Sophie Hayes (12546)
Western Resource Advocates
307 West 200 South, Suite 2000
Salt Lake City, UT 84101
801-212-9419
sophie.hayes@westernresources.org

Attorney for Western Resource Advocates

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF PACIFICORP'S 2021 INTEGRATED RESOURCE PLAN	Docket No. 21-035-09

REDACTED REPLY COMMENTS
OF WESTERN RESOURCE ADVOCATES

April 7, 2022

Western Resource Advocates ("WRA") appreciates the opportunity to provide Reply comments pursuant to the September 20, 2021, Scheduling Order and Notice of Technical Conference regarding PacifiCorp's 2021 Integrated Resource Plan ("IRP"). Our Reply comments provide new information, related to our initial comments, based on data responses received following the submission of our initial comments. In addition, they add clarity to one recommendation as well as reiterating and summarizing our recommendations related to the evaluation and modeling of coal-fired generation in future proceedings. The four areas we address are summarized as follows.

- We present new information substantiating the conclusion we presented in our initial comments that Jim Bridger Units 3 and 4 are so costly to operate that they would not be dispatched beyond 2030 in a least-cost optimization without constraining the model with minimum-take fuel requirements. Their high modeled capacity factors do not reflect a cheap resource with beneficial economics for customers, but could reflect shareholders' interests in assuring cost recovery of past investments.

- We present new information showing that to continue to burn coal at the Jim Bridger plant after the Bridger mine closes will require a costly retrofit, and, if the coal-fired units at Jim Bridger are Reassigned, these costs would be paid primarily by PacifiCorp's Utah customers, since Idaho Power and PacifiCorp's Pacific Power states would not share in the investment cost.

- By providing specific modeling recommendations (with and without minimum-take obligations), we clarify our previously stated recommendation that any new coal supply agreements be evaluated in the next rate case (and subsequent rate cases if applicable) using IRP optimization tools.

- Finally, we summarize our recommendations pertaining to the evaluation and modeling of coal-fired generation in future rates cases, IRPs, and any Reassignment cases.

I. DISCUSSION

On March 4, 2022, we filed our initial comments in this docket. On March 16, 2022, PacifiCorp provided a data request response to Utah parties as part of the 10th Supplemental Response to DPU Data Request 1.1. This response contained PacifiCorp's March 3, 2022, response to Oregon Administrative Law Judge ("ALJ") Rowe's and ALJ Mapes' Bench Ruling of February 17, 2022, directing the Company to provide additional information related to modeling the Jim Bridger plant ("ALJ Bench Requests"). The confidential Response to ALJ Bench Request 1 is attached to these comments. The new information substantiates our previous conclusions and is the basis for our decision to file Reply comments. "Attach ALJ Bench Request 1-1 CONF.xlsx" is an Excel workbook that PacifiCorp developed to support its written response to ALJ Bench Request 1. This workbook is the source of our analysis and is contained within "Confidential WRA Workpapers" submitted with this filing.

A. Minimum-take requirements drive dispatch at Jim Bridger; removing the minimum-take modeling constraints results in dispatch plummeting and demonstrates that Jim Bridger is costly to operate.

In our initial comments we identified the Jim Bridger plant as one of PacifiCorp's costlier plants, if not the costliest, and we explained that its relatively high modeled capacity factors are the result of high minimum-take requirements; they do not result from a cheap resource with beneficial economics for customers. We noted that PacifiCorp's use of a *projected* take-or-pay contract following closure of the mine was unique to modeling the Jim Bridger plant, and we concluded that without this modeling requirement, Jim Bridger Units 3 and 4 would be dispatched little, if at all, past 2030. We hypothesized that shareholder interests might be driving PacifiCorp's decision to model Jim Bridger differently than any of its other coal plants, and we recommended that ahead of the next IRP or any Reassignment filing the Company remove the projected take-or-pay contract at Jim Bridger and model the plant consistent with how it had treated other coal supply agreements. In addition, we recommended that the Company develop an alternative mine plan, with lower minimum-takes, that reflects the economics of the fuel supply and plant consistent with customers' interests.[1] The analysis in our initial comments was based on Short-Term ("ST") modeling results.

Attach ALJ Bench Request CONF.xlsx substantiates our conclusions regarding the effect of removing the minimum-take provisions on Jim Bridger's dispatch. ALJ Bench Request 1 reiterates a request for sensitivity analysis that removes "any take or pay assumptions in

[1] *Comments of Western Resource Advocates*, 16-22 (March 4, 2022, Docket No. 21-035-09).

PLEXOS in any years after there is an existing contract" and asks for additional information.[2] The responsive results confirm that, without minimum-take requirements, capacity factors plummet. However, there appears to be a mismatch between PacifiCorp's written Response to ALJ Bench Request 1, describing what it did, and the modeling results in the confidential attachment. Based on PacifiCorp's written response, it appears that the request to PacifiCorp was to remove the projected take-or-pay contract following the mine closure in 2028.[3] PacifiCorp says that it did so across all three of the models it used in developing the 2021 IRP, i.e., the ST, Medium Term ("MT"), and Long Term ("LT") models.[4] However, based on the results of the modeling simulations, as presented in the confidential attachment, it appears that PacifiCorp only made changes to the ST and MT models, not to the LT model.[5] It further appears that, in addition to removing projected take-or-pay contract obligations following mine closure, the Company also removed the minimum-take requirements associated with mined fuel from the Bridger Coal Company, through 2028, in the ST and MT studies.[6]

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[2] *Response to ALJ Bench Request 1*.

[3] In its response to ALJ Bench Request 1 PacifiCorp states: "Referencing the Public Utility Commission of Oregon (OPUC) staff's Final Comment Report dated February 11, 2022, specifically OPUC staff's requested sensitivity removing take-or-pay assumptions as discussed on pages 9-13, the Company responds as follows…" *Response to ALJ Bench Request 1*.

[4] In its response to ALJ Bench Request 1 PacifiCorp states: "Please refer to Confidential Attachment ALJ Bench Request 1-1, reporting Jim Bridger Unit 3 and Jim Bridger Unit 4 generation assuming no minimum take-or-pay obligations across the LT, MT and ST models as compared to outcomes of the P02-MM study as filed in the 2021 IRP." *Response to ALJ Bench Request 1*.

[5] As can be seen in the tab "WRA Compare LT Results" of "WRA Confidential Workpapers," the results are essentially identical to the capacity factors WRA derived from the P02-MM results and the PO2-MM CETA results. They are also similar to the capacity factors from the ST modeling of the Preferred Portfolio that we provided with our initial comments. Additionally, PacifiCorp did not provide LT tabs in its supporting workbook, but it did provide ST and MT tabs.

[6] In addition to an examination of the results, this perspective is supported by the naming convention PacifiCorp used for this simulation: "P02-MM No JB Minimum Fuel (Oregon Study)."

Confidential Table 1 displays the annual capacity factors for Jim Bridger Units 3 and 4 assuming the optimized dispatch of the PO2-MM resources.[7]

[redacted]

As can be seen in the LT results, the minimum-take requirements result in relatively high capacity factors over the life of the plant, with particularly high capacity factors over the years the mine operates. (As we noted in our initial comments, the apparent increase in generation in 2024 is explained by the natural gas conversion of Units 1 & 2 at the end of 2023. Prior to their conversion, units 1 & 2 carry the bulk of the dispatch at Jim Bridger, confirming that Units 3 and 4 are more expensive to operate.)

Without minimum-take requirements, dispatch plummets in the MT and ST modeling results; demonstrating that operating Jim Bridger at such high capacity factors is not in customers' economic interests and results in excess emissions. Significantly, Jim Bridger Units 3

[7] WRA developed the capacity factors in Table 1 from "Attach ALJ Bench Request 1-1 CONF.xlsx, Tab 'OR study JB No Minimum,'" which provided GWh by year for the LT, MT and ST models. PO2-MM is the capacity expansion portfolio that is the basis for the Preferred Portfolio. P02-MM was modified to meet Washington's CETA requirements by adding a situs assigned solar resource; therefore, the Preferred Portfolio's capacity expansion identification is "P02-MM CETA."

and 4 are so costly to operate that in the Short-Term model results, the optimization tool does not dispatch either unit past [redacted] other than in the year [redacted].[8]

These results substantiate the conclusion that we reached in our initial comments regarding the economics of operating the Jim Bridger plant, and they support our recommendations regarding the modeling of Jim Bridger in the 2023 IRP or any Reassignment filing. The Company should model only *existing* take-or-pay contracts and should develop an alternative mine plan for the Bridger Coal Company with lower minimum-takes obligations that reflect the economics of the fuel supply and plant consistent with customers' interests.

B. Retrofitting the Jim Bridger plant to burn Powder River Basin coal after mine closure is costly, and if the Rocky Mountain Power States were to accept the Reassignment of Jim Bridger Units 3 and 4, these costs would fall primarily on Utah's customers.

In its Confidential Response to ALJ Bench Request 1, PacifiCorp explains that in order to continue to burn coal following the closure of the Bridger mine in 2028, the plant would need to be retrofitted to burn Powder River Basin coal, at a cost of [redacted].[9] Despite this needed investment, PacifiCorp's IRP modeling had demonstrated that continuing to operate Jim Bridger through 2037 was cost-effective.

There are two flaws in PacifiCorp's approach. First, PacifiCorp assumed that Jim Bridger would dispatch consistent with the high capacity factors that are driven by the assumed minimum-take requirements. This level of output is clearly not in customers' best interest; in a least-cost optimization, the units do not dispatch past [redacted] without assuming a significant minimum-take obligation to drive the dispatch. Second, PacifiCorp assumed that its customers

[8] While the units do generate some in the MT simulation, the capacity factors are minimal.
[9] *Response to ALJ Bench Request 1*.

would pay [redacted].[10] However, as Idaho Power has announced [redacted], Idaho Power's stated intention is to be out of coal-fired generation by 2028.[11] Given that Idaho Power and the Pacific Power states will not pay for coal-fired generation costs past 2029, if the Rocky Mountain Power states were to accept the Reassignment of Jim Bridger Units 3 and 4, this substantial retrofit cost would land primarily on PacifiCorp's Utah customers (as would any unexpected reclamation and remediation costs of both the plant and mine), because Utah represents the most significant share of the Rocky Mountain Power states' load. Retrofitting the plant to continue to operate on coal and Reassigning the vast majority of the costs to Utah is not in Utah customers' best interest. Other options, including retirement, should be considered. PacifiCorp should evaluate further options in its 2023 IRP.

C. We clarify our previous recommendation regarding the modeling of new take-or-pay contracts in the next rate case and any applicable subsequent rate cases.

In our initial comments we recommended that, as part of the next rate case and any applicable subsequent rate cases, Parties and the Commission should scrutinize the terms of all new coal supply agreements using then current IRP assumptions.[12] We wish to clarify that, in addition to using then current IRP modeling assumptions, the IRP modeling tools should be used to undertake two simulations to evaluate each contract, one with the take-or-pay contract

[10] *Response to ALJ Bench Request 1*.
[11] "Idaho Power's latest Integrated Resource Plan (IRP), submitted to state regulators at the end of December, proposes to phase out all coal-fired power by the end of 2028." Emma Penrod, *Idaho Power to accelerate coal retirements, add 3.8 GW clean energy*, UTILITY DIVE (January 7, 2022), https://www.utilitydive.com/news/idaho-power-to-accelerate-coal-retirements-add-38-gw-clean-energy-but-is/616802/#:~:text=Idaho%20Power's%20latest%20Integrated%20Resource,coal%20to%20end%20by%202030.
[12] *Comments of Western Resource Advocates*, 26 (March 4, 2022, Docket No. 21-035-09).

obligations in place, and one without it. If the dispatch between the two runs is similar, this would indicate that that the contract may be in the economic interest of customers. If the dispatch with the must-take obligation in place is significantly higher, this would indicate that the contract is not in customers' interest, and some mitigating rate adjustment may be warranted.

II. RECOMMENDATIONS

Based on the discussion above and on sections III and IV of our initial comments, we provide the following recommendations pertaining to the modeling and evaluation of PacifiCorp's coal-fired generation.

- Any future take-or-pay contracts that PacifiCorp signs should be of short duration and any minimum-take obligations should reflect the limited hours of operation established using IRP optimization tools.
- The Commission should direct PacifiCorp to evaluate the terms of all new coal-supply agreements using IRP optimization tools with then current assumptions in future rate cases. *The IRP modeling simulations should be undertaken with and without the minimum-take component of each contract to determine whether the minimum-take volumes result in dispatch that reflects customers' interests.*
- Ahead of the next IRP and ahead of any Reassignment filings, we request that the Commission provide guidance to the Company regarding its modeling of the Jim Bridger plant. Specifically, we request that the Commission:
    - Guide the Company to address Idaho Power's intended 2028 exit from the Jim Bridger plant such that any potential costs to be incurred beyond Idaho Power's exit are not discounted by assuming Idaho Power bears one third of these future costs. PacifiCorp should evaluate options other than retrofitting the plant to continue to burn coal, including retirement.
    - Guide the Company *to develop an alternative mine plan* with lower minimum-takes that reflects the economics of the fuel supply and plant consistent with customers' interests.
    - Guide the Company to model only existing take-or-pay contracts. *Projected* take-or-pay contracts should not be assumed.

An optimized portfolio with these changes will provide the Commission and the stakeholder community a better understanding of the actual economics of PacifiCorp's coal fleet, including the Jim Bridger plant, ahead of any Reassignment proceedings.

Dated this 7th day of April 2022.

Respectfully submitted,

WESTERN RESOURCE ADVOCATES

___*/s/ Sophie Hayes*_________
Sophie Hayes, #12546
Managing Senior Staff Attorney
801-212-9419
sophie.hayes@westernresources.org

Nancy Kelly,
Senior Policy Advisor
208-234-0636
nancy.kelly@westernresources.org

Jamie Dalton,
Consultant
801-856-7754
jamie.dalton@westernresources.org