***	
Distribution Depreciation Expense	***403373***	***3***	***(68,242)***	***Situs***	***Situs***	***(54,358)***	
General Depreciation Expense	403GP	3	12,156	CA	Situs	-	
General Depreciation Expense	***403GP***	***3***	***78,140***	***OR***	***Situs***	***78,140***	
General Depreciation Expense	403GP	3	(52,264)	WA	Situs	-	
General Depreciation Expense	403GP	3	67,823	WYP	Situs	-	
General Depreciation Expense	403GP	3	528,150	UT	Situs	-	
General Depreciation Expense	403GP	3	24,683	ID	Situs	-	
General Depreciation Expense	403GP	3	22,602	WYU	Situs	-	
General Depreciation Expense	***403GP***	***3***	***(4,879)***	***SG***	***26.023%***	***(1,270)***	
General Depreciation Expense	***403GP***	***3***	***7,396***	***SG***	***26.023%***	***1,925***	
General Depreciation Expense	***403GP***	***3***	***(247,710)***	***SG***	***26.023%***	***(64,461)***	
General Depreciation Expense	***403GP***	***3***	***911,966***	***SO***	***27.213%***	***248,172***	
General Depreciation Expense	403GP	3	-	SG	26.023%	-	
General Depreciation Expense	403GP	3	-	SG	26.023%	-	
General Depreciation Expense	403GP	3	70,117	CN	31.217%	21,888	
General Depreciation Expense	403GP	3	12,426	SE	25.101%	3,119	
Total Depreciation Expense			146,433,656			33,888,460	6.1.7_SR

Description of Adjustment:

This adjustment reflects the incremental depreciation expense for the proposed depreciation study rates. The depreciation expense is calculated by applying the proposed composite depreciation rates to the December 2020 projected plant balances. The Company's application to implement revised depreciation rates was filed September 13, 2018, under Docket No. UM 1968. This adjustment is subject to change depending on the outcome of that docket.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated to reflect the incremental depreciation expense for the depreciation study rates as agreed to in the settlement of the 2018 Depreciation Study, UM 1968. The incremental decommissioning costs related to the January 2020 Decommissioning Study has also been removed from this adjustment. The depreciation expense is calculated by applying the proposed composite depreciation rates to the December 2020 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2021
Vehicle Depreciation Expense - Adjustment to Proposed Depreciation Rates

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	***500***	***3***	***238,317***	***SG***	***26.023%***	***62,016***	
Fuel Related-Non NPC	***501***	***3***	***434***	***SE***	***25.101%***	***109***	
Steam Maintenance	***512***	***3***	***212,948***	***SG***	***26.023%***	***55,415***	
Hydro Operations	***535***	***3***	***47,409***	***SG-P***	***26.023%***	***12,337***	
Hydro Operations	***535***	***3***	***26,410***	***SG-U***	***26.023%***	***6,873***	
Hydro Maintenance	***545***	***3***	***11,610***	***SG-P***	***26.023%***	***3,021***	
Hydro Maintenance	***545***	***3***	***2,780***	***SG-U***	***26.023%***	***724***	
Other Operations	***548***	***3***	***39,472***	***SG***	***26.023%***	***10,272***	
Other Operations	***549***	***3***	***172***	***Situs***	***Situs***	***172***	
Other Maintenance	***553***	***3***	***11,082***	***SG***	***26.023%***	***2,884***	
Other Power Supply Expenses	***557***	***3***	***119,570***	***SG***	***26.023%***	***31,115***	
Other Power Supply Expenses	***557***	***3***	***209***	***Situs***	***Situs***	***-***	
Transmission Operations	***560***	***3***	***76,562***	***SG***	***26.023%***	***19,923***	
Transmission Maintenance	***571***	***3***	***59,034***	***SG***	***26.023%***	***15,362***	
Distribution Operations	***580***	***3***	***88,004***	***SNPD***	***26.853%***	***23,632***	
Distribution Operations	***580***	***3***	***92,577***	***Situs***	***Situs***	***26,746***	
Distribution Maintenance	***593***	***3***	***28,365***	***SNPD***	***26.853%***	***7,617***	
Distribution Maintenance	***593***	***3***	***320,201***	***Situs***	***Situs***	***103,585***	
Customer Accounts	***903***	***3***	***118,982***	***CN***	***31.217%***	***37,143***	
Customer Accounts	***903***	***3***	***67,791***	***Situs***	***Situs***	***24,948***	
Customer Services	***908***	***3***	***13,317***	***CN***	***31.217%***	***4,157***	
Customer Services	***908***	***3***	***237***	***OTHER***	***0.000%***	***-***	
Customer Services	***908***	***3***	***22,502***	***Situs***	***Situs***	***7,888***	
Administrative & General	***920***	***3***	***187,345***	***SO***	***27.213%***	***50,982***	
Administrative & General	***920***	***3***	***1,723***	***Situs***	***Situs***	***333***	
Administrative & General	***935***	***3***	***8,707***	***SO***	***27.213%***	***2,369***	
Administrative & General	***935***	***3***	***74***	***Situs***	***Situs***	***57***	
			1,795,832			509,680	6.1.18_SR
Customer Services	***910***	***3***	***230***	***CN***	***31.217%***	***72***	
Fuel Related - Non-NPC	***501***	***3***	***142,469***	***SE***	***25.101%***	***35,762***	
Steam Operations	***506***	***3***	***439,391***	***SG***	***26.023%***	***114,341***	
Hydro Operations	***535***	***3***	***121,766***	***SG-P***	***26.023%***	***31,687***	
Hydro Operations	***535***	***3***	***47,172***	***SG-U***	***26.023%***	***12,275***	
			751,028			194,137	6.1.18_SR
Total Vehicle Depreciation			2,546,860			703,817	
Adjustment to Tax:							
Accum. Def Inc Tax Balance	282	3	(58,226)	CA	Situs	-	
Accum. Def Inc Tax Balance	282	3	(154,102)	ID	Situs	-	
Accum. Def Inc Tax Balance	282	3	(787,720)	UT	Situs	-	
Accum. Def Inc Tax Balance	282	3	(127,985)	WA	Situs	-	
Accum. Def Inc Tax Balance	282	3	(250,607)	WYP	Situs	-	
Accum. Def Inc Tax Balance	282	3	(51,024)	WYU	Situs	-	
Accum. Def Inc Tax Balance	282	3	(594,083)	OR	Situs	(594,083)	
Accum. Def Inc Tax Balance	282	3	(6,501)	SE	25.101%	(1,632)	
Accum. Def Inc Tax Balance	282	3	(1,262,064)	SG	26.023%	(328,422)	
Accum. Def Inc Tax Balance	***282***	***3***	***(116,512)***	***SO***	***27.213%***	***(31,706)***	
			(3,408,824)			(955,844)	

Description of Adjustment:

This adjustment reflects the incremental depreciation expense for the proposed depreciation study rates for vehicles. The Company's application to implement revised depreciation rates was filed September 13, 2018, under Docket No. UM-1968. This adjustment is subject to change depending on the outcome of that docket.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment reflects the incremental depreciation expense for the depreciation study rates for vehicles as agreed to in the settlement of the 2018 Depreciation Study, UM 1968.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation & Amortization Expense
Tax Impacts

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	19,398	CA	Situs	-	
Schedule M Adjustment	SCHMAT	3	7,544	CN	31.217%	2,355	
Schedule M Adjustment	SCHMAT	3	31,626,078	SG	26.023%	8,229,938	
Schedule M Adjustment	SCHMAT	3	21,835,696	SG	26.023%	5,682,223	
Schedule M Adjustment	SCHMAT	3	(761,473)	ID	Situs	-	
Schedule M Adjustment	SCHMAT	3	(633,177)	OR	Situs	(633,177)	
Schedule M Adjustment	SCHMAT	3	(26,180)	SE	25.101%	(6,572)	
Schedule M Adjustment	SCHMAT	3	186,239,669	SG	26.023%	48,464,465	
Schedule M Adjustment	***SCHMAT***	***3***	***1,336,526***	***SO***	***27.213%***	***363,708***	
Schedule M Adjustment	SCHMAT	3	(620,959)	UT	Situs	-	
Schedule M Adjustment	SCHMAT	3	(638,546)	WA	Situs	-	
Schedule M Adjustment	SCHMAT	3	(2,655,497)	WYP	Situs	-	
Schedule M Adjustment	SCHMAT	3	(90,593)	SG	26.023%	(23,575)	
Schedule M Adjustment	SCHMAT	3	972,570	SG	26.023%	253,088	
			236,611,056			62,332,453	
Deferred Income Tax Expense	41110	3	(4,770)	CA	Situs	-	
Deferred Income Tax Expense	41110	3	(1,855)	CN	31.217%	(579)	
Deferred Income Tax Expense	41110	3	(7,775,777)	SG	26.023%	(2,023,462)	
Deferred Income Tax Expense	41110	3	(5,368,655)	SG	26.023%	(1,397,065)	
Deferred Income Tax Expense	41110	3	187,220	ID	Situs	-	
Deferred Income Tax Expense	41110	3	155,677	OR	Situs	155,677	
Deferred Income Tax Expense	41110	3	6,437	SE	25.101%	1,616	
Deferred Income Tax Expense	41110	3	(45,790,003)	SG	26.023%	(11,915,764)	
Deferred Income Tax Expense	***41110***	***3***	***(328,606)***	***SO***	***27.213%***	***(89,423)***	
Deferred Income Tax Expense	41110	3	152,673	UT	Situs	-	
Deferred Income Tax Expense	41110	3	156,997	WA	Situs	-	
Deferred Income Tax Expense	41110	3	652,897	WYP	Situs	-	
Deferred Income Tax Expense	41110	3	22,274	SG	26.023%	5,796	
Deferred Income Tax Expense	41110	3	(239,122)	SG	26.023%	(62,226)	
			(58,174,613)			(15,325,431)	
Accum. Def Inc Tax Balance	282	3	569	CN	31.217%	178	
Accum. Def Inc Tax Balance	282	3	(47,632)	OR	Situs	(47,632)	
Accum. Def Inc Tax Balance	282	3	(1,968)	SE	25.101%	(494)	
Accum. Def Inc Tax Balance	282	3	16,456,188	SG	26.023%	4,282,333	
Accum. Def Inc Tax Balance	***282***	***3***	***100,546***	***SO***	***27.213%***	***27,361***	
			16,507,703			4,261,746	
Surrebuttal Incremental Tax Change:							
Schedule M Adjustment	***SCHMAT***	***3***	***(82,753,473)***	***SG***	***26.023%***	***(21,534,632)***	
Schedule M Adjustment	***SCHMAT***	***3***	***(29,975)***	***SG-P***	***26.023%***	***(7,800)***	
Schedule M Adjustment	***SCHMAT***	***3***	***(3,334)***	***SG-U***	***26.023%***	***(868)***	
Schedule M Adjustment	***SCHMAT***	***3***	***(7,441,196)***	***OR***	***Situs***	***(7,441,196)***	
Schedule M Adjustment	***SCHMAT***	***3***	***(26,519)***	***SO***	***27.213%***	***(7,217)***	
			(90,254,497)			(28,991,712)	

Description of Adjustment:

This adjustment includes the associated tax impacts.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation & Amortization Expense
Tax Impacts

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Surrebuttal Incremental Tax Change:							
Deferred Income Tax Expense	41110	3	20,346,265	SG	26.023%	5,294,634	
Deferred Income Tax Expense	41110	3	7,370	SG-P	26.023%	1,918	
Deferred Income Tax Expense	41110	3	820	SG-U	26.023%	213	
Deferred Income Tax Expense	41110	3	1,829,537	OR	Situs	1,829,537	
Deferred Income Tax Expense	41110	3	6,520	SO	27.213%	1,774	
			22,190,512			7,128,076	
Accumulated Def Inc Tax Balance	282	3	(6,242,523)	SG	26.023%	(1,624,469)	
Accumulated Def Inc Tax Balance	282	3	(2,261)	SG-P	26.023%	(588)	
Accumulated Def Inc Tax Balance	282	3	(250)	SG-U	26.023%	(65)	
Accumulated Def Inc Tax Balance	282	3	(561,327)	OR	Situs	(561,327)	
Accumulated Def Inc Tax Balance	282	3	(1,999)	SO	27.213%	(544)	
			(6,808,360)			(2,186,993)	
Surrebuttal Vehicle Incremental Change:							
Schedule M Adjustment	SCHMAT	3	(101,994)	SG	26.023%	(26,542)	
Schedule M Adjustment	SCHMAT	3	(9,300)	CN	31.217%	(2,903)	
Schedule M Adjustment	SCHMAT	3	(8,166)	SNPD	26.853%	(2,193)	
Schedule M Adjustment	SCHMAT	3	(11,489)	OR	Situs	(11,489)	
Schedule M Adjustment	SCHMAT	3	(10,028)	SE	25.101%	(2,517)	
Schedule M Adjustment	SCHMAT	3	(13,757)	SO	27.213%	(3,744)	
			(154,733)			(49,387)	
Deferred Income Tax Expense	41110	3	25,077	SG	26.023%	6,526	
Deferred Income Tax Expense	41110	3	2,286	CN	31.217%	714	
Deferred Income Tax Expense	41110	3	2,008	SNPD	26.853%	539	
Deferred Income Tax Expense	41110	3	2,825	OR	Situs	2,825	
Deferred Income Tax Expense	41110	3	2,465	SE	25.101%	619	
Deferred Income Tax Expense	41110	3	3,382	SO	27.213%	920	
			38,043			12,143	
Accumulated Def Inc Tax Balance	282	3	(7,695)	SG	26.023%	(2,002)	
Accumulated Def Inc Tax Balance	282	3	(703)	CN	31.217%	(219)	
Accumulated Def Inc Tax Balance	282	3	(615)	SNPD	26.853%	(165)	
Accumulated Def Inc Tax Balance	282	3	(865)	OR	Situs	(865)	
Accumulated Def Inc Tax Balance	282	3	(755)	SE	25.101%	(190)	
Accumulated Def Inc Tax Balance	282	3	(1,037)	SO	27.213%	(282)	
			(11,670)			(3,724)	

Description of Adjustment:

This adjustment includes the associated tax impacts of updates to this adjustment made in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 ME Jun 2019 Expense	Annualized Existing Rates Dec 2020 Expense	Adjustment to Test Period	Proposed Rates Dec 2020 Expense	Adjustment to Proposed Depreciation Rates
DEPRECIATION EXPENSE							
Steam Production Plant:							
Pre-merger Pacific	403SP	SG	30,169,736	46,484,878	16,315,142	67,679,763	21,194,885
Pre-merger Utah	403SP	SG	30,130,900	39,066,942	8,936,043	52,792,588	13,725,646
Post-merger	403SP	SG	161,917,762	245,668,733	83,750,971	336,779,683	91,110,950
Post-merger - Cholla	403SP	SG	15,145,184	25,709,005	10,563,821	25,709,005	-
Total Steam Plant			237,363,582	356,929,558	119,565,977	482,961,039	126,031,481
Hydro Production Plant:							
Pre-merger Pacific	403HP	SG	(74,556)	4,239,647	4,314,203	4,061,689	(177,958)
Pre-merger Utah	403HP	SG	1,386,317	1,308,818	(77,499)	1,302,614	(6,204)
Post-merger	403HP	SG-P	32,771,109	16,518,077	(16,253,032)	17,645,728	1,127,651
Post-merger	403HP	SG-U	5,700,987	7,008,828	1,307,840	7,360,160	351,333
Total Hydro Plant			39,783,857	29,075,369	(10,708,489)	30,370,191	1,294,822
Other Production Plant:							
Pre-merger Utah	403OP	SG	-	-	-	-	-
Post-merger	403OP	SG	57,519,990	57,512,156	(7,833)	68,420,667	10,908,511
Post-merger Wind	403OP	SG-W	67,675,190	34,191,854	(33,483,336)	50,049,597	15,857,743
Black Cap Solar	403OP	OR	-	4,752	4,752	5,998	1,246
Post-merger	403OP	SG	3,259,020	3,267,075	8,056	4,137,038	869,963
Total Other Production Plant			128,454,199	94,975,837	(33,478,362)	122,613,300	27,637,463
Transmission Plant:							
Pre-merger Pacific	403TP	SG	8,665,935	8,426,538	(239,396)	8,180,861	(245,677)
Pre-merger Utah	403TP	SG	10,823,573	10,610,129	(213,443)	10,352,124	(258,005)
Post-merger	403TP	SG	91,403,582	100,005,399	8,601,817	98,255,709	(1,749,690)
Total Transmission Plant			110,893,089	119,042,066	8,148,978	116,788,694	(2,253,372)
Distribution Plant:							
California	403364	CA	7,937,175	8,373,979	436,804	8,373,979	-
Oregon	403364	OR	53,608,264	57,917,455	4,309,191	51,778,214	(6,139,241)
Washington	403364	WA	14,311,535	15,219,815	908,280	15,101,449	(118,366)
Eastern Wyoming	403364	WYP	16,472,691	20,083,504	3,610,813	18,945,115	(1,138,389)
Utah	403364	UT	54,969,349	85,435,788	30,466,439	85,711,083	275,296
Idaho	403364	ID	7,065,187	10,576,685	3,511,499	10,272,310	(304,376)
Western Wyoming	403364	WYU	3,841,152	4,087,882	246,730	3,805,617	(282,265)
Total Distribution Plant			158,205,353	201,695,108	43,489,755	193,987,767	(7,707,341)
General Plant:							
California	403GP	CA	402,578	520,515	117,937	532,670	12,156
Oregon	403GP	OR	5,078,614	5,712,913	634,299	5,791,053	78,140
Washington	403GP	WA	1,153,845	1,211,691	57,846	1,159,427	(52,264)
Eastern Wyoming	403GP	WYP	2,030,031	2,210,564	180,533	2,278,387	67,823
Utah	403GP	UT	4,800,293	5,620,256	819,963	6,148,405	528,150
Idaho	403GP	ID	919,901	1,066,763	146,862	1,091,446	24,683
Western Wyoming	403GP	WYU	388,208	362,311	(25,897)	384,913	22,602
Pre-merger Pacific	403GP	SG	23,762	25,347	1,585	20,468	(4,879)
Pre-merger Utah	403GP	SG	73,045	69,461	(3,584)	76,857	7,396
Post-merger	403GP	SG	9,665,735	10,445,515	779,781	10,197,805	(247,710)
General Office	403GP	SO	15,567,254	16,922,698	1,355,444	17,834,663	911,966
General Office	403GP	SG	144,337	137,286	(7,051)	137,286	-
General Office	403GP	SG	8,187	8,879	692	8,879	-
Customer Service	403GP	CN	1,040,345	775,894	(264,451)	846,011	70,117
Fuel Related	403GP	SE	95,328	104,976	9,648	117,402	12,426
Total General Plant			41,391,464	45,195,068	3,803,604	46,625,672	1,430,603
Total Depreciation Expense			716,091,544	846,913,007	**130,821,463**	993,346,663	**146,433,656**
					Ref 6.1_SR		**Ref 6.1.2_SR**

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 ME Jun 2019 Expense	Annualized Existing Rates Dec 2020 Expense	Adjustment to Test Period	Proposed Rates Dec 2020 Expense	Adjustment to Proposed Depreciation Rates
AMORTIZATION EXPENSE							
Intangible Plant:							
California	404IP	CA	1,765	4,102	2,337	4,102	-
Customer Service	404IP	CN	9,726,915	10,650,150	923,235	10,650,150	-
Pre-merger Utah	404IP	SG	16,485	16,485	(0)	16,485	-
Pre-merger Pacific	404IP	SG	78,646	-	(78,646)	-	-
Idaho	404IP	ID	23,042	23,033	(8)	23,033	-
Oregon	404IP	OR	10,341	13,738	3,397	13,738	-
Fuel Related	404IP	SE	1,239	-	(1,239)	-	-
Post-merger	404IP	SG	14,326,925	7,564,896	(6,762,029)	7,564,896	-
Hydro Relicensing	404IP	SG-P	10,915,568	2,616,793	(8,298,775)	2,616,793	-
Hydro Relicensing	404IP	SG-U	315,841	314,803	(1,038)	314,803	-
Post-merger	404IP	SG	21,649	-	(21,649)	-	-
General Office	404IP	SO	10,992,229	16,442,185	5,449,956	16,442,185	-
Utah	404IP	UT	(3,576,248)	(3,416,491)	159,758	(3,416,491)	-
Washington	404IP	WA	3,024	3,024	-	3,024	-
Eastern Wyoming	404IP	WYP	107,692	105,757	(1,935)	105,757	-
Western Wyoming	404IP	WYU	-	-	-	-	-
Total Intangible Plant			42,965,111	34,338,476	(8,626,636)	34,338,476	-
Hydro Production Plant:							
Pre-merger Pacific	404HP	SG	-	-	-	-	-
Post-merger	404HP	SG-P	311,125	311,696	571	311,696	-
Post-merger	404HP	SG-U	-	-	-	-	-
Total Hydro Plant			311,125	311,696	571	311,696	-
Other Production Plant:							
Post-merger	404OP	SG	-	-	-	-	-
Total Other Plant			-	-	-	-	-
General Plant:							
California	404GP	CA	67,062	28,016	(39,046)	28,016	-
General Office	404GP	CN	-	-	-	-	-
Oregon	404GP	OR	308,163	249,902	(58,262)	249,902	-
General Office	404GP	SO	289,934	284,353	(5,581)	284,353	-
Utah	404GP	UT	728	728	(0)	728	-
Washington	404GP	WA	82,034	80,507	(1,526)	80,507	-
Eastern Wyoming	404GP	WYP	118,538	48,119	(70,419)	48,119	-
Western Wyoming	404GP	WYU	-	-	-	-	-
Total General Plant			866,459	691,624	(174,834)	691,624	-
Total Amortization			44,142,695	35,341,796	**(8,800,899)**	35,341,796	**-**
					Ref 6.1.1_SR		**Ref 6.1.2_SR**
Total Depreciation and Amortization			760,234,239	882,254,803	122,020,564	1,028,688,459	146,433,656
				Ref. 6.1.17_SR		**Ref. 6.1.17_SR**	

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Existing Rate	*Settlement* Proposed Rate	Adjusted EPIS Balance Jun 2019	Depreciation Expense Jun 2019	Adjustments	Adjusted EPIS Balance Jul 2019	Depreciation Expense Jul 2019	Adjustments	Adjusted EPIS Balance Aug 2019	Depreciation Expense Aug 2019	Adjustments	Adjusted EPIS Balance Sep 2019	Depreciation Expense Sep 2019	Adjustments	Adjusted EPIS Balance Oct 2019	Depreciation Expense Oct 2019
DEPRECIATION EXPENSE																	
Steam Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Geothermal - Blundell	SG																
Pollution Control Equipment	SG																
Pollution Control Equipment	SG																
Post-merger - Cholla	SG																
Total Steam Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG-P																
Post-merger	SG-U																
Klamath	SG-P																
Total Hydro Plant																	
Other Production Plant:																	
Pre-merger Utah	SG	[redacted]															
Post-merger	SG																
Post-merger Wind	SG-W																
Black Cap Solar	OR																
Post-merger	SG																
Total Other Plant																	
Transmission Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Total Transmission Plant																	
Distribution Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Total Distribution Plant																	
General Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Pre-merger Pacific	SG																
Pre-merger Utah	SG																
Post-merger	SG																
General Office	SO																
General Office	SG																
General Office	SG																
Customer Service	CN																
Fuel Related	SE																
Total General Plant																	
Mining Plant:																	
Coal Mine	SE	[redacted]															
Total Mining Plant																	
Total Depreciation Expense				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Existing Rate	*Settlement* Proposed Rate	Adjusted EPIS Balance Jun 2019	Depreciation Expense Jun 2019	Adjustments	Adjusted EPIS Balance Jul 2019	Depreciation Expense Jul 2019	Adjustments	Adjusted EPIS Balance Aug 2019	Depreciation Expense Aug 2019	Adjustments	Adjusted EPIS Balance Sep 2019	Depreciation Expense Sep 2019	Adjustments	Adjusted EPIS Balance Oct 2019	Depreciation Expense Oct 2019
AMORTIZATION EXPENSE																	
Intangible Plant:																	
California	CA	[redacted]															
Customer Service	CN																
Pre-merger Utah	SG																
Pre-merger Pacific	SG																
Idaho	ID																
Oregon	OR																
Fuel Related	SE																
Post-merger	SG																
Hydro Relicensing	SG-P																
Hydro Relicensing	SG-U																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Klamath	SG-P																
Total Intangible Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Post-merger	SG-P																
Post-merger	SG-U																
Total Hydro Plant																	
Other Production Plant:																	
Post-merger	SG	[redacted]															
Total Other Plant																	
General Plant:																	
California	CA	[redacted]															
General Office	CN																
Oregon	OR																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Total General Plant																	
Total Amortization				[redacted]													
Total Depreciation & Amortization				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Existing Rate	*Settlement* Proposed Rate	Adjustments	Adjusted EPIS Balance Nov 2019	Depreciation Expense Nov 2019	Adjustments	Adjusted EPIS Balance Dec 2019	Depreciation Expense Dec 2019	Adjustments	Adjusted EPIS Balance Jan 2020	Depreciation Expense Jan 2020	Adjustments	Adjusted EPIS Balance Feb 2020	Depreciation Expense Feb 2020	Adjustments	Adjusted EPIS Balance Mar 2020
DEPRECIATION EXPENSE																	
Steam Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Geothermal - Blundell	SG																
Pollution Control Equipment	SG																
Pollution Control Equipment	SG																
Post-merger - Cholla	SG																
Total Steam Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG-P																
Post-merger	SG-U																
Klamath	SG-P																
Total Hydro Plant																	
Other Production Plant:																	
Pre-merger Utah	SG	[redacted]															
Post-merger	SG																
Post-merger Wind	SG-W																
Black Cap Solar	OR																
Post-merger	SG																
Total Other Plant																	
Transmission Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Total Transmission Plant																	
Distribution Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Total Distribution Plant																	
General Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Pre-merger Pacific	SG																
Pre-merger Utah	SG																
Post-merger	SG																
General Office	SO																
General Office	SG																
General Office	SG																
Customer Service	CN																
Fuel Related	SE																
Total General Plant																	
Mining Plant:																	
Coal Mine	SE	[redacted]															
Total Mining Plant																	
Total Depreciation Expense				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Existing Rate	*Settlement* Proposed Rate	Adjustments	Adjusted EPIS Balance Nov 2019	Depreciation Expense Nov 2019	Adjustments	Adjusted EPIS Balance Dec 2019	Depreciation Expense Dec 2019	Adjustments	Adjusted EPIS Balance Jan 2020	Depreciation Expense Jan 2020	Adjustments	Adjusted EPIS Balance Feb 2020	Depreciation Expense Feb 2020	Adjustments	Adjusted EPIS Balance Mar 2020
AMORTIZATION EXPENSE																	
Intangible Plant:																	
California	CA	[redacted]															
Customer Service	CN																
Pre-merger Utah	SG																
Pre-merger Pacific	SG																
Idaho	ID																
Oregon	OR																
Fuel Related	SE																
Post-merger	SG																
Hydro Relicensing	SG-P																
Hydro Relicensing	SG-U																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Klamath	SG-P																
Total Intangible Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Post-merger	SG-P																
Post-merger	SG-U																
Total Hydro Plant																	
Other Production Plant:																	
Post-merger	SG	[redacted]															
Total Other Plant																	
General Plant:																	
California	CA	[redacted]															
General Office	CN																
Oregon	OR																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Total General Plant																	
Total Amortization				[redacted]													
Total Depreciation & Amortization				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Existing Rate	*Settlement* Proposed Rate	Depreciation Expense Mar 2020	Adjustments	Adjusted EPIS Balance Apr 2020	Depreciation Expense Apr 2020	Adjustments	Adjusted EPIS Balance May 2020	Depreciation Expense May 2020	Adjustments	Adjusted EPIS Balance Jun 2020	Depreciation Expense Jun 2020	Adjustments	Adjusted EPIS Balance Jul 2020	Depreciation Expense Jul 2020	Adjustments
DEPRECIATION EXPENSE																	
Steam Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Geothermal - Blundell	SG																
Pollution Control Equipment	SG																
Pollution Control Equipment	SG																
Post-merger - Cholla	SG																
Total Steam Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG-P																
Post-merger	SG-U																
Klamath	SG-P																
Total Hydro Plant																	
Other Production Plant:																	
Pre-merger Utah	SG	[redacted]															
Post-merger	SG																
Post-merger Wind	SG-W																
Black Cap Solar	OR																
Post-merger	SG																
Total Other Plant																	
Transmission Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Total Transmission Plant																	
Distribution Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Total Distribution Plant																	
General Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Pre-merger Pacific	SG																
Pre-merger Utah	SG																
Post-merger	SG																
General Office	SO																
General Office	SG																
General Office	SG																
Customer Service	CN																
Fuel Related	SE																
Total General Plant																	
Mining Plant:																	
Coal Mine	SE	[redacted]															
Total Mining Plant																	
Total Depreciation Expense				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Existing Rate	*Settlement* Proposed Rate	Depreciation Expense Mar 2020	Adjustments	Adjusted EPIS Balance Apr 2020	Depreciation Expense Apr 2020	Adjustments	Adjusted EPIS Balance May 2020	Depreciation Expense May 2020	Adjustments	Adjusted EPIS Balance Jun 2020	Depreciation Expense Jun 2020	Adjustments	Adjusted EPIS Balance Jul 2020	Depreciation Expense Jul 2020	Adjustments
AMORTIZATION EXPENSE																	
Intangible Plant:																	
California	CA	[redacted]															
Customer Service	CN																
Pre-merger Utah	SG																
Pre-merger Pacific	SG																
Idaho	ID																
Oregon	OR																
Fuel Related	SE																
Post-merger	SG																
Hydro Relicensing	SG-P																
Hydro Relicensing	SG-U																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Klamath	SG-P																
Total Intangible Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Post-merger	SG-P																
Post-merger	SG-U																
Total Hydro Plant																	
Other Production Plant:																	
Post-merger	SG	[redacted]															
Total Other Plant																	
General Plant:																	
California	CA	[redacted]															
General Office	CN																
Oregon	OR																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Total General Plant																	
Total Amortization				[redacted]													
Total Depreciation & Amortization				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Existing Rate	*Settlement* Proposed Rate	Adjusted EPIS Balance Aug 2020	Depreciation Expense Aug 2020	Adjustments	Adjusted EPIS Balance Sep 2020	Depreciation Expense Sep 2020	Adjustments	Adjusted EPIS Balance Oct 2020	Depreciation Expense Oct 2020	Adjustments	Adjusted EPIS Balance Nov 2020	Depreciation Expense Nov 2020	Adjustments	Adjusted EPIS Balance Dec 2020	Depreciation Expense Dec 2020
DEPRECIATION EXPENSE																	
Steam Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Geothermal - Blundell	SG																
Pollution Control Equipment	SG																
Pollution Control Equipment	SG																
Post-merger - Cholla	SG																
Total Steam Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG-P																
Post-merger	SG-U																
Klamath	SG-P																
Total Hydro Plant																	
Other Production Plant:																	
Pre-merger Utah	SG	[redacted]															
Post-merger	SG																
Post-merger Wind	SG-W																
Black Cap Solar	OR																
Post-merger	SG																
Total Other Plant																	
Transmission Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Total Transmission Plant																	
Distribution Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Total Distribution Plant																	
General Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Pre-merger Pacific	SG																
Pre-merger Utah	SG																
Post-merger	SG																
General Office	SO																
General Office	SG																
General Office	SG																
Customer Service	CN																
Fuel Related	SE																
Total General Plant																	
Mining Plant:																	
Coal Mine	SE	[redacted]															
Total Mining Plant																	
Total Depreciation Expense				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Existing Rate	*Settlement* Proposed Rate	Adjusted EPIS Balance Aug 2020	Depreciation Expense Aug 2020	Adjustments	Adjusted EPIS Balance Sep 2020	Depreciation Expense Sep 2020	Adjustments	Adjusted EPIS Balance Oct 2020	Depreciation Expense Oct 2020	Adjustments	Adjusted EPIS Balance Nov 2020	Depreciation Expense Nov 2020	Adjustments	Adjusted EPIS Balance Dec 2020	Depreciation Expense Dec 2020
AMORTIZATION EXPENSE																	
Intangible Plant:																	
California	CA	[redacted]															
Customer Service	CN																
Pre-merger Utah	SG																
Pre-merger Pacific	SG																
Idaho	ID																
Oregon	OR																
Fuel Related	SE																
Post-merger	SG																
Hydro Relicensing	SG-P																
Hydro Relicensing	SG-U																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Klamath	SG-P																
Total Intangible Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Post-merger	SG-P																
Post-merger	SG-U																
Total Hydro Plant																	
Other Production Plant:																	
Post-merger	SG	[redacted]															
Total Other Plant																	
General Plant:																	
California	CA	[redacted]															
General Office	CN																
Oregon	OR																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Total General Plant																	
Total Amortization				[redacted]													
Total Depreciation & Amortization				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Existing Rate	*Settlement* Proposed Rate	Annualized Depreciation Expense	Depreciation Expense
DEPRECIATION EXPENSE					
Steam Production Plant:					
Pre-merger Pacific	SG	[redacted]			
Pre-merger Utah	SG				
Post-merger	SG				
Geothermal - Blundell	SG				
Pollution Control Equipment	SG				
Pollution Control Equipment	SG				
Post-merger - Cholla	SG				
Total Steam Plant					
Hydro Production Plant:					
Pre-merger Pacific	SG	[redacted]			
Pre-merger Utah	SG				
Post-merger	SG-P				
Post-merger	SG-U				
Klamath	SG-P				
Total Hydro Plant					
Other Production Plant:					
Pre-merger Utah	SG	[redacted]			
Post-merger	SG				
Post-merger Wind	SG-W				
Black Cap Solar	OR				
Post-merger	SG				
Total Other Plant					
Transmission Plant:					
Pre-merger Pacific	SG	[redacted]			
Pre-merger Utah	SG				
Post-merger	SG				
Total Transmission Plant					
Distribution Plant:					
California	CA	[redacted]			
Oregon	OR				
Washington	WA				
Eastern Wyoming	WYP				
Utah	UT				
Idaho	ID				
Western Wyoming	WYU				
Total Distribution Plant					
General Plant:					
California	CA	[redacted]			
Oregon	OR				
Washington	WA				
Eastern Wyoming	WYP				
Utah	UT				
Idaho	ID				
Western Wyoming	WYU				
Pre-merger Pacific	SG				
Pre-merger Utah	SG				
Post-merger	SG				
General Office	SO				
General Office	SG				
General Office	SG				
Customer Service	CN				
Fuel Related	SE				
Total General Plant					
Mining Plant:					
Coal Mine	SE	[redacted]			
Total Mining Plant					
Total Depreciation Expense				[redacted]	

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Existing Rate	*Settlement* Proposed Rate	Annualized E i ti R t Depreciation Expense	P d R t Depreciation Expense
AMORTIZATION EXPENSE					
Intangible Plant:					
California	CA	[redacted]			
Customer Service	CN				
Pre-merger Utah	SG				
Pre-merger Pacific	SG				
Idaho	ID				
Oregon	OR				
Fuel Related	SE				
Post-merger	SG				
Hydro Relicensing	SG-P				
Hydro Relicensing	SG-U				
General Office	SO				
Utah	UT				
Washington	WA				
Eastern Wyoming	WYP				
Western Wyoming	WYU				
Klamath	SG-P				
Total Intangible Plant					
Hydro Production Plant:					
Pre-merger Pacific	SG	[redacted]			
Post-merger	SG-P				
Post-merger	SG-U				
Total Hydro Plant					
Other Production Plant:					
Post-merger	SG	[redacted]			
Total Other Plant					
General Plant:					
California	CA	[redacted]			
General Office	CN				
Oregon	OR				
General Office	SO				
Utah	UT				
Washington	WA				
Eastern Wyoming	WYP				
Western Wyoming	WYU				
Total General Plant					
Total Amortization				[redacted]	
Total Depreciation & Amortization				[redacted]	
				Ref. 6.1.7 SR	**Ref. 6.1.7 SR**
				[redacted]	

PacifiCorp
Oregon General Rate Case - December 2021
Vehicle Depreciation Expense - Adjustment to Proposed Depreciation Rates

Factor	Vehicle Balance	Year Ending June 2019 Depreciation Existing Rates	Annual Depreciation Study Rates		Difference[1]	
CA	6,490,286	341,236	414,761		73,525	
DGP	332,616	17,488	21,256		3,768	
DGU	1,512,598	79,527	96,662		17,135	
OR	65,421,209	3,439,613	4,180,735		741,123	
SE	724,778	38,106	46,317		8,211	
SG	65,023,909	3,418,724	4,155,346		736,622	
SO	12,987,017	682,811	829,934		147,123	
SSGCH	1,677,855	88,216	107,223		19,008	
SSGCT	44,655	2,348	2,854		506	
UT	87,802,654	4,616,349	5,611,019		994,670	
WA	14,265,617	750,035	911,643		161,608	
WYP	27,933,718	1,468,655	1,785,101		316,447	
WYU	5,687,450	299,026	363,456		64,430	
ID	17,176,761	903,092	1,097,679		194,587	
Total	**307,081,124**	**16,145,224**	**19,623,986**		**3,478,762**	
			Labor Pool Allocation	78.41%	2,727,734	
			Direct Allocation	21.59%	**751,028**	**Ref 6.1.3_SR**
					3,478,762	
			Labor Pool Allocation	78.41%	2,727,734	
			Capital/Non Utility		931,902	
					1,795,832	**Ref 6.1.3_SR**

1) This is the difference between depreciation study rates and the exitsing rates.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Depreciation Reserve	***108SP***	***3***	***(82,198,824)***	***SG***	***26.023%***	***(21,390,298)***	
Steam Depreciation Reserve	***108SP***	***3***	***(60,012,565)***	***SG***	***26.023%***	***(15,616,849)***	
Steam Depreciation Reserve	***108SP***	***3***	***(1,081,410,413)***	***SG***	***26.023%***	***(281,411,458)***	
Steam Depreciation Reserve	108SP	3	(117,630,520)	SG	26.023%	(30,610,558)	
Hydro Depreciation Reserve	***108HP***	***3***	***29,558,740***	***SG***	***26.023%***	***7,691,962***	
Hydro Depreciation Reserve	***108HP***	***3***	***(1,664,394)***	***SG***	***26.023%***	***(433,119)***	
Hydro Depreciation Reserve	***108HP***	***3***	***(62,151,220)***	***SG-P***	***26.023%***	***(16,173,384)***	
Hydro Depreciation Reserve	***108HP***	***3***	***(8,910,619)***	***SG-U***	***26.023%***	***(2,318,778)***	
Other Depreciation Reserve	108OP	3	-	SG	26.023%	-	
Other Depreciation Reserve	108OP	3	(60,242,101)	SG	26.023%	(15,676,581)	
Other Depreciation Reserve	108OP	3	1,128,647,420	SG-W	26.023%	293,703,771	
Other Depreciation Reserve	108OP	3	(4,278)	OR	Situs	(4,278)	
Other Depreciation Reserve	***108OP***	***3***	***(4,457,626)***	***SG***	***26.023%***	***(1,159,992)***	
Transmission Depreciation Reserve	***108TP***	***3***	***(9,151,691)***	***SG***	***26.023%***	***(2,381,511)***	
Transmission Depreciation Reserve	***108TP***	***3***	***(8,986,073)***	***SG***	***26.023%***	***(2,338,413)***	
Transmission Depreciation Reserve	***108TP***	***3***	***(119,243,150)***	***SG***	***26.023%***	***(31,030,207)***	
Distribution Depreciation Reserve	***108360***	***3***	***(1,747,959)***	***Situs***	***Situs***	***(416,810)***	
Distribution Depreciation Reserve	***108361***	***3***	***(3,348,843)***	***Situs***	***Situs***	***(798,550)***	
Distribution Depreciation Reserve	***108362***	***3***	***(28,117,744)***	***Situs***	***Situs***	***(6,704,832)***	
Distribution Depreciation Reserve	***108364***	***3***	***(33,841,093)***	***Situs***	***Situs***	***(8,069,596)***	
Distribution Depreciation Reserve	***108365***	***3***	***(21,528,430)***	***Situs***	***Situs***	***(5,133,573)***	
Distribution Depreciation Reserve	***108366***	***3***	***(10,677,635)***	***Situs***	***Situs***	***(2,546,141)***	
Distribution Depreciation Reserve	***108367***	***3***	***(24,928,277)***	***Situs***	***Situs***	***(5,944,286)***	
Distribution Depreciation Reserve	***108368***	***3***	***(38,394,045)***	***Situs***	***Situs***	***(9,155,273)***	
Distribution Depreciation Reserve	***108369***	***3***	***(22,990,793)***	***Situs***	***Situs***	***(5,482,282)***	
Distribution Depreciation Reserve	***108370***	***3***	***(6,505,834)***	***Situs***	***Situs***	***(1,551,352)***	
Distribution Depreciation Reserve	***108371***	***3***	***(241,416)***	***Situs***	***Situs***	***(57,567)***	
Distribution Depreciation Reserve	***108373***	***3***	***(1,718,071)***	***Situs***	***Situs***	***(409,684)***	
General Depreciation Reserve	108GP	3	(898,602)	CA	Situs	-	
General Depreciation Reserve	***108GP***	***3***	***(7,283,693)***	***OR***	***Situs***	***(7,283,693)***	
General Depreciation Reserve	108GP	3	(1,233,808)	WA	Situs	-	
General Depreciation Reserve	108GP	3	(1,349,773)	WYP	Situs	-	
General Depreciation Reserve	108GP	3	(8,324,354)	UT	Situs	-	
General Depreciation Reserve	108GP	3	(1,882,120)	ID	Situs	-	
General Depreciation Reserve	108GP	3	(515,832)	WYU	Situs	-	
General Depreciation Reserve	***108GP***	***3***	***177,331***	***SG***	***26.023%***	***46,146***	
General Depreciation Reserve	***108GP***	***3***	***(31,150)***	***SG***	***26.023%***	***(8,106)***	
General Depreciation Reserve	***108GP***	***3***	***(11,486,254)***	***SG***	***26.023%***	***(2,989,026)***	
General Depreciation Reserve	***108GP***	***3***	***(3,722,818)***	***SO***	***27.213%***	***(1,013,087)***	
General Depreciation Reserve	108GP	3	(98,010)	SG	26.023%	(25,505)	
General Depreciation Reserve	108GP	3	(16,608)	SG	26.023%	(4,322)	
General Depreciation Reserve	108GP	3	1,465,176	CN	31.217%	457,385	
General Depreciation Reserve	108GP	3	(176,323)	SE	25.101%	(44,260)	
Mining Depreciation Reserve	108MP	3	-	SE	25.101%	-	
Total Depreciation Reserve			(687,274,293)			(176,284,105)	6.2.2_SR

Description of Adjustment:

This adjustment steps forward the depreciation reserve to a December 2020 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2019 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2019 to December 31, 2020. An incremental amount has been added to the December 31, 2020 balance to reflect the annualized 2020 depreciation & amortization expense being added in through adjustment 6.1.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated to reflect the corresponding updates required to depreciation reserves as a result of application of proposed depreciation study rates to test period levels in adjustment 6.1_SR in Surrebuttal. Allocation changes as a result of revisions to the Company's revenue requirement calculations in Surrebuttal has also been incoroporated.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Amortization Reserve	111IP	3	(2,745)	CA	Situs	-	
Intangible Amortization Reserve	111IP	3	(15,390,066)	CN	31.217%	(4,804,326)	
Intangible Amortization Reserve	111IP	3	(33,004)	ID	Situs	-	
Intangible Amortization Reserve	111IP	3	(24,727)	SG	26.023%	(6,435)	
Intangible Amortization Reserve	111IP	3	(8,524)	OR	Situs	(8,524)	
Intangible Amortization Reserve	111IP	3	1,106,269	SE	25.101%	277,690	
Intangible Amortization Reserve	111IP	3	(5,439,908)	SG	26.023%	(1,415,607)	
Intangible Amortization Reserve	111IP	3	(7,481,317)	SG-P	26.023%	(1,946,836)	
Intangible Amortization Reserve	111IP	3	(472,205)	SG-U	26.023%	(122,880)	
Intangible Amortization Reserve	***111IP***	***3***	***(3,634,198)***	***SO***	***27.213%***	***(988,971)***	
Intangible Amortization Reserve	111IP	3	-	SG	26.023%	-	
Intangible Amortization Reserve	111IP	3	5,147,222	UT	Situs	-	
Intangible Amortization Reserve	111IP	3	(4,535)	WA	Situs	-	
Intangible Amortization Reserve	111IP	3	79,128	WYP	Situs	-	
Intangible Amortization Reserve	111IP	3	-	WYU	Situs	-	
Intangible Amortization Reserve	111IP	3	-	SG	26.023%	-	
Hydro Amortization Reserve	111HP	3	-	SG	26.023%	-	
Hydro Amortization Reserve	111HP	3	(467,544)	SG-P	26.023%	(121,667)	
Hydro Amortization Reserve	111HP	3	-	SG-U	26.023%	-	
Other Amortizaton Reserve	111OP	3	-	SG	26.023%	-	
General Amortization Reserve	111GP	3	(42,023)	CA	Situs	-	
General Amortization Reserve	111GP	3	-	CN	31.217%	-	
General Amortization Reserve	111GP	3	-	SG	26.023%	-	
General Amortization Reserve	111GP	3	(374,852)	OR	Situs	(374,852)	
General Amortization Reserve	***111GP***	***3***	***(426,530)***	***SO***	***27.213%***	***(116,071)***	
General Amortization Reserve	111GP	3	(1,092)	UT	Situs	-	
General Amortization Reserve	111GP	3	(120,761)	WA	Situs	-	
General Amortization Reserve	111GP	3	(72,178)	WYP	Situs	-	
General Amortization Reserve	111GP	3	-	WYU	Situs	-	
			(27,663,592)			(9,628,479)	6.2.3_SR

Description of Adjustment:

This adjustment steps forward the depreciation reserve to a December 2020 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2019 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2019 to December 31, 2020. An incremental amount has been added to the December 31, 2020 balance to reflect the annualized 2020 depreciation & amortization expense being added in through adjustment 6.1.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated to reflect the corresponding updates required to depreciation reserves as a result of application of proposed depreciation study rates to test period levels in adjustment 6.1_SR in Surrebuttal. Allocation changes as a result of revisions to the Company's revenue requirement calculations in Surrebuttal has also been incoroporated.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 ME Jun 2019 Reserve	Test Period Reserve Adjusted 2020	Adjustment to Test Period
DEPRECIATION RESERVE					
Steam Production Plant:					
Pre-merger Pacific	108SP	SG	(759,016,718)	(841,215,541)	(82,198,824)
Pre-merger Utah	108SP	SG	(726,882,090)	(786,894,654)	(60,012,565)
Post-merger	108SP	SG	(1,488,197,425)	(2,569,607,838)	(1,081,410,413)
Post-merger - Cholla	108SP	SG	(246,321,600)	(363,952,120)	(117,630,520)
Total Steam Plant			(3,220,417,832)	(4,561,670,153)	(1,341,252,322)
Hydro Production Plant:					
Pre-merger Pacific	108HP	SG	(175,334,101)	(145,775,361)	29,558,740
Pre-merger Utah	108HP	SG	(30,353,650)	(32,018,044)	(1,664,394)
Post-merger	108HP	SG-P	(189,513,434)	(251,664,654)	(62,151,220)
Post-merger	108HP	SG-U	(51,987,503)	(60,898,122)	(8,910,619)
Total Hydro Plant			(447,188,687)	(490,356,180)	(43,167,494)
Other Production Plant:					
Pre-merger Utah	108OP	SG	-	-	-
Post-merger	108OP	SG	(418,175,116)	(478,417,217)	(60,242,101)
Post-merger - Wind	108OP	SG-W	(681,674,033)	446,973,386	1,128,647,420
Black Cap Solar	108OP	OR	-	(4,278)	(4,278)
Post-merger	108OP	SG	(36,871,542)	(41,329,167)	(4,457,626)
Total Other Plant			(1,136,720,691)	(72,777,276)	1,063,943,414
Transmission Plant:					
Pre-merger Pacific	108TP	SG	(351,699,893)	(360,851,583)	(9,151,691)
Pre-merger Utah	108TP	SG	(418,414,202)	(427,400,276)	(8,986,073)
Post-merger	108TP	SG	(1,043,195,644)	(1,162,438,794)	(119,243,150)
Total Transmission Plant			(1,813,309,739)	(1,950,690,653)	(137,380,914)
Distribution Plant:					
California	108364	CA	(138,842,809)	(147,062,217)	(8,219,408)
Oregon	108364	OR	(1,017,251,759)	(1,063,521,705)	(46,269,946)
Washington	108364	WA	(254,269,518)	(271,158,882)	(16,889,363)
Eastern Wyoming	108364	WYP	(264,618,132)	(284,397,235)	(19,779,103)
Utah	108364	UT	(998,035,522)	(1,085,042,946)	(87,007,425)
Idaho	108364	ID	(149,207,836)	(159,630,533)	(10,422,697)
Western Wyoming	108364	WYU	(58,760,424)	(64,212,621)	(5,452,197)
Total Distribution Plant			(2,880,985,998)	(3,075,026,138)	(194,040,140)
General Plant:					
California	108GP	CA	(7,234,341)	(8,132,943)	(898,602)
Oregon	108GP	OR	(84,544,724)	(91,828,418)	(7,283,693)
Washington	108GP	WA	(24,157,433)	(25,391,240)	(1,233,808)
Eastern Wyoming	108GP	WYP	(23,971,348)	(25,321,121)	(1,349,773)
Utah	108GP	UT	(85,056,354)	(93,380,708)	(8,324,354)
Idaho	108GP	ID	(16,831,634)	(18,713,754)	(1,882,120)
Western Wyoming	108GP	WYU	(5,782,407)	(6,298,239)	(515,832)
Pre-merger Pacific	108GP	SG	(843,233)	(665,902)	177,331
Pre-merger Utah	108GP	SG	(2,907,693)	(2,938,844)	(31,150)
Post-merger	108GP	SG	(113,184,624)	(124,670,878)	(11,486,254)
General Office	108GP	SO	(102,867,839)	(106,590,658)	(3,722,818)
General Office	108GP	SG	(2,712,809)	(2,810,818)	(98,010)
General Office	108GP	SG	(110,482)	(127,090)	(16,608)
Customer Service	108GP	CN	(6,314,416)	(4,849,240)	1,465,176
Fuel Related	108GP	SE	(1,583,569)	(1,759,892)	(176,323)
Total General Plant			(478,102,906)	(513,479,745)	(35,376,838)
Mining Plant:					
Coal Mine	108MP	SE	-	-	-
Total Mining Plant			-	-	-
Total Depreciation Reserve			(9,976,725,853)	(10,664,000,146)	**(687,274,293)**
					Ref 6.2_SR

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 ME Jun 2019 Reserve	Test Period Reserve Adjusted 2020	Adjustment to Test Period
AMORTIZATION RESERVE					
Intangible Plant:					
California	111IP	CA	(2,672)	(5,417)	(2,745)
Customer Service	111IP	CN	(137,070,357)	(152,460,423)	(15,390,066)
Idaho	111IP	ID	(930,856)	(963,860)	(33,004)
Pre-merger Utah	111IP	SG	(489,827)	(514,554)	(24,727)
Oregon	111IP	OR	(105,941)	(114,464)	(8,524)
Fuel Related	111IP	SE	-	1,106,269	1,106,269
Post-merger	111IP	SG	(91,016,089)	(96,455,997)	(5,439,908)
Hydro Relicensing	111IP	SG-P	(105,420,483)	(112,901,800)	(7,481,317)
Hydro Relicensing	111IP	SG-U	(6,044,246)	(6,516,451)	(472,205)
General Office	111IP	SO	(290,867,606)	(294,501,804)	(3,634,198)
Pre-merger Pacific	111IP	SG	-	-	-
Utah	111IP	UT	30,396,632	35,543,854	5,147,222
Washington	111IP	WA	(4,535)	(9,071)	(4,535)
Eastern Wyoming	111IP	WYP	(153,589)	(74,461)	79,128
Western Wyoming	111IP	WYU	-	-	-
General Office	111IP	SG	(21,945)	(21,945)	-
Total Intangible Plant			(601,731,514)	(627,890,126)	(26,158,612)
Hydro Production Plant:					
Pre-merger Pacific	111HP	SG	-	-	-
Post-merger	111HP	SG-P	(2,515,843)	(2,983,387)	(467,544)
Post-merger	111HP	SG-U	-	-	-
Total Hydro Plant			(2,515,843)	(2,983,387)	(467,544)
Other Production Plant:					
Post-merger	111OP	SG	-	-	-
Total Other Plant			-	-	-
General Plant:					
California	111GP	CA	(505,769)	(547,793)	(42,023)
General Office	111GP	CN	-	-	-
Idaho	111GP	ID	(333,771)	(333,771)	-
Oregon	111GP	OR	(4,176,900)	(4,551,753)	(374,852)
General Office	111GP	SO	(3,442,703)	(3,869,233)	(426,530)
Utah	111GP	UT	(17,944)	(19,035)	(1,092)
Washington	111GP	WA	(1,691,029)	(1,811,790)	(120,761)
Eastern Wyoming	111GP	WYP	(4,351,504)	(4,423,682)	(72,178)
Western Wyoming	111GP	WYU	-	-	-
Total General Plant			(14,519,621)	(15,557,057)	(1,037,436)
Total Amortization Reserve			(618,766,978)	(646,430,570)	**(27,663,592)**
					Ref 6.2.1_SR
Total Depreciation & Amortization Reserve			(10,595,492,832)	(11,310,430,716)	(714,937,885)
				Ref. 6.2.11_SR	

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Adjusted Reserve Balance Jun 2019	Adjustments	Adjusted Reserve Balance Jul 2019	Adjustments	Adjusted Reserve Balance Aug 2019	Adjustments	Adjusted Reserve Balance Sep 2019	Adjustments	Adjusted Reserve Balance Oct 2019	Adjustments	Adjusted Reserve Balance Nov 2019	Adjustments	Adjusted Reserve Balance Dec 2019
DEPRECIATION RESERVE														
Steam Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG													
Geothermal - Blundell	SG													
Pollution Control Equipment	SG													
Pollution Control Equipment	SG													
Post-merger - Cholla	SG													
Total Steam Plant														
Hydro Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG-P													
Post-merger	SG-U													
Klamath	SG-P													
Total Hydro Plant														
Other Production Plant:														
Pre-merger Utah	SG	[redacted]												
Post-merger	SG													
Post-merger Wind	SG-W													
Black Cap Solar	OR													
Post-merger	SG													
Total Other Plant														
Transmission Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG													
Total Transmission Plant														
Distribution Plant:														
California	CA	[redacted]												
Oregon	OR													
Washington	WA													
Eastern Wyoming	WYP													
Utah	UT													
Idaho	ID													
Western Wyoming	WYU													
Total Distribution Plant														
General Plant:														
California	CA	[redacted]												
Oregon	OR													
Washington	WA													
Eastern Wyoming	WYP													
Utah	UT													
Idaho	ID													
Western Wyoming	WYU													
Pre-merger Pacific	SG													
Pre-merger Utah	SG													
Post-merger	SG													
General Office	SO													
General Office	SG													
General Office	SG													
Customer Service	CN													
Fuel Related	SE													
Total General Plant														
Mining Plant:														
Coal Mine	SE	[redacted]												
Total Mining Plant														
Total Depreciation Reserve		[redacted]												

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Adjusted Reserve Balance Jun 2019	Adjustments	Adjusted Reserve Balance Jul 2019	Adjustments	Adjusted Reserve Balance Aug 2019	Adjustments	Adjusted Reserve Balance Sep 2019	Adjustments	Adjusted Reserve Balance Oct 2019	Adjustments	Adjusted Reserve Balance Nov 2019	Adjustments	Adjusted Reserve Balance Dec 2019
AMORTIZATION RESERVE														
Intangible Plant:														
California	CA	[redacted]												
Customer Service	CN													
Idaho	ID													
Pre-merger Utah	SG													
Montana	MT													
Oregon	OR													
Fuel Related	SE													
Post-merger	SG													
Hydro Relicensing	SG-P													
Hydro Relicensing	SG-U													
General Office	SO													
Pre-merger Pacific	SG													
Utah	UT													
Washington	WA													
Eastern Wyoming	WYP													
Western Wyoming	WYU													
General Office	SG													
Klamath	SG-P													
Total Intangible Plant														
Hydro Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Post-merger	SG-P													
Post-merger	SG-U													
Total Hydro Plant														
Other Production Plant:														
Post-merger	SG	[redacted]												
Total Other Plant														
General Plant:														
California	CA	[redacted]												
General Office	CN													
General Office	ID													
Oregon	OR													
General Office	SO													
Utah	UT													
Washington	WA													
Eastern Wyoming	WYP													
Western Wyoming	WYU													
Total General Plant														
Total Amortization Reserve		[redacted]												
Total Depreciation & Amortization Reserve		[redacted]												

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Adjustments	Adjusted Reserve Balance Jan 2020	Adjustments	Adjusted Reserve Balance Feb 2020	Adjustments	Adjusted Reserve Balance Mar 2020	Adjustments	Adjusted Reserve Balance Apr 2020	Adjustments	Adjusted Reserve Balance May 2020	Adjustments	Adjusted Reserve Balance Jun 2020	Adjustments
DEPRECIATION RESERVE														
Steam Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG													
Geothermal - Blundell	SG													
Pollution Control Equipment	SG													
Pollution Control Equipment	SG													
Post-merger - Cholla	SG													
Total Steam Plant														
Hydro Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG-P													
Post-merger	SG-U													
Klamath	SG-P													
Total Hydro Plant														
Other Production Plant:														
Pre-merger Utah	SG	[redacted]												
Post-merger	SG													
Post-merger Wind	SG-W													
Black Cap Solar	OR													
Post-merger	SG													
Total Other Plant														
Transmission Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG													
Total Transmission Plant														
Distribution Plant:														
California	CA	[redacted]												
Oregon	OR													
Washington	WA													
Eastern Wyoming	WYP													
Utah	UT													
Idaho	ID													
Western Wyoming	WYU													
Total Distribution Plant														
General Plant:														
California	CA	[redacted]												
Oregon	OR													
Washington	WA													
Eastern Wyoming	WYP													
Utah	UT													
Idaho	ID													
Western Wyoming	WYU													
Pre-merger Pacific	SG													
Pre-merger Utah	SG													
Post-merger	SG													
General Office	SO													
General Office	SG													
General Office	SG													
Customer Service	CN													
Fuel Related	SE													
Total General Plant														
Mining Plant:														
Coal Mine	SE	[redacted]												
Total Mining Plant														
Total Depreciation Reserve		[redacted]												

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Adjustments	Adjusted Reserve Balance Jan 2020	Adjustments	Adjusted Reserve Balance Feb 2020	Adjustments	Adjusted Reserve Balance Mar 2020	Adjustments	Adjusted Reserve Balance Apr 2020	Adjustments	Adjusted Reserve Balance May 2020	Adjustments	Adjusted Reserve Balance Jun 2020	Adjustments
AMORTIZATION RESERVE														
Intangible Plant:														
California	CA	[redacted]												
Customer Service	CN													
Idaho	ID													
Pre-merger Utah	SG													
Montana	MT													
Oregon	OR													
Fuel Related	SE													
Post-merger	SG													
Hydro Relicensing	SG-P													
Hydro Relicensing	SG-U													
General Office	SO													
Pre-merger Pacific	SG													
Utah	UT													
Washington	WA													
Eastern Wyoming	WYP													
Western Wyoming	WYU													
General Office	SG													
Klamath	SG-P													
Total Intangible Plant														
Hydro Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Post-merger	SG-P													
Post-merger	SG-U													
Total Hydro Plant														
Other Production Plant:														
Post-merger	SG	[redacted]												
Total Other Plant														
General Plant:														
California	CA	[redacted]												
General Office	CN													
General Office	ID													
Oregon	OR													
General Office	SO													
Utah	UT													
Washington	WA													
Eastern Wyoming	WYP													
Western Wyoming	WYU													
Total General Plant														
Total Amortization Reserve		[redacted]												
Total Depreciation & Amortization Reserve		[redacted]												

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Adjusted Reserve Balance Jul 2020	Adjustments	Adjusted Reserve Balance Aug 2020	Adjustments	Adjusted Reserve Balance Sep 2020	Adjustments	Adjusted Reserve Balance Oct 2020	Adjustments	Adjusted Reserve Balance Nov 2020	Adjustments	Adjusted Reserve Balance Dec 2020
DEPRECIATION RESERVE												
Steam Production Plant:												
Pre-merger Pacific	SG	[redacted]										
Pre-merger Utah	SG											
Post-merger	SG											
Geothermal - Blundell	SG											
Pollution Control Equipment	SG											
Pollution Control Equipment	SG											
Post-merger - Cholla	SG											
Total Steam Plant												
Hydro Production Plant:												
Pre-merger Pacific	SG	[redacted]										
Pre-merger Utah	SG											
Post-merger	SG-P											
Post-merger	SG-U											
Klamath	SG-P											
Total Hydro Plant												
Other Production Plant:												
Pre-merger Utah	SG	[redacted]										
Post-merger	SG											
Post-merger Wind	SG-W											
Black Cap Solar	OR											
Post-merger	SG											
Total Other Plant												
Transmission Plant:												
Pre-merger Pacific	SG	[redacted]										
Pre-merger Utah	SG											
Post-merger	SG											
Total Transmission Plant												
Distribution Plant:												
California	CA	[redacted]										
Oregon	OR											
Washington	WA											
Eastern Wyoming	WYP											
Utah	UT											
Idaho	ID											
Western Wyoming	WYU											
Total Distribution Plant												
General Plant:												
California	CA	[redacted]										
Oregon	OR											
Washington	WA											
Eastern Wyoming	WYP											
Utah	UT											
Idaho	ID											
Western Wyoming	WYU											
Pre-merger Pacific	SG											
Pre-merger Utah	SG											
Post-merger	SG											
General Office	SO											
General Office	SG											
General Office	SG											
Customer Service	CN											
Fuel Related	SE											
Total General Plant												
Mining Plant:												
Coal Mine	SE	[redacted]										
Total Mining Plant												
Total Depreciation Reserve		[redacted]										

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Adjusted Reserve Balance Jul 2020	Adjustments	Adjusted Reserve Balance Aug 2020	Adjustments	Adjusted Reserve Balance Sep 2020	Adjustments	Adjusted Reserve Balance Oct 2020	Adjustments	Adjusted Reserve Balance Nov 2020	Adjustments	Adjusted Reserve Balance Dec 2020
AMORTIZATION RESERVE												
Intangible Plant:												
California	CA	[redacted]										
Customer Service	CN											
Idaho	ID											
Pre-merger Utah	SG											
Montana	MT											
Oregon	OR											
Fuel Related	SE											
Post-merger	SG											
Hydro Relicensing	SG-P											
Hydro Relicensing	SG-U											
General Office	SO											
Pre-merger Pacific	SG											
Utah	UT											
Washington	WA											
Eastern Wyoming	WYP											
Western Wyoming	WYU											
General Office	SG											
Klamath	SG-P											
Total Intangible Plant												
Hydro Production Plant:												
Pre-merger Pacific	SG	[redacted]										
Post-merger	SG-P											
Post-merger	SG-U											
Total Hydro Plant												
Other Production Plant:												
Post-merger	SG	[redacted]										
Total Other Plant												
General Plant:												
California	CA	[redacted]										
General Office	CN											
General Office	ID											
Oregon	OR											
General Office	SO											
Utah	UT											
Washington	WA											
Eastern Wyoming	WYP											
Western Wyoming	WYU											
Total General Plant												
Total Amortization Reserve		[redacted]										
Total Depreciation & Amortization Reserve		[redacted]										

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Balance	Incremental Reserve For Study Rates	CY 2020 Adjusted Year End Balance
DEPRECIATION RESERVE				
Steam Production Plant:				
Pre-merger Pacific	SG	[redacted]	[redacted]	[redacted]
Pre-merger Utah	SG			
Post-merger	SG			
Geothermal - Blundell	SG			
Pollution Control Equipment	SG			
Pollution Control Equipment	SG			
Post-merger - Cholla	SG			
Total Steam Plant				
Hydro Production Plant:				
Pre-merger Pacific	SG	[redacted]	[redacted]	[redacted]
Pre-merger Utah	SG			
Post-merger	SG-P			
Post-merger	SG-U			
Klamath	SG-P			
Total Hydro Plant				
Other Production Plant:				
Pre-merger Utah	SG	[redacted]	[redacted]	[redacted]
Post-merger	SG			
Post-merger Wind	SG-W			
Black Cap Solar	OR			
Post-merger	SG			
Total Other Plant				
Transmission Plant:				
Pre-merger Pacific	SG	[redacted]	[redacted]	[redacted]
Pre-merger Utah	SG			
Post-merger	SG			
Total Transmission Plant				
Distribution Plant:				
California	CA	[redacted]	[redacted]	[redacted]
Oregon	OR			
Washington	WA			
Eastern Wyoming	WYP			
Utah	UT			
Idaho	ID			
Western Wyoming	WYU			
Total Distribution Plant				
General Plant:				
California	CA	[redacted]	[redacted]	[redacted]
Oregon	OR			
Washington	WA			
Eastern Wyoming	WYP			
Utah	UT			
Idaho	ID			
Western Wyoming	WYU			
Pre-merger Pacific	SG			
Pre-merger Utah	SG			
Post-merger	SG			
General Office	SO			
General Office	SG			
General Office	SG			
Customer Service	CN			
Fuel Related	SE			
Total General Plant				
Mining Plant:				
Coal Mine	SE	[redacted]	[redacted]	[redacted]
Total Mining Plant				
Total Depreciation Reserve		[redacted]	[redacted]	[redacted]

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/4403_CONF for redacted information.

Description	Factor	Balance	Incremental Reserve For Study Rates	CY 2020 Adjusted Year End Balance
AMORTIZATION RESERVE				
Intangible Plant:				
California	CA	[redacted]	[redacted]	[redacted]
Customer Service	CN	[redacted]	[redacted]	[redacted]
Idaho	ID	[redacted]	[redacted]	[redacted]
Pre-merger Utah	SG	[redacted]	[redacted]	[redacted]
Montana	MT	[redacted]	[redacted]	[redacted]
Oregon	OR	[redacted]	[redacted]	[redacted]
Fuel Related	SE	[redacted]	[redacted]	[redacted]
Post-merger	SG	[redacted]	[redacted]	[redacted]
Hydro Relicensing	SG-P	[redacted]	[redacted]	[redacted]
Hydro Relicensing	SG-U	[redacted]	[redacted]	[redacted]
General Office	SO	[redacted]	[redacted]	[redacted]
Pre-merger Pacific	SG	[redacted]	[redacted]	[redacted]
Utah	UT	[redacted]	[redacted]	[redacted]
Washington	WA	[redacted]	[redacted]	[redacted]
Eastern Wyoming	WYP	[redacted]	[redacted]	[redacted]
Western Wyoming	WYU	[redacted]	[redacted]	[redacted]
General Office	SG	[redacted]	[redacted]	[redacted]
Klamath	SG-P	[redacted]	[redacted]	[redacted]
Total Intangible Plant		[redacted]	[redacted]	[redacted]
Hydro Production Plant:				
Pre-merger Pacific	SG	[redacted]	[redacted]	[redacted]
Post-merger	SG-P	[redacted]	[redacted]	[redacted]
Post-merger	SG-U	[redacted]	[redacted]	[redacted]
Total Hydro Plant		[redacted]	[redacted]	[redacted]
Other Production Plant:				
Post-merger	SG	[redacted]	[redacted]	[redacted]
Total Other Plant		[redacted]	[redacted]	[redacted]
General Plant:				
California	CA	[redacted]	[redacted]	[redacted]
General Office	CN	[redacted]	[redacted]	[redacted]
General Office	ID	[redacted]	[redacted]	[redacted]
Oregon	OR	[redacted]	[redacted]	[redacted]
General Office	SO	[redacted]	[redacted]	[redacted]
Utah	UT	[redacted]	[redacted]	[redacted]
Washington	WA	[redacted]	[redacted]	[redacted]
Eastern Wyoming	WYP	[redacted]	[redacted]	[redacted]
Western Wyoming	WYU	[redacted]	[redacted]	[redacted]
Total General Plant		[redacted]	[redacted]	[redacted]
Total Amortization Reserve		[redacted]	[redacted]	[redacted]
Total Depreciation & Amortization Reserve		[redacted]	[redacted]	[redacted]

Ref. 6.2.3_SR

PacifiCorp
Oregon General Rate Case - December 2021
Decommissioning & Other Plant Closure Costs

Note: Please see Confidential Exhibit PAC/4404_CONF for redacted information.

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Annual Closure Costs	***407***	***3***	***105,100,892***	***SG***	***26.023%***	***27,350,019***	***6.4.1_SR***
Bridger Reclamation Costs	501	3	[redacted]	SE	25.101%	[redacted]	6.4.2
Adjustment to Rate Base							
Accum. Reg Liab. - Closure Costs	***254***	***3***	***(52,550,446)***	***SG***	***26.023%***	***(13,675,009)***	***6.4.1_SR***
Bridger Reclamation Costs	254	3	[redacted]	SE	25.101%	[redacted]	6.4.2
Adjustment to Tax:							
Schedule M Adjustment	***SCHMAT***	***3***	***105,100,892***	***SG***	***26.023%***	***27,350,019***	***6.4.1_SR***
Deferred Income Tax Expense	***41110***	***3***	***(25,840,740)***	***SG***	***26.023%***	***(6,724,441)***	***6.4.1_SR***
Accumulated Def Inc Tax Balance	***190***	***3***	***12,920,370***	***SG***	***26.023%***	***3,362,220***	***6.4.1_SR***
Schedule M Adjustment	SCHMAT	3	[redacted]	SE	25.101%	[redacted]	6.4.2
Deferred Income Tax Expense	41110	3		SE	25.101%		6.4.2
Accumulated Def Inc Tax Balance	190	3		SE	25.101%		6.4.2

Description of Adjustment:

This adjustment adds into test period results other plant closure costs detailed in the 2018 depreciation study. The Company proposes inclusion of these costs in rates with the accumulation of a credit balance to a regulatory liability account. An annual level of expense is reflected in this adjustment, while the regulatory liability balance is included on a 13-month-average basis for the year ending December 2021. Please refer to the supplemental testimony of Mr. Steven R. McDougal in Docket No. UM-1968 for additional information about the other plant closure costs.

This adjustment has been modified to reflect incremental decommissioning costs in addition to other plant closure costs as detailed in the depreciation study.

PacifiCorp
Oregon General Rate Case - December 2021
Decommissioning & Other Plant Closure Costs
2018 Depreciation Study

Note: Please see Confidential Exhibit PAC/4404_CONF for redacted information.

Plant	Plant Closure Date	Remaining Life (Years)	*Incremental Decommissioning Costs*	Other Closure Costs	Total Company Annual Amount
Hunter	2029	9.0	[redacted]		
Huntington	2029	9.0			
Dave Johnston	2027	7.0			
Jim Bridger	2025	5.0			
Naughton	2029	9.0			
Wyodak	2029	9.0			
Hayden	2023	3.0			
				Total	**105,100,892**
					Ref 6.4_SR

	407 Mthly Accum.	SCHMAT Tax	41110 Def Inc Tax Exp	254 Reg. Liab.	190 ADIT
Dec-20	-			-	-
Jan-21	8,758,408	8,758,408	(2,153,395)	(8,758,408)	2,153,395
Feb-21	8,758,408	8,758,408	(2,153,395)	(17,516,815)	4,306,790
Mar-21	8,758,408	8,758,408	(2,153,395)	(26,275,223)	6,460,185
Apr-21	8,758,408	8,758,408	(2,153,395)	(35,033,631)	8,613,580
May-21	8,758,408	8,758,408	(2,153,395)	(43,792,038)	10,766,975
Jun-21	8,758,408	8,758,408	(2,153,395)	(52,550,446)	12,920,370
Jul-21	8,758,408	8,758,408	(2,153,395)	(61,308,854)	15,073,765
Aug-21	8,758,408	8,758,408	(2,153,395)	(70,067,261)	17,227,160
Sep-21	8,758,408	8,758,408	(2,153,395)	(78,825,669)	19,380,555
Oct-21	8,758,408	8,758,408	(2,153,395)	(87,584,077)	21,533,950
Nov-21	8,758,408	8,758,408	(2,153,395)	(96,342,484)	23,687,345
Dec-21	8,758,408	8,758,408	(2,153,395)	(105,100,892)	25,840,740
Annual Total	**105,100,892**	**105,100,892**	**(25,840,740)**		
		Ref 6.4_SR	**Ref 6.4_SR**		
			13 Mo. Avg.	**(52,550,446)**	**12,920,370**
				Ref 6.4_SR	**Ref 6.4_SR**

Tab 7 - Taxes

Pacificorp
Oregon General Rate Case - December 2021
Tab 7 Adjustment Summary

		Total Adjustments	7.2_SR Property Tax Expense	7.3 Production Tax Credit	7.4_SR PowerTax ADIT Balance	7.5_SR Pro Forma Tax Balances	7.6 Wyoming Wind Generation Tax	7.7 AFUDC - Equity
1	Operating Revenues:							
2	General Business Revenues	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-
5	Other Operating Revenues	-	-	-	-	-	-	-
6	Total Operating Revenues	-	-	-	-	-	-	-
7								
8	Operating Expenses:	-						
9	Steam Production	-	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-	-
12	Other Power Supply	-	-	-	-	-	-	-
13	Transmission	-	-	-	-	-	-	-
14	Distribution	-	-	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-	-
18	Administrative & General	-	-	-	-	-	-	-
19								
20	Total O&M Expenses	-	-	-	-	-	-	-
21			-	-	-	-	-	-
22	Depreciation	-	-	-	-	-	-	-
23	Amortization	-	-	-	-	-	-	-
24	Taxes Other Than Income	8,706,254	8,697,511	-	-	-	8,743	-
25	Income Taxes - Federal	(58,202,979)	(1,743,831)	3,672,861	16,138,457	(78,661,284)	(1,753)	1,176,213
26	Income Taxes - State	(4,820,031)	(394,929)	(35)	3,654,914	(8,621,435)	(397)	266,380
27	Income Taxes - Def Net	9,162,753	-	-	(22,022,116)	27,111,767	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	(45,154,003)	6,558,751	3,672,826	(2,228,745)	(60,170,951)	6,593	1,442,593
32								
33	Operating Rev For Return:	45,154,003	(6,558,751)	(3,672,826)	2,228,745	60,170,951	(6,593)	(1,442,593)
34		-						
35	Rate Base:	-						
36	Electric Plant In Service	-	-	-	-	-	-	-
37	Plant Held for Future Use	-	-	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-	-	-
44	Working Capital	(513,402)	61,993	34,716	187,087	(824,997)	62	13,635
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	(513,402)	61,993	34,716	187,087	(824,997)	62	13,635
49		-	-	-	-	-	-	-
50	Rate Base Deductions:	-	-	-	-	-	-	-
51	Accum Prov For Deprec	-	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	501,974,114	-	-	345,259,313	83,977,767	-	-
54	Unamortized ITC	16,454	-	-	-	16,454	-	-
55	Customer Adv For Const	-	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	(346,485,546)	-	-	-	-	-	-
58			-	-	-	-	-	-
59	Total Rate Base Deductions	155,505,022	-	-	345,259,313	83,994,221	-	-
60								
61	Total Rate Base:	154,991,620	61,993	34,716	345,446,400	83,169,224	62	13,635
62								
63	Return on Rate Base	0.900%	-0.186%	-0.104%	-0.613%	1.378%	0.000%	-0.037%
64								
65	Return on Equity	1.681%	-0.348%	-0.195%	-1.145%	2.576%	0.000%	-0.068%
66								
67	TAX CALCULATION:							
68	Operating Revenue	(8,706,254)	(8,697,511)	-	-	-	(8,743)	-
69	Other Deductions	-	-	-	-	-	-	-
70	Interest (AFUDC)	(5,867,696)	-	-	-	-	-	(5,867,696)
71	Interest	3,435,574	1,374	770	7,657,231	1,843,545	1	302
72	Schedule "M" Additions	(10,289,835)	-	-	(47,212,735)	36,922,900	-	-
73	Schedule "M" Deductions	89,604,124	-	-	(135,374,676)	224,978,800	-	-
74	Income Before Tax	(106,168,091)	(8,698,885)	(770)	80,504,710	(189,899,444)	(8,745)	5,867,394
75								
76	State Income Taxes	(4,820,031)	(394,929)	(35)	3,654,914	(8,621,435)	(397)	266,380
77	Taxable Income	(101,348,059)	(8,303,956)	(735)	76,849,796	(181,278,009)	(8,348)	5,601,014
78								
79	Federal Income Taxes + Other	(58,202,979)	(1,743,831)	3,672,861	16,138,457	(78,661,284)	(1,753)	1,176,213
	APPROXIMATE PRICE CHANGE	(45,996,456)	8,988,057	5,033,210	32,249,076	(73,900,584)	9,035	1,976,917

Pacificorp
Oregon General Rate Case - December 2021
Tab 7 Adjustment Summary

		7.8_SR Removal of TCJA Deferred Balances
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19		
20	Total O&M Expenses	-
21		-
22	Depreciation	-
23	Amortization	-
24	Taxes Other Than Income	-
25	Income Taxes - Federal	1,216,357
26	Income Taxes - State	275,471
27	Income Taxes - Def Net	4,073,102
28	Investment Tax Credit Adj.	-
29	Misc Revenue & Expense	-
30		
31	Total Operating Expenses:	5,564,930
32		
33	Operating Rev For Return:	(5,564,930)
34		
35	Rate Base:	
36	Electric Plant In Service	-
37	Plant Held for Future Use	-
38	Misc Deferred Debits	-
39	Elec Plant Acq Adj	-
40	Nuclear Fuel	-
41	Prepayments	-
42	Fuel Stock	-
43	Material & Supplies	-
44	Working Capital	14,101
45	Weatherization Loans	-
46	Misc Rate Base	-
47		
48	Total Electric Plant:	14,101
49		-
50	Rate Base Deductions:	-
51	Accum Prov For Deprec	-
52	Accum Prov For Amort	-
53	Accum Def Income Tax	72,737,034
54	Unamortized ITC	-
55	Customer Adv For Const	-
56	Customer Service Deposits	-
57	Misc Rate Base Deductions	(346,485,546)
58		-
59	Total Rate Base Deductions	(273,748,512)
60		
61	Total Rate Base:	(273,734,411)
62		
63	Return on Rate Base	0.462%
64		
65	Return on Equity	0.863%
66		
67	TAX CALCULATION:	
68	Operating Revenue	-
69	Other Deductions	-
70	Interest (AFUDC)	-
71	Interest	(6,067,649)
72	Schedule "M" Additions	-
73	Schedule "M" Deductions	-
74	Income Before Tax	6,067,649
75		
76	State Income Taxes	275,471
77	Taxable Income	5,792,178
78		
79	Federal Income Taxes + Other	1,216,357
	APPROXIMATE PRICE CHANGE	(20,352,168)

PacifiCorp
Oregon General Rate Case - December 2021
Interest True-Up

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Interest	***427***	***3***	***10,714,591***	***OR***	***Situs***	***10,714,591***	***Below***

	Total Company		
Adjustment Detail:			
Interest June 2019 - Unadjusted	309,427,198	82,375,935	2.15
Interest December 2021 - Normalized	363,572,244	93,090,526	Below
Adjustment:	54,145,046	10,714,591	
Normalized Total Rate Base	16,402,108,093	4,199,662,927	2.2
Weighted Cost of Debt	2.217%	2.217%	2.1
Normalized Interest	363,572,244	93,090,526	2.15

Description of Adjustment:

This adjustment synchronizes interest expense with the jurisdictional allocated rate base. This is calculated by multiplying net rate base by the Company’s weighted cost of debt. A separate column is not shown for adjustment 7.1 on page 7.0.2 as the interest true-up component is calculated and shown on the adjustment summary pages for each of the adjustments individually.

This adjustment has been updated to synchronize interest expense with recalculated rate base reflective of corrections and modificationsas a result of updating revenue requirement calculation in Rebuttal.

This adjustment has been updated to synchronize interest expense with recalculated rate base reflective of corrections and modificationsas a result of updating revenue requirement calculation in Surrebuttal

PacifiCorp
Oregon General Rate Case - December 2021
Property Tax Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	***408***	***3***	***31,960,976***	***GPS***	***27.213%***	***8,697,511***	***7.2.1***

Description of Adjustment:

This adjustment normalizes the difference between actual accrued property tax expense and forecasted property tax expense resulting from estimated capital additions. For additional information on the Company's property tax estimation procedures and methodologies, please refer to Confidential Exhibit PAC/1303.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
PowerTax ADIT Balance

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
California	282	1	28,128,928	CA	Situs	-	
Idaho	282	1	84,223,812	ID	Situs	-	
Oregon	282	1	345,259,313	OR	Situs	345,259,313	
Other	282	1	9,767,176	OTHER	0.000%	-	
Utah	282	1	630,642,618	UT	Situs	-	
Washington	282	1	81,929,211	WA	Situs	-	
Wyoming	282	1	195,704,899	WYP	Situs	-	
			1,375,655,958			345,259,313	7.4.1
Schedule M Adjustment	***SCHMAT***	***3***	***(219,384,355)***	***SCHMDEXP***	***26.726%***	***(58,632,312)***	***7.4.1***
Schedule M Adjustment	***SCHMAT***	***3***	***1,157,113***	***SO***	***27.215%***	***314,912***	***7.4.1***
Schedule M Adjustment	***SCHMAT***	***3***	***12,457,371***	***CIAC***	***26.756%***	***3,333,142***	***7.4.1***
Schedule M Adjustment	***SCHMAT***	***3***	***25,762,565***	***SNP***	***26.292%***	***6,773,507***	***7.4.1***
Schedule M Adjustment	SCHMDT	3	(542,029,385)	TAXDEPR	26.274%	(142,410,583)	7.4.1
Schedule M Adjustment	SCHMDT	3	(2,451,204)	SG	26.023%	(637,868)	7.4.1
Schedule M Adjustment	***SCHMDT***	***3***	***30,764,682***	***SNP***	***26.292%***	***8,088,667***	***7.4.1***
Schedule M Adjustment	***SCHMDT***	***3***	***(1,977,270)***	***GPS***	***27.215%***	***(538,120)***	***7.4.1***
Deferred Income Tax Expense	***41110***	***3***	***53,939,154***	***SCHMDEXP***	***26.726%***	***14,415,692***	***7.4.1***
Deferred Income Tax Expense	***41110***	***3***	***(284,495)***	***SO***	***27.215%***	***(77,426)***	***7.4.1***
Deferred Income Tax Expense	***41110***	***3***	***(3,062,844)***	***CIAC***	***26.756%***	***(819,506)***	***7.4.1***
Deferred Income Tax Expense	***41110***	***3***	***(6,334,139)***	***SNP***	***26.292%***	***(1,665,375)***	***7.4.1***
Deferred Income Tax Expense	41010	3	(133,266,597)	TAXDEPR	26.274%	(35,013,920)	7.4.1
Deferred Income Tax Expense	41010	3	(602,668)	SG	26.023%	(156,830)	7.4.1
Deferred Income Tax Expense	***41010***	***3***	***7,563,989***	***SNP***	***26.292%***	***1,988,728***	***7.4.1***
Deferred Income Tax Expense	***41010***	***3***	***(486,144)***	***GPS***	***27.215%***	***(132,306)***	***7.4.1***
DIT Expense - Flowthrough	41110	3	(346,092)	OR	Situs	(346,092)	7.4.1
Schedule M Adjustment	***SCHMDT***	***1***	***427,698***	***SO***	***27.215%***	***116,399***	
Deferred Income Tax Expense	***41010***	***1***	***105,156***	***SO***	***27.215%***	***28,619***	

Description of Adjustment:

This adjustment reflects the accumulated deferred income tax balances for property on a jurisdictional basis as maintained in the PowerTax System for the 12 months ended December 31, 2020. Updates the related tax depreciation and book depreciation schedule m items and associated deferred income tax expense for the 12 months ended December 31, 2020. This adjustment also corrects the allocation of the tax schedule m addition and related deferred income tax expense for post-employment costs to correspond with the ADIT treatment.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Adjustment Permanent	***SCHMAP***	***3***	***13,784***	***SCHMDEXP***	***26.279%***	***3,622***	
	SCHMAP	3	(40,125)	SE	25.101%	(10,072)	
	SCHMAP	***3***	***1,346,781***	***SO***	***27.213%***	***366,498***	
	SCHMDP	***3***	***544,541***	***SCHMDEXP***	***26.279%***	***143,100***	
	SCHMDP	3	3,545,057	SE	25.101%	889,862	
	SCHMDP	***3***	***(106,610)***	***SNP***	***26.314%***	***(28,053)***	
Schedule M Adjustment Temporary	SCHMAT	3	(397,328)	BADDEBT	33.239%	(132,068)	
	SCHMAT	3	(3,943,164)	CA	Situs	-	
	SCHMAT	***3***	***(41,493,092)***	***CIAC***	***26.853%***	***(11,142,083)***	
	SCHMAT	***3***	***591,042***	***GPS***	***27.213%***	***160,840***	
	SCHMAT	3	(138,437)	ID	Situs	-	
	SCHMAT	3	(3,747,653)	OR	Situs	(3,747,653)	
	SCHMAT	3	(52,473,014)	OTHER	0.000%	-	
	SCHMAT	***3***	***157,464,116***	***SCHMDEXP***	***26.279%***	***41,379,966***	
	SCHMAT	3	(20,599,304)	SE	25.101%	(5,170,732)	
	SCHMAT	3	89,547,299	SG	26.023%	23,302,565	
	SCHMAT	***3***	***(7,933,430)***	***SNP***	***26.314%***	***(2,087,613)***	
	SCHMAT	***3***	***(2,098,862)***	***SNPD***	***26.853%***	***(563,605)***	
	SCHMAT	***3***	***(20,027,066)***	***SO***	***27.213%***	***(5,449,947)***	
	SCHMAT	3	50,974	TROJD	25.858%	13,181	
	SCHMAT	3	291,300	UT	Situs	-	
	SCHMAT	3	(10,508,304)	WA	Situs	-	
	SCHMAT	3	(714,354)	WYP	Situs	-	
	SCHMDT	3	(917,171)	CA	Situs	-	
	SCHMDT	***3***	***(20,990,264)***	***GPS***	***27.213%***	***(5,712,061)***	
	SCHMDT	3	1,450,496	ID	Situs	-	
	SCHMDT	3	11,918,060	OR	Situs	11,918,060	
	SCHMDT	3	(103,998,630)	OTHER	0.000%	-	
	SCHMDT	3	(88,607,033)	SE	25.101%	(22,241,684)	
	SCHMDT	3	(2,872,490)	SG	26.023%	(747,498)	
	SCHMDT	***3***	***(4,214,274)***	***SNP***	***26.314%***	***(1,108,950)***	
	SCHMDT	***3***	***(1,526,070)***	***SNPD***	***26.853%***	***(409,793)***	
	SCHMDT	***3***	***451,285***	***SO***	***27.213%***	***122,808***	
	SCHMDT	3	921,659,360	TAXDEPR	26.274%	242,153,009	
	SCHMDT	3	4,319,027	UT	Situs	-	
	SCHMDT	3	5,900,574	WA	Situs	-	
	SCHMDT	3	557,818	WYP	Situs	-	
Current Tax Credits	40910	3	519	SE	25.101%	130	
	40910	3	(156,034,664)	SG	26.023%	(40,604,327)	
	40910	***3***	***41,507***	***SO***	***27.213%***	***11,295***	

Description of Adjustment:

This adjustment normalizes base period schedule M, deferred tax expense, and accumulated deferred income tax balances to an estimated pro forma level for the CY December 2021 test period.

This adjustment has been revised to reflect updates to Test Period ITC balances and has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Removal of TCJA Deferred Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustments to Rate Base:							
Reg Liab - Non-Property EDIT - OR	254	1	15,768,651	OR	Situs	15,768,651	B15
Reg Liab - Excess Income Tax Deferral - OR	254	1	50,091,425	OTHER	0.000%	-	B15
Reg Liab - Protected PP&E EDIT - OR	***254***	***1***	***(376,963,650)***	***OR***	***Situs***	***(376,963,650)***	
Reg Liab - Protected PP&E EDIT Amort - OR	254	1	14,709,453	OR	Situs	14,709,453	B15
Adjustments to Tax:							
DTL 705.289 RL-Protected PP&E EDIT - OR	***190***	***1***	***92,682,546***	***OR***	***Situs***	***92,682,546***	
DTA 705.348 - Protected PP&E EDIT Amortization - C	190	1	(2,069,852)	OR	Situs	(2,069,852)	
DTL Non-Prot PP&E EDIT - OR	282	1	(18,163,331)	OR	Situs	(18,163,331)	
DTL PMI PP&E - Protected Property EDIT	***282***	***1***	***1,146,032***	***SE***	***25.101%***	***287,671***	
Protected PP&E EDIT Amortization - OR	***41110***	***1***	***4,073,102***	***OR***	***Situs***	***4,073,102***	

Description of Adjustment:

This adjustment reflects the removal of tax deferral balances as a result of the Tax Cuts and Jobs Act that was enacted on December 22, 2017. The tax rate was reduced from 35% to 21% effective January 1, 2018. The related tax deferral balances will be removed from the base period and amortization via a separate tariff or rider will be proposed as part of the GRC.

Current Tax: Pursuant to Docket UM-1985, Order 19-028, the benefit of the new tax rate will be returned using a rolling deferral and amortization process until the the next general rate case. Therefore, the amount deferred in 2018 will be returned over 12 months starting on February 1, 2019 through Schedule 195, and the deferral in 2019 will be returned in 2020. Both the 2018 and 2019 deferrals are to be reduced by $1.5m to offset the 2018 TAM. The return of the deferral for 2020 will need to be decided upon in the current rate case.

Non-protected PP&E EDIT, Non-Property EDIT and Deferred Protected EDIT Amortization: Pursuant to Docket UM-1985, Order No. 19-028, all EDIT will continue to be deferred until the next rate case, with the exception of the balances utilized as part of the 2019 OR RAC Settlement. Pursuant to the Oregon Renewable Adjustment Clause settlement (UE 352, Order 19-034), approximately $159.7m of non-protected EDIT balances will be used to accelerate the depreciation on Oregon's share of certain repowered wind facilities in September 2019, December 2019 and Q1 2020. As of December 2019, $90.5m, or $120.0m including gross up, of non-protected EDIT balances have been amortized pursuant to this settlement. Another $30.9m, or $40.4m including gross up, is expected to be amortized in Q1 2020.

Protected PP&E EDIT: This adjustment also reflects the level of protected property EDIT amortization for the test period and adjusts the rate base to the appropriate levels.

This adjustment has been updated to reflect proposal by AWEC witness Mr. Bradley Mullins to apply remaining EDFIT balance related to Cholla Unit 4 as an offset to the unrecovered investment amount upon closure of the unit.

This adjustment has been updated to reflect the RSGM amortization schedule based on the settlement agreements in the Oregon Depreciation Study, Docket No. UM 1968.

Tab 8 - Rate Base

Pacificorp

Oregon General Rate Case - December 2021
Tab 8 Adjustment Summary

		8.2_R	8.3	8.4	8.5_SR	8.6	8.7
	Total Adjustments	Trapper Mine Rate Base	Jim Bridger Mine Rate Base	Customer Advances for Construction	Pro Forma Plant Additions	Miscellaneous Rate Base	FERC 105 (PHFU) Adjustment
1 Operating Revenues:							
2 General Business Revenues	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	4,630,292	-	-	-	-	-	-
6 Total Operating Revenues	4,630,292	-	-	-	-	-	-
7							
8 Operating Expenses:	-						
9 Steam Production	(6,582,064)	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-
12 Other Power Supply	4,042,177	-	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	(2,456,792)	-	-	-	-	-	-
19							
20 Total O&M Expenses	(4,996,679)	-	-	-	-	-	-
21		-	-	-	-	-	-
22 Depreciation	24,453,462	-	-	-	-	-	-
23 Amortization	(4,372,483)	-	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-
25 Income Taxes - Federal	(21,566,849)	5,445	(86,402)	(11,199)	(454,057)	11,175	47,544
26 Income Taxes - State	(4,884,294)	1,233	(19,568)	(2,536)	(102,831)	2,531	10,767
27 Income Taxes - Def Net	21,021,939	(14,535)	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	9,655,096	(7,857)	(105,970)	(13,736)	(556,889)	13,706	58,311
32							
33 Operating Rev For Return:	(5,024,804)	7,857	105,970	13,736	556,889	(13,706)	(58,311)
34							
35 Rate Base:							
36 Electric Plant In Service	727,351,260	1,515,183	19,290,185	-	102,188,319	-	-
37 Plant Held for Future Use	(10,699,976)	-	-	-	-	-	(10,699,976)
38 Misc Deferred Debits	(121,119,473)	-	-	-	-	873,314	-
39 Elec Plant Acq Adj	(2,488,575)	-	-	-	-	-	-
40 Nuclear Fuel	(676,340)	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	(3,388,408)	-	-	-	-	(3,388,408)	-
43 Material & Supplies	(1,723,272)	-	-	-	-	-	-
44 Working Capital	(389,510)	(92,202)	(1,002)	(130)	(5,264)	130	551
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	586,865,706	1,422,981	19,289,183	(130)	102,183,055	(2,514,964)	(10,699,425)
49		-	-	-	-	-	-
50 Rate Base Deductions:		-	-	-	-	-	-
51 Accum Prov For Deprec	(90,733,913)	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	23,887,309	18,662	155,128	-	-	-	-
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	2,520,464	-	-	2,520,464	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	10,384,883	-	-	-	-	-	-
58		-	-	-	-	-	-
59 Total Rate Base Deductions	(53,941,258)	18,662	155,128	2,520,464	-	-	-
60							
61 Total Rate Base:	532,924,448	1,441,643	19,444,311	2,520,334	102,183,055	(2,514,964)	(10,699,425)
62							
63 Return on Rate Base	-1.221%	-0.003%	-0.043%	-0.006%	-0.218%	0.005%	0.022%
64							
65 Return on Equity	-2.280%	-0.006%	-0.080%	-0.010%	-0.407%	0.010%	0.042%
66							
67 TAX CALCULATION:							
68 Operating Revenue	(10,454,008)	-	-	-	-	-	-
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	11,812,905	31,956	431,006	55,866	2,265,009	(55,747)	(237,165)
72 Schedule "M" Additions	17,431,380	59,116	-	-	-	-	-
73 Schedule "M" Deductions	102,748,040	-	-	-	-	-	-
74 Income Before Tax	(107,583,573)	27,160	(431,006)	(55,866)	(2,265,009)	55,747	237,165
75							
76 State Income Taxes	(4,884,294)	1,233	(19,568)	(2,536)	(102,831)	2,531	10,767
77 Taxable Income	(102,699,279)	25,927	(411,439)	(53,330)	(2,162,178)	53,216	226,398
78							
79 Federal Income Taxes + Other	(21,566,849)	5,445	(86,402)	(11,199)	(454,057)	11,175	47,544
APPROXIMATE PRICE CHANGE	61,340,659	136,562	1,841,897	238,743	9,679,471	(238,234)	(1,013,522)

Pacificorp
Oregon General Rate Case - December 2021
Tab 8 Adjustment Summary

	8.8_R Regulatory Assets & Liabilities Amortization	8.9_SR Remove Rolling Hills	8.10_R Carbon Plant Closure	8.11_SR Pension and Other Post-retirement Plan Balances Removal	8.12_SR Deer Creek Mine Adjustment	8.13 Repowering Projects Capital Addition	8.14_SR EV 2020 Capital Addition	8.15_SR Cholla Unit 4 Retirement
1 Operating Revenues:								
2 General Business Revenues	-	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-	-
5 Other Operating Revenues	4,630,292	-	-	-	-	-	-	-
6 Total Operating Revenues	4,630,292	-	-	-	-	-	-	-
7								
8 Operating Expenses:								
9 Steam Production	-	-	-	-	1,305,530	-	-	(7,887,593)
10 Nuclear Production	-	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-	-
12 Other Power Supply	-	(77,714)	-	-	-	24,949	4,094,942	-
13 Transmission	-	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-	-
18 Administrative & General	-	(337,539)	-	-	(2,119,252)	-	-	-
19								
20 Total O&M Expenses	-	(415,253)	-	-	(813,723)	24,949	4,094,942	(7,887,593)
21	-	-	-	-	-	-	-	-
22 Depreciation	-	-	(1,447,151)	-	-	13,454,031	18,969,710	(6,690,160)
23 Amortization	(2,756,732)	-	(1,615,751)	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-	-
25 Income Taxes - Federal	(8,137)	1,378,679	317,706	300,975	(1,576,551)	(5,798,187)	(17,525,040)	1,841,127
26 Income Taxes - State	(1,843)	312,233	71,952	68,163	(357,045)	(1,313,129)	(3,968,937)	416,964
27 Income Taxes - Def Net	1,816,212	(1,454,204)	397,260	-	2,150,507	3,411,689	13,103,492	1,644,883
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-	-
30								
31 Total Operating Expenses:	(950,500)	(178,546)	(2,275,984)	369,138	(596,812)	9,779,353	14,674,167	(10,674,780)
32								
33 Operating Rev For Return:	5,580,792	178,546	2,275,984	(369,138)	596,812	(9,779,353)	(14,674,167)	10,674,780
34								
35 Rate Base:								
36 Electric Plant In Service	-	(52,556,663)	-	-	-	278,134,317	520,861,050	(142,916,286)
37 Plant Held for Future Use	-	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	(897,435)	(118,324,302)	(2,771,050)	-	-	-
39 Elec Plant Acq Adj	(2,488,575)	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	(676,340)	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-	(1,723,272)
44 Working Capital	(94)	12,058	3,683	3,489	(25,968)	(66,980)	(164,456)	(53,210)
45 Weatherization Loans	-	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-	-
47								
48 Total Electric Plant:	(2,488,670)	(52,544,606)	(893,752)	(118,997,153)	(2,797,018)	278,067,337	520,696,594	(144,692,768)
49	-	-	-	-	-	-	-	-
50 Rate Base Deductions:	-	-	-	-	-	-	-	-
51 Accum Prov For Deprec	-	18,337,869	-	-	-	(198,226,193)	(5,507,586)	94,709,923
52 Accum Prov For Amort	-	-	-	-	-	-	-	-
53 Accum Def Income Tax	4,319,896	11,746,394	1,953,136	24,500,716	(293,623)	(4,135,280)	(15,005,533)	594,445
54 Unamortized ITC	-	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	(7,270,878)	26,763,683	-	-	-	(9,107,921)
58	-	-	-	-	-	-	-	-
59 Total Rate Base Deductions	4,319,896	30,084,263	(5,317,742)	51,264,398	(293,623)	(202,361,472)	(20,513,119)	86,196,447
60								
61 Total Rate Base:	1,831,226	(22,460,342)	(6,211,494)	(67,732,755)	(3,090,640)	75,705,864	500,183,476	(58,496,321)
62								
63 Return on Rate Base	0.143%	0.056%	0.075%	0.150%	0.024%	-0.439%	-1.336%	0.353%
64								
65 Return on Equity	0.268%	0.105%	0.140%	0.280%	0.044%	-0.820%	-2.497%	0.659%
66								
67 TAX CALCULATION:								
68 Operating Revenue	7,387,024	415,253	3,062,901	-	813,723	(13,478,980)	(23,064,652)	14,577,753
69 Other Deductions	-	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-	-
71 Interest	40,591	(497,860)	(137,685)	(1,501,377)	(68,508)	1,678,111	11,087,162	(1,296,641)
72 Schedule "M" Additions	(2,756,732)	(1,753,901)	-	-	1,768,936	7,667,380	18,969,710	(6,690,160)
73 Schedule "M" Deductions	4,630,292	(7,718,157)	1,615,751	-	10,515,600	21,433,833	72,239,405	-
74 Income Before Tax	(40,591)	6,877,370	1,584,836	1,501,377	(7,864,433)	(28,923,543)	(87,421,509)	9,184,234
75								
76 State Income Taxes	(1,843)	312,233	71,952	68,163	(357,045)	(1,313,129)	(3,968,937)	416,964
77 Taxable Income	(38,748)	6,565,138	1,512,884	1,433,215	(7,507,388)	(27,610,415)	(83,452,573)	8,767,270
78								
79 Federal Income Taxes + Other	(8,137)	1,378,679	317,706	300,975	(1,576,551)	(5,798,187)	(17,525,040)	1,841,127
APPROXIMATE PRICE CHANGE	(7,455,347)	(2,539,728)	(3,751,544)	(6,416,105)	(1,133,123)	21,128,482	71,208,944	(20,596,059)

Pacificorp
Oregon General Rate Case - December 2021
Tab 8 Adjustment Summary

		8.16
		Klamath Facilities Capital Additions
1	Operating Revenues:	
2	General Business Revenues	-
3	Interdepartmental	-
4	Special Sales	-
5	Other Operating Revenues	-
6	Total Operating Revenues	-
7		
8	Operating Expenses:	
9	Steam Production	-
10	Nuclear Production	-
11	Hydro Production	-
12	Other Power Supply	-
13	Transmission	-
14	Distribution	-
15	Customer Accounting	-
16	Customer Service & Info	-
17	Sales	-
18	Administrative & General	-
19		
20	Total O&M Expenses	-
21		-
22	Depreciation	167,031
23	Amortization	-
24	Taxes Other Than Income	-
25	Income Taxes - Federal	(9,924)
26	Income Taxes - State	(2,248)
27	Income Taxes - Def Net	(33,366)
28	Investment Tax Credit Adj.	-
29	Misc Revenue & Expense	-
30		
31	Total Operating Expenses:	121,493
32		
33	Operating Rev For Return:	(121,493)
34		
35	Rate Base:	
36	Electric Plant In Service	835,155
37	Plant Held for Future Use	-
38	Misc Deferred Debits	-
39	Elec Plant Acq Adj	-
40	Nuclear Fuel	-
41	Prepayments	-
42	Fuel Stock	-
43	Material & Supplies	-
44	Working Capital	(115)
45	Weatherization Loans	-
46	Misc Rate Base	-
47		
48	Total Electric Plant:	835,040
49		-
50	Rate Base Deductions:	-
51	Accum Prov For Deprec	(47,927)
52	Accum Prov For Amort	-
53	Accum Def Income Tax	33,366
54	Unamortized ITC	-
55	Customer Adv For Const	-
56	Customer Service Deposits	-
57	Misc Rate Base Deductions	-
58		-
59	Total Rate Base Deductions	(14,561)
60		
61	Total Rate Base:	820,479
62		
63	Return on Rate Base	-0.004%
64		
65	Return on Equity	-0.008%
66		
67	TAX CALCULATION:	
68	Operating Revenue	(167,031)
69	Other Deductions	-
70	Interest (AFUDC)	-
71	Interest	18,187
72	Schedule "M" Additions	167,031
73	Schedule "M" Deductions	31,318
74	Income Before Tax	(49,505)
75		
76	State Income Taxes	(2,248)
77	Taxable Income	(47,257)
78		
79	Federal Income Taxes + Other	(9,924)
	APPROXIMATE PRICE CHANGE	250,221

PacifiCorp
Oregon General Rate Case - December 2021
Cash Working Capital

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Cash Working Capital	***CWC***	***3***	***(982,148)***	***OR***	***Situs***	***(982,148)***	***Below***

Adjustment Detail:			
Cash Working Capital June 2019 - Unadjusted	30,507,253	8,581,870	2.28
Cash Working Capital December 2021 - Normalized	26,286,717	7,599,721	2.28
Adjustment:	(4,220,536)	(982,148)	

Description of Adjustment:

This adjustment is necessary to compute the cash working capital for the normalized results of operations in this filing. Cash working capital is calculated by taking total operation and maintenance expense allocated to the jurisdiction and adding its share of allocated taxes, including state and federal income taxes and taxes other than income. This total is divided by the number of days in the year to determine the Company's average daily cost of service. The daily cost of service is multiplied by net lag days to produce the adjusted cash working capital balance. Net lag days for Oregon are calculated using the Company's 2015 lead lag study. A separate column is not shown for adjustment 8.1 on page 8.0.2 as the cash working capital component is calculated and shown on the adjustment summary pages for each of the adjustments individually.

This adjustment has been modified for Cash Working Capital impacts as a result of corrections and updates to adjustments made in Rebuttal.

This adjustment has been modified for Cash Working Capital impacts as a result of updates to adjustments made in Surrebuttal.

PacifiCorp
Update Cash Working Capital
Twelve Months Ending December 31, 2021

	Total	California	Oregon	Washington	Wyoming	Wy-PPL	Utah	Idaho	Wy-UPL	FERC
Lead/Lag Study as of 12/15										
Revenue Lag Days	41.52	41.17	40.25	41.27	37.72	37.72	40.88	37.54	37.72	35.62
Expense Lag Days	35.72	40.25	36.80	35.20	36.83	36.83	36.81	36.86	36.83	35.10
Net Lag Days	5.80	0.92	3.45	6.07	0.89	0.89	4.07	0.68	0.89	0.53
O&M Expense	*2,705,589,331*	*56,860,354*	*721,588,211*	*201,511,007*	*386,723,777*	*314,599,236*	*1,173,258,345*	*164,950,470*	*72,124,540*	*697,168*
Taxes Other than Income	*232,644,663*	*5,595,067*	*86,350,580*	*15,157,576*	*28,715,005*	*23,730,700*	*85,497,294*	*11,288,906*	*4,984,305*	*40,234*
Federal Income Tax	*(69,537,734)*	*(1,049,003)*	*(12,184,312)*	*(8,554,981)*	*(8,319,163)*	*(5,159,385)*	*(38,497,532)*	*(3,503,920)*	*(3,159,778)*	*2,571,177*
State Income Tax	*26,667,797*	*414,237*	*8,278,357*	*1,410,019*	*4,319,495*	*3,842,466*	*9,943,401*	*1,707,967*	*477,029*	*594,321*
Total	*2,895,364,057*	*61,820,653*	*804,032,836*	*209,523,622*	*411,439,115*	*337,013,018*	*1,230,201,508*	*174,443,423*	*74,426,097*	*3,902,900*
Divided by Days in Year	365	365	365	365	365	365	365	365	365	365
Avg. Daily Cost of Service	*7,932,504*	*169,372*	*2,202,830*	*574,037*	*1,127,230*	*923,323*	*3,370,415*	*477,927*	*203,907*	*10,693*
Net Lag Days	5.80	0.92	3.45	6.07	0.89	0.89	4.07	0.68	0.89	0.53
Cash Working Capital	*26,286,717*	*155,687*	*7,599,721*	*3,484,407*	*1,002,217*	*820,924*	*13,712,135*	*326,892*	*181,293*	*5,659*
	Ref. 2.28_SR		**Ref. 2.28_SR**							

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant	312	3	(9,035,332)	SG	26.023%	(2,351,231)	
Steam Plant	312	3	(12,666,409)	SG	26.023%	(3,296,133)	
Steam Plant	312	3	120,137,241	SG	26.023%	31,262,873	
Steam Plant	312	3	(2,762,573)	SG	26.023%	(718,894)	
Hydro Plant	332	3	(29,973,957)	SG	26.023%	(7,800,013)	
Hydro Plant	332	3	(299,898)	SG	26.023%	(78,041)	
Hydro Plant	332	3	64,834,906	SG-P	26.023%	16,871,749	
Hydro Plant	332	3	14,934,525	SG-U	26.023%	3,886,357	
Other Plant	343	3	-	SG	26.023%	-	
Other Plant	343	3	30,376,033	SG	26.023%	7,904,644	
Other Plant	343	3	129,823	OR	Situs	129,823	
Other Plant	343	3	(788,972,444)	SG-W	26.023%	(205,311,400)	
Other Plant	343	3	98,649	SG	26.023%	25,671	
Transmission Plant	355	3	(3,285,630)	SG	26.023%	(855,007)	
Transmission Plant	355	3	(6,758,020)	SG	26.023%	(1,758,615)	
Transmission Plant	355	3	378,024,647	SG	26.023%	98,371,965	
Distribution Plant	360	3	4,532,263	OR	Situs	1,235,048	
Distribution Plant	361	3	8,683,178	OR	Situs	2,366,178	
Distribution Plant	362	3	72,906,185	OR	Situs	19,867,039	
Distribution Plant	364	3	87,746,195	OR	Situs	23,910,963	
Distribution Plant	365	3	55,820,826	OR	Situs	15,211,255	
Distribution Plant	366	3	27,685,920	OR	Situs	7,544,453	
Distribution Plant	367	3	64,636,252	OR	Situs	17,613,471	
Distribution Plant	368	3	99,551,493	OR	Situs	27,127,924	
Distribution Plant	369	3	59,612,573	OR	Situs	16,244,511	
Distribution Plant	370	3	16,868,904	OR	Situs	4,596,800	
Distribution Plant	371	3	625,965	OR	Situs	170,576	
Distribution Plant	373	3	4,454,768	OR	Situs	1,213,931	
General Plant	397	3	4,221,163	CA	Situs	-	
General Plant	397	3	18,336,747	OR	Situs	18,336,747	
General Plant	397	3	1,354,438	WA	Situs	-	
General Plant	397	3	6,027,961	WYP	Situs	-	
General Plant	397	3	39,192,530	UT	Situs	-	
General Plant	397	3	5,950,004	ID	Situs	-	
General Plant	397	3	(507,171)	WYU	Situs	-	
General Plant	397	3	(241,632)	SG	26.023%	(62,879)	
General Plant	397	3	(202,408)	SG	26.023%	(52,672)	
General Plant	397	3	11,783,211	SG	26.023%	3,066,302	
General Plant	***397***	***3***	***18,189,475***	***SO***	***27.213%***	***4,949,885***	
General Plant	397	3	(191,169)	SG	26.023%	(49,747)	
General Plant	397	3	(239)	SG	26.023%	(62)	
General Plant	397	3	(2,812,019)	CN	31.217%	(877,830)	
General Plant	397	3	(51,850)	SE	25.101%	(13,015)	
Mining Plant	399	3	-	SE	25.101%	-	
			358,955,126			98,682,626	

Description of Adjustment:

To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be used and useful by December 31, 2020. This adjustment includes the year end balance of the plant additions that will be placed into service by December 31, 2020. Capital additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. Projects over $10 million (total company basis) are described on pages 8.5.27 through 8.5.30. Retirements of plant in service are also walked forward through the test period. This adjustment includes the repowering retirements. This adjustment reflects the net impact of capital additions, and retirements. The related tax impact is included in adjustments 7.4 and 7.5.

This adjustment has been updated for allocation fctor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Intangible Plant	303	3	636,932	CA	Situs	-	
Intangible Plant	303	3	(613,062)	CN	31.217%	(191,380)	
Intangible Plant	302	3	-	SG	26.023%	-	
Intangible Plant	302	3	-	SG	26.023%	-	
Intangible Plant	303	3	(1,552)	ID	Situs	-	
Intangible Plant	303	3	873,840	OR	Situs	873,840	
Intangible Plant	303	3	(1,106,269)	SE	25.101%	(277,690)	
Intangible Plant	302	3	(6,109,166)	SG	26.023%	(1,589,766)	
Intangible Plant	302	3	(240,294)	SG-P	26.023%	(62,531)	
Intangible Plant	302	3	-	SG-U	26.023%	-	
Intangible Plant	303	3	-	SG	26.023%	-	
Intangible Plant	***303***	***3***	***17,466,783***	***SO***	***27.213%***	***4,753,219***	
Intangible Plant	303	3	(24,922)	UT	Situs	-	
Intangible Plant	303	3	-	WA	Situs	-	
Intangible Plant	303	3	(241,316)	WYP	Situs	-	
Intangible Plant	303	3	-	WYU	Situs	-	
			10,640,974			3,505,693	
		Total	369,596,101			102,188,319	8.5.3

Description of Adjustment:

To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be used and useful by December 31, 2020. This adjustment includes the year end balance of the plant additions that will be placed into service by December 31, 2020. Capital additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. Projects over $10 million (total company basis) are described on pages 8.5.27 through 8.5.30. Retirements of plant in service are also walked forward through the test period. This adjustment includes the repowering retirements. This adjustment reflects the net impact of capital additions, and retirements. The related tax impact is included in adjustments 7.4 and 7.5.

This adjustment has been updated for allocation fctor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue

PacifiCorp
Oregon General Rate Case - December 2021
Remove Rolling Hills

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Plant	341	1	(3,478,252)	SG	26.023%	(905,133)	
Other Plant	343	1	(179,652,601)	SG	26.023%	(46,750,336)	
Other Plant	344	1	(5,850,373)	SG	26.023%	(1,522,421)	
Other Plant	345	1	(12,324,482)	SG	26.023%	(3,207,155)	
Other Plant	346	1	(659,497)	SG	26.023%	(171,618)	
			(201,965,205)			(52,556,663)	8.9.1
Adjustment to Depreciation Reserve:							
Other Plant	108OP	1	70,468,924	SG	26.023%	18,337,869	8.9.1
Adjustment to O&M Expense:							
Administrative & General	***929***	***1***	***(1,240,365)***	***SO***	***27.213%***	***(337,539)***	***8.9.1***
Misc. Oth. Power Supply	549	1	(387)	SG	26.023%	(101)	8.9.1
Misc. Oth. Power Supply	553	1	(298,253)	SG	26.023%	(77,613)	8.9.1
Adjustment to Tax:							
Schedule M Adjustment	***SCHMAT***	***1***	***(6,674,158)***	***SCHMDEXP***	***26.279%***	***(1,753,901)***	
Schedule M Adjustment	SCHMDT	1	(29,347,530)	TAXDEPR	26.274%	(7,710,650)	
Schedule M Adjustment	SCHMDT	1	(27,588)	GPS	27.215%	(7,508)	
Deferred Tax Expense	***41110***	***1***	***1,640,949***	***SCHMDEXP***	***26.279%***	***431,225***	
Deferred Tax Expense	41010	1	(7,215,560)	TAXDEPR	26.274%	(1,895,787)	
Deferred Tax Expense	41010	1	(6,783)	GPS	27.215%	(1,846)	
Deferred Tax Expense - Flowthrough	41110	1	12,204	OR	Situs	12,204	
Accumulated Def Inc Tax Balance	282	1	11,746,394	OR	Situs	11,746,394	

Description of Adjustment:

This adjustment removes the gross plant, accumulated depreciation and O&M amounts related to the Rolling Hills wind resource from the 12 months ended June 2019. This treatment is consistent with Commission Order No. 08-548. Depreciation expense for Rolling Hills is removed in Adjustment 6.1, Depreciation / Amortization Expense Adjustment.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Pension and Other Postretirement Plan Balances Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Net Prepaid Balance	***128***	***1***	***(2,485,363)***	***SO***	***27.213%***	***(676,340)***	***8.11.1***
Net Prepaid Balance	***182M***	***1***	***(434,809,482)***	***SO***	***27.213%***	***(118,324,302)***	***8.11.1***
Net Prepaid Balance	***2283***	***1***	***98,349,221***	***SO***	***27.213%***	***26,763,683***	***8.11.1***
			(338,945,624)			(92,236,959)	
Adjustment to Tax:							
ADIT Balances	***190***	***1***	***(7,560,157)***	***SO***	***27.213%***	***(2,057,339)***	***8.11.2***
ADIT Balances	***283***	***1***	***97,593,593***	***SO***	***27.213%***	***26,558,054***	***8.11.2***
			90,033,436			24,500,716	

Description of Adjustment:

This adjustment removes the Company's net prepaid asset associated with its pension and other postretirement welfare plans, net of associated accumulated deferred income taxes in unadjusted results. Per Order No. 15-226 in Docket UM 1633, the net pension and post retirement prepaid is not to be included in rate base for Oregon.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Deer Creek Mine Closure

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove base period expense							
Unrecovered Plant amortization	501	1	(8,319,574)	SE	25.101%	(2,088,337)	8.12.1
Unrec. Plant amortization - OR	501	1	(1,881,937)	OR	Situs	(1,881,937)	8.12.1
Closure cost amortization - WY	506	1	(3,233,528)	SG	26.023%	(841,449)	8.12.1
Add pro forma expense							
Closure Cost amortization	506	3	20,330,668	SE	25.101%	5,103,300	8.12.2
Prepaid Royalties amortization	506	3	4,039,412	SE	25.101%	1,013,953	8.12.5
Post-Retire. Settlement Loss amort.	***926***	***3***	***2,774,358***	***SO***	***27.213%***	***754,983***	***8.12.3***
Post-Retire. Settlement Benefits amort.	926	3	(3,681,646)	OR	Situs	(3,681,646)	8.12.4
UMWA Pension Withdrawal Pmt.	***926***	***3***	***2,967,013***	***SO***	***27.213%***	***807,411***	***8.12.7_R***
Adjustment to Rate Base:							
Remove base period regulatory assets							
Closure Costs	182M	1	(68,072,677)	SE	25.101%	(17,087,255)	B.15-16
Unrecovered Plant	182M	1	(2,436,501)	SE	25.101%	(611,598)	B.16
Unrecovered Plant	182M	1	3,467,455	OR	Situs	3,467,455	B.16
Post-Retire. Settlement Loss	***182M***	***1***	***(8,323,073)***	***SO***	***27.213%***	***(2,264,950)***	***8.12.3***
Post-Retire. Settlement Savings	182M	1	8,283,704	OR	Situs	8,283,704	8.12.4
Add pro forma regulatory assets							
Closure Costs	182M	3	50,826,671	SE	25.101%	12,758,251	8.12.2
Post-Retire. Settlement Loss	***182M***	***3***	***6,935,894***	***SO***	***27.213%***	***1,887,458***	***8.12.3***
Post-Retire. Settlement Savings	182M	3	(9,204,116)	OR	Situs	(9,204,116)	8.12.4
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	4,039,412	SE	25.101%	1,013,953	8.12.6
Schedule M Adjustment	***SCHMAT***	***3***	***2,774,358***	***SO***	***27.213%***	***754,983***	***8.12.6***
Schedule M Adjustment	SCHMDT	3	69,638,487	SE	25.101%	17,480,296	8.12.6
Schedule M Adjustment	SCHMDT	3	(6,964,697)	OR	Situs	(6,964,697)	8.12.6
Deferred Income Tax Expense	41110	3	(993,154)	SE	25.101%	(249,296)	8.12.6
Deferred Income Tax Expense	***41110***	***3***	***(682,120)***	***SO***	***27.213%***	***(185,625)***	***8.12.6***
Deferred Income Tax Expense	41010	3	17,121,736	SE	25.101%	4,297,811	8.12.6
Deferred Income Tax Expense	41010	3	(1,712,382)	OR	Situs	(1,712,382)	8.12.6
Accumulated Def Inc Tax Balance	283	3	23,852,621	SE	25.101%	5,987,363	8.12.6
Accumulated Def Inc Tax Balance	190	3	(28,303,872)	SE	25.101%	(7,104,693)	8.12.6
Accumulated Def Inc Tax Balance	***283***	***3***	***(492,377)***	***SO***	***27.213%***	***(133,990)***	***8.12.6***
Accumulated Def Inc Tax Balance	283	3	957,698	OR	Situs	957,698	8.12.6

Description of Adjustment:

Oregon Order No. 15-161 in Docket UM 1712 approved closure of the Deer Creek mine located in Utah and ruled on several issues. This adjustment removes the Deer Creek Unrecovered Plant Regulatory Assets from results because these amounts have been recovered through a separate tariff riders. Order No. 15-161 authorized a creation of a deferred account to track the Deer Creek Mine closure costs and costs due to Retiree Medical Obligation Settlement Loss to be addressed in the current ratemaking proceedings. The Company is proposing to include all deferred costs and savings in the rate base to be amortized over three years. *This adjustment has been updated to include the $3 million annual payment resulting from the Company's withdrawal from the 1974 Pension Trust associated with the Deer Creek mine. These pension costs were previously included in the TAM, but are being moved from the TAM to base rates as proposed by CUB witness Bob Jenks. Additionally in the process of updating this adjustment the Company discovered an error in the regulatory asset amount removed from the base period. This has been updated to remove the correct amount. This adjustment has also been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Rebuttal.*

This adjustment has also been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
EV 2020 Capital Additions Adjustment

PAGE 8.14_SR

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
EV 2020 Capital - Wind	343	3	1,234,267,946	SG	26.023%	321,189,013	8.14.2_SR
EV 2020 Capital - Transmission	355	3	767,301,451	SG	26.023%	199,672,037	8.14.2_SR
Adjustment to Depreciation Expense:							
EV 2020 - Wind Depr. Expense	403OP	3	40,787,714	SG	26.023%	10,614,037	8.14.2_SR
EV 2020 - Trans. Depr. Expense	403TP	3	13,402,634	SG	26.023%	3,487,718	8.14.2_SR
EV 2020 - Proposed Wind Depr.	403OP	3	18,916,819	SG	26.023%	4,922,654	8.14.2_SR
EV 2020 - Proposed Trans Depr.	***403TP***	***3***	***(210,199)***	***SG***	***26.023%***	***(54,699)***	8.14.2_SR
Adjustment to Depreciation Reserve:							
EV 2020 - Wind Depr. Reserve	108OP	3	(1,705,133)	SG	26.023%	(443,721)	8.14.2_SR
EV 2020 - Trans. Depr. Reserve	108TP	3	(752,845)	SG	26.023%	(195,910)	8.14.2_SR
EV 2020 - Proposed Wind Depr.	108OP	3	(18,916,819)	SG	26.023%	(4,922,654)	8.14.2_SR
EV 2020 - Proposed Trans Depr.	***108TP***	***3***	***210,199***	***SG***	***26.023%***	***54,699***	8.14.2_SR
Adjustment to Operations & Maintenance Expense:							
Incremental Wind O&M Expense	549	3	15,736,078	SG	26.023%	4,094,942	8.14.3_SR
Adjustment to Tax:							
Actual 2020:							
Schedule M Adj - EV 2020 Wind	SCHMAT	3	1,705,133	SG	26.023%	443,720	
Schedule M Adj - EV 2020 Wind	SCHMDT	3	240,685,840	SG	26.023%	62,632,792	
DIT Exp - EV 2020 Wind	41010	3	58,757,231	SG	26.023%	15,290,178	
DIT Exp - Flowthru - EV 2020 Wind	41010	3	13,398	SG	26.023%	3,487	
ADIT Balance - EV 2020 Wind	282	3	(56,622,286)	SG	26.023%	(14,734,609)	
Annualized 2020:							
Schedule M Adj - EV 2020 Wind	SCHMAT	3	39,082,581	SG	26.023%	10,170,316	
DIT Exp - EV 2020 Wind	41110	3	(9,609,078)	SG	26.023%	(2,500,535)	
ADIT Balance - EV 2020 Wind	282	3	2,940,148	SG	26.023%	765,104	
Incremental for New Depr Rates:							
Schedule M Adj - EV 2020 Wind	SCHMAT	3	18,916,819	SG	26.023%	4,922,654	
DIT Exp - EV 2020 Wind	41110	3	(4,651,003)	SG	26.023%	(1,210,313)	
ADIT Balance - EV 2020 Wind	282	3	1,423,096	SG	26.023%	370,327	
Actual 2020:							
Schedule M Adj - EV 2020 Trans	SCHMAT	3	744,745	SG	26.023%	193,802	
Schedule M Adj - EV 2020 Trans	SCHMDT	3	36,916,379	SG	26.023%	9,606,614	
DIT Exp - Flowthru EV 2020 Trans	41010	3	10,755	SG	26.023%	2,799	
DIT Exp - EV 2020 Trans	41010	3	8,893,375	SG	26.023%	2,314,290	
ADIT Balance - EV 2020 Trans	282	3	(6,340,734)	SG	26.023%	(1,650,026)	

Description of Adjustment:

This adjustment adds the capital additions, and incremental operations and maintenance amounts for the EV 2020 wind and transmission projects set to occur before the end of 2020. For more details on EV 2020 projects, please refer to direct testimonies of company witnesses Mr. Rick T. Link, Mr. Chad A. Teply, Mr. Timothy J. Hemstreet, and Mr. Richard A. Vail.

This adjustment has been updated to correct actual 2020 tax balances.

This adjustment has been updated for changes to the proposed transmission plant composite depreciation rate.

PacifiCorp
Oregon General Rate Case - December 2021
EV 2020 Capital Additions Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Annualized 2020:							
Schedule M Adj - EV 2020 Trans	SCHMAT	3	12,657,889	SG	26.023%	3,293,916	
DIT Exp - EV 2020 Trans	41110	3	(3,112,145)	SG	26.023%	(809,862)	
ADIT Balance - EV 2020 Trans	282	3	952,241	SG	26.023%	247,798	
Incremental for New Depr Rates:							
Schedule M Adj - EV 2020 Trans	***SCHMAT***	***3***	**(210,199)**	***SG***	***26.023%***	***(54,699)***	
DIT Exp - EV 2020 Trans	***41110***	***3***	**51,681**	***SG***	***26.023%***	***13,449***	
ADIT Balance - EV 2020 Trans	***282***	***3***	**(15,857)**	***SG***	***26.023%***	***(4,126)***	

Description of Adjustment:

This adjustment adds the capital additions, and incremental operations and maintenance amounts for the EV 2020 wind and transmission projects set to occur before the end of 2020. For more details on EV 2020 projects, please refer to direct testimonies of company witnesses Mr. Rick T. Link, Mr. Chad A. Teply, Mr. Timothy J. Hemstreet, and Mr. Richard A. Vail.

This adjustment has been updated to correct actual 2020 tax balances.

This adjustment has been updated for changes to the proposed transmission plant composite depreciation rate.

PacifiCorp
Oregon General Rate Case - December 2021
EV 2020 Capital Additions Adjustment

EV 2020 CAPITAL ADDITIONS

Note: Please see Confidential Exhibit PAC/4405_CONF for redacted information.

Electric Plant in Service

	Account	Factor	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Other Plant Wind	343	SG	[redacted]												1,234,267,946
Transmission Plant	355	SG													767,301,451

Depreciation Expense*

	Account	Factor	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Other Plant Wind	403OP	SG	[redacted]												1,699,959
Transmission Plant	403TP	SG													566,543

Depreciation Reserve

	Account	Factor	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Other Plant Wind	108OP	SG	[redacted]												(1,705,133)
Transmission Plant	108TP	SG													(752,845)

	12 ME Jun 2019	Dec 2020	Adjustment	
343	-	1,234,267,946	**1,234,267,946**	**Ref. 8.14_SR**
355	-	767,301,451	**767,301,451**	**Ref. 8.14_SR**
403OP	-	40,787,714	**40,787,714**	**Ref. 8.14_SR**
403TP	-	13,402,634	**13,402,634**	**Ref. 8.14_SR**
108OP	-	(1,705,133)	**(1,705,133)**	**Ref. 8.14_SR**
108TP	-	(752,845)	**(752,845)**	**Ref. 8.14_SR**

	December 2020 EPIS Balance	Annualized Depreciation Expense	Proposed Rates** Depreciation Expense	Adjustment to Proposed Rates Depreciation Expense	
Other Prod.	1,234,267,946	40,787,714	59,704,533	18,916,819	**Ref. 8.14_SR**
Transmission	767,301,451	13,402,634	***13,192,435***	***(210,199)***	**Ref. 8.14_SR**

**Composite Depreciation Rate - Wind*	*3.305%*
**Composite Depreciation Rate - Trans*	*1.747%*
***Proposed Composite Depreciation Rate - Wind*	*4.837%*
***** Proposed Composite Depr. Rate - Trans***	***1.719%***

PacifiCorp
Oregon General Rate Case - December 2021
Cholla Unit 4 Retirement

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense							
Remove O&M expense	506	3	(30,310,513)	SG	26.023%	(7,887,593)	8.15.1
Remove Depr. expense	403SP	3	(25,709,005)	SG	26.023%	(6,690,160)	6.1.4
Adjustment to Rate Base							
Remove Gross Unrecovered Plant	312	3	(549,199,953)	SG	26.023%	(142,916,286)	8.5.2
Remove Accumulated Depreciation	108SP	3	363,952,120	SG	26.023%	94,709,923	6.2.2
Remove M&S Inventory	154	3	(6,622,205)	SG	26.023%	(1,723,272)	8.15.1
Add Decomm. Reg. Liability	***254***	***3***	***(9,107,921)***	***OR***	***Situs***	***(9,107,921)***	***8.15.2_SR***
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	(25,709,005)	SG	26.023%	(6,690,160)	Above
Deferred Income Tax Expense	41110	3	6,320,970	SG	26.023%	1,644,883	
Accumulated Def Inc Tax Balance	282	3	(6,320,970)	SG	26.023%	(1,644,883)	
Accumulated Def Inc Tax - OR	***190***	***3***	***2,239,328***	***OR***	***Situs***	***2,239,328***	

Description of Adjustment:

Consistent with the IRP, the Company will be closing Cholla Unit 4 in December 2020. Recovery of Cholla plant will be included in a separate tariff rider. This adjustment removes Cholla-related expenses and rate base balances from test period results.

This adjustment adds Oregon's share of decommissioning costs to rate base as a regulatory liability.

PacifiCorp
Oregon General Rate Case - December 2021
Cholla Unit 4 Retirement
Decommissioning Costs

The Company is proposing to use accrued TCJA tax benefits to completely offset Oregon's allocation of the closure costs. This adjustment adds Oregon's decommissioning costs to rate base as a regulatory liability.

Amounts to Recover	*Amount*	
Decommissioning Costs	*35,000,000*	*Ref Exhibit PAC/3106*
OR SG Factor	*26.0226%*	
Oregon allocation of Cholla decomm. costs	9,107,921	
Adjustment to Rate Base	***(9,107,921)***	***Ref. 8.15_SR***

Tab R - Reply Adjustments

Pacificorp
Oregon General Rate Case - December 2021
Reply Adjustment Summary

		Total Adjustments	R_1_SR Remove Cyber Security Project	R_2_SR Remove Hydro Fish Ladder Project	R_3 Update Central Utah Water Conservancy District Project	R_4 Update Reliability Coordinator Fees
1	Operating Revenues:					
2	General Business Revenues	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-
4	Special Sales	-	-	-	-	-
5	Other Operating Revenues	-	-	-	-	-
6	Total Operating Revenues	-	-	-	-	-
7						
8	Operating Expenses:					
9	Steam Production	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	-	-	-	-	-
12	Other Power Supply	-	-	-	-	-
13	Transmission	(575,553)	-	-	-	(575,553)
14	Distribution	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-
17	Sales	-	-	-	-	-
18	Administrative & General	-	-	-	-	-
19						
20	Total O&M Expenses	(575,553)	-	-	-	(575,553)
21			-	-	-	-
22	Depreciation	(151,034)	(7,442)	(57,282)	(86,311)	-
23	Amortization	83,908	(22,655)	-	106,562	-
24	Taxes Other Than Income	-	-	-	-	-
25	Income Taxes - Federal	92,694	30,747	24,702	(78,152)	115,397
26	Income Taxes - State	20,993	6,963	5,594	(17,699)	26,134
27	Income Taxes - Def Net	59,790	(26,568)	(4,980)	91,338	-
28	Investment Tax Credit Adj.	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-
30						
31	Total Operating Expenses:	(469,203)	(18,954)	(31,965)	15,738	(434,021)
32						
33	Operating Rev For Return:	469,203	18,954	31,965	(15,738)	434,021
34						
35	Rate Base:					
36	Electric Plant In Service	(2,800,015)	(690,778)	(2,067,632)	(41,605)	-
37	Plant Held for Future Use	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-
41	Prepayments	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-
44	Working Capital	(4,366)	356	286	(906)	(4,102)
45	Weatherization Loans	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-
47						
48	Total Electric Plant:	(2,804,381)	(690,422)	(2,067,346)	(42,511)	(4,102)
49			-	-	-	-
50	Rate Base Deductions:		-	-	-	-
51	Accum Prov For Deprec	126,132	675	5,895	119,563	-
52	Accum Prov For Amort	(154,459)	944	-	(155,403)	-
53	Accum Def Income Tax	(4,599)	2,044	383	(7,026)	-
54	Unamortized ITC	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-
58			-	-	-	-
59	Total Rate Base Deductions	(32,926)	3,662	6,278	(42,867)	-
60			-	-	-	-
61	Total Rate Base:	(2,837,307)	(686,759)	(2,061,068)	(85,378)	(4,102)
62						
63	Return on Rate Base	0.016%	0.002%	0.004%	0.000%	0.010%
64						
65	Return on Equity	0.030%	0.003%	0.008%	0.000%	0.019%
66						
67	TAX CALCULATION:					
68	Operating Revenue	642,679	30,097	57,282	(20,252)	575,553
69	Other Deductions		-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-
71	Interest	(62,892)	(15,223)	(45,686)	(1,892)	(91)
72	Schedule "M" Additions	(67,127)	(30,097)	(57,282)	20,252	-
73	Schedule "M" Deductions	176,053	(138,156)	(77,536)	391,745	-
74	Income Before Tax	462,392	153,378	123,222	(389,852)	575,644
75						
76	State Income Taxes	20,993	6,963	5,594	(17,699)	26,134
77	Taxable Income	441,399	146,415	117,628	(372,153)	549,509
78						
79	Federal Income Taxes + Other	92,694	30,747	24,702	(78,152)	115,397
	APPROXIMATE PRICE CHANGE	(932,483)	(96,136)	(254,395)	12,827	(594,779)

PacifiCorp
Oregon General Rate Case - December 2021
Remove Cyber Security Project

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
General Plant	***397***	***3***	***(496,971)***	***SO***	***27.213%***	**(135,240)**	R_1.1_SR
Intangible Plant	***303***	***3***	***(2,041,450)***	***SO***	***27.213%***	**(555,538)**	R_1.1_SR
			(2,538,420)			(690,778)	
Adjustment to Depreciation Expense:							
General Plant	***403GP***	***3***	***(27,347)***	***SO***	***27.213%***	***(7,442)***	R_1.1_SR
Intangible Plant	***404IP***	***3***	***(83,250)***	***SO***	***27.213%***	***(22,655)***	R_1.1_SR
			(110,596)			(30,097)	
Adjustment to Depreciation Reserve:							
General Plant	***108GP***	***3***	***2,480***	***SO***	***27.213%***	***675***	R_1.1_SR
Intangible Plant	***111IP***	***3***	***3,469***	***SO***	***27.213%***	***944***	R_1.1_SR
			5,948			1,619	
Adjustment to Tax:							
Schedule M Adj - General Plant	***SCHMAT***	***3***	***(27,347)***	***SO***	***27.213%***	***(7,442)***	
Schedule M Adj - Intangible Plant	***SCHMAT***	***3***	***(83,250)***	***SO***	***27.213%***	***(22,655)***	
			(110,596)			(30,097)	
Schedule M Adj - General Plant	***SCHMDT***	***3***	***(99,394)***	***SO***	***27.213%***	***(27,048)***	
Schedule M Adj - Intangible Plant	***SCHMDT***	***3***	***(408,290)***	***SO***	***27.213%***	***(111,108)***	
			(507,684)			(138,156)	
Def Inc Tax Expense - General Plant	***41010***	***3***	***(17,714)***	***SO***	***27.213%***	***(4,820)***	
Def Inc Tax Expense - Intangible Plant	***41010***	***3***	***(79,916)***	***SO***	***27.213%***	***(21,747)***	
			(97,630)			(26,568)	
ADIT - General Plant	***282***	***3***	***1,363***	***SO***	***27.213%***	***371***	
ADIT - Intangible Plant	***282***	***3***	***6,147***	***SO***	***27.213%***	***1,673***	
			7,510			2,044	

Description of Adjustment:

This adjustment removes the IronNet cyber security project from rate base because the in-service date has moved beyond December 2020 as stated in OPUC 335.

This adjustment has been updated for changes to the proposed general plant composite depreciation rate in accordance with Settlement details in the Depreciation Study, Docket UM 1968. This adjustment has also been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Surrebuttal.

PacifiCorp
Oregon General Rate Case - December 2021
Remove Cyber Security Project

Electric Plant in Service

	Account	Factor	Dec-20	
General Plant	397	SO	496,971	Ref R_1_SR
Intangible Plant	303	SO	2,041,450	Ref R_1_SR

Depreciation Expense**

	Account	Factor	Dec-20	
General Plant	***403GP***	***SO***	***27,347***	Ref R_1_SR
Intangible Plant	404IP	SO	83,250	Ref R_1_SR

Depreciation Reserve

	Account	Factor	Dec-20	
General Plant	***108GP***	***SO***	***(2,480)***	Ref R_1_SR
Intangible Plant	111IP	SO	(3,469)	Ref R_1_SR

**Composite Depreciation Rate - General Plant*	*5.221%*
**Composite Depreciation Rate - Intangible Plant*	*4.078%*
*****Proposed Composite Depreciation Rate - General Plant***	***5.503%***
*** Proposed Composite Depreciation Rate - Intangible Plant*	4.078%

PacifiCorp
Oregon General Rate Case - December 2021
Remove Fish Passage Project

PAGE R_2_SR

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Hydro Plant	332	3	(7,945,514)	SG-P	26.023%	(2,067,632)	R_2.1_SR
Adjustment to Depreciation Expense:							
Hydro Plant	***403HP***	3	***(220,122)***	***SG-P***	***26.023%***	***(57,282)***	R_2.1_SR
Adjustment to Depreciation Reserve:							
Hydro Plant	***108HP***	3	***22,653***	***SG-P***	***26.023%***	***5,895***	R_2.1_SR
Adjustment to Tax:							
Schedule M Adjustment	***SCHMAT***	***3***	***(220,122)***	***SG***	***26.023%***	***(57,282)***	
Schedule M Adjustment	SCHMDT	3	(297,957)	SG	26.023%	(77,536)	
Deferred Inc Tax Expense	***41010***	3	***(19,137)***	***SG***	***26.023%***	***(4,980)***	
Accum Def Inc Tax Balance	***282***	***3***	***1,472***	***SG***	***26.023%***	***383***	

Description of Adjustment:

This adjustment removes the ILR 4.1.9 Future Fish Passage Stage 1 Ph project from rate base because the in-service date has moved beyond December 2020 as stated in OPUC 386.

This adjustment has been updated for changes to the proposed hydro plant composite depreciation rate in accordance with Settlement details in the Depreciation Study, Docket UM 1968.

PacifiCorp
Oregon General Rate Case - December 2021
Remove Fish Passage Project

Electric Plant in Service

	Account	Factor	Dec-20	
Hydro Plant	332	SG-P	7,945,514	Ref R_2_SR

Depreciation Expense**

	Account	Factor	Dec-20	
Hydro Plant	***403HP***	***SG-P***	***220,122***	Ref R_2_SR

Depreciation Reserve

	Account	Factor	Dec-20	
Hydro Plant	***108HP***	***SG-P***	***(22,653)***	Ref R_2_SR

**Composite Depreciation Rate - Hydro Plant*	*2.593%*
****Proposed Composite Depreciation Rate - Hydro Plant***	***2.770%***

Tab SR - Surrebuttal Adjustments

Pacificorp
Oregon General Rate Case - December 2021
Surrebuttal Adjustment Summary

			SR_1	SR_2
		Total Adjustments	Remove 2021 Wildfire Mitigation Projects	Remove Lassen Substation
1	Operating Revenues:			
2	General Business Revenues	-	-	-
3	Interdepartmental	-	-	-
4	Special Sales	-	-	-
5	Other Operating Revenues	-	-	-
6	Total Operating Revenues	-	-	-
7				
8	Operating Expenses:			
9	Steam Production	-	-	-
10	Nuclear Production	-	-	-
11	Hydro Production	-	-	-
12	Other Power Supply	-	-	-
13	Transmission	-	-	-
14	Distribution	-	-	-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-	-	-
17	Sales	-	-	-
18	Administrative & General	-	-	-
19				
20	Total O&M Expenses	-	-	-
21			-	-
22	Depreciation	(112,269)	(108,881)	(3,388)
23	Amortization	-	-	-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	89,149	86,313	2,836
26	Income Taxes - State	20,190	19,547	642
27	Income Taxes - Def Net	(48,969)	(47,380)	(1,589)
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	-
30				
31	Total Operating Expenses:	(51,900)	(50,400)	(1,499)
32				
33	Operating Rev For Return:	51,900	50,400	1,499
34				
35	Rate Base:			
36	Electric Plant In Service	(6,081,570)	(5,884,491)	(197,079)
37	Plant Held for Future Use	-	-	-
38	Misc Deferred Debits	-	-	-
39	Elec Plant Acq Adj	-	-	-
40	Nuclear Fuel	-	-	-
41	Prepayments	-	-	-
42	Fuel Stock	-	-	-
43	Material & Supplies	-	-	-
44	Working Capital	1,033	1,001	33
45	Weatherization Loans	-	-	-
46	Misc Rate Base	-	-	-
47				
48	Total Electric Plant:	(6,080,536)	(5,883,490)	(197,046)
49			-	-
50	Rate Base Deductions:		-	-
51	Accum Prov For Deprec	12,760	10,952	1,808
52	Accum Prov For Amort	-	-	-
53	Accum Def Income Tax	55,695	54,106	1,589
54	Unamortized ITC	-	-	-
55	Customer Adv For Const	-	-	-
56	Customer Service Deposits	-	-	-
57	Misc Rate Base Deductions	-	-	-
58			-	-
59	Total Rate Base Deductions	68,455	65,058	3,397
60			-	-
61	Total Rate Base:	(6,012,081)	(5,818,432)	(193,649)
62				
63	Return on Rate Base	0.012%	0.012%	0.000%
64				
65	Return on Equity	0.022%	0.022%	0.001%
66				
67	TAX CALCULATION:			
68	Operating Revenue	112,269	108,881	3,388
69	Other Deductions		-	-
70	Interest (AFUDC)	-	-	-
71	Interest	(133,265)	(128,972)	(4,292)
72	Schedule "M" Additions	(112,269)	(108,881)	(3,388)
73	Schedule "M" Deductions	(311,441)	(301,587)	(9,854)
74	Income Before Tax	444,706	430,560	14,146
75				
76	State Income Taxes	20,190	19,547	642
77	Taxable Income	424,517	411,012	13,504
78				
79	Federal Income Taxes + Other	89,149	86,313	2,836
	APPROXIMATE PRICE CHANGE	(685,447)	(663,605)	(21,842)

PacifiCorp
Oregon General Rate Case - December 2021
Remove 2021 Wildfire Mitigation Projects

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Distribution Plant	364	3	(1,424,858)	OR	Situs	(1,424,858)	SR_1.1
Transmission Plant	355	3	(17,137,516)	SG	26.023%	(4,459,633)	SR_1.1
			(18,562,374)			(5,884,491)	
Adjustment to Depreciation Expense:							
Distribution Plant	403364	3	(32,205)	OR	Situs	(32,205)	SR_1.1
Transmission Plant	403TP	3	(294,650)	SG	26.023%	(76,676)	SR_1.1
			(326,855)			(108,881)	
Adjustment to Depreciation Reserve:							
Distribution Plant	108364	3	1,100	OR	Situs	1,100	SR_1.1
Transmission Plant	108TP	3	37,859	SG	26.023%	9,852	SR_1.1
			38,959			10,952	
Adjustment to Tax:							
Distribution:							
Schedule M Adjustment	SCHMAT	3	(32,205)	OR	Situs	(32,205)	
Schedule M Adjustment	SCHMDT	3	(58,122)	OR	Situs	(58,122)	
Deferred Inc Tax Expense	41010	3	(6,371)	OR	Situs	(6,371)	
Accum Def Inc Tax Balance	282	3	7,583	OR	Situs	7,583	
Transmission:							
Schedule M Adjustment	SCHMAT	3	(294,650)	SG	26.023%	(76,676)	
Schedule M Adjustment	SCHMDT	3	(935,591)	SG	26.023%	(243,465)	
Deferred Inc Tax Expense	41010	3	(157,589)	SG	26.023%	(41,009)	
Accum Def Inc Tax Balance	282	3	178,779	SG	26.023%	46,523	

Description of Adjustment:

The Company identified in OPUC 612 that some of the Wildfire Mitigation projects in-service dates have moved beyond December 2020. This adjustment removes those projects from the case.

PacifiCorp
Oregon General Rate Case - December 2021
Remove 2021 Wildfire Mitigation Projects

Electric Plant in Service

	Account	Factor	Dec-20	
Distribution Plant	364	OR	1,424,858	**Ref. SR_1**
Transmission Plant	355	SG	17,137,516	**Ref. SR_1**

Depreciation Expense**

	Account	Factor	Dec-20	
Distribution Plant	403364	OR	32,205	**Ref. SR_1**
Transmission Plant	403TP	SG	294,650	**Ref. SR_1**

Depreciation Reserve

	Account	Factor	Dec-20	
Distribution Plant	108364	OR	(1,100)	**Ref. SR_1**
Transmission Plant	108TP	SG	(37,859)	**Ref. SR_1**

**Composite Depreciation Rate - Transmission Plant*	*1.750%*
**Composite Depreciation Rate - Distribution Plant*	*2.528%*
***Proposed Composite Depreciation Rate - Transmission Plant*	1.719%
***Proposed Composite Depreciation Rate - Distribution Plant*	*2.260%*

PacfiCorp
Oregon General Rate Case - December 2021
Wildfire Mitigation Program Capital Costs in UE 374 (Table 1 in Exhibit 1100)
From Attachment to Data Response OPUC 612

Mitigation Program	Description	Cateogry	Location	2019 Capital Costs	2020 Capital Costs	Actual or Current Estimated In-Service Date
System Hardening	Roseburg Circuit 5U19 (1.9 miles)	Oregon Distribution	Roseburg	$ 515,000		2019
	Medford Reconductor 5R284 and 5R285	Oregon Distribution	Medford	$ 35,000		2019
	Merlin Hugo Road (16.1 miles)	Oregon Distribution	Grants Pass		$ 3,139,264	2020
	Merlin Hugo Road Tie (0.7 miles)	Oregon Distribution	Grants Pass		$ 175,000	2020
	Merlin Russel Road (14.4 miles)	Oregon Distribution	Grants Pass		$ 2,960,690	2020
	Obrien Redwood Hwy pt1 (11.5 miles)	Oregon Distribution	Grants Pass		$ 2,496,028	2020
	Selma McMullin Creek Road (11.3 miles)	Oregon Distribution	Grants Pass		$ 2,388,562	2020
	Hood River East Fork (2 miles)	Oregon Distribution	Hood River		$ 518,857	2020
	Replace identified poles based on risk modeling on all circuits within the FHCA	Oregon Distribution	All FHCA Areas		$ 1,685,600	2020
Advanced Protection and Control	Merlin 5R232 5R251 5R234Relay	Oregon Distribution	Grants Pass	$ 223,649		2019
	4L50-FIOLI RECL0943 REPLC-GREAT MEADOW	Oregon Distribution	Klamath Falls	$ 30,221		2019
	OKN-5R55-DU1-9044 HWY 66-RPLC RECLOSURE	Oregon Distribution	Medford	$ 44,641		2019
	DOB-4R35-DU1-MEADOWS/DODGE-RPL RECLOSURE	Oregon Distribution	Medford	$ 24,741		2019
	New O'Brien Recloser	Oregon Distribution	Grants Pass		$ 45,000	2020
	Oak Knoll Recloser	Oregon Distribution	Medford		$ 45,000	2020
	Prospect Central Recloser	Oregon Distribution	Medford		$ 45,000	2020
	Dodge Bridge Recloser	Oregon Distribution	Medford		$ 90,000	2020
	Cave Junction Recloser	Oregon Distribution	Grants Pass		$ 45,000	2020
	Easy Valley Recloser	Oregon Distribution	Grants Pass		$ 45,000	2020
	Fielder Creek Recloser	Oregon Distribution	Grants Pass		$ 90,000	2020
	Jerome Prairie Recloser	Oregon Distribution	Grants Pass		$ 90,000	2020
	Merlin Recloser	Oregon Distribution	Grants Pass		$ 90,000	2020
	Replace DPU relay with SEL 751 w/HIFD	Oregon Distribution	Hood River		$ 65,000	2020
	Replace DPU relay with SEL 751 w/HIFD and Add DFA	Oregon Distribution	Hood River		$ 130,000	2020
	Replace DPU relay with SEL 751 w/HIFD	Oregon Distribution	Hood River		$ 65,000	2020
	Replace DPU relay with SEL 751 w/HIFD	Oregon Distribution	Hood River		$ 65,000	2020
	Replace DPU relay with SEL 751 w/HIFD and Add DFA	Oregon Distribution	Hood River		$ 130,000	2020
	Updated Project Totals for Surrebuttal			**$ 873,252**	**$ 14,404,000**	
	Total Amount in Original Filing			$ 1,008,441	$ 15,693,669	$ 16,702,110
	Adjustment to Remove 2021 Capital			**$ (135,189)**	**$ (1,289,669)**	**$ (1,424,858)**
						Ref SR-1.1

PacfiCorp
Oregon General Rate Case - December 2021
Wildfire Mitigation Program Capital Costs in UE 374 (Table 1 in Exhibit 1100)
From Attachment to Data Response OPUC 612

Mitigation Program	Description	Cateogry	Location	2019 Capital Costs	2020 Capital Costs	Actual or Current Estimated In-Service Date
System Hardening	Preliminary Engineering for Transmission Rebuilds	Transmission	Various UT	$ 35,000		2020
	Spanish Fork - Santaquin 46kV (2.5 miles)	Transmission	American Fork UT		$ 3,000,000	2020
	Snyderville - Silver Creek 138kV (9 miles)	Transmission	Park City UT		$ 4,500,000	2020
Advanced Protection and Control	Fort Jones Substation	Transmission	Yreka CA	$126,019		2019
	CAVE JUNCTION 3R245 RLY Design	Transmission	Yreka CA	$89,779		2019
	COPCO 230kV Sub Add SCADA Cntrl Design	Transmission	Yreka CA	$55,456		2019
	COPCO 2 Replace 3G200 Relays Design	Transmission	Yreka CA	$163,492		2019
	MOTT SW Replace 3G232 Relays Design	Transmission	Yreka CA	$135,183		2019
	WEED JUNCTION Replace 3G219 Relys Design	Transmission	Weed CA	$100,225		2019
	WEED JUNCTION Replace 3G223 Relys Design	Transmission	Weed CA	$517,214		2019
	Weed Sub Add SCADA Revise Logic 2G15	Transmission	Weed CA	$120,633		2019
	Cave Junction - Happy Camp	Transmission	Grants Pass OR		$350,000	2020
	Mott - McCloud	Transmission	Yreka CA		$75,000	2020
	Copco 2 - Weed Junction	Transmission	Yreka CA		$150,000	2020
	Alturas - Newell	Transmission	Klamath CA CA		$245,000	2020
	Copco 230 - Weed Jnct	Transmission	Yreka CA		$146,000	2020
	Park City Stage 1: Park City - Snyderville 46kV (Park City CB 47)	Transmission	Park City UT		$224,000	2020
	Park City Stage 2: Park City - Silver Creek 46kV (Park City CB 46, Silver Creek CB 45)	Transmission	Park City UT		$448,000	2020
	Judge Stage 1: Midway-Judge 46kV (Midway CB 45, Judge CB 44)	Transmission	Park City UT		$448,000	2020
	Judge Stage 2: Judge – Brighton 46kV (Judge CB 42)	Transmission	Park City UT		$224,000	2020
	Park City-Judge 46kV (Park City CB 44, Judge CB 41)	Transmission	Park City UT		$448,000	2020
	Silver Creek - Oakley 46kV (Silver Creek 42)	Transmission	Park City UT		$224,000	2020
	Silver Creek - Kamas 46kV (Silver Creek 44)	Transmission	Park City UT		$224,000	2020
	El Monte-Eden 46kV (El Monte CB 53)	Transmission	Ogden UT		$224,000	2020
Condition Corrections	Priority A / B Fire Threat conditions in FHCA	Transmission	Various UT	$ 200,000		2019
	Updated Project Totals for Surrebuttal			**$ 1,543,000**	**$ 10,930,000**	
	Total Amount in Original Filing			$ 3,292,220	$ 26,318,296	$ 29,610,516
	Adjustment to Remove 2021 Capital			**$ (1,749,220)**	**$ (15,388,296)**	**$ (17,137,516)**
						Ref SR-1.1

PacifiCorp
Oregon General Rate Case - December 2021
Remove Lassen Substation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Transmission Plant	355	3	(757,337)	SG	26.023%	(197,079)	SR_2.1
Adjustment to Depreciation Expense:							
Transmission Plant	403TP	3	(13,021)	SG	26.023%	(3,388)	SR_2.1
Adjustment to Depreciation Reserve:							
Transmission Plant	108TP	3	6,947	SG	26.023%	1,808	SR_2.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	(13,021)	SG	26.023%	(3,388)	
Schedule M Adjustment	SCHMDT	3	(37,867)	SG	26.023%	(9,854)	
Deferred Inc Tax Expense	41010	3	(6,106)	SG	26.023%	(1,589)	
Accum Def Inc Tax Balance	282	3	6,106	SG	26.023%	1,589	

Description of Adjustment:

The Lassen Substation project is not expected to be in service by 12/31/2020 and therefore the Company is removing the amounts previously included in the general rate case.

PacifiCorp
Oregon General Rate Case - December 2021
Remove Lassen Substation

Electric Plant in Service

	Account	Factor	Dec-20	
Transmission Plant	355	SG	757,337	**Ref. SR_2**

Depreciation Expense**

	Account	Factor	Dec-20	
Transmission Plant	403TP	SG	13,021	**Ref. SR_2**

Depreciation Reserve

	Account	Factor	Dec-20	
Transmission Plant	108TP	SG	(6,947)	**Ref. SR_2**

**Composite Depreciation Rate - Transmission Plant* *1.750%*

***Proposed Composite Depreciation Rate - Transmission Plant* *1.719%*

Tab 10 - Allocation Factors

Oregon General Rate Case
Pro Forma Factors December 31, 2021
2020 Protocol Factors

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

DESCRIPTION	2020 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Situs	S	-	-	-	-	-	-	-			Situs
System Generation	SG	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%	Pg 10.16
Divisional Generation - Pac. Power	DGP	3.2512%	55.0569%	16.6974%	0.0000%	0.0000%	24.9944%	0.0000%	0.0000%	0.0000%	Pg 10.16
Divisional Generation - R.M.P.	DGU	0.0000%	0.0000%	0.0000%	83.4313%	11.1832%	5.3318%	0.0537%	0.0000%	0.0000%	Pg 10.16
System Capacity	SC	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	0.0000%	0.0000%	Pg 10.16
System Energy	SE	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	0.0000%	0.0000%	Pg 10.16
System Overhead	***SO***	***2.2324%***	***27.2129%***	***7.6985%***	***43.5002%***	***5.7392%***	***13.5964%***	***0.0203%***	***0.0000%***	***0.0000%***	***Pg 10.7***
Gross Plant-System	***GPS***	***2.2324%***	***27.2129%***	***7.6985%***	***43.5002%***	***5.7392%***	***13.5964%***	***0.0203%***	***0.0000%***	***0.0000%***	***Pg 10.6***
System Net Plant	***SNP***	***2.0890%***	***26.3141%***	***7.3984%***	***44.8444%***	***5.7463%***	***13.5684%***	***0.0207%***	***0.0186%***	***0.0000%***	***Pg 10.6***
Division Net Plant Distribution	***SNPD***	***3.6189%***	***26.8529%***	***6.1393%***	***48.0686%***	***5.0984%***	***10.2218%***	***0.0000%***	***0.0000%***	***0.0000%***	***Pg 10.5***
Customer - System	CN	2.3966%	31.2171%	6.9361%	47.8254%	4.2022%	7.4227%	0.0000%	0.0000%	0.0000%	Pg 10.10
CIAC	***CIAC***	***3.6189%***	***26.8529%***	***6.1393%***	***48.0686%***	***5.0984%***	***10.2218%***	***0.0000%***	***0.0000%***	***0.0000%***	***Pg 10.11***
Bad Debt Expense	BADDEBT	5.6391%	33.2389%	12.8715%	35.0446%	5.5372%	7.6686%	0.0000%	0.0000%	0.0000%	Pg 10.10
Accumulated Investment Tax Credit 1984	ITC84	3.2870%	70.9760%	14.1800%	0.0000%	0.0000%	10.9460%	0.0000%	0.0000%	0.6110%	Fixed
Accumulated Investment Tax Credit 1985	ITC85	5.4200%	67.6900%	13.3600%	0.0000%	0.0000%	11.6100%	0.0000%	0.0000%	1.9200%	Fixed
Accumulated Investment Tax Credit 1986	ITC86	4.7890%	64.6080%	13.1260%	0.0000%	0.0000%	15.5000%	0.0000%	0.0000%	1.9770%	Fixed
Accumulated Investment Tax Credit 1988	ITC88	4.2700%	61.2000%	14.9600%	0.0000%	0.0000%	16.7100%	0.0000%	0.0000%	2.8600%	Fixed
Accumulated Investment Tax Credit 1989	ITC89	4.8806%	56.3558%	15.2688%	0.0000%	0.0000%	20.6776%	0.0000%	0.0000%	2.8172%	Fixed
Accumulated Investment Tax Credit 1990	ITC90	1.5047%	15.9356%	3.9132%	46.9355%	13.9815%	17.3435%	0.0000%	0.0000%	0.3860%	Fixed
Other Electric	OTHER	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	Situs
Non-Utility	NUTIL	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	Situs
System Net Steam Plant	***SNPPS***	***1.5306%***	***25.9187%***	***7.8605%***	***44.1492%***	***5.9192%***	***14.5936%***	***0.0282%***	***0.0000%***	***0.0000%***	***Pg 10.3***
System Net Transmission Plant	SNPT	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%	Pg 10.4
System Net Production Plant	***SNPP***	***1.5339%***	***25.9770%***	***7.8774%***	***44.0282%***	***5.9021%***	***14.6074%***	***0.0283%***	***0.0457%***	***0.0000%***	***Pg 10.4***
System Net Hydro Plant	***SNPPH***	1.5276%	25.8685%	7.8453%	43.7369%	5.8625%	14.5387%	0.0282%	0.5922%	0.0000%	Pg 10.3
System Net Other Production Plant	***SNPPO***	1.5366%	26.0259%	7.8917%	43.9955%	5.8972%	14.6247%	0.0283%	0.0000%	0.0000%	Pg 10.4
System Net General Plant	***SNPG***	***2.6991%***	***28.5683%***	***6.3589%***	***41.3200%***	***6.5077%***	***14.5348%***	***0.0112%***	***0.0000%***	***0.0000%***	***Pg 10.5***
System Net Intangible Plant	***SNPI***	***2.0684%***	***26.3229%***	***7.7319%***	***43.3487%***	***6.3113%***	***14.1958%***	***0.0210%***	***0.0000%***	***0.0000%***	***Pg 10.6***
Trojan Plant Allocator	TROJP	1.5242%	25.8827%	7.8352%	43.9001%	5.9978%	14.8311%	0.0290%	0.0000%	0.0000%	Pg 10.12
Trojan Decommissioning Allocator	TROJD	1.5220%	25.8580%	7.8251%	43.8829%	6.0155%	14.8674%	0.0291%	0.0000%	0.0000%	Pg 10.13
DIT Balance	DITBAL	2.2266%	24.6785%	6.4832%	44.3496%	5.8380%	14.6629%	0.2376%	0.0000%	1.5235%	Pg 10.9
Tax Depreciation	TAXDEPR	1.9379%	26.2736%	5.8206%	44.7704%	5.7046%	13.7111%	0.0220%	0.0000%	1.7599%	Pg 10.13
SCHMAT Depreciation Expense	***SCHMDEXP***	***2.0669%***	***26.2790%***	***7.8498%***	***43.8890%***	***5.7929%***	***14.0998%***	***0.0227%***	***0.0000%***	***0.0000%***	***Pg 10.13***
System Generation Cholla Transaction	SGCT	1.5371%	26.0300%	7.8943%	44.0100%	5.8991%	14.6295%	0.0000%	0.0000%	0.0000%	Pg 10.2

CALCULATION OF INTERNAL FACTORS
Pro Forma Factors December 31, 2021

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
STEAM :											
STEAM PRODUCTION PLANT											
	S	0	0	0	0	0	0	0	0	0	0
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	6,866,740,006	105,521,343	1,786,906,522	541,925,792	3,021,193,806	404,963,909	1,004,282,668	1,945,966	0	0
	SSGCH	0	0	0	0	0	0	0	0	0	0
		6,866,740,006	105,521,343	1,786,906,522	541,925,792	3,021,193,806	404,963,909	1,004,282,668	1,945,966	0	0

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
LESS ACCUMULATED DEPRECIATION											
	S	10,702,263	0	0	0	8,775,068	1,213,075	714,120	0	0	0
	DGP	(759,016,718)	(11,663,826)	(197,516,132)	(59,901,895)	(333,948,366)	(44,762,781)	-111,008,620	(215,098)	0	0
	DGU	(726,882,090)	(11,170,013)	(189,153,855)	(57,365,817)	(319,809,934)	(42,867,651)	-106,308,828	(205,991)	0	0
	SG	(2,465,497,627)	(37,887,356)	(641,587,388)	(194,578,032)	(1,084,757,272)	(145,401,975)	-360,586,906	(698,698)	0	0
	SG-W	0	0	0	0	0	0	0	0	0	0
	SSGCH	(246,321,600)	(3,785,229)	(64,099,365)	(19,439,796)	(108,375,341)	(14,526,742)	-36,025,321	(69,805)	0	0
		(4,187,015,771)	(64,506,424)	(1,092,356,740)	(331,285,540)	(1,838,115,846)	(246,346,073)	(613,215,556)	(1,189,592)	0	0
TOTAL NET STEAM PLANT		2,679,724,236	41,014,919	694,549,781	210,640,252	1,183,077,960	158,617,837	391,067,112	756,375	0	0
SNPPS											
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.5306%	25.9187%	7.8605%	44.1492%	5.9192%	14.5936%	0.0282%	0.0000%	0.0000%

		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
NUCLEAR :									
NUCLEAR PRODUCTION PLANT									
	DGP	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0
	SG	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
LESS ACCUMULATED DEPRECIATION									
	DGP	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0
	SG	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
TOTAL NUCLEAR PLANT		0	0	0	0	0	0	0	0
SNPPN									
SYSTEM NET PLANT PRODUCTION NUCLEAR		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
HYDRO :											
HYDRO PRODUCTION PLANT											
	S	0	0	0	0	0	0	0	0	0	0
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	1,121,598,596	17,235,630	291,869,482	88,516,997	493,475,321	66,145,937	164,037,379	317,850	0	0
		1,121,598,596	17,235,630	291,869,482	88,516,997	493,475,321	66,145,937	164,037,379	317,850	0	0
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)											
	S	3,575,830	0	0	0	0	0	0	0	3,575,830	0
	DGP	(175,334,101)	(2,694,363)	(45,626,549)	(13,837,435)	(77,142,618)	(10,340,275)	(25,643,172)	(49,688)	0	0
	DGU	(30,353,650)	(466,445)	(7,898,819)	(2,395,522)	(13,354,846)	(1,790,097)	(4,439,318)	(8,602)	0	0
	SG	(315,707,685)	(4,851,487)	(82,155,451)	(24,915,773)	(138,903,483)	(18,618,765)	(46,173,258)	(89,468)	0	0
		(517,819,605)	(8,012,295)	(135,680,818)	(41,148,731)	(229,400,947)	(30,749,138)	(76,255,748)	(147,758)	3,575,830	0
TOTAL NET HYDRO PRODUCTION PLANT		603,778,991	9,223,335	156,188,663	47,368,267	264,074,375	35,396,799	87,781,630	170,092	3,575,830	0
SNPPH											
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.5276%	25.8685%	7.8453%	43.7369%	5.8625%	14.5387%	0.0282%	0.5922%	0.0000%

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
OTHER :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)											
	S	204,809	0	204,809	0	0	0	0	0	0	0
	DGP & DGU	0	0	0	0	0	0	0	0	0	0
	SG	5,365,913,703	82,458,113	1,396,352,007	423,479,996	2,360,867,781	316,453,133	784,782,025	1,520,647	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		5,366,118,513	82,458,113	1,396,556,816	423,479,996	2,360,867,781	316,453,133	784,782,025	1,520,647	0	0
LESS ACCUMULATED DEPRECIATION											
	S	(4,278)	0	(4,278)	0	0	0	0	0	0	0
	DGP	376,504,462	5,785,752	97,976,373	29,713,879	165,652,544	22,204,236	55,064,981	106,698	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	(1,194,313,760)	(18,353,046)	(310,791,882)	(94,255,706)	(525,468,174)	(70,434,292)	(174,672,204)	(338,457)	0	0
	SSGCT	(36,871,542)	(566,606)	(9,594,946)	(2,909,916)	(16,222,556)	(2,174,488)	(5,392,581)	(10,449)	0	0
		(854,685,118)	(13,133,899)	(222,414,733)	(67,451,744)	(376,038,186)	(50,404,543)	(124,999,804)	(242,208)	0	0
TOTAL NET OTHER PRODUCTION PLANT		4,511,433,395	69,324,214	1,174,142,084	356,028,252	1,984,829,595	266,048,590	659,782,221	1,278,439	0	0
SNPPO											
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.5366%	26.0259%	7.8917%	43.9955%	5.8972%	14.6247%	0.0283%	0.0000%	0.0000%
PRODUCTION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
TOTAL PRODUCTION PLANT											
	S	204,809	0	204,809	0	0	0	0	0	0	0
	DGP & DGU	0	0	0	0	0	0	0	0	0	0
	SG	13,354,252,306	205,215,086	3,475,128,010	1,053,922,786	5,875,536,909	787,562,980	1,953,102,071	3,784,463	0	0
	SSGCH	0	0	0	0	0	0	0	0	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		13,354,457,115	205,215,086	3,475,332,820	1,053,922,786	5,875,536,909	787,562,980	1,953,102,071	3,784,463	0	0
LESS ACCUMULATED DEPRECIATION											
	S	14,273,815	0	(4,278)	0	8,775,068	1,213,075	714,120	0	3,575,830	0
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	(5,545,899,962)	(85,223,966)	(1,443,189,170)	(437,684,582)	(2,440,057,232)	(327,067,768)	(811,105,591)	(1,571,653)	0	0
	SSGCH	0	0	0	0	0	0	0	0	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		(5,531,626,147)	(85,223,966)	(1,443,193,448)	(437,684,582)	(2,431,282,165)	(325,854,693)	(810,391,471)	(1,571,653)	3,575,830	0
TOTAL NET PRODUCTION PLANT		7,822,830,968	119,991,121	2,032,139,372	616,238,204	3,444,254,744	461,708,287	1,142,710,600	2,212,810	3,575,830	0
SNPP											
SYSTEM NET PRODUCTION PLANT		100.0000%	1.5339%	25.9770%	7.8774%	44.0282%	5.9021%	14.6074%	0.0283%	0.0457%	0.0000%
TRANSMISSION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
TRANSMISSION PLANT											
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	7,563,761,458	116,232,487	1,968,289,853	596,934,996	3,327,865,806	446,070,538	1,106,224,282	2,143,495	0	0
		7,563,761,458	116,232,487	1,968,289,853	596,934,996	3,327,865,806	446,070,538	1,106,224,282	2,143,495	0	0

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
LESS ACCUMULATED DEPRECIATION											
	DGP	(351,699,893)	(5,404,580)	(91,521,571)	(27,756,292)	(154,739,154)	(20,741,395)	(51,437,233)	(99,668)	0	0
	DGU	(418,414,202)	(6,429,780)	(108,882,391)	(33,021,412)	(184,091,781)	(24,675,851)	(61,194,414)	(118,574)	0	0
	SG	(1,181,074,399)	(18,149,596)	(307,346,651)	(93,210,851)	(519,643,186)	(69,653,504)	(172,735,905)	(334,705)	0	0
		(1,951,188,494)	(29,983,956)	(507,750,613)	(153,988,555)	(858,474,121)	(115,070,750)	(285,367,552)	(552,948)	0	0
TOTAL NET TRANSMISSION PLANT		5,612,572,964	86,248,531	1,460,539,240	442,946,441	2,469,391,685	330,999,788	820,856,730	1,590,548	0	0
SNPT											
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%

DESCRIPTION	FACTOR	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
DISTRIBUTION :									
DISTRIBUTION PLANT - PACIFIC POWER									
	S	3,831,275,999	312,274,943	2,289,423,905	551,435,929	0	0	678,141,221	0
LESS ACCUMULATED DEPRECIATION									
	S	(1,771,591,135)	(147,062,217)	(1,063,520,605)	(271,158,882)	0	0	(289,849,432)	0
		2,059,684,864	165,212,726	1,225,903,300	280,277,048	0	0	388,291,789	0
DNPDP									
DIVISION NET PLANT DISTRIBUTION PACIFIC POWER		100.0000%	8.0213%	59.5190%	13.6078%	0.0000%	0.0000%	18.8520%	0.0000%
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER									
	S	3,809,010,231	0	0	0	3,279,501,681	392,387,444	137,121,106	0
LESS ACCUMULATED DEPRECIATION									
	S	(1,303,433,903)	0	0	0	(1,085,042,946)	(159,630,533)	(58,760,424)	0
		2,505,576,328	0	0	0	2,194,458,734	232,756,911	78,360,682	0
DNPDU									
DIVISION NET PLANT DISTRIBUTION R.M.P.		100.0000%	0.0000%	0.0000%	0.0000%	87.5830%	9.2896%	3.1275%	0.0000%
TOTAL NET DISTRIBUTION PLANT		4,565,261,191	165,212,726	1,225,903,300	280,277,048	2,194,458,734	232,756,911	466,652,471	0
DNPD & SNPD									
SYSTEM NET PLANT DISTRIBUTION		100.0000%	3.6189%	26.8529%	6.1393%	48.0686%	5.0984%	10.2218%	0.0000%

DESCRIPTION	FACTOR	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
GENERAL :									
GENERAL PLANT									
	S	729,616,912	23,758,164	232,415,134	49,657,933	269,991,497	50,840,840	102,953,345	0
	DGP	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0
	SE	3,631,101	52,810	911,460	272,977	1,574,308	238,115	580,249	1,182
	SG	319,706,957	4,912,944	83,196,167	25,231,397	140,663,062	18,854,621	46,758,164	90,602
	SO	330,145,823	7,370,121	89,842,278	25,416,413	143,614,247	18,947,602	44,888,014	67,150
	CN	14,495,900	347,405	4,525,194	1,005,448	6,932,721	609,147	1,075,985	0
	DEU	0	0	0	0	0	0	0	0
	SSGCT	0	0	0	0	0	0	0	0
	SSGCH	0	0	0	0	0	0	0	0
	Remove Capital Lease	(19,601,761)	(221,984)	(5,817,080)	(1,068,955)	(9,723,198)	(798,537)	(1,968,307)	(3,701)
		1,377,994,933	36,219,459	405,073,152	100,515,213	553,052,637	88,691,787	194,287,451	155,234

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
LESS ACCUMULATED DEPRECIATION											
	S	(280,754,247)	(8,680,736)	(96,380,170)	(27,203,031)	(93,399,743)	(19,047,524)	(36,043,043)	0		
	DGP	(843,233)	(12,958)	(219,431)	(66,548)	(371,001)	(49,729)	(123,326)	(239)		
	DGU	(2,907,693)	(44,683)	(756,658)	(229,476)	(1,279,312)	(171,480)	(425,259)	(824)		
	SE	(1,759,892)	(25,595)	(441,759)	(132,304)	(763,022)	(115,408)	(281,230)	(573)		
	SG	(124,639,316)	(1,915,335)	(32,434,431)	(9,836,583)	(54,838,181)	(7,350,566)	(18,228,898)	(35,322)		
	SO	(110,457,411)	(2,465,833)	(30,058,673)	(8,503,609)	(48,049,246)	(6,339,329)	(15,018,254)	(22,466)		
	CN	(4,849,240)	(116,216)	(1,513,790)	(336,348)	(2,319,168)	(203,775)	(359,944)	0		
	SSGCT	(110,482)	(1,698)	(28,750)	(8,719)	(48,609)	(6,516)	(16,158)	(31)		
	SSGCH	(2,712,809)	(41,688)	(705,944)	(214,096)	(1,193,568)	(159,987)	(396,757)	(769)		
		(529,034,323)	(13,304,741)	(162,539,608)	(46,530,715)	(202,261,851)	(33,444,314)	(70,892,869)	(60,224)		
TOTAL NET GENERAL PLANT		848,960,610	22,914,718	242,533,544	53,984,499	350,790,786	55,247,473	123,394,582	95,009		
SNPG											
SYSTEM NET GENERAL PLANT		100.0000%	2.6991%	28.5683%	6.3589%	41.3200%	6.5077%	14.5348%	0.0112%		
MINING :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**		
GENERAL MINING PLANT											
	SE	84,739,827	1,232,428	21,270,957	6,370,519	36,739,977	5,556,946	13,541,404	27,596		
LESS ACCUMULATED DEPRECIATION											
	SE	0	0	0	0	0	0	0	0		
		84,739,827	1,232,428	21,270,957	6,370,519	36,739,977	5,556,946	13,541,404	27,596		
SNPM											
SYSTEM NET PLANT MINING		100.0000%	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%		
INTANGIBLE :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**		
INTANGIBLE PLANT											
	S	(7,815,888)	1,118,099	5,489,081	2,036,363	(26,215,920)	4,369,593	5,386,895	0		
	DGP	0	0	0	0	0	0	0	0		
	DGU	0	0	0	0	0	0	0	0		
	SE	(1,106,269)	(16,089)	(277,690)	(83,166)	(479,636)	(72,545)	(176,781)	(360)		
	CN	175,494,022	4,205,841	54,784,072	12,172,421	83,930,701	7,374,612	13,026,374	0		
	SG	370,077,269	5,686,985	96,303,848	29,206,642	162,824,740	21,825,195	54,124,983	104,876		
	SO	401,152,776	8,955,268	109,165,334	30,882,912	174,502,446	23,022,805	54,542,418	81,592		
	SSGCT	0	0	0	0	0	0	0	0		
	SSGCH	0	0	0	0	0	0	0	0		
		937,801,910	19,950,105	265,464,645	74,215,172	394,562,331	56,519,660	126,903,889	186,108		
LESS ACCUMULATED AMORTIZATION											
	S	34,376,581	(5,417)	(114,464)	(9,071)	35,543,854	(963,860)	(74,461)	0		
	DGP	0	0	0	0	0	0	0	0		
	DGU	(489,827)	(7,527)	(127,466)	(38,657)	(215,512)	(28,887)	(71,639)	(139)		
	SE	1,106,269	16,089	277,690	83,166	479,636	72,545	176,781	360		
	CN	(152,460,423)	(3,653,824)	(47,593,660)	(10,574,790)	(72,914,793)	(6,406,694)	(11,316,662)	0		
	SG	(216,496,162)	(3,326,901)	(56,338,001)	(17,085,961)	(95,252,895)	(12,767,796)	(31,663,255)	(61,353)		
	SO	(294,498,335)	(6,574,332)	(80,141,560)	(22,672,076)	(128,107,502)	(16,901,735)	(40,041,232)	(59,899)		
	SSGCT	0	0	0	0	0	0	0	0		
	SSGCH	(21,945)	(337)	(5,711)	(1,732)	(9,655)	(1,294)	(3,210)	(6)		
		(628,483,843)	(13,552,250)	(184,043,171)	(50,299,121)	(260,476,866)	(36,997,720)	(82,993,677)	(121,037)		
TOTAL NET INTANGIBLE PLANT		309,318,067	6,397,855	81,421,474	23,916,051	134,085,465	19,521,939	43,910,212	65,071		
SNPI											
SYSTEM NET INTANGIBLE PLANT		100.0000%	2.0684%	26.3229%	7.7319%	43.3487%	6.3113%	14.1958%	0.0210%		

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
GROSS PLANT :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
PRODUCTION PLANT		13,354,457,115	205,215,086	3,475,332,820	1,053,922,786	5,875,536,909	787,562,980	1,953,102,071	3,784,463	0	0
TRANSMISSION PLANT		7,563,761,458	116,232,487	1,968,289,853	596,934,996	3,327,865,806	446,070,538	1,106,224,282	2,143,495	0	0
DISTRIBUTION PLANT		7,640,286,229	312,274,943	2,289,423,905	551,435,929	3,279,501,681	392,387,444	815,262,327	0	0	0
GENERAL PLANT		1,462,734,760	37,451,886	426,344,109	106,885,732	589,792,614	94,248,733	207,828,855	182,830	0	0
INTANGIBLE PLANT		937,801,910	19,950,105	265,464,645	74,215,172	394,562,331	56,519,660	126,903,889	186,108	0	0
TOTAL GROSS PLANT		30,959,041,472	691,124,508	8,424,855,332	2,383,394,615	13,467,259,340	1,776,789,354	4,209,321,425	6,296,897	0	0
GPS											
GROSS PLANT-SYSTEM FACTOR		100.0000%	2.2324%	27.2129%	7.6985%	43.5002%	5.7392%	13.5964%	0.0203%	0.0000%	0.0000%
ACCUMULATED DEPRECIATION AND AMORTIZATION											
PRODUCTION PLANT		(5,531,626,147)	(85,223,966)	(1,443,193,448)	(437,684,582)	(2,431,282,165)	(325,854,693)	(810,391,471)	(1,571,653)	3,575,830	0
TRANSMISSION PLANT		(1,951,188,494)	(29,983,956)	(507,750,613)	(153,988,555)	(858,474,121)	(115,070,750)	(285,367,552)	(552,948)	0	0
DISTRIBUTION PLANT		(3,075,025,038)	(147,062,217)	(1,063,520,605)	(271,158,882)	(1,085,042,946)	(159,630,533)	(348,609,856)	0	0	0
GENERAL PLANT		(529,034,323)	(13,304,741)	(162,539,608)	(46,530,715)	(202,261,851)	(33,444,314)	(70,892,869)	(60,224)	0	0
INTANGIBLE PLANT		(628,483,843)	(13,552,250)	(184,043,171)	(50,299,121)	(260,476,866)	(36,997,720)	(82,993,677)	(121,037)	0	0
		(11,715,357,844)	(289,127,129)	(3,361,047,445)	(959,661,854)	(4,837,537,949)	(670,998,010)	(1,598,255,425)	(2,305,862)	3,575,830	0
NET PLANT		19,243,683,628	401,997,378	5,063,807,887	1,423,732,761	8,629,721,392	1,105,791,344	2,611,066,000	3,991,035	3,575,830	0
SNP											
SYSTEM NET PLANT FACTOR (SNP)		100.0000%	2.0890%	26.3141%	7.3984%	44.8444%	5.7463%	13.5684%	0.0207%	0.0186%	0.0000%
NON-UTILITY RELATED INTEREST PERCENTAGE		0.0000%									
INT											
INTEREST FACTOR SNP - NON-UTILITY		100.0000%	2.0890%	26.3141%	7.3984%	44.8444%	5.7463%	13.5684%	0.0207%	0.0186%	0.0000%
TOTAL GROSS PLANT (LESS SO FACTOR)		30,229,630,300	674,841,254	8,226,361,344	2,327,240,594	13,149,963,683	1,734,927,270	4,110,147,616	6,148,539	0	0
SO											
SYSTEM OVERHEAD FACTOR (SO)		100.0000%	2.2324%	27.2129%	7.6985%	43.5002%	5.7392%	13.5964%	0.0203%	0.0000%	0
IBT											
INCOME BEFORE TAXES		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
INCOME BEFORE STATE TAXES		632,873,449	9,124,154	182,342,659	31,057,687	219,017,649	37,620,414	95,143,069	13,090,768	62,037,194	(16,560,145)
Interest Synchronization		970,812	20,280	255,461	71,825	435,355	55,785	131,724	201	180	-
		633,844,261	9,144,434	182,598,119	31,129,511	219,453,005	37,676,199	95,274,793	13,090,970	62,037,375	(16,560,145)
INCOME BEFORE TAXES (FACTOR)		100.0000%	1.4427%	28.8080%	4.9112%	34.6225%	5.9441%	15.0313%	2.0653%	9.7875%	-2.6127%

See Calculation of EXCTAX

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
DITEXP:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Pacific Power												
Production	S											
Transmission	S											
Distribution	S											
General	S											
Mining Plant	S											
Non Utility	NUTIL											
Total Pacific Power		0	0	0	0	0	0	0	0	0	0	
Rocky Mountain Power												
Production	S											
Transmission	S											
Distribution	S											
General	S											
Mining Plant	S											
Non-Utility	NUTIL											
Total Rocky Mountain Power		0	0	0	0	0	0	0	0	0	0	
PC (Post Merger)												
Prod / Other Prod	S											
Cholla Unit 4	S											
Gadsby Unit 4, 5 & 6	S											
Hydro-PPL	S											
Hydro-UPL	S											
Transmission	S											
Distribution	S											
General/ Intangibles	S											
Mining	S											
WCA - CAEE 2007+	S											
WCA - CAGE 2007+	S											
WCA - CAGW 2007+	S											
WCA_CAGW 2007+ -Marengo	S											
WCA CAGW 2007+ -Goodnoe	S											
WCA - General 2007+	S											
WCA - JBG 2007+	S											
Non Utility	NUTIL											
Total PC (Post Merger)		0	0	0	0	0	0	0	0	0	0	
Total Deferred Taxes		0	0	0	0	0	0	0	0	0	0	
Percentage of Total (DITEXP)		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
DITBAL :		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Pacific Power											
Production	S	9,777,915	697,070	7,388,948	2,746,555	(3,240,319)	(149,348)	2,337,872	(2,863)	0	0
Transmission	S	8,964,074	351,488	4,959,478	1,365,447	303,754	(12,702)	1,996,680	(71)	0	0
Distribution	S	1,278,542	917,694	994,681	1,458,402	(2,185,933)	(6,120)	99,818	0	0	0
General	S	(748,972)	(5,380)	(278,915)	(19,951)	(302,365)	(14,904)	(127,251)	(206)	0	0
Mining Plant	S	4,407	67	1,103	336	1,870	274	749	8	0	0
Non Utility	NUTIL	(1,939,785)	0	0	0	0	0	0	0	0	(1,939,785)
Total Pacific Power		17,336,181	1,960,939	13,065,295	5,550,789	(5,422,993)	(182,800)	4,307,868	(3,132)	0	(1,939,785)
Rocky Mountain Power											
Production	S	18,611,188	(9,592)	(2,228,923)	(47,850)	17,745,620	3,059,945	(78,228)	170,216	0	0
Transmission	S	20,683,211	1,825	(100,528)	10,247	17,826,162	2,184,329	663,447	97,729	0	0
Distribution	S	18,593,410	263,279	1,661,579	517,101	13,212,021	1,742,856	1,196,574	0	0	0
General	S	(909,654)	(9,869)	(242,130)	(36,183)	(413,403)	(75,137)	(132,168)	(764)	0	0
Mining Plant	S	9,054	137	2,264	690	3,847	564	1,536	16	0	0
Non-Utility Plant	NUTIL	0	0	0	0	0	0	0	0	0	0
Total Rocky Mountain Power		56,987,209	245,780	(907,738)	444,005	48,374,247	6,912,557	1,651,161	267,197	0	0
PacifiCorp											
Prod / Other Prod	S	249,204,266	4,416,468	70,492,822	20,097,986	102,213,229	13,773,712	37,374,866	835,183	0	0
Cholla Unit 4	S	(23,473,392)	(420,509)	(6,755,315)	0	(10,252,543)	(1,493,615)	(3,559,253)	(62,043)	0	(930,114)
Gadsby Unit 4, 5 & 6	S	4,467,390	69,872	1,143,934	0	1,940,779	256,188	670,438	12,457	0	373,722
Hydro-PPL	S	21,982,344	426,497	6,524,494	1,845,885	8,716,933	1,155,368	3,242,695	70,472	0	0
Hydro-UPL	S	6,648,954	134,299	1,984,897	578,643	2,629,171	345,414	957,174	19,356	0	0
Transmission	S	178,123,314	3,241,193	51,872,161	14,499,795	72,076,958	9,589,293	26,294,460	549,454	0	0
Distribution	S	649,653,591	22,915,562	184,256,564	41,938,309	304,899,112	31,887,516	63,751,946	0	0	4,582
General/ Intangibles	S	17,901,804	441,815	6,029,398	1,274,868	6,458,219	993,470	2,653,270	50,763	0	1
Mining	S	2,017	30	506	154	864	129	333	1	0	0
WCA - CAEE 2007+	S	(2,206)	(5)	(503)	0	(814)	(133)	(354)	(1)	0	(396)
WCA - CAGE 2007+	S	1,266,183,891	20,172,688	331,877,489	0	536,650,055	71,262,382	195,743,841	3,704,700	0	106,772,736
WCA - CAGW 2007+	S	297,854,804	4,850,882	80,671,915	64,830,916	128,365,959	17,126,528	46,695,258	872,634	0	(45,559,288)
WCA_CAGW 2007+ -Marengo	S	(43,905,412)	0	0	0	(43,905,412)	0	0	0	0	0
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0	0	0	0
WCA - General 2007+	S	128,707,004	2,814,055	35,368,245	8,649,374	54,884,383	7,256,658	18,183,677	171,127	0	1,379,485
WCA - JBG 2007+	S	108,364,789	1,712,739	28,746,072	23,672,595	46,838,488	6,250,113	16,787,031	233,279	0	(15,875,528)
Oregon Extra Book Depreciation	S	(106,317,436)	0	(106,317,436)	0	0	0	0	0	0	0
Non Utility	NUTIL	(1,131,206)	0	0	0	0	0	0	0	0	(1,131,206)
Total PC (Post Merger)		2,754,264,516	60,775,586	685,895,243	177,388,525	1,211,515,381	158,403,023	408,795,382	6,457,382	0	45,033,994
Total Deferred Taxes		2,828,587,906	62,982,305	698,052,800	183,383,319	1,254,466,635	165,132,780	414,754,411	6,721,447	0	43,094,209
Percentage of Total (DITBAL)		100.0000%	2.2266%	24.6785%	6.4832%	44.3496%	5.8380%	14.6629%	0.2376%	0.0000%	1.5235%

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.

OPRV-WY

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers			
Less: Uncollectibles (net)			
Total Interstate Revenues			
	0.0000%	0.0000%	0.0000%

OPRV-ID

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers			
Less: Interstate Sales for Resale			
Montana Power			
Portland General Electric			
Puget Sound Power & Light			
Washington Water Power Co.			
Less: Uncollectibles (net)	0	0	0
Total Interstate Revenues			
	0.0000%	0.0000%	0.0000%

BADDEBT

	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	OTHER	Non-Utility
Account 904 Balance	13,282,984	749,042	4,415,121	1,709,723	4,654,972	735,512	1,018,615	0	0	0
Bad Debts Expense Allocation Factor - BADDEBT	100.0000%	5.6391%	33.2389%	12.8715%	35.0446%	5.5372%	7.6686%	0.0000%	0.0000%	0.0000%

Customer Factors	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Total Electric Customers	1,984,793	47,567	619,594	137,667	949,235	83,405	147,325	0	0	0
CN										
Customer System factor - CN	107.4227%	2.3966%	31.2171%	6.9361%	47.8254%	4.2022%	7.4227%	0.0000%	0.0000%	0.0000%
Pacific Power Customers	935,782	47,567	619,594	137,667	0	0	130954	0	0	0
CNP										
Customer Service Pacific Power factor - CNP	100.0000%	5.0831%	66.2114%	14.7114%	0.0000%	0.0000%	13.9941%	0.0000%	0.0000%	0.0000%
Rocky Mountain Power Customers	1,049,011	0	0	0	949,235	83,405	16,371	0	0	0
CNU										
Customer Service R.M.P. factor - CNU	100.0000%	0.0000%	0.0000%	0.0000%	90.4886%	7.9508%	1.5606%	0.0000%	0.0000%	0.0000%

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Pro Forma Factors December 31, 2021

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
CIAC		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
TOTAL NET DISTRIBUTION PLANT		4,565,261,191	165,212,726	1,225,903,300	280,277,048	2,194,458,734	232,756,911	466,652,471	0	0	0	
CIAC FACTOR: Same as (SNPD Factor)		100.0000%	3.6189%	26.8529%	6.1393%	48.0686%	5.0984%	10.2218%	0.0000%	0.0000%	0.0000%	
IDSIT		Total Company	Idaho - PPL	Idaho - UPL	Idaho Total							
	Payroll											
Idaho State Income Tax Allocation			0.00%	0.00%	0.00%							
	Property											
			0.00%	0.00%	0.00%							
	Sales											
			0.00%	0.00%	0.00%							
	Average											
		Idaho - PPL Factor	0.00%	0.00%								
		Idaho - UPL Factor	0.00%	0.00%								
			0.00%	0.00%								
EXCTAX												
Excise Tax (Superfund)		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Total Taxable Income		604,140,994	8,709,917	174,064,302	29,647,668	209,074,248	35,912,447	90,823,574	12,496,448	59,220,706	(15,808,315)	
Less Other Electric Items:												
419	OTH	0	0	0	0	0	0	0	0	0	0	
432	OTH	0	0	0	0	0	0	0	0	0	0	
40910	OTH	0	0	0	0	0	0	0	0	0	0	
SCHMDT	OTH	0	0	0	0	0	0	0	0	0	0	
SCHMDT (Steam)	OTH											
Total Taxable Income Excluding Other		604,140,994	8,709,917	174,064,302	29,647,668	209,074,248	35,912,447	90,823,574	12,496,448	59,220,706	(15,808,315)	
Excise Tax (Superfund) Factor - EXCTAX		100.0000%	1.4417%	28.8119%	4.9074%	34.6069%	5.9444%	15.0335%	2.0685%	9.8025%	-2.6167%	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

DESCRIPTION		2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
Trojan Allocators			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Premerger												
Dec 1991 Plant			16,918,976									
Dec 1992 Plant			17,094,202									
Average		SG	17,006,589	261,341	4,425,562	1,342,167	7,482,474	1,002,958	2,487,268	4,819	0	0
Dec 1991 Reserve			(7,851,432)									
Dec 1992 Reserve			(8,434,030)									
Average		SG	(8,142,731)	(125,130)	(2,118,953)	(642,627)	(3,582,598)	(480,215)	(1,190,900)	(2,308)	0	0
Postmerger												
Dec 1991 Plant			4,284,960									
Dec 1992 Plant			3,485,613									
Average		SG	3,885,287	59,705	1,011,054	306,628	1,709,429	229,134	568,236	1,101	0	0
Dec 1991 Reserve			(129,394)									
Dec 1992 Reserve			(240,609)									
Average		SG	(185,002)	(2,843)	(48,142)	(14,600)	(81,396)	(10,910)	(27,057)	(52)	0	0
Net Plant			12,564,143	193,073	3,269,521	991,567	5,527,909	740,967	1,837,546	3,561	0	0
Division Net Plant Nuclear Pacific Power		**DNPPNP**	100.0000%	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%
Division Net Plant Nuclear Rocky Mountain Power		**DNPPNP**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
System Net Nuclear Plant		**SNNP**	100.0000%	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%
Account 182.22			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Pre-merger	(101)	SG	17,094,202	262,687	4,448,361	1,349,081	7,521,021	1,008,125	2,500,082	4,844	0	0
		(108) SG	(8,434,030)	(129,606)	(2,194,757)	(665,617)	(3,710,762)	(497,394)	(1,233,504)	(2,390)	0	0
Post-merger	(101)	SG	3,485,613	53,563	907,048	275,086	1,533,583	205,563	509,782	988	0	0
		(108) SG	(240,609)	(3,697)	(62,613)	(18,989)	(105,862)	(14,190)	(35,190)	(68)	0	0
		(107) SG	1,778,549	27,331	462,825	140,364	782,517	104,889	260,118	504	0	0
		(120) SE	1,975,759	28,735	495,945	148,532	856,614	129,563	315,726	643	0	0
		(228) SG	7,220,849	110,963	1,879,055	569,872	3,176,993	425,847	1,056,072	2,046	0	0
		(228) SG	1,472,376	22,626	383,151	116,200	647,809	86,833	215,340	417	0	0
		(228) SNNP	3,531,000	54,261	918,859	278,668	1,553,552	208,240	516,420	1,001	0	0
		(228) SE	1,743,025	25,350	437,525	131,036	755,710	114,302	278,535	568	0	0
Total Acct 182.22			29,626,734	452,213	7,675,401	2,324,234	13,011,174	1,771,779	4,383,381	8,553	0	0
Revised Study	(228)	SNNP	112,680	1,732	29,322	8,893	49,576	6,645	16,480	32	0	0
		(228) SE	941,950	13,699	236,443	70,813	408,394	61,770	150,523	307	0	0
December 1993 Adj.			1,054,630	15,431	265,766	79,706	457,970	68,415	167,003	339	0	0
Adjusted Acct 182.22			30,681,364	467,644	7,941,167	2,403,940	13,469,144	1,840,194	4,550,384	8,892	0	0
TROJP Trojan Plant Allocator			100.0000%	1.5242%	25.8827%	7.8352%	43.9001%	5.9978%	14.8311%	0.0290%	0.0000%	0.0000%

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
Account 228.42		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Plant - Premerger	SG	7,220,849	110,963	1,879,055	569,872	3,176,993	425,847	1,056,072	2,046	0	0
- Postmerger	SG	1,472,376	22,626	383,151	116,200	647,809	86,833	215,340	417	0	0
Storage Facility	SE	1,743,025	25,350	437,525	131,036	755,710	114,302	278,535	568	0	0
Transition Costs	SNNP	3,531,000	54,261	918,859	278,668	1,553,552	208,240	516,420	1,001	0	0
Total Acct 228.42		13,967,250	213,200	3,618,590	1,095,777	6,134,063	835,222	2,066,367	4,032	0	0
Transition Costs	SNNP	112,680	1,732	29,322	8,893	49,576	6,645	16,480	32	0	0
Storage Facility	SE	941,950	13,699	236,443	70,813	408,394	61,770	150,523	307	0	0
December 1993 Adj.		1,054,630	15,431	265,766	79,706	457,970	68,415	167,003	339	0	0
Adjusted Acct 228.42		15,021,880	228,631	3,884,356	1,175,483	6,592,033	903,637	2,233,370	4,371	0	0
TROJD		100.0000%	1.5220%	25.8580%	7.8251%	43.8829%	6.0155%	14.8674%	0.0291%	0.0000%	0.0000%
Trojan Decommissioning Allocator											
SCHMA		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Amortization Expense :											
Amortization of Limited Term Plant	Acct 404	40,096,318	834,240	11,086,682	3,004,029	13,937,824	2,098,677	4,876,085	6,619	4,252,162	0
Amortization of Other Electric Plant	Acct 405	0	0	0	0	0	0	0	0	0	0
Amortization of Plant Acquisitions	Acct 406	5,083,195	73,478	1,244,288	377,363	2,405,402	281,991	699,318	1,355	0	0
Amort of Prop. Losses, Unrecovered Plant, etc.	Acct 407	100,852,699	1,615,088	22,976,570	8,295,569	46,241,763	6,198,293	15,371,341	29,785	124,290	0
Total Amortization Expense :		146,032,212	2,522,806	35,307,540	11,676,961	62,584,989	8,578,962	20,946,744	37,758	4,376,453	0
Schedule M Amortization Factor		100.0000%	1.7276%	24.1779%	7.9962%	42.8570%	5.8747%	14.3439%	0.0259%	2.9969%	0.0000%
SCHMD		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Depreciation Expense :											
Steam	Acct 403.1	457,252,035	7,026,602	118,989,017	36,086,508	201,179,455	26,966,300	66,874,571	129,581	0	0
Nuclear	Acct 403.2	0	0	0	0	0	0	0	0	0	0
Hydro	Acct 403.3	30,937,935	475,424	8,050,865	2,441,634	13,611,918	1,824,555	4,524,772	8,768	0	0
Other	Acct 403.4	233,687,426	3,590,988	60,816,057	18,442,229	102,813,982	13,781,291	34,176,656	66,223	0	0
Transmission	Acct 403.5	129,673,458	1,992,695	33,744,448	10,233,880	57,053,077	7,647,453	18,965,158	36,748	0	0
Distribution	Acct 403.6	193,955,562	8,373,979	51,746,009	15,101,449	85,711,083	10,272,310	22,750,732	0	0	0
General	Acct 403.7&8	46,598,325	1,112,632	13,647,610	3,421,868	18,944,049	2,772,459	6,693,088	6,619	0	0
Mining	Acct 403.9	0	0	0	0	0	0	0	0	0	0
Experimental	Acct 403.4	0	0	0	0	0	0	0	0	0	0
Total Depreciation Expense :		1,092,104,741	22,572,320	286,994,006	85,727,568	479,313,565	63,264,368	153,984,976	247,939	0	0
Schedule M Depreciation Factor		100.0000%	2.0669%	26.2790%	7.8498%	43.8890%	5.7929%	14.0998%	0.0227%	0.0000%	0.0000%
Tax Depreciation by Function		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Based on Tax Depreciation Schedule M Differences		970,347,616	18,804,463	254,945,162	56,479,728	434,428,196	55,354,251	133,045,780	213,286	-	17,076,750
Tax Depr factor		100.0000%	1.9379%	26.2736%	5.8206%	44.7704%	5.7046%	13.7111%	0.0220%	0.0000%	1.7599%

REDACTED
Docket No. UE 374
Exhibit PAC/4403
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Shelley E. McCoy

Depreciation Expense & Reserves Adjustment Support

August 2020

THIS ATTACHMENT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 374
Exhibit PAC/4404
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Shelley E. McCoy

Decommissioning & Other Plant Closure Costs Details Adjustment Support

August 2020

THIS ATTACHMENT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 374
Exhibit PAC/4405
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Shelley E. McCoy

Energy Vision 2020 Wind Project Capital Additions Adjustment Support

August 2020

THIS ATTACHMENT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 374
Exhibit PAC/4406
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Shelley E. McCoy

Federal Tax Act Adjustment, Tax Cuts & Jobs Act
Deferral Balances Amortization Schedule

August 2020

PacifiCorp
Oregon General Rate Case - December 2021
TCJA Deferral Balances
Amortization of Projected 12/31/20 Balance

Interest Rate, 2020 MBTR	2.63%
Amortization Period (months)	24
Projected Current Tax Benefits Deferral, 12/31/20	$ (52,539,363)
Projected EDIT Amortization Deferral, 12/31/20	(25,296,938)
Total Projected 12/31/20 Balance	(77,836,301)
Cholla Unit 4 Unrecovered Balances and Closure Costs	64,486,660
Remaining balance to return over two years	$ (13,349,640)
Annual rate credit	$ 6,851,712

	Month	Year	Beginning Balance	Amortization	Interest	Ending Balance
1	January	2021	$ (13,349,640)	$ 570,976	$ (28,632)	$ (12,807,296)
2	February	2021	(12,807,296)	570,976	(27,444)	(12,263,764)
3	March	2021	(12,263,764)	570,976	(26,252)	(11,719,040)
4	April	2021	(11,719,040)	570,976	(25,059)	(11,173,123)
5	May	2021	(11,173,123)	570,976	(23,862)	(10,626,009)
6	June	2021	(10,626,009)	570,976	(22,663)	(10,077,696)
7	July	2021	(10,077,696)	570,976	(21,461)	(9,528,181)
8	August	2021	(9,528,181)	570,976	(20,257)	(8,977,462)
9	September	2021	(8,977,462)	570,976	(19,050)	(8,425,536)
10	October	2021	(8,425,536)	570,976	(17,840)	(7,872,400)
11	November	2021	(7,872,400)	570,976	(16,628)	(7,318,052)
12	December	2021	(7,318,052)	570,976	(15,413)	(6,762,489)
13	January	2022	(6,762,489)	570,976	(14,195)	(6,205,709)
14	February	2022	(6,205,709)	570,976	(12,975)	(5,647,708)
15	March	2022	(5,647,708)	570,976	(11,752)	(5,088,484)
16	April	2022	(5,088,484)	570,976	(10,527)	(4,528,035)
17	May	2022	(4,528,035)	570,976	(9,298)	(3,966,357)
18	June	2022	(3,966,357)	570,976	(8,067)	(3,403,448)
19	July	2022	(3,403,448)	570,976	(6,834)	(2,839,306)
20	August	2022	(2,839,306)	570,976	(5,597)	(2,273,927)
21	September	2022	(2,273,927)	570,976	(4,358)	(1,707,309)
22	October	2022	(1,707,309)	570,976	(3,116)	(1,139,449)
23	November	2022	(1,139,449)	570,976	(1,872)	(570,345)
24	December	2022	(570,345)	570,969	(624)	0
Total				**13,703,417**	**(353,777)**	

Docket No. UE 374
Exhibit PAC/4407
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Shelley E. McCoy

Responses to PacifiCorp Data Requests 97 and 98

August 2020

Filed: August 7, 2020 – Response Due By: **August 10, 2020**

TO:
DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 2000
PORTLAND, OR 97232
datarequest@pacificorp.com

FROM: Paul Rossow
Research Analyst

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 374- PacifiCorp Data Request filed August 3, 2020

PAC Data Request No 97:

97. Regarding the data provided in response to Standard Data Request OPUC 57, is Mr. Rossow aware that in discussions between members of Staff and the Company it was communicated that the Company does not perform state allocations at the transactional level, but rather on a summary basis and therefore the data provided in OPUC 57 was total company and not Oregon allocated?

OPUC Response No 97:

97. Staff was informed that several telephone conversations had taken place to obtain the Oregon business purpose descriptions for each transaction along with the equivalent Oregon-allocated dollar amounts related to OPUC 57.

Filed: August 7, 2020 – Response Due By: **August 10, 2020**

TO:
DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 2000
PORTLAND, OR 97232
datarequest@pacificorp.com

FROM: Paul Rossow
Research Analyst

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 374- PacifiCorp Data Request filed August 3, 2020

PAC Data Request No 98:

98. Is Mr. Rossow aware that as the data provided in OPUC 57 was total company amounts, the Company offered to provide the Oregon allocation information, including allocation factor and percentage, for a subset of data as needed by Staff to determine the proper amounts for their recommended disallowed transactions or reductions?

OPUC Response No 98:

98. This Staff member is aware that PacifiCorp filed data under OPUC 57 on three separate occasions. Staff used data provided in PacifiCorp's 3rd Supplement to OPUC Standard Data Request 57 in the development of testimony in this proceeding. It is this Staff member's understanding that the data provided in PacifiCorp's 3rd Supplement to OPUC Standard Data Request 57 is the Oregon-allocated amounts.

Docket No. UE 374
Exhibit PAC/4408
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Shelley E. McCoy

Attachment to Staff Data Request 571

August 2020

FERC	BASE YEAR BALANCE	Miscellaneous General Expenses & Revenues	Wage & Employee Benefits Adjustment	Revenue Sensitive Items & Uncollectible Expense	Insurance Expense	Incremental O&M Expense	Credit Facility Fees Adjustment	O&M Expense Escalation	Depreciation & Amortiation Expense	Remove Rolling Hills	TEST YEAR BALANCE
WP Ref		McCoy_4.1	McCoy_4.2	McCoy_4.3	McCoy_4.4	McCoy_4.7	McCoy_4.9	McCoy_4.11	McCoy_6.1	McCoy_8.9	
560	1,896,906	-	531,171	-	-	-	-	2,789	21,321	-	2,452,188
561	5,203,844	-	-	-	-	-	-	53,840	-	-	5,257,684
570	3,085,319	-	-	-	-	-	-	37,092	-	-	3,122,411
580	2,448,058	-	1,340,836	-	-	-	-	10,072	53,822	-	3,852,787
581	3,257,550	-	-	-	-	-	-	(1,953)	-	-	3,255,597
583	1,649,600	-	-	-	-	-	-	12,276	-	-	1,661,875
587	5,498,261	-	-	-	-	-	-	42,409	-	-	5,540,670
588	311,196	-	-	-	-	-	-	(17,512)	-	-	293,685
590	1,614,620	-	-	-	-	-	-	3,144	-	-	1,617,764
592	3,140,807	-	-	-	-	-	-	22,773	-	-	3,163,581
593	28,566,357	(161,609)	2,963,991	-	-	4,780,000	-	246,761	118,976	-	36,514,476
594	6,241,556	-	-	-	-	-	-	72,832	-	-	6,314,388
921	2,574,376	(11,280)	-	-	-	-	412,694	95,892	-	-	3,071,681
922	(8,986,571)	-	-	-	-	-	-	(90,496)	-	-	(9,077,067)
924	7,581,128	-	-	-	1,027,485	-	-	-	-	-	8,608,613
928	6,293,068	(204)	-	178,521	-	-	-	296,359	-	-	6,767,743
929	(35,414,448)	(4,930)	-	-	-	-	-	(2,139,531)	-	(337,569)	(37,896,478)
Grand Total	**34,961,628**	**(178,023)**	**4,835,998**	**178,521**	**1,027,485**	**4,780,000**	**412,694**	**(1,353,254)**	**194,119**	**(337,569)**	**44,521,599**