ORDER NO. 24-073

ENTERED Mar 19 2024

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 82

In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Integrated Resource Plan.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED.

In this order, we adopt the recommendations made by Staff of the Oregon Public Utility Commission to acknowledge in part and not acknowledge in part PacifiCorp, dba Pacific Power's Integrated Resource Plan (IRP). We do not acknowledge PacifiCorp's Clean Energy Plan (CEP). We also adopt Staff's 21 recommendations, which set firm direction for what we require to be provided with PacifiCorp's 2025 IRP.

While we understand that development of PacifiCorp's 2025 IRP is a multi-stakeholder, multi-state process in which the company might reasonably seek our flexibility in setting requirements for the analysis, we are reacting to the rigidity PacifiCorp has displayed in responding to Oregon Staff and stakeholders' reasonable requests for adjustments and additional analysis during our review of its filed IRP and CEP, and even in its forthcoming IRP Update. We expect PacifiCorp to embrace the letter and spirit of the Staff recommendations that we adopt here, to follow them assiduously in developing its 2025 IRP, and to return to us for clarification if there is any doubt about what we require. With the urgency of reliability, cost control, and House Bill (HB) 2021 compliance challenges upon us, we would rather review any emerging questions or uncertainty about our direction before an IRP is locked down rather than find the IRP deficient and the company unwilling to adjust until the next cycle.

I. INTRODUCTION

The purpose of the IRP review process is to provide the utility with the input of the Commission, Commission Staff, and stakeholders on the reasonableness of the plan presented. Our acknowledgment decision provides PacifiCorp with guidance to consider in taking resource actions that, ultimately, rest with the company.[1]

We take seriously our role in informing PacifiCorp's direction, but also reinforce that we do not control PacifiCorp's resource decisions and that any risks associated with carrying out even acknowledged actions rest with the company.

Our goal in an IRP proceeding is to acknowledge that a utility's action plan and preferred portfolio represent the least-cost, least-risk strategy for meeting customer needs, based on the best data available at the time and using the best available tools to analyze and review that data. In this particular IRP proceeding, we are asked to review a plan and portfolio that PacifiCorp had already abandoned by suspending the 2022 All-Source RFP, and that was further impacted by the stay of the federal Ozone Transport Rule. We are left without a plan that reflects PacifiCorp's reality, and without any willingness by PacifiCorp to adjust its action plan to reflect that reality. Therefore, we have no basis on which to acknowledge the majority of PacifiCorp's IRP, nor can we acknowledge its CEP without the foundation of a viable IRP action plan. We expect that, in 2025, we will be given a plan that follows Staff's recommendations and reflects both updated operating circumstances and an action plan that the company can stand behind. Recognizing that circumstances are rapidly evolving, that plan may describe action items and the key factors that would instigate a change in course. We also invite the company to present an IRP Update with revised actions that can serve as the foundation for a refiled CEP, which we will consider for acknowledgment and as a demonstration of continual progress.

II. IRP AND CEP PROCESS

A. Overall Purpose of the IRP

The IRP is a road map for providing reliable and least-cost, least-risk electric service to the utility's customers, consistent with state and federal energy policies, while addressing and planning for uncertainties.[2] The primary outcome of the process is the "selection of a

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[1] *See In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 6 (Apr. 20, 1989) (explaining, "The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission* * *.").

[2] *In the Matter of Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at Appendix A, Guidelines 1-13 (Jan. 8, 2007) corrected by Order No. 07-047 (Feb. 9, 2007); *In the Matter of Investigation into* the *Treatment of CO_2 Risk in the Integrated Resource Planning Process*, Docket No. UM 1302, Order No. 08-339 (June 30, 2008) (refining Guideline 8 addressing environmental costs.).

portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[3]

Our IRP guidelines provide procedural and substantive requirements for utilities to meet in developing their IRPs.[4] Consistent with our guidelines, which require modeling of at least a 20-year time horizon, a utility's IRP must include the following key components:

- Identification of capacity and energy needs to bridge the gap between expected loads and resources;
- Identification and estimated costs of all supply-side and demand-side resource options;
- Construction of a representative set of resource portfolios;
- Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;
- Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; and
- Creation of a two- to four-year Action Plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.

In reviewing an IRP, we assess reasonableness based on the information available at the time. Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. Acknowledgment, or non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our examination of whether the costs associated with a utility's resource investment should be recovered in customer rates. The question of whether a specific utility investment or procurement decision was prudent and reasonable will be examined in the subsequent rate proceeding.

B. Overall Purpose of the CEP

The Commission is tasked with ensuring progress towards, and evaluating compliance with, the emissions reductions targets required by HB 2021. Oregon electric companies subject to HB 2021 must file clean energy plans (CEPs), which we are charged with evaluating for acknowledgment pursuant to ORS 469A.415(6).[5] CEPs must meet statutory requirements set forth in ORS 469A.415, and also must demonstrate continual

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[3] Order No. 07-002 at Appendix A, Guideline 1.
[4] Order No. 07-002 and Order No. 07-047 (adopting 13 IRP Guidelines); Order No. 08-339 (June 30, 2008) (refming Guideline 8 addressing environmental costs).
[5] ORS 469A.410(1) lists the required greenhouse gas emission reductions; the Commission's required evaluation is described in ORS 469A.415(4)(e) and (6).

progress towards meeting the HB 2021 targets in a way that results in “an affordable, reliable and clean electric system.”[6]

Oregon electric companies subject to HB 2021’s requirements must submit a CEP to the Commission concurrent with the development of each IRP.[7] CEPs “must be based on or included in an [IRP] filing,” and must be filed concurrently with the IRP.[8]

Each CEP must:

(1) incorporate the clean energy targets articulated in ORS 469A.410;

(2) “[i]nclude annual goals set by the electric company for actions that make progress towards meeting the clean energy targets * * * including acquisition of nonemitting generation resources, energy efficiency measures and acquisition and use of demand response resources;”

(3) “[i]nclude a risk-based examination of resiliency opportunities that includes costs, consequences, outcomes and benefits based on reasonable and prudent industry resiliency standards;”

(4) “[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy;”

(5) “[d]emonstrate the electric company is making continual progress within the planning period towards meeting the clean energy targets * * * including demonstrating a projected reduction of annual greenhouse gas emissions;” and

(6) “[r]esult in an affordable, reliable[,] and clean electric system.”[9]

The actions and investments proposed in a CEP can include “the development or acquisition of clean energy resources, acquisition of energy efficiency and demand response * * * development of new transmission * * * retirement of existing generating facilities, changes in system operation and any other necessary action.”[10]

The CEP must also “present annual goals for actions that balance expected costs and associated risks and uncertainties for the utility and its customers, including a demonstration of making continual progress towards meeting the clean energy targets, the

[6] ORS 469A.415(4)(f).
[7] ORS 469A.415(1).
[8] ORS 469A.415(3).
[9] ORS 469A.415(4)(a) - (f).
[10] ORS 469A.415(5).

pace of greenhouse gas emissions reductions, and community impacts and benefits."[11] The CEP must be "written in language that is as clear and simple as possible, with the goal that it may be understood by non-expert members of the public."[12]

III. PACIFICORP'S 2023 IRP AND CEP

After PacifiCorp filed its amended IRP and CEP in May 2023, we adopted a procedural schedule. This schedule allowed numerous opportunities for submission of written comments from Staff and intervenors, as well as opportunities to obtain feedback from PacifiCorp. On January 24, 2024, Staff filed its Round 2 Comments and Recommendations, in which it recommended truncating the schedule and bringing PacifiCorp's IRP to the February 20 regular public meeting for decision. Due to changed circumstances, including suspension of PacifiCorp's 2022 All-Source RFP and stay of the federal Ozone Transport Rule, Staff recommended only partial acknowledgment of the IRP and that instead of finishing the established procedural schedule, stakeholder and Staff attention should instead turn to the IRP update, to be filed in April 2024. On January 30, 2024, Staff filed a motion to modify the procedural schedule consistent with that recommendation, which was granted. After engagement with parties and Commissioner deliberation on February 20, we adopted the decision memorialized in this order at our March 5 regular public meeting.

C. PacifiCorp's Preferred Portfolio and Action Items

PacifiCorp states its preferred portfolio includes "substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, advanced nuclear, and non-emitting peaking resources."[13] Among other things, PacifiCorp states that it plans 1,792 MW of wind, and 495 MW of solar additions with 200 MW of battery storage capacity from the 2020 All-Source RFP, as well as resource selections from the 2022 All-Source RFP. It also includes 1500 MW of advanced nuclear resources, including the 500 MW Natrium demonstration project. PacifiCorp asks for acknowledgment of the preferred portfolio, as well as a variety of actions, specifically:

- Existing Resource Actions – PacifiCorp seeks to exit Colstrip Units 3 and 4, and Craig Unit 1. It seeks to convert Naughton Units 1 and 2 and Jim Bridger Units 1 and 2 to gas. Finally, it seeks acknowledgment of its compliance plans for Wyoming House Bill 200 (Carbon Capture, Utilization, and Storage); regional haze; and the Ozone Transport Rule.

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[11] OAR 860-027-0400(5).
[12] *Id*.
[13] Amended IRP at 10 (May 31, 2023).

- New Resource Actions – PacifiCorp seeks acknowledgment of its customer preference RFP; its 2024 All-Source RFP; and its 2022 All-Source RFP (now suspended).
- Transmission Action Items – PacifiCorp seeks acknowledgment for three long transmission segments – Energy Gateway South, Segment F; Energy Gateway West, Segment D.1; and Boardway-to-Hemingway – and for local reinforcement projects. It also seeks acknowledgment of continued permitting activities for Gateway West Segments D.3 and E.
- Demand-Side Management (DSM) Actions – PacifiCorp seeks acknowledgment of its energy efficiency targets.
- Market Purchases – PacifiCorp seeks acknowledgment of its intent to acquire short-term firm market purchases for on-peak delivery from 2023-2025.
- Renewable Energy Credit (REC) Actions – PacifiCorp seeks acknowledgment of its intent to pursue unbundled REC RFPs and purchases to meet state compliance obligations and to sell RECs that are not required to meet state RPS obligations.

D. PacifiCorp's CEP

PacifiCorp's CEP first discusses its community engagement strategy, community benefit indicators and metrics, local resiliency, and community-based renewable energy. It then discusses the company's procurement strategy and the IRP's projection that the company will need to acquire over 30 GWs of new resources, including over 800 MW of small-scale renewables. PacifiCorp's CEP finally lays out two pathways for complying with HB 2021: Pathway 1 achieves compliance by allocating the company's gas resources in such a way that the amount allocated to Oregon is capped; Pathway 2 achieves compliance by assuming that new large commercial load is 100 percent served with non-emitting generation through voluntary renewable options.

E. Stakeholder Engagement

Numerous stakeholders filed comments and otherwise participated in this proceeding. Some of their recommendations were incorporated by Staff into their initial and supplemental Staff Reports. Participating stakeholders were: the Oregon Citizens' Utility Board; Energy Advocates; Columbia River Inter-Tribal Fish Commission; NewSun Energy LLC; Renewable Northwest; Swan Lake North Hydro, LLC and FFP Project 101, LLC; Alliance of Western Energy Consumers; Fervo Energy; Sierra Club; Cascade Policy Institute; and Community Advocates.

F. Staff Report

On February 7, 2024, Staff submitted an extensive Staff Report, in which it reiterated its recommendation for partial acknowledgment. That Staff Report is attached as Appendix A. In it, Staff recommends acknowledging eleven action plan items and the company's load forecast. It recommends not acknowledging nine action plan items, the preferred portfolio, and the company's long-term IRP/CEP strategy. It also makes thirteen recommendations that it asks the Commission to adopt and lists over 50 expectations that it intends to work with the company on for the IRP Update or 2025 IRP; it states that it does not seek the Commission impose those expectations.

Staff recommends this course of action because "the 2023 IRP/CEP would not be revised to reflect major events—like the suspended acquisition of over 1 GW of renewable and storage capacity by 2027"—and therefore "Staff and stakeholders lack the shared analytic foundation from which most of the important acknowledgment decisions could be made."[14] Staff's recommendations are also premised on the fact that "the IRP Update will be filed in April 2024, presenting an opportunity to address these issues in a prompt and efficient manner."[15]

On March 1, 2024, Staff filed a report containing an updated set of recommendations, responding to Commissioner deliberation in the February 20 public meeting, including some edited recommendations and a number of new ones. This report is attached as Appendix B and stands as Staff's final recommendations in this proceeding. It did not change Staff's acknowledgment recommendations but did provide specific expectations for PacifiCorp's 2025 IRP and the analyses that PacifiCorp is to provide with that document.

IV. DISCUSSION

We adopt the recommendations set forth in Staff's March 1 report. We acknowledge certain elements and action items in the IRP, but do not acknowledge many other action items. Moreover, we do not acknowledge PacifiCorp's preferred portfolio or the CEP. The plans and many of the action items simply no longer reflect PacifiCorp's reality; most significantly, when PacifiCorp suspended the 2022 All-Source RFP and declined to update its analysis or the further procurement actions set forth in its action plan, we were left with few reality-based actions to acknowledge. Also, when the decision not to take those actions fundamentally undermines a preferred portfolio that was already substantially altered by the federal Ozone Transport Rule, we find it curious that PacifiCorp continues to assert that we should acknowledge its IRP and CEP. In short,

[14] Staff Report at 4.
[15] *Id.*

when the IRP and CEP are superseded by events, and the company makes no effort or space to adjust and provide visibility into what actions it is actually planning to take, acknowledgment is not appropriate. Much in the way we would not acknowledge actions that PacifiCorp has already taken, we do not see a point in acknowledging actions that PacifiCorp has already abandoned.

In saying this, we recognize that not all of these changed circumstances are in the company's control—there are real changes in federal regulations, real operating circumstances and pressures affecting the company, and some inflexibility in PacifiCorp's six-state IRP structure. Nonetheless, we expect PacifiCorp to design its IRP process so that Oregon-specific analysis is upfront and visible to us in our review. If IRP timelines in other states do not allow for testing assumptions and making adjustments during review of the filed IRP and CEP, we expect the company to make an extra effort to ensure a full exploration of alternatives for Oregon.

As to the CEP specifically, the elements that made up the basic actions that would move the company toward the HB 2021 targets were removed at the company's discretion and there has been no engagement around how those can be revised. PacifiCorp chose to pull back on the actions on which the CEP relied as the foundation for movement toward the clean energy targets—movement toward resource acquisitions that would reduce emissions but also, importantly, reduce customers' exposure to electricity market price volatility, for instance.

Beyond the changed circumstances, we are concerned that the CEP was treated as a manual or outboard adjustment to the preferred portfolio development and analysis in the IRP. Without alternative portfolio testing that incorporates state policy requirements, we are unable to see alternatives to the company's allocation-only approach. Had PacifiCorp's plans stayed on track, this approach may have been acceptable for a first iteration given PacifiCorp's persuasive assertion that the IRP preferred portfolio with reallocation was least cost for HB 2021 compliance, and we are not concluding that an allocation approach is legally invalid. It may well be a viable pathway, but going forward, we expect the company to integrate the requirements of state policies into the IRP itself. We need modeling of state policy in order to be able to see, among other things, achievement of the small-scale resource requirement in context of other resources and as a relative cost driver. As we understand it, a key element of HB 2021 is to be able to use the planning process to see tradeoffs and alternative paradigms, and we conclude that adopting requirements for 2025 is necessary to be able to understand PacifiCorp's alternatives for progress to HB 2021 compliance.

To that end, we are approving Staff's clear recommendations laying out a roadmap for the company's next IRP and we emphasize the importance of the company following these recommendations in its 2025 IRP. At the same time, we invite the company to find a way to include in its 2024 IRP update some of the items that Staff is looking for and to update the CEP. We also voice our support for Staff continuing to pursue its non-binding "expectations;" it is not our intention to only support the items that have been formed into recommendations for our adoption.

We particularly want to call out Recommendations 15, 16, and 17 as difficult but important analyses. Stakeholders have worked with the company over successive IRP cycles to effectively model the comparative economics and flexibility of the many resource options, including careful analysis of when it is cost effective to retire a thermal facility. This rigor must continue as cost pressures mount. Recommendation 16, derived from CUB's comments, is a sound recommendation to incorporate actual carbon prices from California and Washington as PacifiCorp is modeling the cost of resources and the resulting dispatch. PacifiCorp has historically put a long-term price on carbon as a proxy for future regulatory requirements. HB 2021 requires a specific carbon budget and a carbon price, and without it, the CEP is not precise enough to establish compliance. Remedying this is especially important so that the CEP can test how much the portfolio as a whole will meet the Oregon requirements, how much will need to be solved with allocation, and what the cost will be. It will also help us determine whether the company is on a least-cost path to compliance. We also note that analysis of the federal loan program is a critical, near-term priority given capital constraints and rate pressure.

In general, we expect to see more cost information in the course of PacifiCorp's planning, both due to affordability concerns and because we need the company to be clearer about constraints that may be impacting their progress and how they are allocating their resources among their many priorities. The company should be transparent with stakeholders if the IRP Update or the 2025 IRP action plan are being driven by constraints that are not visible in the modeling The company needs to do more to communicating the many moving parts in the company's planning and procurement landscape.

We recognize that we committed in our order in docket UM 2273 to consider, alongside IRP and CEP review processes, whether utilities have demonstrated continual progress.[16] We are not doing so here simply because we expect, in a matter of weeks, to have a more realistic view of PacifiCorp's status with the IRP/CEP Update that are to be filed in April 2024. We will assess continual progress in connection with our review of the update. If we do not find that PacifiCorp has demonstrated "continual progress [toward the HB 2021 targets] and [that it] is taking actions as soon as practicable that facilitate

[16] *In the Matter of Public Utility Commission of Oregon, Investigation of House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 23-465 (Dec. 4, 203).

rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers," we will consider in a holistic manner whether we need to take actions to fulfill our responsibility to ensure this progress.

V. ORDER

IT IS ORDERED that the Integrated Resource Plan filed by PacifiCorp, dba Pacific Power, is acknowledged in part to the extent and with the conditions contained in Staff's February 7, 2024, and March 1, 2024 reports attached as Appendix A and Appendix B.

Made, entered, and effective Mar 19 2024.

Megan W. Decker	**Letha Tawney**
Chair	Commissioner

ITEM NO. RA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: FEBRUARY 20, 2024

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** __________N/A__________

DATE: February 7, 2024

TO: Public Utility Commission

FROM: JP Batmale

THROUGH: Kim Herb **SIGNED**

SUBJECT: PACIFICORP:
Docket No. LC 82
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP), subject to the condition that the Company implements Staff's recommended conditions, including four recommended IRP analyses as part of the IRP Update. Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Direct the Company to revise and resubmit certain elements of the IRP, and to revise and resubmit the CEP, by the next IRP Update in April 2024, consistent with Staff's recommendations.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (PUC or Commission) should acknowledge PacifiCorp's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PGE's CEP or decline to acknowledge the CEP and direct the Company to revise and resubmit certain portions of the plan. Whether the Commission should direct PGE to take any additional actions prior to filing its next IRP or IRP Update or CEP.

Applicable Law

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[1] In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of "IRP Guidelines" to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047), and 08-339 clarify the procedural steps and substantive analysis required of Oregon's regulated utilities before the Commission considers acknowledgement of a utility's resource plan.[2] These orders are incorporated in OAR 860-027-0400(2), which requires any IRP to satisfy their requirements.

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.[3] Further, the IRP must also include an "Action Plan" with resource activities that the utility intends to take over the next two to four years.[4] The utility's IRP should satisfy the IRP Guidelines and Commission rules for its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives reviewed to meet its future resource needs, and its near-term Action Plan to achieve the IRP goal of selecting the "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[5] This is often referred to as the "least cost/least risk portfolio."

The Commission reviews the utility's plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonably based on the information available at the time.[6] However, the Commission explains: "We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers."[7] The Commission may also provide direction on additional analysis or actions for the next IRP or IRP Update.[8]

[1] Order No. 89-507.
[2] Order Nos. 07-002 and 07-047. Additional refinements to the process have been adopted: See Order No. 08-339 (IRP Guideline 8 was later refined to specify how utilities should treat carbon dioxide (CO2) risk in their IRP analysis); Order No. 12-013 (guideline added directing utilities to evaluate their need and supply of flexible capacity in IRP filings).
[3] Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.
[4] Order No. 14-415 at 3.
[5] Order No. 07-002 at 1-2.
[6] *Id.* at 1.
[7] *Id.*
[8] OAR 860-027-0400(7), (10).

In 2021, the legislature passed Oregon House Bill (HB) 2021, codified as ORS 469A.400 to 469A.475, which requires the state's large investor-owned electric utilities (IOUs) and electricity service suppliers (ESSs) to decarbonize their retail electricity sales with consideration for direct benefits to local communities.

ORS 469A.415 requires large electric IOUs to, "develop a clean energy plan for meeting the clean energy targets set forth in ORS 469A.410 concurrent with the development of each integrated resource plan," and file the plan with the Commission and Oregon Department of Environmental Quality (DEQ).

ORS 469A.420 outlines the requirements and considerations for the Commission to acknowledge the CEP "…if the commission finds the plan to be in the public interest and consistent with the clean energy targets...."

In addition, ORS 469A.415(6) requires the Commission to ensure that the utilities demonstrate continual progress within the CEP planning period toward meeting the clean energy targets and are taking actions as soon as practicable to reduce emissions at reasonable cost to retail electricity consumers.

Additional requirements for the filing, review, and update of IRPs and CEPs are provided in OAR 860-027-0400.

Finally, PacifiCorp's previous IRP, LC 77, resulted in Order No. 22-178, which provided specific direction to the Company on analytic matters for this IRP.

Analysis

Background
PacifiCorp filed its 2023 Integrated Resource Plan and Clean Energy Plan (IRP/CEP or Plans) with PUC on May 31, 2023. PacifiCorp's filing shortly followed PGE's filing of the first IRP/CEP on March 31, 2023, both of which followed from the passage of HB 2021 and direction from Docket UM 2225.

Originally three rounds of comments had been planned in the lead up to a final Staff memo for an April 2024 Special Public Meeting to acknowledge PacifiCorp's 2023 IRP/CEP. Round 0 comments provided preliminary notes about improvements PacifiCorp could make in advance of participants' in-depth review of the IRP/CEP. Round 1 comments evaluated the reasonableness of the plan and explored acknowledgement considerations. Round 2 comments were meant to focus on Staff's draft recommendations for Commission acknowledgement of the IRP/CEP. The Company would respond with a final set of comments, typically including a final set of revisions to the IRP. Then in March a public meeting memo from Staff with final acknowledgement recommendations was to be published, giving stakeholders and the Company a final opportunity to make written comments to the Commission.

Round 1 comments by Staff and stakeholders reflected the fact that there had been material changes impacting the IRP/CEP analysis since the documents were filed in May 2023. These changes rendered moot most of the IRP's Action Plan and Preferred Portfolio. The changes also undermined PacifiCorp's CEP and plan to meet the HB 2021 targets. Of particular concern, PacifiCorp confirmed in response to an information request that the Company will not be able to procure the clean energy additions included in the Preferred Portfolio through 2028 given the suspension of the 2022 All-Source RFP.[9]

In PacifiCorp's December 2023 LC 82 Round 1 reply comments, PacifiCorp made it plain that changes would not be made to the 2023 IRP/CEP, despite Staff and stakeholders' requests. Instead, the Company pointed toward the IRP Update – planned for April 2024 – for any revisions of the Company's now obsolete IRP analysis. PacifiCorp reinforced this position several information request responses.

As the 2023 IRP/CEP would not be revised to reflect major events – like the suspended acquisition of over 1 GW of renewable and storage capacity by 2027 – Staff and stakeholders lacked the shared analytic foundation from which most of the important acknowledgement determinations could be made. Given this threshold issue, Staff saw little value in continuing multiple rounds of comments on the plan as filed. Staff's Round 2 comments included proposed ***final*** recommendations, rather than ***draft*** recommendations, and a request to shorten the procedural schedule and end LC 82 in February, rather than April.[10] A revised schedule consistent with Staff's request was adopted by the ALJ in a ruling on February 5, 2024.

Staff sees benefits to an abbreviated schedule, and non-acknowledgment as proposed by Staff followed by revision and resubmission of the CEP and additional actions for the IRP Update. The first, the Company's planned IRP Update will be filed in April 2024, presenting an opportunity to address these issues in a prompt and efficient manner. Second, by directing a revised and resubmitted CEP in mid-2024, the Commission can avoid an extensive delay in the acknowledgment of a CEP the Company to implement, given the looming emissions reductions targets in HB 2021, rather than stalling consideration of the CEP to 2025. Finally, the Commission could consider providing

[9] PacifiCorp response to OPUC Staff Information Request No. 243.
[10] LC 82, OPUC Staff Second Round Comments, January 24, 2024, pg. 4 and Staff procedural motion on January 30, 2024 to change the schedule.

direction to shape PacifiCorp's quickly moving small-scale renewable request for proposal (SSR RFP).

Staff's redacted Round 2 comments are included with this memo as Attachment A. The Round 2 comments provide more details to Staff's recommendations. The Round 2 comments also include more background information on the IRP itself and stakeholder comments than is contained in this memo. This public meeting memo includes no new analyses. It does, however, seek to reemphasize and clarify the positions taken by Staff in the Round 2 comments and address potential shortcomings in the SSR RFP currently under development.

Acknowledgement Recommendations for the IRP and CEP

Staff made thirteen acknowledgement recommendations in our Round 2 comments.[11] They spanned the IRP and CEP. Staff also listed over fifty expectations for the IRP Update or the 2025 IRP. These expectations amounted to issues that did not require Commissioner deliberation and would not require an order. Instead, Staff plans to work with PacifiCorp and stakeholders to meet these expectations.

The table below summarizes the recommendations from Staff's comments regarding the IRP.[12]

Table 1

	Acknowledge	Not Acknowledge
IRP	• Eleven Action Plan Items (1a, 1b, 1e, 1f, 3a-3c, 3e, 4a, 6a, 6b) • Load Forecast	• Nine Action Plan Items (1c, 1d, 1g, 1h, 2a – 2c, 3d, 5a) • Preferred Portfolio • Long-Term IRP/CEP Strategy

With regard to the CEP, Staff believes that the necessary changes to the Preferred Portfolio in the IRP Update will significantly impact PacifiCorp's Oregon-allocated GHG emissions and/or the allocation strategies needed for PacifiCorp to comply with HB 2021. Staff does not believe the CEP is consistent with the emissions reduction targets of HB 2021, given the present circumstances. Staff therefore recommends that PacifiCorp be directed to revise and resubmit the CEP so that the emission strategy and information on costs to Oregon ratepayers is consistent with the information in the IRP Update.

With regard to PacifiCorp's allocation approach to CEP compliance pathways, Staff stated previously that we find the approach of testing hypothetical allocations to be a reasonable approach to forecasting future Oregon-allocated emissions in years beyond

[11] LC 82, OPUC Staff Second Round Comments, January 24, 2024, Appendix A, pgs. 55-56.
[12] *Id.*, pg. 4.

the current allocation agreement. It would, however, generate more insight if PacifiCorp tested more options and was more transparent about those options and their tradeoffs. Additionally, Staff is clear in our Round 2 comments that the Company is not expected to make significant revisions in community-focused areas of the CEP as part of a revised filing; only the CEP Compliance pathways and demonstration of continual progress on emission reductions. With that said, Staff did include four CEP, community-focused recommendations:

> **Staff Recommendation 5.** Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.
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> **Staff Recommendation 6.** Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.
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> **Staff Recommendation 7.** Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.
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> **Staff Recommendation 8.** Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Beyond these recommendations, to the extent that the CEP's community-based activities or strategies have changed since it was filed in May 2023, the Company should provide new information in the revised CEP filing. Otherwise, Staff expects PacifiCorp to leverage the CBIAG and 2025 IRP process to continue to improve the community-based elements of the CEP.

Minimum Changes Sought by Staff in the IRP Update and Revised CEP
Staff's Round 2 comments identified four analytic threshold issues that would need to be addressed in the IRP Update and reflected in the revised and resubmitted CEP for

Staff to consider recommending acknowledgment of the revised and resubmitted CEP.[13] These were in addition to the thirteen acknowledgement recommendations.

1. Align the updated Preferred Portfolio and Action Plan with PacifiCorp's updated plans in light of key developments since the filing of the IRP, including the suspension of the 2022 AS RFP and the stay of the Ozone Transport Rule.
2. Include Oregon's Small Scale Renewable requirement in the updated Preferred Portfolio.
3. Confirm that the updated Preferred Portfolio can support simultaneous compliance with the clean energy requirements and GHG targets in Oregon, Washington, and California.
4. Fix any confirmed analytical errors identified in this docket, including any errors in the calculation or application of granularity adjustments.

On January 31, 2024, PacifiCorp released a draft of the IRP Update. This draft outlined eight areas that PacifiCorp planned to revise with new information in the IRP Update. They are:

- System coincident peak load forecast,
- Natural gas and power market price updates,
- Stay of the ozone transport rule,
- Suspension of the 2022 all-source RFP,
- Natural gas generation and the use of either green hydrogen or green ammonia,
- Preference for peaking type resources,
- Demand-side management,
- Front office transactions,
- Contracted resources, and
- Transmission option updates.

It appears that PacifiCorp plans to update the Preferred Portfolio and Action Plan in the IRP Update, though these updates were not completed and included in the draft document. PacifiCorp makes no mention of Staff's other three recommendations. Further, the draft IRP Update outline included no mention of seeking acknowledgement of a revised Preferred Portfolio and Action Plan as part of the IRP Update. All of these things are crucial.

If Staff's additional analyses are not addressed as part of the April 2024 IRP Update, Staff is concerned that the basis from which to assess the acknowledgability of a revised and resubmitted CEP will be compromised and more time wasted. Thus, Staff

[13] *Id.,* pg. 3.

requests that the Commission order PacifiCorp to conduct Staff's recommended analyses within the IRP Update, in addition to all thirteen recommendations from Staff's Round 2 comments.

Timing of Resubmission of Revised CEP

Due to the circumstances surrounding this IRP and CEP, Staff finds that PacifiCorp should seek to resubmit its revised CEP with the IRP update. However, given that April is less than two months away, Staff is open to PacifiCorp filing a request in its reply comments for an extended CEP filing date of four to eight weeks.[14] Regardless of the timing, Staff plans to work quickly to review the CEP once it is filed.

SSR RFP

The 2023 IRP/CEP forecasted a need of approximately 490 MW of new, renewable capacity – all less than 20 MW in size – to meet HB 2021's 2030 SSR requirement. Because the Company believes acquiring this volume and type of capacity by 2030 may be difficult, PacifiCorp plans to move rapidly. On January 24, 2024, PacifiCorp held a bidders workshop for its SSR RFP. The workshop outlined the Company's initial approach to acquiring the SSR resources necessary to meet a key component of HB 2021. Per the bidders conference presentation, the RFP will be finalized and issued by March 29, 2024. Staff appreciates the Company's sense of urgency on this topic.

However, Staff is concerned about the strategic choices made by PacifiCorp in designing this RFP. First, the timing was such that the bidders conference was the same day as Staff's comments were due. Staff did include two SSR RFP recommendations that were not part of the RFP. They were:

> **Staff Recommendation 5.** Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.
>
> **Staff Recommendation 9.** The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

Should the Commission choose to accept Staff recommendation we would hope to see the SSR RFP be updated accordingly.

[14] OAR 860-027-0400(9)(c).

Beyond this, the Company also appears to be establishing RFP parameters that limits the pool of potential resources, drives up SSR project costs borne by Oregon ratepayers, and/or limits insights into the community benefits of projects. Specifically:

- The RFP bars energy storage from being paired with eligible renewable systems.
- No RFP mechanism like non-price scoring or sensitivities to identify, track, and/or allow for project selection that accounts for community benefits.
- Premium peak hour pricing, like what was approved for Oregon PURPA projects, is not allowed. Only flat pricing and on-peak/off-peak.
- Requiring ODOE RPS certification, which includes WREGIS certification and metering.
- Requiring CAISO EIM visibility and dispatchability.

Staff has included two attachments associated with the SSR RFP. Attachment B is the bidders conference presentation and Attachment C Staff's response.

Time permitting at the Public Meeting, Staff suggests that it may be productive to discuss with PacifiCorp their SSR acquisition strategy. The SSR RFP represents one of the first actions by PacifiCorp to meet the HB 2021 targets. As such, a better understanding of PacifiCorp's strategy and approach to SSR acquisition could help all parties learn more about balancing tradeoffs around the economic and technical feasibility of HB 2021 actions.

PROPOSED COMMISSION MOTION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP), subject to the condition that the Company implements Staff's recommended conditions, including four recommended IRP analyses as part of the IRP Update. Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Direct the Company to revise and resubmit certain elements of the IRP, and to revise and resubmit the CEP, by the next IRP Update in April 2024, consistent with Staff's recommendations.

LC 82

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket No. LC 82

In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Integrated Resource Plan.	OPUC STAFF ROUND 2 COMMENTS AND RECOMMENDATIONS

Table of Contents

Executive Summary

In this second round of comments on the PacifiCorp (PAC or Company) Integrated Resource Plan (IRP) and Clean Energy Plan (CEP), the Oregon Public Utilities Commission (OPUC) Staff puts forth draft recommendations for acknowledgment and future expectations. Our recommendations and expectations cover this IRP, the planned IRP Update (April 2024), and the next IRP (April 2025). As detailed below – and throughout this document – Staff also puts forth a plan and rationale to revise the current IRP/CEP process to enable the Commission to consider the significant changes to the Preferred Portfolio and Action Plan that PacifiCorp plans to include in the IRP Update to be filed in April 2024.

Staff finds the 2023 IRP was an insightful first attempt at putting forth a comprehensive resource plan to meet HB 2021’s decarbonization targets and community benefit goals while accomplishing traditional IRP analysis. PacifiCorp staff conducted more complex modeling than in any previous IRP and demonstrated a commendable level of engagement and candor with Staff and stakeholders. However, Staff has determined that a change of course in this IRP is necessary. This is spurred by two developments.

First, events outside the LC 82 process profoundly changed the relationship between this IRP/CEP’s conclusions, action plan, and the market and policy realities faced by PacifiCorp. The two most notable of these events were the judgment against PacifiCorp in the wildfire lawsuits in August 2023 and the Tenth Circuit Court of Appeals’ stay of the Ozone Transport Rule in July 2023. The combination of these two events, along with other events, led PacifiCorp to suspend its 2022 AS RFP in September 2023. As noted by many stakeholders in the first round of comments, the RFP suspension, which removed approximately 1.5 GW of new, non-emitting capacity by 2027 from the Preferred Portfolio, cast into doubt several important elements of the IRP/CEP. These included the Preferred Portfolio itself, many action plan items, and any understanding of the potential of forecasted emissions reductions to achieve CEP compliance. In short, the IRP/CEP map no longer matches the territory of operational and market realities. Thus, Staff and stakeholders argued in the first round of comments that additional analysis within this IRP/CEP was necessary in order for several elements to be acknowledged. Independent of these outside events, Staff and stakeholders also noted in Round 1 comments the need for improvements to the IRP/CEP to consider acknowledgement. These included:

- Including Oregon’s Small Scale Renewable (SSR) requirement in the Preferred Portfolio in 2030 to capture the portfolio benefits of SSRs.
- Adding more energy efficiency (EE) in Oregon to reflect the higher value that EE brings to Oregon in the context of HB 2021.
- Utilizing more reasonable resource cost estimates.
- Addressing any identified errors with the granularity adjustments that PacifiCorp applied within its PLEXOS modeling.
- Analyzing the sufficiency of the Preferred Portfolio to enable simultaneous compliance with clean energy and GHG policies in Oregon, Washington, and California.
- Reoptimizing select portfolios for a clearer understanding of portfolio NPVRR and the ability to compare actions.

- Articulating more clearly the Oregon implication of coal-to-gas conversions vis-à-vis emissions, decarbonization efforts, and future MSP allocations.

While PacifiCorp has signaled an openness to eventually considering the improvements listed above, the Company was also clear that it would not conduct additional analysis to revise its filed IRP/CEP.[1] The Company has pushed all additional analysis or changes to this IRP/CEP to either the IRP Update or the next IRP.

While it would be unwieldy to constantly revise a filed IRP/CEP, additional analysis has been done in the past when staff or stakeholders indicate they cannot support acknowledgement without material revisions. Conducting additional analysis within the IRP/CEP timeframe to adjust to large-scale and material events impacting the Preferred Portfolio – or in response to stakeholder insights and requests – is reasonable. The IRP process is designed for rounds of comments to consider, discuss, and debate changes to achieve acknowledgement. Accordingly, the IRP/CEP is deemed reasonable to acknowledge at the end of the process, not upon filing.

Because PacifiCorp will not voluntarily make changes to this IRP/CEP, some of the most important issues before us lack a shared analytic foundation from which an acknowledgement determination can be made. As such, Staff does not see a path to recommending acknowledgment of PacifiCorp's current IRP/CEP. At the same time, Staff is concerned that non-acknowledgement and reconsideration at an undetermined future date could delay important activities that the Company must or should undertake to comply with HB 2021. Time is limited for the utility to adopt a CEP that can be acknowledged and successfully implemented before the first emissions reduction target in 2030. Given this tension and the indications from PacifiCorp that there will be significant changes to the Preferred Portfolio and Action Plan in the IRP Update to be filed in April 2024, Staff recommends that the schedule be updated to allow the Commission to consider the information in the forthcoming IRP Update. Staff also recommends that PacifiCorp be directed to address, within the IRP Update, a limited number of threshold issues that have been raised within this docket.

Specifically, Staff recommends that PacifiCorp be directed to, at a minimum:

- Align the updated Preferred Portfolio and Action Plan with PacifiCorp's updated plans in light of key developments since the filing of the IRP, including the suspension of the 2022 AS RFP and the stay of the Ozone Transport Rule.
- Include Oregon's Small Scale Renewable requirement in the updated Preferred Portfolio.
- Confirm that the updated Preferred Portfolio can support simultaneous compliance with the clean energy requirements and GHG targets in Oregon, Washington, and California.
- Fix any confirmed analytical errors identified in this docket, including any errors in the calculation or application of granularity adjustments.

With regard to the CEP, Staff believes that the changes to the Preferred Portfolio in the IRP Update may significantly impact PacifiCorp's Oregon-allocated GHG emissions and/or the allocation strategies

[1] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 96. "Pertaining to the 2022 AS RFP, PacifiCorp has no revised plan or substantive updates available at this time and is actively working to incorporate a number of updated assumptions as part of portfolio development for its 2023 IRP Update, anticipated to be filed April 1, 2024. The result will be comprehensive changes to the portfolio, and not just specific line items that could be modified in a few figures in the filed 2023 IRP."

needed for PacifiCorp to comply with HB 2021. Staff therefore recommends that PacifiCorp be directed to revise and resubmit the CEP so that the emission strategy and information on costs to Oregon ratepayers is consistent with the information in the IRP Update.

Staff also describes in these comments a number of issues regarding PacifiCorp's efforts to incorporate community impacts into planning decisions and presents a number of expectations regarding community engagement, community benefit indicators (CBIs), community-based renewable energy (CBREs), and resiliency. Staff views PacifiCorp's efforts on these fronts as important first steps upon which to build in future planning cycles. Staff does not expect the Company would make significant revisions in these areas prior to filing a revised CEP, but does expect the Company would update information in a revised CEP filing to the extent that their plans have changed.

To accommodate the timing of PacifiCorp's planned IRP Update filing, Staff proposes that the Commission take up these recommendations at the February 20, 2024, Public Meeting. This will allow Staff and stakeholders to focus the remaining efforts for this IRP/CEP on reviewing the April 2024 IRP Update and a revised and resubmitted CEP. Staff believes a revised CEP should be submitted with the IRP Update.

The table below summarizes those IRP items that Staff plans to recommend and not recommend for acknowledgement in LC 82:

Table 1: IRP Elements Recommended for Acknowledgement

	Acknowledge	Not Acknowledge
IRP	Eleven Action Plan Items (1a, 1b, 1e, 1f, 3a-3c, 3e, 4a, 6a, 6b) Load Forecast	Nine Action Plan Items (1c, 1d, 1g, 1h, 2a – 2c, 3d, 5a) Preferred Portfolio Long-Term IRP/CEP Strategy

Finally, Staff is incredibly grateful to the following stakeholders for their work in LC 82: Alliance of Western Energy Consumers (AWEC); Community Advocates; Columbia River Inter-Tribal Fish Commission (CRITFC); Oregon Citizens' Utility Board (CUB); Energy Advocates; Fervo; NewSun Energy LLC (NewSun); Renewable Northwest (RNW); Sierra Club; and Swan Lake and FFP Project 101. The comments and overall engagement throughout this IRP have deepened Staff's understanding of the issues surrounding HB 2021. They have also improved this IRP/CEP and future filings by PacifiCorp as they chart a pathway to a reliable, affordable, equitable and decarbonized system.

Key Challenges & Vulnerabilities

In Round 1 comments, Staff identified key challenges and key vulnerabilities to LC 82. The challenges represented issues within IRP and CEP that would require more explanation of the near-term resource strategy and general implementation. Staff's identified vulnerabilities represented more critical issues that called into question the ability to acknowledge a particular aspect of LC 82. While all of the identified topics from Round 1 are covered in these comments, we revisit the most pressing or unresolved items below.

Composition and Costs of Small-Scale Renewables and Community-Based Renewable Energy (Challenge)

In Reply comments, PacifiCorp addressed questions around costs and composition of SSRs. While the Company reasserted that SSRs remain uneconomic, the Company is clearly committed to trying to meet the 2030 SSR target in HB 2021.[2] Staff appreciates PacifiCorp's approach of letting the RFP run its course and then pivot to other methods of acquiring SSRs based on the RFP results.[3] Staff also appreciates PacifiCorp's thorough response on the potential barriers in Oregon rule to SSR procurement.[4] The Company's four suggestions provide a solid basis for fruitful public dialogue. Staff will not address each of the Company's suggestions in its comments, but would be open to participating or leading an informal public discussion on PacifiCorp's suggestions.

Both Staff and the Company see some overlap between CBRE and SSR projects.[5] However, PacifiCorp has modeled CBRE Projects and SSR projects separately, most notably with CBRE projects having a higher cost per MWh. PacifiCorp plans to acquire CBRE projects through a grant pilot program rather than an RFP.[6]

Staff would note the initial SSR RFP filing limits the range of projects from 3 MW to 20 MW. We think the bound at the low-end of the range may unnecessarily exclude potential CBRE projects that are smaller in nature. Staff will work to expand this range in the SSR RFP so that it can potentially capture these projects and establish two channels for acquiring this resource.

State Policy Compliance in IRP Portfolios (Vulnerability)

In Round 1 Comments, Staff raised a central concern to PacifiCorp's CEP compliance allocation methodology: would the Preferred Portfolio contain a sufficient amount of non-emitting resources in 2030 to simultaneously comply with the clean energy and GHG policies of Oregon, Washington, and California? Staff is concerned that if PacifiCorp continues to evaluate compliance with each state-level policy in separate analyses outside of the IRP, resources could be erroneously double-counted toward policy compliance in multiple states.

Staff requested that PacifiCorp demonstrate in this IRP that the Preferred Portfolio could simultaneously comply with clean energy and GHG policies in Oregon, Washington, and California and that, in future IRPs, the Company to constrain the Preferred Portfolio to ensure that simultaneous policy compliance is feasible.

PacifiCorp's Response Comments noted that, "there is no feasible single-pass modeling solution that guarantees Oregon compliance while simultaneously meeting all other portfolio requirements."[7] PacifiCorp also suggested that Staff's request to demonstrate simultaneous compliance of state-level policies would not be possible due to limitations of PLEXOS and the fact that resource allocations have not yet been determined.[8]

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[2] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 53.
[3] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 52.
[4] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 85.
[5] LC 82, PacifiCorp Clean Energy Plan, May 31, 2023, page 36.
[6] LC 82, PacifiCorp Clean Energy Plan, May 31, 2023, page 54.
[7] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 24.
[8] *Ibid*.

Yet elsewhere in PacifiCorp comments, the Company expresses openness to developing a more "unified" portfolio that integrates systemwide and state-level constraints.[9]

From Staff's perspective, ensuring that PacifiCorp can simultaneously comply with all state-level policies to which it is bound should be foundational to the Company's IRP process. Staff appreciates PacifiCorp's concern that a "single pass" modeling solution to this problem may not be available through the PLEXOS model. However, this limitation does not prevent PacifiCorp from demonstrating that simultaneous state-level policy compliance is feasible or ensuring that portfolios meet this requirement. PacifiCorp already uses multiple modeling passes to make adjustments to portfolios to respect other complicated constraints (e.g. the reliability and granularity adjustments). PacifiCorp could similarly adopt an iterative process within the IRP in the event that a portfolio was found not to comply with one or more state-level policies simultaneously.

Staff also appreciates PacifiCorp's concern that evaluating state-level policy compliance may require the Company to make assumptions regarding future allocation. However, Staff does not see this as an impediment to testing the feasibility of simultaneous policy compliance. PacifiCorp could, for example, demonstrate that there is some feasible allocation (i.e. all allocation factors fall between 0 and 1 and sum to 1) that achieves simultaneous policy compliance, without adopting that allocation strategy. Such an exercise could be used to test the limitations of what can be achieved through allocation and to identify if there are high-level constraints that could inform allocation discussions in MSP.

Because PacifiCorp would not or could not conduct this analysis – and given its centrality to the IRP and CEP – Staff conducted a high level and approximate exercise to make a "back of the envelope" determination of the non-emitting sufficiency of the Preferred Portfolio in 2030. Staff's simple analysis, which was based on public information from PacifiCorp's IRP and CEP workpapers, identified multiple energy allocation strategies for the Preferred Portfolio that would likely result in simultaneous policy compliance in Oregon, Washington, and California in 2030.

Further, the policy-feasible allocations that Staff tested also resulted in the majority of the load in Idaho, Utah, and Wyoming being met with non-emitting generation by 2030 under the Preferred Portfolio.

Staff's findings are in fact consistent with PacifiCorp's assertion that the proposed renewable additions originally proposed in this IRP are primarily being driven by economics, rather than policy compliance. Staff's analysis also bolstered Staff's view that it is reasonable for PacifiCorp to incorporate this type of analysis into future IRPs and IRP Updates.

Staff Expectations:

- In the next IRP, PacifiCorp should demonstrate that simultaneous compliance with all state-level policies is feasible with the Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP.
- In the next CEP, PacifiCorp should transparently explore and describe constraints that HB 2021 compliance potentially places on allocation.

[9] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 54.

CEP Compliance Pathways (Vulnerability)

Staff finds that considering the effect of allocation pathways in the CEP on HB 2021 compliance is an acceptable, flexible approach to beginning a conversation about HB 2021 compliance that reflects how DEQ conducts annual emissions compliance evaluation. However, Staff also recognizes that it represents a complete departure from the allocation methodology approved in the 2020 MSP. Staff agrees with CUB that this was done with limited discussion outside of MSP. CUB observed that, beyond comparing compliance costs across portfolios, PacifiCorp's approach to developing CEP pathways – along with changes in coal retirements and this IRP's quick pivot to coal-to-gas conversions – represent a fundamental break from the approach of the 2020 Multi-State Protocol (MSP) with no transparent discussion or analytic demonstration of how these changes to the allocation methodology are in the best interest of Oregon.[10] Further, AWEC speculated that PacifiCorp's proposed pathways most likely exceeded HB 2021's incremental cost cap, that neither pathway can be enforced or guaranteed, and that because both pathways do not reflect the current MSP allocation they should be prohibited.[11] Both RNW and the Energy Advocates generally objected to PacifiCorp's approach as just an allocation exercise with no meaningful emission reductions and little chance of being accomplished within the MSP framework.

The Company's response points out that CEP pathways are compliant with the 2020 MSP prior to its expiration at the end of 2024, and that no MSP has been agreed upon for the time period after 2024 when most CEP cost will be incurred. Further, PacifiCorp counters CUB that the CEP does include cost analysis. The CEP pathways also represent issues to be considered in the current MSP negotiations, not actual positions that must be taken. To this end, PacifiCorp notes that the pathways were not the primary means to achieve CEP compliance. Rather, the IRP's proposed system-wide, Preferred Portfolio would in fact achieve 98 percent of the Oregon CEP emission reduction targets by 2030.[12] Finally, PacifiCorp argues for a narrow interpretation of HB 2021's cost cap that should be applied once costs are incurred and to conduct such an analysis in a rate case.[13]

Staff agrees with PacifiCorp that the expiration of the 2020 MSP provides a level of flexibility in proposing CEP compliance pathways. Yet the analysis in this CEP – while instructive and insightful –falls short of providing actionable insights *and* a forum to discuss the tradeoffs for Oregonians around MSP allocation methodologies capable of meeting HB 2021's goals. In this sense Staff agrees with CUB: by limiting the CEP pathways to only "illustrate" what could eventually occur in MSP, the IRP/CEP falls short of providing an actionable "plan" around which to debate the costs and risks of various CEP Compliance Pathways. Finally, Staff agrees with the Company's assertion that UM 2273 will be the best place to address policy issues around HB 2021's cost cap, not this IRP/CEP.

Staff Expectations:

- PacifiCorp should utilize its 2025 IRP public input workshops to clarify with stakeholders the relationship between MSP, IRP "actions," Oregon's CEP requirements, and Oregon's DEQ compliance methodology and explore improvements such that HB 2021 targets and activities are informative to and reflected in MSP decisions. As part of this process, changes to MSP disclosure rules should be explored to increase transparency.

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[10] LC 82, CUB Round 1 Comments, October 25, 2023, page 5.

[11] LC 82, AWEC Round 1 Comments, October 25, 2023, page 3-5.

[12] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 23.

[13] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 26.

- To improve an understanding of tradeoffs in the IRP Update and/or as part of the revised CE, the Company should report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (inclusive of Oregon's SSR requirement) under various allocation pathways and that PacifiCorp.

Coal-to-Gas Conversions (Vulnerability)

In Opening Comments (Round 1), Staff recognized that PacifiCorp's 2023 IRP makes a significant departure from its 2021 IRP in its plans to retire coal-fired generation resources. Specifically, while the 2021 IRP only included gas conversions of Jim Bridger Units 1 and 2, the current plan adds Jim Bridger Units 3 and 4 and Naughton Units 1 and 2 to the list.

PacifiCorp's analysis shows that the conversions are selected by its optimization model based on economics. Staff appreciated this analysis and sought more information from the Company to better understand the cost and risks associated with these conversions for Oregon customers as well as the consistency of these actions with HB 2021 emissions reduction targets. Staff appreciates PacifiCorp's responses to some of the questions posed by Staff, however, expresses disappointment that the Company did not answer most of the questions posed by Staff.

In response to Staff's question regarding the prominence of gas conversions in this plan compared to the 2021 IRP, PacifiCorp explains that the previously realized benefits from Bridger 1 and 2 conversions in the 2021 IRP portfolio analysis prompted the Company to explore this option for the other coal plants, and the conversions were endogenously selected within its optimization model. The Company also points out that gas conversions identified in the 2021 and 2023 IRP are a better outcome compared to a new gas plant selected in its 2019 IRP. Further, the Ozone Transport Rule limiting nitrous oxide emissions also favors gas conversions over coal. PacifiCorp also sees benefits in using the converted plants as a backup resource to be used in "limited circumstances" as it integrates clean energy resources into its system. The delay in the Natrium demonstration project has further necessitated the conversion of the Naughton Units 1 and 2.

PacifiCorp did not provide explanations in its Reply Comments to Staff's other requests in which Staff sought to understand if the Company has evaluated the risks of these converted units becoming stranded assets, or what factors could alter the decisions around future coal plant retirement and conversions. Staff had also asked for an analysis with a portfolio variant that does not allow any conversion beyond Jim Bridger 1 and 2, and to test this variant across various gas and CO_2 price options. Staff expected PacifiCorp to either include this portfolio in its CEP alongside other high-performing portfolio variants or introduce constraints related to HB 2021 in its IRP analysis. PacifiCorp indicated that more detailed analysis around coal retirement and conversion options will be provided in its 2023 IRP Update due to be filed in April 2023. Staff looks forward to receiving the updated analysis and expects PacifiCorp to include a detailed analysis of risk of regrets, potential changes in future retirement and conversion plan and the portfolio variant that Staff suggested.

CUB pointed out that coal to gas conversions nullify the agreement reached in the 2020 Multi-State Protocol regarding Oregon's exit from these coal plants, which was key to the determination of the 2020 MSP agreement. CUB had also expressed concerns with the implications of coal to gas conversion for decommissioning and cost allocation to Oregon customers. PAC is inclined to address MSP issues in the MSP process. PacifiCorp indicated that the main component of gas conversion costs is the cost of natural gas pipeline transport and therefore there is no significant impact on depreciation and decommissioning costs.

Energy Advocates commented that coal to gas conversion is not shown to be least cost least risk in the presence of HB 2021. PacifiCorp indicated that they provided economic analysis showing system benefits from conversion of all Bridger units and Naughton units (in both 2021 (JB1 and 2) and 2023 IRPs). Conversion should be consistent with HB 2021, since these plants would have lower emissions compared to before and will be operated with low-capacity factor but meet peak and reliability needs. In response to Energy Advocates' comments on whether the benefits from these conversions and costs will only be limited to Oregon customers, PacifiCorp replied that these plants will retire in 2037, before HB 2021's 2040 timeline, hence Oregon is not the only one sharing costs. Moreover, conversion costs are much lower than cost of new renewables.

Sierra Club had expressed concern around availability of firm gas capacity for the converted units. PacifiCorp did not disclose the pipeline information in its Reply Comments due to confidentiality agreements with third parties.

Staff believes that the Company's decision to continue to operate coal generation units as natural gas plants must be evaluated in the light of HB 2021. Staff understands that inter-state protocol and cost allocation concerns raised by CUB are vital and expects the Company to respond to those in the appropriate docket. Further, Staff understands that the conversions of Jim Bridger 1 and 2 was acknowledged in the 2021 IRP and the conversion plan for Naughton 1 and 2 is also well under way, and therefore these items are not appropriate action items for acknowledgement in this IRP.[14]

Staff Expectations:

- PacifiCorp should provide analysis around risk of regret for coal to gas conversions in its 2023 IRP Update.
- PacifiCorp remove Action Items 1c and 1d from the Action Plan because the Company has already taken these actions.

RFP Suspension

As previously noted in Staff's Round 1 comments, PacifiCorp recently suspended its 2022 All Source Request for Proposals (2022 AS RFP), which sought bids from resources capable of coming online by the end of 2026. The suspension raises concerns around the Company's ability to execute certain Action Plan items in the 2023 IRP and procure sufficient near-term resources to meet Oregon's HB 2021. RNW's Round 1 comment similarly noted the risk from this suspension and encouraged PacifiCorp to resume the RFP as soon as possible or have the Commission to direct the Company to do so.[15]

PacifiCorp's Round 1 Response Comments did not provide much information to assuage 2022 AS RFP suspension concerns. The Company failed to address many of the questions raised by Staff and stakeholders. Despite stating previously in LC 82 that the greatest risk to the IRP was under procurement of resources, the Company now stated that it did not have any revised plan or substantive updates available that reflected the impacts of the RFP suspension.[16] However, the Company did state that it had

[14] PacifiCorp Response to Staff DR Nos. 222 and 223.
[15] LC 82, Renewable Northwest, Round 1 Comments, October 25, 2023, page 7.
[16] LC 82, PacifiCorp Reply Comments, page 96.

engaged in a bilateral effort to procure battery storage technology by June 1, 2026, and that in the IRP Update a new RFP may be put forth.

Given that the Preferred Portfolio included 2,531 MW of wind, 6,383 MW of solar, and 6,411 MW of battery capacity on the system by 2028, the impact of suspending a near-term RFP puts these builds at risk. In response to discovery, PacifiCorp confirmed that it is unable to procure the amount of wind and solar included in the Preferred Portfolio in years leading up to 2028.[17] Table 2 summarizes the difference in installed capacity between the Preferred Portfolio and the additions that may actually occur if PacifiCorp is unable to procure any additional new renewables, other than the bilateral storage mentioned above.

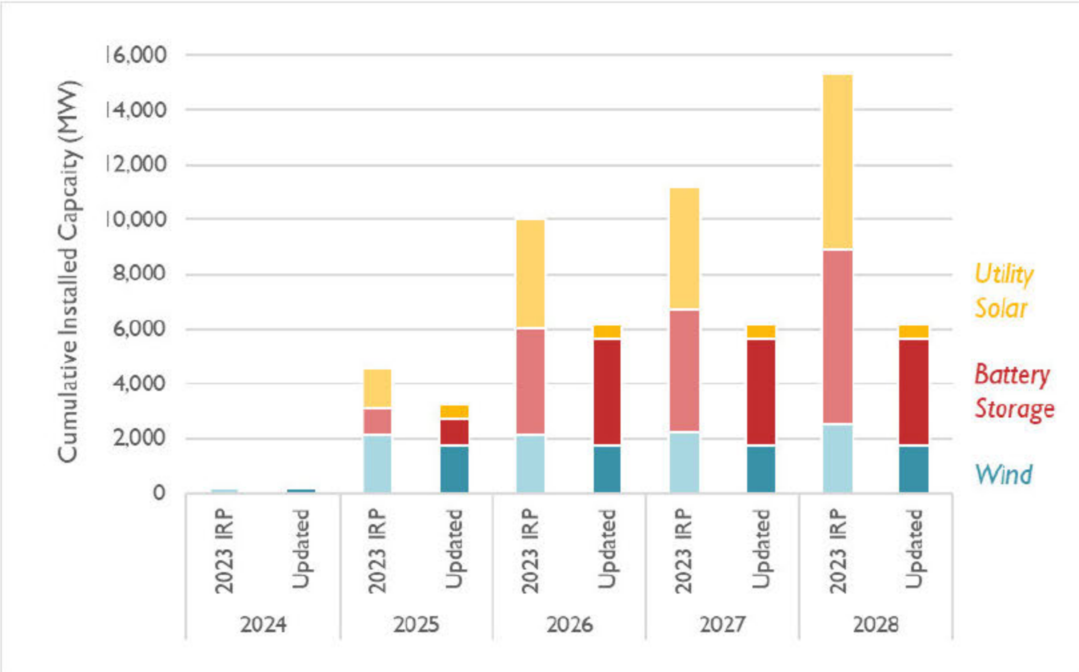
Table 2: Difference in Installed Capacity Between 2023 IRP Preferred Portfolio and Current Reality

Cumulative Installed Capacity Delta (MW)	2024	2025	2026	2027	2028
Renewable- Utility Solar	0	-974	-3,498	-3,981	-5,888
Renewable- Battery	0	0	0	-628	-2,528
Renewable- Wind	0	-339	-339	-439	-739
Total	**0**	**-1,313**	**-3,837**	**-5,048**	**-9,155**

The figure below demonstrates the impact that this delayed procurement could have on renewable resource builds over the next five years. The “2023 IRP” chart series on the left represents the data as presented in the Preferred Portfolio. The “Updated” chart series on the right represents capacity that PacifiCorp has currently indicated it can procure based on the 2020AS RFP and bilateral storage contracts. Solar is the resource that is most at risk due to the 2022AS RFP suspension, as the 2020AS RFP did not result in a large number of solar additions and PacifiCorp has not indicated any alternative procurement processes for solar.

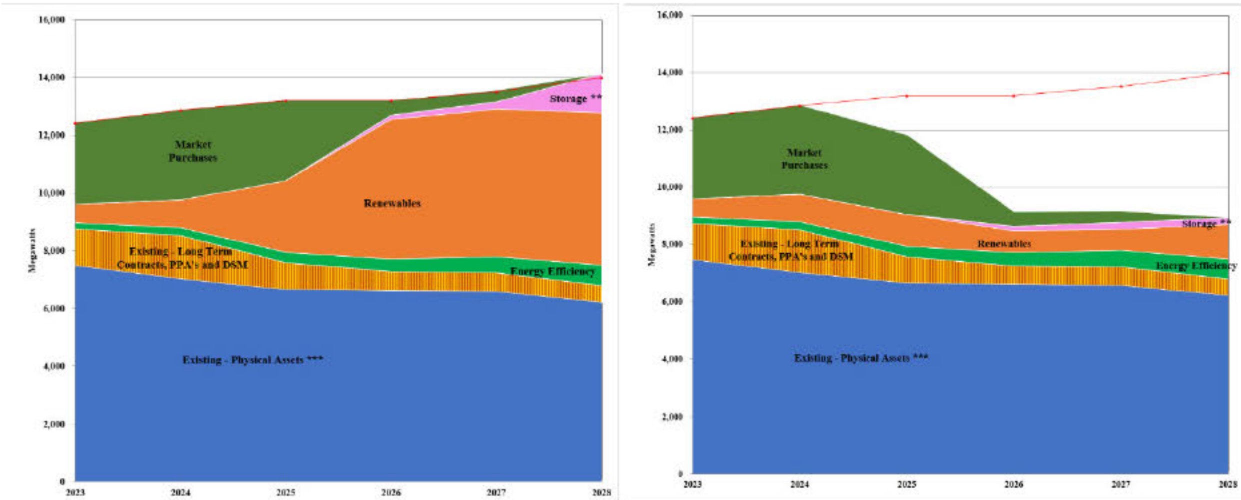
[17] PacifiCorp Response to Staff DR No. 243.

Figure 1. Difference in Installed Cumulative Capacity Between 2023 IRP Preferred Portfolio and Current Reality



This delay will also have a significant impact on the generation mix of the system. Figure 9.60 in the IRP shows the projected generation by resource type for the Preferred Portfolio. Over the next five years, PacifiCorp's Preferred Portfolio relied heavily on market purchases (also referred to as front office transactions or FOTs) and existing resources in the near-term while transitioning to rely more and more on new renewable resources. The left side of the figure below is a reproduction of Figure 9.60 as published in the IRP for years through 2028. The right side of the figure below demonstrates what the generation mix could look like if PacifiCorp does not procure new renewables and instead has a capacity mix that resembles the "Updated" chart series in Figure 9 above.

Figure 2. Reproduction of Figure 9.60 in IRP, with and without 2022AS RFP Suspension Impacts



Without the guarantee of additional solar, storage, and wind resources coming online over the next few years, PacifiCorp may end up relying more heavily on FOTs or delaying thermal resource retirements relative to the Preferred Portfolio. This could lead to decarbonization risks, which the Company has not adequately addressed in the current IRP.

As PacifiCorp will not remove the Action Plan items related to the 2022 and the proposed 2024 AS RFP from the filed IRP, nor update any analysis in this IRP/CEP to reflect the indefinite suspension of these procurements, the filed plans do not appear feasible. Staff finds little value in continuing to review this IRP/CEP. Too much is indeterminate and unknown. Further, as the CEP compliance pathways, and thus any determination of continual progress of emission reductions and compliance with the reduction targets, rests so squarely upon the IRP's Preferred Portfolio, without a revised analysis and procurement plan by PacifiCorp, Staff cannot determine the extent to which the CEP demonstrates compliance with the emissions reduction targets or can be substantiated to meet most if not all of the public interest factors detailed in HB 2021.[18]

Staff Recommendation 1. Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.

Staff Recommendation 2. Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.

Staff Recommendation 3. Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.

Action Plan Changes

PacifiCorp reply comments did not offer alternatives or revisions to the following Action Plan items that were impacted by events external to the IRP/CEP.

[18] See ORS 469A.420(2).

- Action Plan Item 1h: Per the non-confidential response to Sierra Club Information Request (IR) No. 37, the very near-term installation of the proposed selective, non-catalytic reduction (SNCR) installations at several coal plants is being paused and reevaluated due to the Federal Court stay of the Ozone Transport Rule.
- As noted previously all Action Plan Items Under Category 2 involve the acquisition of new resources either through the suspended 2022 AS RFP or through a proposed, new 2024 AS RFP. No alternatives or revisions to these activities were offered by the Company. Instead, PacifiCorp points to the potential for new procurements to be proposed with the April 2024 IRP Update.

Staff Recommendation 4. Do not acknowledge Action Plan items 1h and 2a.

CEP Comments

CEP acknowledgement hinges upon a finding that the CEP is, "in the public interest and consistent with the clean energy targets…" of HB 2021.[19] The recent order in UM 2273 provides an excellent overview of the public interest factors for valuating a CEP.[20] As noted above, given the Company's unwillingness to revise its analysis, Staff recommends not acknowledging the CEP. In the sections below, Staff details its determination that the community-focused elements of the LC 82 CEP appear reasonable with certain recommended changes, while the GHG emission reduction related portion of the CEP is not consistent with the clean energy targets nor does it appear to meet most if not all of the public interest factors detailed in HB 2021. For this reason, Staff does not recommend acknowledgement, but identifies portions of the CEP that may be included and/or improved in the revised and resubmitted CEP.

Community Benefits Indicators (CBI)

In Round 1 Comments Staff expressed concern that the interim CBIs provided no incremental information for evaluating the Company's IRP or CEP portfolios and did not materially affect its plans.[21] Staff requested that for the next IRP, the Company adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.[22]

The Energy Advocates recommend greater granularity for the Company's CBIs.[23] They also encourage the Company to include better measures of distributional justice when creating CBIs.[24] The Energy Advocates then state that the Company's CBIs do not offer any sense of how PacifiCorp brings economic benefits to communities,[25] a sentiment that is echoed by NewSun Energy.[26] The Community Advocates Cohort is discouraged by the lack of details in the Company's proposed CBIs and believes the Company's CO2 emissions CBI is not an indicator of community benefits.[27] Renewable Northwest (RNW) would like more detail about how the Company chose the 17 metrics that were included in the CEP.[28] RNW also recommends that the Company adopt additional environmental CBIs and believes that the language the Company uses when describing its resiliency CBIs expresses a hope instead of indicating that it is strongly committed to improvements or has any planned actions.[29] CRITFC supports past recommendations by the Energy Advocates to improve CBIs and wants better accounting for tribal needs in the Company's CEP.[30] In particular, CRITFC wants the CBI to incorporate tribal energy metrics and create metrics that target reducing peak loads, maximizing energy efficiency, strategically siting renewable resources, reducing reliance on Federal hydro resources, and minimizing the transmission and distribution system.[31]

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[19] ORS 469A.420(2).
[20] UM 2273, Investigation into HB 2021 Implementation Issues, Order No. 24-002, Jan. 5, 2024, starting on page 17.
[21] Staff's Round 1 Comments, page 19.
[22] Staff's Round 1 Comments, page 21.
[23] Energy Advocates' Round 1 Comments, page 7-8.
[24] Energy Advocates' Round 1 Comments, page 11.
[25] Energy Advocates' Round 1 Comments, page 12.
[26] NewSun Energy's Round 1 Comments, page 6.
[27] Community Advocates Cohort's Round 1 Comments.
[28] RNW's Round 1 Comments, page 65.
[29] RNW's Round 1 Comments, page 65.
[30] CRITFC's Round 1 Comments, page 4.
[31] CRITFC's Round 1 Comments, page 7.

PacifiCorp stated in Round 1 Response Comments that it intends its CBIs to be a holistic representation of all the Company's activities to increase community benefits and highlights that it has added two new draft CBIs through its stakeholder process.[32] The Company states that it intends to refine its approach to resiliency and that there is additional work necessary to develop its CBIs.[33] In response to Staff's suggestion to frame CBIs as a metric rather than a goal, the Company states that it would consider it, but anticipates that it may cause confusion.[34] The Company did not appear to directly respond to any other concerns raised by Staff or stakeholders regarding CBIs.

Staff finds that the Company failed to fully respond to Round 1 comments by both Staff and stakeholders. In particular, the Company failed to:

- Provide any timeline to refine CBIs or provide any detail about how they could be refined.
- Discuss how it is attempting to implement tribal concerns brought up by CRITFC or greater CBI granularity brought up by Energy Advocates and Staff into CBIs.
- Discuss whether or how it would incorporate additional environmental CBIs into its next CEP.
- Provide any explanation about how the 17 metrics were chosen, as requested by RNW.

Staff agrees with the Company that developing CBIs is an iterative process that should be done in consultation with local communities and tribal governments. Staff is worried by the Company's apparent lack of response to published concerns by stakeholders, lack of record keeping, and lack of target timeline to improve CBIs. Staff would note the importance of maximizing to the extent possible Oregon community benefits across such planning activities such as portfolio development[35] and resource selection.[36] As such, relying solely on measures of systemwide impacts provides very little value when evaluating whether the Company's IRP and CEP provide tangible benefits to Oregon communities. Staff's Round 1 comments to recommended that CBIs better addressing energy efficiency, local emissions, and CBRE impacts were meant to bridge this gap.

With the following draft recommendations and expectations, Staff recognizes that the CBIs in this CEP are interim, but also seeks to stress the importance of using CBIs to meaningfully inform utility decisions and to track progress over time. Staff expects that the further development of CBIs be done in coordination with local communities and tribal governments and describes additional recommendations and expectations regarding this coordination in the Community Engagement section.[37]

Staff believes that in order to have an effective set of CBIs, it is critical to provide baseline measures of community impact prior to the next IRP/CEP update, and to develop more CBIs that address local non-GHG emissions, energy efficiency, and CBRE actions.

Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

[32] LC 82, PacifiCorp Reply Comments, page 13.
[33] LC 82, PacifiCorp Reply Comments, page 16-17.
[34] LC 82, PacifiCorp Reply Comments, page 18.
[35] UM 2225, Order No. 23-060, February 23, 2023, Appendix A, page 5.
[36] UM 2273, Order No. 24-002, January 3, 2024, page 23.
[37] UM LC 80, Staff's Round 2 Comments, page 31.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

Staff Expectations:
In the next IRP/CEP, Staff expects PacifiCorp to:

- Adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.
- Better inform CBIs and methods with input from stakeholders and community.
- Enhance tribal-focused CBIs.
- Use CBIs to better reflect the health impacts of EE.
- Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios.
- Enhance the ability of CBIs to better reflect the resiliency benefits of actions.
- Incorporate CBIs reflecting community-level impacts of non-GHG emissions, energy efficiency, and the Company's CBRE actions.

Community Based Renewable Energy (CBRE)

Staff found PacifiCorp's identified CBRE resources a reasonable starting point, but questioned whether more should be available based on a forecast of market activities not just existing programs. Staff also questioned whether net benefits were appropriately considered. Staff encouraged PacifiCorp to not limit CBRE potential to the activities and resources identified in the CEP and consider energy efficiency and flexible loads as potential valuable contributors. Lastly, Staff drew the connection between CBRE and SSR, and encouraged PacifiCorp to more aggressively pursue CBREs. Further, Staff encouraged PacifiCorp to pursue a CBRE strategy targeted at Oregon load pockets to avoid significant local transmission and distributions system upgrades.

RNW encouraged PacifiCorp to better quantify the benefits of CBRE and identify above market costs. Energy Advocates similarly encouraged PacifiCorp to consider broad benefits of CBRE, beyond a levelized cost of electricity analysis. RNW and Energy Advocates highlighted that PacifiCorp's CBRE potential relied on tallying existing programs which could be counted as CBRE. Both entities encouraged PacifiCorp to take initiative to identify additional CBRE resources. Energy Advocates highlighted that costs are likely inflated due to modeling not considering the IIJA and IRA. CUB raised government funding and questioned how funds may support CBRE development.

In response to Round 1 comments, PacifiCorp emphasized the Company's commitment to launching the CBRE Pilot proposal to external parties in the first quarter of 2024. The Company highlighted some of the ways in which the landscape of CBRE is quickly developing since the initial CEP filing. Of note, PacifiCorp anticipates a larger CBRE potential in Group B, siting 20 new projects in the pipeline. Initially, Group B included 3.5 MW of small-scale and community-focused renewable projects, primarily solar plus storage.

PacifiCorp commented on features of the Company's modeling that were raised by Staff and stakeholders. PacifiCorp clarified that the 10 percent adder was used to treat CBRE resources commensurately with energy efficiency. For the CBRE scenario, PacifiCorp clarified that the Company had to force the model to acquire CBRE resources as the model would not have otherwise done so for cost reasons. Finally, PacifiCorp emphasized the dynamic nature of the planning environment for CBRE and committed to ongoing refinement of CBRE Pilot Approach. In particular, the Company resolved to support projects that are "in-flight" via other co-funding mechanisms and programs. PacifiCorp contends that despite commitment to ongoing improvement, costs were not inflated in this first round of analysis even though large federal legislation, namely the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA), were not included in initial analysis.

CBRE Resource Potential
Staff recommends that PacifiCorp consider more ambitious CBRE potential than the 95 MW identified, including 92 MW of which are in existing programs. The initial potential study tallied pending projects, and did not rely on forecasting sophistication of consumer adoption curves, historical cost declines, or enabling funding and programs. Staff appreciates PacifiCorp's acknowledgement that the 3.5 MW, Group B, potential is likely much greater due to new funding and programs. Due to rapid increases in renewable energy acquisition, Staff finds that 95 MW could significantly undercount the CBRE potential if effective program designs are deployed that recognize the benefits of CBRE, especially in the preferred portfolio.

Due to the magnitude of the 490 MW SSR requirement and the potential of CBRE resources to grow, Staff would like PacifiCorp to take a more aggressive approach than the "measured and incremental approach to investigating CBREs".[38] Staff encourages a sense of urgency and recommends PacifiCorp immediately publish the CBRE Grant Pilot Proposal to the CBIAG. Feedback should be solicited and processed quickly, such that PacifiCorp files the first round of the CBRE Grant Pilot for Staff approval by the end of Q2 2024. A quick feedback cycle is essential such that PacifiCorp may consider amending its CBRE potential based on feedback and results of an initial CBRE Grant Pilot.

Staff Recommendation 7. Direct PacifiCorp to pursue the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

CBRE Activities
In the upcoming 2024 CEP update, Staff recommends PacifiCorp include an acquisition target of CBRE in its Action Plan. PacifiCorp's Round 1 comments identified a growing pool of known CBRE resources suggesting that 95 MW is likely a floor for a 2030 acquisition goal.[39] Many of PacifiCorp's CBRE actions are positive steps, but the current Action Plan, with no firm acquisition target, falls short of Staff's expectations. Staff appreciates that PacifiCorp continues to develop the CBRE Grant Pilot with stakeholders and is prioritizing "in-flight projects", such that the Company can accelerate how quickly those come online. Further, Staff expects PacifiCorp to be proactive beyond publishing a CBRE Grant Pilot. PacifiCorp should report regularly to the CBIAG on development activities, including on concrete actions PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

Staff Expectation:
- Report regularly to the CBIAG on development including concrete and proactive activities PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

[38] LC 82, PacifiCorp Reply Comments, page 4.
[39] LC 82, PacifiCorp Reply Comments, page 92.

CBRE Inclusion in Preferred Portfolio

In Portland General Electric's (PGE) 2023 IRP/CEP, PGE clearly communicated the fixed cost minus the benefit streams of CBRE resources. PGE's modeling selected the entire 155 MW of CBRE potential for the resource's value within the balancing authority.[40] Acknowledging that PGE and PacifiCorp have different geographic and resource characteristics, PacifiCorp's load pockets are an example where prioritization for CBRE resources would maximize benefits to both individual communities and to all ratepayers.

Staff disagrees with PacifiCorp's blanket characterization that a commitment to pursuing CBRE resources would break from historical least-cost, least-risk paradigm. Much of the CBRE resources identified have complementary, non-ratepayer sources of funding to reduce costs and avoid separate SSR procurement. As PacifiCorp acknowledged, the IRA and IIJA incentives were not accounted for in CBRE analysis which both reduces the potential and inflates the cost. Further, as was raised by Energy Advocates and RNW, PacifiCorp did not provide a transparent accounting of the benefits of CBRE resources to the system, particularly with respect to investments that can be avoided as a result. Without this clear articulation of value and despite PacifiCorp's claims of "considerable favor to SSRs" in PLEXOS modeling, Staff is not persuaded that all CBRE resources are as uneconomic as the Company portrays.[41]

Also undermining PacifiCorp's argument that pursuing CBRE breaks from the least-cost, least-risk paradigm is the fact that the Company's potential study found 92 MW of CBRE in existing programs. Proper cost consideration should have included these resources in the IRP preferred portfolio. Staff expects PacifiCorp to include these CBRE resources in the 2024 IRP update preferred portfolio and to update the CBRE potential in the 2024 CEP update.

Staff requested PacifiCorp address CBRE's role in minimizing costs in Oregon's load pockets.[42] PacifiCorp acknowledged the request but failed to respond in a quantitative manner. Staff highlights that PacifiCorp is versed in the dynamics of storage as a tool to manage transmission constraints, as section 6 in Round 1 comments includes robust discussion of specific examples (storage in lieu of B2H) and general agreement that less transmission expense is a "chief advantage of SSR".[43] However, it is unclear whether the Company applied a commensurate benefit to small scale and customer sited renewables and storage.

Staff Expectations:

In the IRP/CEP update:

- Include at least 92 MW of CBRE in the preferred portfolio, depending on the current pipeline of existing programs.

By the next IRP/CEP:

- Highlight and communicate the relative benefits of CBRE in load pockets.

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[40] See Docket No. LC 80, *Portland General Electric 2023 Integrated Resource Plan and Clean Energy Plan,* Figure 77. Net cost of a microgrid CBRE, page 251, https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf.

[41] Id., page 84.

[42] Staff Round 1 Comments, DR No. 16, page 25, https://edocs.puc.state.or.us/efdocs/HAC/lc82hac144131.pdf.

[43] LC 82, PacifiCorp Reply Comments, page 53, https://edocs.puc.state.or.us/efdocs/HAC/lc82hac1546.pdf.

- Quantify the costs and benefits of CBRE for meeting HB 2021 guidance to "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy."[44]
- Identify one or more new, specific CBRE resource opportunities in Oregon and report on findings regarding specific costs and benefits.

CBRE Program Design

Staff encourages PacifiCorp to consider CBRE program designs that scale quickly and provide meaningful capacity distributed across the geographically diverse territory and specifically to load pockets. Staff highlights Green Mountain Power's (GMP) residential storage programs that have 1.1 percent of customers enrolled today and are poised to double annual customer acquisition rates.[45] A similar program growing at the same, per capita rate as GMP's could add 200 MW of distributed storage capacity to PacifiCorp's Oregon territory by 2030.[46] GMP's rate-based cost to operate the programs is reduced by the benefit of a 30 percent federal tax credit, monthly customer participation fees, and GMP's ongoing economic dispatch of the aggregated capacity. Over the system's lifetime, GMP identifies a positive lifetime net-present value of $2,749, despite the upfront, fixed cost of $22,000.[47]

Staff highlights Green Mountain Power as an example of a program design that delivers resilience, helps increase renewables adoptions, and scales quickly. Staff encourages PacifiCorp to be more expansive in its consideration of CBRE resources and consider additional energy efficiency and demand response capacity. For example, many buildings and communities across the state lack basic weatherization and existing programs are not scaled up to meet the need. In one example, the Northwest Energy Efficiency Alliance's 2016-2017 Residential Building Stock Analysis showed that 11 percent of Oregon's single family homes have uninsulated walls.[48] Efficient buildings that can maintain comfort during severe heat and cold events deliver not just energy savings but are better able to participate in demand response programs and deliver capacity savings.

Staff Expectation:

- Engage the CBIAG on potential program designs that can scale quickly to meet community and system needs.

Community Engagement

In Order No. 22-390, the Commission adopted expectations for PacifiCorp and PGE to furnish details on community engagement.[49] PacifiCorp used its existing IRP public input process, DSP efforts, and CETA Washington Equity Advisory Group as the basis of its CEP engagement efforts. The Company's

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[44] ORS 469A.415(4)(d).

[45] Howland, Ethan, *Vermont PUC lifts caps on Green Mountain Power battery storage programs with Tesla, others,* Utility Dive, Aug. 29, 2023, https://www.utilitydive.com/news/vermont-puc-green-mountain-power-gmp-battery-storage-programs-tesla/692052/.

[46] Ibid. GMP anticipates growth of 474 residential battery installs per 100,000 customers. At 10 kW capacity per install, PacifiCorp's 610,000 customers could accumulate 200 MW of capacity by 2030.

[47] Ibid.

[48] *Residential Building Stock Assessment II Single Family Report,* Northwest Energy Efficiency Alliance, April 2019, neea.org/img/uploads/Residential-Building-Stock-Assessment-II-Single-Family-Homes-Report-2016-2017.pdf.

[49] *In the Matter of Near-term Guidance on Roadmap Acknowledgement and Community Lens Analysis the First Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390, Appendix A at page 54 (October 25, 2022) *corrected,* Order No. 22-470 (December 5, 2022).

engagement efforts consist of customer surveys, sharing the Company's planning decisions at public "stakeholder engagement venue" meetings, and a Feedback Tracker to document the Company's response meeting questions and comments. The engagement venues include, among others, a CEP Engagement Series, the Community Benefits and Impacts Advisory Group (CBIAG), and the Oregon Tribal Nations Clean Energy Engagement Series.

Staff Round 1 Comments asserted that PacifiCorp had not successfully articulated the Company's path from engagement and input to planning and action. While the CEP discussed tribal engagement opportunities, Staff found the CEP lacked detail on whether the Company had successfully incorporated Tribal perspectives into the Company's decision making and engagement strategy. Additionally, it was not clear that the Company's plan included the perspectives of environmental justice communities. To this extent, Staff suggested improvements including reevaluating the Feedback Tracker to include a clear description of why feedback was or was not included in IRP/CEP.[50] Going forward, Staff also recommended a dedicated stakeholder and cross-utility community engagement working group similar to that put forward in LC 80.[51]

In Opening Comments, the consensus among CUB, RNW, Energy Advocates, and Community Advocates, was that PacifiCorp had not meaningfully considered input from environmental justice communities. Energy Advocates and Community Advocates further noted that PacifiCorp had not measured the effectiveness of their engagement strategy. CRITFC advanced that there is no indication from the CEP or IRP that PacifiCorp has consulted with affected Tribes prior to making decisions, particularly around hydropower reliance.

In Reply Comments, PacifiCorp did not oppose working with PGE to create a common community engagement strategy group along the lines of Staff's suggestion.[52] PacifiCorp committed to timely updating the Feedback Tracker following public workshops,[53] but did not address Staff's additional suggestions to improve the Feedback Tracker. PacifiCorp stated the Company continues to pursue a dialogue with its sovereign tribal partners across its six-state service area and intends to hire a tribal-affairs representative. The Company further commented that it was developing a Tribal CBI focused on TE. PacifiCorp linked components of its DSP/Clean Energy survey to outreach and accessibility practices. Regarding environmental justice, the Company referenced an educational component at CBIAG meetings.

On December 19, 2023, following Round 1 Reply Comments, PacifiCorp met with Staff informally to explain how the Company had used the community engagement process to develop its Interim CBIs. PacifiCorp explained that, due to time constraints, the Interim CBIs presented in the CEP did not originate with the CBIAG. Instead, PacifiCorp selected CBIs previously developed through Washingtons' Clean Energy Transformation Act (CETA) engagement process. According to PacifiCorp, CBIAG members had approved of the Washington CBIs and also suggested additional CBIs; however, PacifiCorp stated at the meeting with Staff that it could not provide Staff with documentation of this approval or the

[50] *In the Matter of Near-term Guidance on Roadmap Acknowledgement and Community Lens Analysis the First Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390, Appendix A at page 54 (Oct. 25, 2022) *corrected,* Order No. 22-470 (Dec. 5, 2022).

[51] *See In the Matter of Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Round 2 Comments and Recommendations at pages 29-30 (October 24, 2023).

[52] LC 82, PacifiCorp Reply Comments, December 1, 2023, pages 10, 11.

[53] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 11.

proposed CBIs from CBIAG members[54] beyond the map showing the Company had opposed CBIs proposed by Joint Advocates that were not in line with the Washington CBIs.[55] Going forward, Company representatives committed to:

- Working with the CBIAG to evolve CBIs to be Oregon specific and reflective of CBIAG member feedback;
- Leveraging other efforts to inform and bolster CBIs, including through a 2023 survey and by developing channels to streamline community input from adjacent initiatives to CBIAG members; and
- Making changes to how the Company received and documented input to ensure CBIAG member feedback and knowledge was captured and could be referenced at a later date.[56]

After review of Stakeholder and PacifiCorp comments, Staff has identified the following key adjustments to the Company's platforms and methods that can improve community engagement in future CEP/ IRP processes.

Accountability and Transparency

PacifiCorp's CEP includes available venues for public input, yet the Company's community engagement strategy could be improved and ultimately more effective through better documentation of stakeholder input. This CEP did not provide a clear roadmap of how or why PacifiCorp used stakeholder input to inform the Company's IRP and CEP. Going forward, this documentation can help close the gaps between the Company's interpretation of effective engagement and stakeholders' priorities and expectations. Accordingly, Staff reiterates the need for Feedback Tracker improvements and looks forward to working with PacifiCorp and stakeholders to implement these improvements. Staff also recommends the utility conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts. Additionally, Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document how Environmental Justice community priorities are addressed. Finally, as introduced in Round 1 Comments, Staff believes it is a priority to develop clear, actionable expectations for engagement in future IRP/CEP development and review. Consistent with LC 80, Staff recommends the establishment of a working group that can operate in coordination with the broader investigation into the Commission's planning and procurement policies in 2024.

Cross-venue Engagement Planning

Staff recognizes that stakeholder engagement addressing critical issues, such as wildfire risk, transportation electrification (TE), and energy affordability is occurring in separate dockets and venues outside of the CEP process. As discussed at the informal December 19 meeting with PacifiCorp, Staff is encouraged by the Company's work to streamline input channels. In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in these adjacent dockets and venues to inform CBIs, CBREs, and portfolio decisions.

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[54] Staff and PacifiCorp meeting held December 19, 2023.
[55] PacifiCorp response to Staff DR 35 Attachment.
[56] Staff and PacifiCorp meeting held December 19, 2023.

Tribal Engagement

In Opening Comments, Staff recognized that engagement with Tribal Nations requires intentional recognition and a focused approach that the utility and industry as a whole is working to better understand and practice. Staff appreciates PacifiCorp's introduction of a Tribal TE CBI. Going forward, Staff expects the Company to provide updates to the CBIAG and Staff on the Tribal CBI development and strategy to actively increase Tribal Nation priorities in planning conversations and resource decision-making.

Notably, in December 2023, the U.S. Government reached a settlement agreement to support the Columbia Basin Restoration Initiative (CBRI) in partnership with the Six Sovereigns.[57] This comprehensive agreement leveraged the collective knowledge and priorities of Tribal Nations, Oregon and Washington states, federal agencies, and interest groups. The CBRI anticipates changes to the energy system as part of the work to restore fisheries while supporting decarbonization and resilient communities. For these reasons, Staff views the CBRI as an opportunity for PacifiCorp to improve its engagement strategy with Tribal Nations impacted by the construction and operation of the Columbia River Federal dams.

Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Staff Expectations:

- Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document Environmental Justice community priorities.
- In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in related dockets and venues to inform CBIs, CBREs, and portfolio decisions.
- PacifiCorp should include the following additions and enhancements to the Feedback Tracker:
  - Organization/entity attribution or affiliation.
  - Flag for whether and where PacifiCorp incorporated the feedback into specific utility planning, actions, resource selection, and project prioritization.
  - Clear description of why feedback was or was not included.
- Staff encourages PacifiCorp to report on its Tribal engagement strategy by December 31 of each year to the CBIAG. The review should include successes, opportunities for improvement, feedback received, a discussion of Tribal CBIs and CEP/DSP project development, and any work to involve Tribal Nations in planning and resource decision-making.
- PacifiCorp should conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts.

[57] *See* Northwest Power and Conservation Council memorandum, *Report on the US Government Commitments: Power Related Topics*, January 3, 2024, https://www.nwcouncil.org/fs/18579/2024_01_p2.pdf. The Six Sovereigns include the Nez Perce Tribe, Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Confederated Tribes of the Umatilla Indian Reservation, and the States of Oregon and Washington.

Resiliency Analysis Framework

PacifiCorp's CEP outlines the beginnings of the Company's Resiliency Analysis Framework. The Resiliency Analysis Framework combines census tract level community[58] and utility[59] resilience scores into a composite community-resilience score. The Company plans to use the community-resilience score to identify census tracts for additional analysis and project prioritization.[60] After identifying threats, probabilities, and consequences, PacifiCorp plans to use a risk-spend efficiency (RSE) or cost-benefit analysis (CBA) to account for the costs at specific project locations. The Company's goal is to include resilience risk scores in project and program prioritization, including when assessing the IRP, CBRE, and SSR.[61]

In Opening Comments, Staff requested an update on the Resiliency Analysis Framework timeline, which includes PAC's plan to incorporate community-utility resilience scores and risk drivers into CEP program planning by Q1 2024.[62] By extension, Staff asked how the Company planned to use the Resiliency Analysis Framework in the IRP, CEP, and/or DSP. Staff also asked for additional information on the resiliency scoring metrics.

Energy Advocates and CRITFC argued that PacifiCorp should improve community resiliency and consider how SAIDI/SAIFI/CAIDI data can be connected with information about lived experiences and community resources that can be used during an outage. Energy Advocates added that PacifiCorp should clearly define resiliency in the CEP and improve the readability of the CEP to include important definitions for SAIDI, SAIFI, and CAIDI. CRITFC discussed the link between healthy salmon ecosystems, utility resource planning to meet HB 2021 requirements, and tribal community resiliency.

In Round 1 Reply Comments, PacifiCorp did not directly respond to requests for information about resiliency planning and community data points. Instead, PacifiCorp stated that much of Staff and stakeholders' comments, questions, and concerns would be addressed in the next CEP.[63] PacifiCorp's future planning approach will, "evolve as [the Company] gain[s] experience and receive[s]additional stakeholder input."[64] PacifiCorp explains that it is still evaluating how to include additional community input.

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[58] To develop the community resilience score, PacifiCorp assigns social vulnerability and community resilience scores to census tracts using FEMA National Risk Index (NRI) values. PacifiCorp response to Staff DR No. 97.

[59] To develop the utility resilience score, PacifiCorp applies System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) including major events to calculate the annual number of customers and minutes interrupted at each transformer in each census tract. PacifiCorp response to Staff DR No. 97.

[60] For example, PacifiCorp explains that by sorting the largest census tract CAIDI values first, and then sorting by the lower NRI values the Company can identify customers experiencing longer system outages with lower community resilience or higher social vulnerability. PacifiCorp response to Staff DR No. 99.

[61] LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 29.

[62] *See* LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 32; *see also* PacifiCorp response to Staff DR No. 30.

[63] *See* LC 82, PacifiCorp Reply Comments, December 1, 2023, page 48 (In Round 1 comments Staff requested an updated Table 9 timeline. PacifiCorp acknowledged Staff's request in its Round 1 Reply Comments but did not provide an updated Table 9 timeline.); *see also* LC 82, PacifiCorp Round 1 Reply Comments, December 1, 2023, page 49 ("PacifiCorp is also evaluating how to apply its resilience analysis to DSP and CEP programs and will provide additional information in its upcoming CEP consistent with Staff recommendations. … PacifiCorp is currently developing a preliminary resilience cost-benefit analysis and will include this framework in its upcoming CEP.").

[64] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 48.

PacifiCorp did not address Staff's questions on how the Company's wildfire plan was incorporated into the CEP resiliency analysis beyond directing Staff to review the Company's Wildfire Mitigation Plan. PacifiCorp disagreed with Staff's assessment about its use of the terms "resiliency" and "reliability", but states it will be clearer in the next CEP. In response to Stakeholder requests, PacifiCorp has provided definitions of SAIDI, SAIFI, and CAIDI.

Staff also understands that PacifiCorp is currently evaluating the geographic scope of the Resiliency Analysis Framework to develop more granular resilience scores.[65] Of note, PacifiCorp's current methodology to calculate SAIDI/SAIFI/CAIDI scores at the census tract level results in higher values than under the traditional use, which applies these metrics to the state or utility level.[66] As stated in Staff Round 1 Comments, Staff is still interested in understanding how these census-level SAIDI/SAIFI/CAIDI data has been successfully used in the past for resiliency-related planning. Staff expects the Resiliency Analysis Framework to consider direct benefits to Oregon communities. Nevertheless, Staff is concerned that limiting the scope of resilience metrics to transformer outages within Oregon census tracts, as discussed in step two of the Resiliency Analysis Framework, may result in unnecessary grid-hardening at the expense of PacifiCorp's Oregon ratepayers or overlook cross-state resiliency issues such as wildfire, extreme weather, and load pockets.[67] Given the nascent state of the Resiliency Analysis Framework, Staff sees an opportunity to open discussions with the Company and Stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework.

PacifiCorp states it accounts for non-energy related resilience assets and services in the NRI values.[68] As noted in Round 1 comments, the NRI values use well known indices and Staff continues to find them helpful. That said, Staff would like further insight on how the Company plans to consider these assets and services to meet its goal to prioritize enhancing community resilience over acquiring additional capacity[69] and avoid extraneous utility projects and their associated costs. Staff also expects further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.

Staff understands that resiliency analysis is an evolving field and expects that PacifiCorp will significantly improve upon its Resiliency Analysis Framework in the next CEP. In the meantime, Staff recommends that PacifiCorp incorporate resiliency-related factors into the Q1 2024 SSR RFP and the CBRE Grant Pilot so that these efforts can bring tangible community benefits to their system.

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[65] *See e.g.*, PacifiCorp response to Staff DR No. 96.

[66] LC 82, PacifiCorp 2023 CEP, CBI, May 31, 2023, page 20.

[67] *See e.g., In the Matter of Investigation into House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 24-002 at page 25 (January 5, 2024) ("Grid-connected facilities located outside Oregon contribute to reliable service for Oregon electricity customers and to reducing GHG emissions on the grid, and facilities located inside Oregon do not serve Oregon customers exclusively. There may be resiliency benefits to in-state resources and resource strategies that are worthwhile to consider, but those must be based on reliability and resiliency analysis or related valuation methodologies, not assumed based solely on geographic location or the presence of specific electricity market transaction receipts.").

[68] LC 82, PacifiCorp response to Staff DR Nos. 102, 104.

[69] LC 82 PacifiCorp 2023 CEP, CBRE, May 31, 2023, page 45; *see also* PacifiCorp response to Staff DR 109.

Figure 3: SSR RFP Procurement Timeline[70]

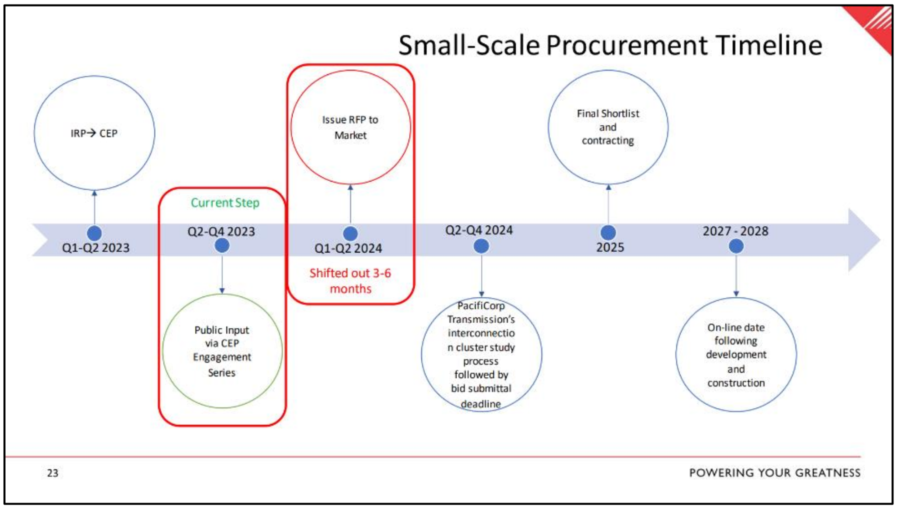
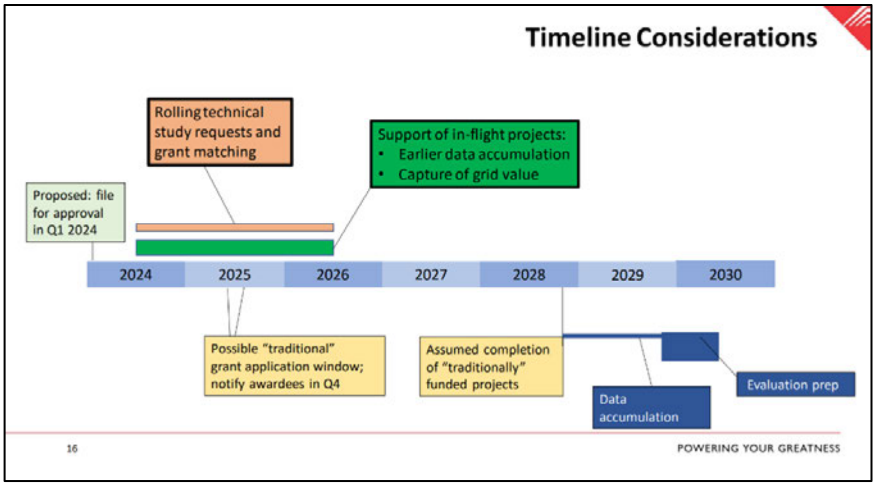


Figure 4: Timeline Considerations for the CBRE Pilot[71]



PacifiCorp's community-utility resilience score accounts for time and duration of outages through SAIDI/SAIFI/CAIDI metrics. It is not clear to Staff what additional information Stakeholders need regarding SAIDI/SAIFI/CAIDI methodologies and definitions. Prior to the next CEP filing, Staff expects PacifiCorp work with Stakeholders to identify gaps in Resiliency Analysis Framework comprehension and the vulnerabilities and complexities of these data sets as a measure of community level impacts.

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[70] PacifiCorp CEP Engagement Series, 4th meeting, slide 23 (August 25, 2023) available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/cep/CEP_Engagement_Series_August_Meeting.pdf.

[71] PacifiCorp CEP Engagement Series, 4th meeting, slide 16 (August 25, 2023) available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/cep/CEP_Engagement_Series_August_Meeting.pdf.

Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

Staff Expectations:

- PacifiCorp should specify how it intends to incorporate CBIAG feedback and other community input into the community-utility resilience scores and risk drivers by March 1, 2024.
- By the next IRP, PacifiCorp should explain how it will use the Resiliency Analysis Framework in IRP and CEP resource planning, project prioritization, and portfolio selection considering HB 2021's requirement that resiliency planning consider costs, consequences, outcomes and benefits.
- Prior to the next CEP, Staff expects the Company to open discussions with stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework; work with Stakeholders to identify gaps in comprehension of the Resiliency Analysis Framework; and identify the vulnerabilities and complexities of SAIDI/SAIFI/CAIDI data sets and NRI values as a measure of community level impacts. The Company is encouraged to discuss how it can incorporate the lived experiences of communities into the community-resiliency score. The results of these discussions should be included in the next CEP.
- By the next CEP, PacifiCorp should be able to articulate further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.
- At a CBIAG meeting before the next CEP and prior to any CBRE Grant Pilot project selection, provide details for how a completed Resiliency Analysis Framework will be used to impact project selection. Staff expects to work with PacifiCorp in helping to craft this presentation and what will be covered.

Acquisition of Federal Incentives

One of the specifically enumerated, HB 2021 public interest factors for weighing CEP acknowledgement is the extent to which the availability of federal incentives were considered.[72] In Round 1 comments Staff joined Sierra Club and CUB in calling for PacifiCorp to fully incorporate the financing opportunities and tax credits made available through the Interest Reduction Act (IRA) more fully into its IRP/CEP analysis. This included rerunning variant portfolios. Specifically: apply a 30 percent reduction to transmission network upgrade costs for low cost, renewable projects in select cluster study areas; and, assuming low cost federal financing and loan guarantees be used for targeted early plant retirements. Suggestions also included regular reporting to the Commission on progress pursuing federal incentives, exploring how Justice 40 incentives could be used for CBREs, and applying tax bonus credits to eligible "energy communities" in Oregon.

PacifiCorp responded that it used the available IRA information at the time of filing and continues to examine evolving legislation for use in future analysis where appropriate. Further, the Company stated that the PLEXOS model did account for federal incentives, as appropriate. The Company also shared that it was actively pursuing EIR programs, financing it can qualify for, and applying for grants and that it will communicate the details of IRA financing and other incentives as they become known. Finally, the Company stated that a variant study can be reported once the IRA financing details are better known.

[72] ORS 469A.420(2).

Staff appreciates all of the work done by PacifiCorp, stakeholders, and especially Sierra Club, to highlight the enormous cost-saving opportunities available through the federal government's IRA initiatives. However, this funding is limited to $2 Billion, expires in September 2026, and utilizes a first-come, first-served competitive application process. In short, time is of the essence if PacifiCorp wants to secure low-cost financing for planned investments to replace aging infrastructure.

Staff Expectations:

- The IRP Update includes two variant portfolios that directly reflect Sierra Club's suggested analysis around reduced upgrade costs and early retirements using the EIR program.
- PacifiCorp details in the IRP Update the timeline for submitting an EIR application and the scope of the projects it is seeking to be financed through the U.S. Department of Energy Loan Program Office's EIR program.
- PacifiCorp provides a brief update at every IRP public input meeting and every CBIAG meeting leading up to the 2025 IRP that details the Company's activities to apply for federal incentives and detailing any funding secured.

IRP Comments

In this section, Staff will not revisit all topics raised in our Round 1 comments on the IRP aspects of LC 82. Rather we have sought to prioritize those items which have the greatest bearing on acknowledgement/non-acknowledgement or are most critical for improvement in the next IRP/CEP.

Preferred Portfolio Modeling Process

Staff, RNW, and Sierra Club included an extensive number of comments on portfolio modeling for both improved development and selection. Most notable were the comments on the granularity adjustment, reliability adjustment, the inclusion of CEP resource additions (i.e., Oregon SSRs and higher levels of EE in Oregon), and the re-optimization of variant portfolios.

In developing the second round of comments, Staff's team explored the extent to which the processes around the granularity adjustment, the reliability adjustment, and portfolio reoptimization may have led to suboptimal portfolio development and selection.

Granularity Adjustment

In Round 1 comments, Sierra Club raised potential issues with PacifiCorp's application of granularity adjustments in their capacity expansion runs. PacifiCorp did not address Sierra Club's methodological questions about why the granularity adjustments did not seem to make sense and instead stated that there are "no logical alternatives" to the granularity adjustments, because they were "dictated by model math."[73] The Company's responses to earlier discovery from Sierra Club were similarly unclear.[74]

Staff engaged Synapse to further investigate the development and application of granularity adjustments. Synapse examined the workpaper that the Company used to develop the granularity adjustments,[75] and it identifies a potential errors and omissions in the calculations. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]. [BEGIN HIGHLY CONFDENTIAL]** [redacted]

[redacted] **[END HIGHLY CONFDENTIAL]**. Thus the Company may be adding erroneous adjustment factors to its capacity expansion modeling, which should be corrected. While the mistake does not appear to systematically favor **[BEGIN CONFIDENTIAL]** [redacted]

[73] LC 82, PacifiCorp Round 1 Reply Comments, page 39.

[74] Sierra Club Round 1 Comments, page 41.

[75] [redacted]

[redacted] **[END CONFIDENTIAL].**

[BEGIN HIGHLY CONFDENTIAL] [redacted] **[END HIGHLY CONFDENTIAL]. [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[76] The inclusion of this adjustment introduces further subjectivity into the LT modeling and highlights the broader shortcomings of PacifiCorp's modeling approach.

[BEGIN HIGHLY CONFDENTIAL]

[redacted]

[END HIGHLY CONFDENTIAL]

The impact of the granularity adjustments, even with the limit of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, significantly changes the resource fixed prices. Figure 6 shows the capacity-weighted average fixed cost and granularity adjustments for each category of units. The granularity adjustments reduce fixed prices enough that they could have affected capacity expansion decisions in the model.

Ideally, PacifiCorp should improve the temporal granularity of LT modeling in future IRP proceedings so that granularity adjustments are no longer necessary. If this is not possible, the Company should at minimum revisit its methodology and correct its workpapers if necessary. It should also clearly explain

[76] PacifiCorp response to OPUC DR No. 240.

its methodology for this adjustment, including clarifying whether it uses the same set of granularity adjustments in each LT model run or whether it adjusts them iteratively. Importantly, PacifiCorp should be able to justify why its results, both with and without the price cap, are reasonable.

[BEGIN HIGHLY CONFDENTIAL]

[redacted]

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Reliability Adjustment

In Round 1 Comments, Sierra Club also raised concerns with the magnitude and potential subjectivity of the reliability adjustments that PacifiCorp made to optimized portfolios to meet reliability-based constraints. Sierra Club confirmed through discovery that PacifiCorp chooses which reliability adjustments to make based on the duration and timing of the shortage, the maximum size of the shortage in megawatts, and the location of the shortage.[77] However, the details of the Company's process are not transparent, including which resources it considers eligible for reliability adjustments and how it values eligible resources. As with the granularity adjustments, the Company stated in its Reply Comments that the reliability adjustments were "dictated by model math."[78] This explanation is even less satisfactory for the reliability adjustments than the granularity adjustments; while it is true that the model determines which hours have unserved energy, the decision about which manual adjustment to make in order to address this problem is at least partially subjective (as illustrated by the alternative portfolio of adjustments that Sierra Club developed for one of the variants in its Round 1 Comments).

[77] PacifiCorp response to Sierra Club DR No. 27.
[78] LC 82, PacifiCorp Reply Comments, page 39.

Staff engaged Synapse to further investigate the Company's reliability adjustments. Synapse confirmed Sierra Club's findings and similarly expressed concern regarding the magnitude of and lack of transparency in PacifiCorp's reliability adjustments.

Table 3 and Table 4 below quantify the reliability adjustments that PacifiCorp made in its preferred portfolio. The reliability adjustments more than triple the capacity of non-emitting peakers added during the study period, increase the amount of new batteries by 70 percent, and increase the amount of new solar by 26 percent. PacifiCorp shifted wind builds earlier, increasing the amount of new capacity by 129 percent between 2023 and 2030, but slightly decreasing the amount added over the entire study period.

In discovery, PacifiCorp stated that only non-emitting resources are eligible for reliability adjustments.[79] However, this is not quite accurate. The Company also manually adjusted the conversion and retirement dates for a number of its thermal resources. In the preferred portfolio, these adjustments took place in two stages. PacifiCorp started with a "Base" scenario, and then it hard-coded coal retirement dates and re-ran PLEXOS to produce a "Base Limited" scenario,[80] which it identified as the "initial" run used to create the preferred portfolio.[81] It then added further adjustments to produce the "reliable" portfolio. Table 3 cTable1ompares coal retirement and conversion dates across these three model runs. The large number of changes further underscores the extent to which PacifiCorp produced the preferred portfolio through manual adjustments, rather than configuring PLEXOS in a way that would allow it to optimize builds and retirements.

Table 3: Reliability Adjustments in Preferred Portfolio 2023-2030

	Builds in Initial Portfolio (MW)	Builds in Reliable Portfolio (MW)	Difference in Cumulative Builds/Retirements (MW)	Percent difference in Cumulative Builds/Retirements
Coal to Gas	375	1,770	1,394	371%
Coal – SNCR	(1,380)	-	1,380	-100%
Gas – EOL	247	247	-	0%
Nuclear	500	500	-	0%
Non-emitting peaker	-	606	606	Inf.
Battery	4,359	7,560	3,201	73%
Battery – LDES	482	-	(482)	-100%
Wind	1,934	4,431	2,497	129%
Solar	6,063	6,583	520	9%

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx" and "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xlsx"

[79] PacifiCorp response to OPUC DR No. 233.
[80] PacifiCorp response to Sierra Club DR No. 40.
[81] PacifiCorp response to Sierra Club DR No. 25.

Table 4: Reliability Adjustments in Preferred Portfolio 2023-2042

	Builds in Initial Portfolio (MW)	Builds in Reliable Portfolio (MW)	Difference in Cumulative Builds/Retirements (MW)	Percent difference in Cumulative Builds/Retirements
Coal to Gas	(349)	0	349	-100%
Coal – SNCR	(2,335)	(2,335)	(0)	0%
Gas – EOL	(652)	(595)	57	-9%
Nuclear	1,500	1,500	-	0%
Non-emitting peaker	289	1,240	951	329%
Battery	4,643	7,910	3,267	70%
Battery – LDES	-	350	350	Inf.
Wind	9,251	9,113	(138)	-1%
Solar	6,246	7,855	1,609	26%

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx" and "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xlsx"

Table1 5: Manual Changes to Coal Retirement and Conversion Dates in the IRP Preferred Portfolio

<table>
<tr><th></th><th>Base</th><th>Base Limited</th><th>Reliable</th></tr>
<tr><td>Craig 1</td><td colspan="3">Retires 2026</td></tr>
<tr><td>Craig 2</td><td colspan="3">Retires 2029</td></tr>
<tr><td>Dave Johnston 1 and 2</td><td colspan="3">Retires 2029</td></tr>
<tr><td>Dave Johnston 3</td><td colspan="3">Retires 2028</td></tr>
<tr><td>Dave Johston 4</td><td>Gas conversion, retires 2040</td><td colspan="2">Retires 2040</td></tr>
<tr><td>Hayden 1</td><td colspan="3">Retires 2029</td></tr>
<tr><td>Hayden 2</td><td colspan="3">Retires 2028</td></tr>
<tr><td>Jim Bridger 1</td><td>Converts 2024, retires 2031</td><td>Converts 2024, retires 2031</td><td>Converts 2024, retires 2038</td></tr>
<tr><td>Jim Bridger 2</td><td>Converts 2024, retires 2030</td><td>Converts 2024, retires 2030</td><td>Converts 2024, retires 2038</td></tr>
<tr><td>Jim Bridger 3</td><td>Retires 2026</td><td>Unclear from workpaper</td><td>Converts 2030, retires 2038</td></tr>
<tr><td>Jim Bridger 4</td><td>Retires 2032</td><td>Unclear from workpaper</td><td>Converts 2030, retires 2038</td></tr>
<tr><td>Hunter 1</td><td>Retires 2031</td><td>SNCR, retires 2031</td><td>SNCR, retires 2032</td></tr>
<tr><td>Hunter 2</td><td>Retires 2031</td><td>SNCR, retires 2032</td><td>SNCR, retires 2033</td></tr>
<tr><td>Hunter 3</td><td>Retires 2030</td><td>SNCR, retires 2030</td><td>SNCR, retires 2033</td></tr>
<tr><td>Huntington 1</td><td>Retires 2030</td><td>SNCR, retires 2030</td><td>SNCR, retires 2033</td></tr>
<tr><td>Huntington 2</td><td>Retires 2026</td><td>SNCR, retires 2028</td><td>SNCR, retires 2033</td></tr>
<tr><td>Naughton 1</td><td>Converts 2026, retires 2032-2033</td><td>Converts 2026, retires 2032</td><td>Converts 2026, retires 2037</td></tr>
<tr><td>Naughton 2</td><td colspan="3">Converts 2026, retires 2037</td></tr>
<tr><td>Wyodak</td><td>Converts 2027, retires 2040</td><td colspan="2">SNCR, retires 2040</td></tr>
</table>

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx," "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xls," "(P)-LT-6530-23I.LT.Initial Run.20.PA0-.EP.MM.Base.xlsx," and Sierra Club Round 1 Comments at page 19.

Staff shares Sierra Club's concerns about both transparency surrounding PacifiCorp's process for making reliability adjustments and the magnitude of the adjustments. The reliability adjustments substantially change the resources in the preferred portfolio, calling into doubt the extent to which PacifiCorp's capacity expansion is economically optimized.

Portfolio Reoptimization

Sierra Club's Round 1 comments also raised concerns regarding the inconsistency of PacifiCorp's practice of re-optimizing portfolio variants. Because re-optimization generally finds the lowest cost way to meet a portfolio's constraints, failure to re-optimize a portfolio could lead to an over-estimation of the costs associated with the specific resource variation being examined by that portfolio. This may lead some portfolio variants to appear artificially more expensive than others. In response to this concern, PacifiCorp noted that they have limited time to conduct re-optimization and must prioritize. Additionally, the variant portfolios identified by Sierra Club for re-optimization were generally meant to test through a counterfactual portfolio, a choice within or not included in the Preferred Portfolio (i.e., P-17's exploration of Colstrip's early retirement).

PacifiCorp's decision to not-reoptimize the PLEXOS LT model for variants P13, P18, and P19 causes the resulting portfolios to retain excess capacity that ratepayers do not necessarily need for a reliable system. For example, the resource builds, conversions, and retirements are identical between the Preferred Portfolio and P13– Max DSM, despite this variant installing an additional ~4,000 MW of DSM capacity over the time frame.

Regardless of the ostensible "purpose" of a variant portfolio, this approach fails to allow Staff and stakeholders to properly compare the preferred portfolio to other variants due to the overbuilt nature of the selected variants. As stated above, P18 results in PacifiCorp having an additional 2,000 MW of capacity starting in 2029, and P19 results in additional 500 MW of capacity starting in 2028. Even though PLEXOS ST captures any cost savings associated with dispatch, it is important for PLEXOS LT to be re-optimized as well to give the opportunity for additional cluster resource and DSM capacity to displace other new resource builds and/or identify earlier retirement dates for existing plants. Without re-optimizing PLEXOS LT, stakeholders are unable to easily tease out which resources would be displaced and how that would impact GHG and PVRR outcomes.

In discovery, PacifiCorp stated that three of the variant studies (P13, P18, and P19) were conducted with the understanding that additional resources would likely result in higher cost PVRR outcomes, and that the purpose of these variants is to assess the magnitude of the impact for determining possible least-regret paths to consider for the preferred portfolio.[82] While the results as presented in this IRP may still be of interest to the Company, PacifiCorp should not be doing this in lieu of re-optimization.

For example, the Max DSM variant as modeled is not currently providing much value for comparison to the preferred portfolio due to the magnitude of the incremental installed capacity that has been required (~4,000 MW) and the magnitude of the PVRR delta ($3 billion). The benefits of pursuing

[82] PacifiCorp response to Sierra Club DR No. 43.

ambitious energy efficiency and demand response are to reduce system load, peak demand, and firm capacity reserve requirement, thus avoiding investments in generation and capacity resources and transmission and distribution infrastructure. By not allowing re-optimization of this portfolio, PacifiCorp fails to allow for a significant portion of DSM benefits to be realized in the PVRR result. This variant design also fails to account for the potential of DSM to reduce the SSR and CBRE requirements, further reducing portfolio costs.

In future studies, PacifiCorp should re-optimize all future variant portfolios that add incremental capacity to the preferred portfolio. This will allow the Commission and stakeholders to assess all variant portfolios on an equal playing field. If a variant does not result in the addition or subtraction capacity from the portfolio and can be fully evaluated using PLEXOS ST only, re-optimization may not be necessary. If there is a scenario where PacifiCorp would legitimately be expected to maintain a system with more resources than needed to cost-effectively meet customer needs (e.g. P21), or if there is a legitimate reason the Company could not change its resource plans in time (e.g. P17), then studies without re-optimization could be used. If the Company is still interested in assessing the magnitude of incremental costs from hard-coded resources without re-optimization, this should be done outside of the variant case analysis.

Table 6 below summarizes PacifiCorp's variant portfolios and how they were modeled.

Table 6: Variant Portfolios

Scenario Name	Re-optimized builds?	If no, why not?	Future Recommendation
P01-JB3-4 GC	Yes		
P02-JB3-4 EOL	Yes		
P03-Hunter3-SCR	Yes		
P04-Huntington RET28	Yes		
P05-No NUC	Yes		
P06-No Forward Tech	Used P05		
P07-D3-D2 32	Yes		
P08-No D3-D2	Yes		
P09-No WY OTR	No	Used to evaluate the impact on P-MM if Wyoming's OTR was not enforced.	
P10-Offshore Wind	Yes		
P11-Max NG	Yes		
P12-RET Coal 30/33 NG 40	Yes		
P13-Max DSM	No	Used to evaluate the impact on P-MM if all DSM was selected.	Re-optimize capacity mix.
P14-All GW	Yes		
P15-No GWS	Yes		

Scenario Name	Re-optimized builds?	If no, why not?	Future Recommendation
P16-No B2H	Yes		
P17-Col3-4 RET25	**No**	Used to evaluate if earlier retirement of Colstrip 4 would result in energy or capacity shortfalls.	
P18-Cluster East	**No**	Used to evaluate the economic impact of adding the next best cluster resource to P-MM.	Re-optimize capacity mix.
P19-Cluster West	**No**	Used to evaluate the economic impact of adding the next best cluster resource to P-MM.	Re-optimize capacity mix.
P20-JB3-4 CCUS	Used P02		
P21-DJ2 CCUS	**No**	Used to evaluate the impact of installing CCUS at DJ2.	
P22-DJ4 CCUS	**No**	Used to evaluate the impact of installing CCUS at DJ2.	
P23-RET Coal 30/33	Used P12		
P24-Gas 40-year Life	**Yes**		

Staff Recommendation 10. Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.

Staff Expectations:
Before the next IRP, PacifiCorp should:

- Work with interested participants from the IRP Public Input process to develop and publicly produce a granularity adjustment methodology.
- Increase transparency around reliability adjustments by stating which resources will be eligible to be included as reliability adjustments in the next IRP and how each one will be valued. Further, it should clarify its modeling approach around how to limit the magnitude of the reliability adjustments that it must make.
- Solicit suggestions through the IRP Public Input process and as part of the Draft IRP of variant portfolios.

As part of the next IRP, PacifiCorp should:

- Adjust its modeling approach to better capture resource adequacy needs and the capacity contributions of resource options to reduce the need for and magnitude of reliability adjustments to portfolios.
- Reoptimize variant portfolios that add resources to the preferred portfolio unless there is a clearly explained reason to study an un-optimized portfolio of resources.

Coal Strategy

In its Round 1 Comments, Sierra Club raised concerns about the coal prices that PacifiCorp used in its modeling, which may have erroneously delayed the economic retirement date for Jim Bridger 3 and 4.[83] These units, which are co-owned by PacifiCorp (67 percent) and Idaho Power Company (33 percent) **[BEGIN HIGHLY** [redacted] **[END HIGHLY CONFIDENTIAL]. [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[86]

Fuel costs influence unit economics, so it is important for PacifiCorp to represent them correctly within PLEXOS so that the model is able to determine economic retirement and/or conversion dates. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]

Sources: [redacted] **[END HIGHLY CONFIDENTIAL].**
[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL].**

PacifiCorp's Round 1 Response Comments suggested that the Company accounted for the full cost of coal in the IRP, but represented some of the costs as fixed, rather than modeling all coal costs as variable.[88] **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL].**

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83 Sierra Club Round 1 Comments, page 44.

84 [redacted]

85 [redacted]

86 [redacted]

87 [redacted]

88 LC 82, PacifiCorp Reply Comments, page 82: "PacifiCorp did incorporate significant fixed costs for coal supply to Jim Bridger units 3 & 4."

However, PacifiCorp added the fixed costs for coal supply at Jim Bridger in post-processing rather than modeling them within PLEXOS.[89] As a result, PLEXOS sees only the variable portion of the coal cost (blue line in [redacted]. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Unrealistic coal prices within PLEXOS may make Jim Bridger 3 and 4 appear more economic than they are in actuality, which could result in PLEXOS selecting a delayed economic retirement date. In the future, PacifiCorp should correct its PLEXOS modeling so that the full cost of coal at Jim Bridger is represented within the model.

[BEGIN HIGHLY CONFIDENTIAL]

[redacted]

[END HIGHLY CONFIDENTIAL]

Sources: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

[BEGIN HIGHLY CONFIDENTIAL] [redacted] **[END HIGHLY CONFIDENTIAL].**

Hunter and Huntington

Two of PacifiCorp's coal plants, Hunter and Huntington, are located in Utah and have experienced the impact of disruptions to the Utah coal market for reasons such as the Lila Canyon mine fire and unfavorable coal mining conditions. While it can be hard to fully predict future disruptions to coal markets and resulting impact on fuel prices, it is important to incorporate as much up-to-date information as possible in order to ensure model results are reasonably similar to reality. Synapse, on behalf of Staff, reviewed federal Department of Energy EIA 923 fuel receipts data for 2023 and determined that PacifiCorp paid between $1.79 and $4.19 per MMBTU for coal at Hunter. At Huntington, Synapse determined that PacifiCorp paid between $2.18 and $2.54/MMBTU.

[89] PacifiCorp response to Staff DR No. 228.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL].

On April 3, 2023, PacifiCorp filed its Transition Adjustment Mechanism in Docket No. UE 420 to update its net power costs for 2024. In Witness Owen's testimony, he states that "the significant production shortfall due to the Lila Canyon mine fire negatively affected all large coal consumers including PacifiCorp. Unfortunately, this negative impact is expected to continue into the foreseeable future."[92] If this is PacifiCorp's current position, then the 2023 IRP Update should incorporate the lasting impacts of unfavorable market conditions into its coal price forecast for these Utah plants.

[90] Confidential Attachment OPUC 229, "HTR-HTG Coal Update_2022 12 21 CONF".

[91] US Bureau of Land Management. 2022. *The Bureau of Land Management issues decision on Lila Canyon Mine.* Available at: https://www.blm.gov/press-release/bureau-land-management-issues-decision-lila-canyon-mine.

[92] *In the Matter of PacifiCorp's 2024 Transition Adjustment Mechanism*, Docket UE 420, Exhibit PacifiCorp/200, Owen/4.

Staff Expectation:
In the next IRP PacifiCorp should:

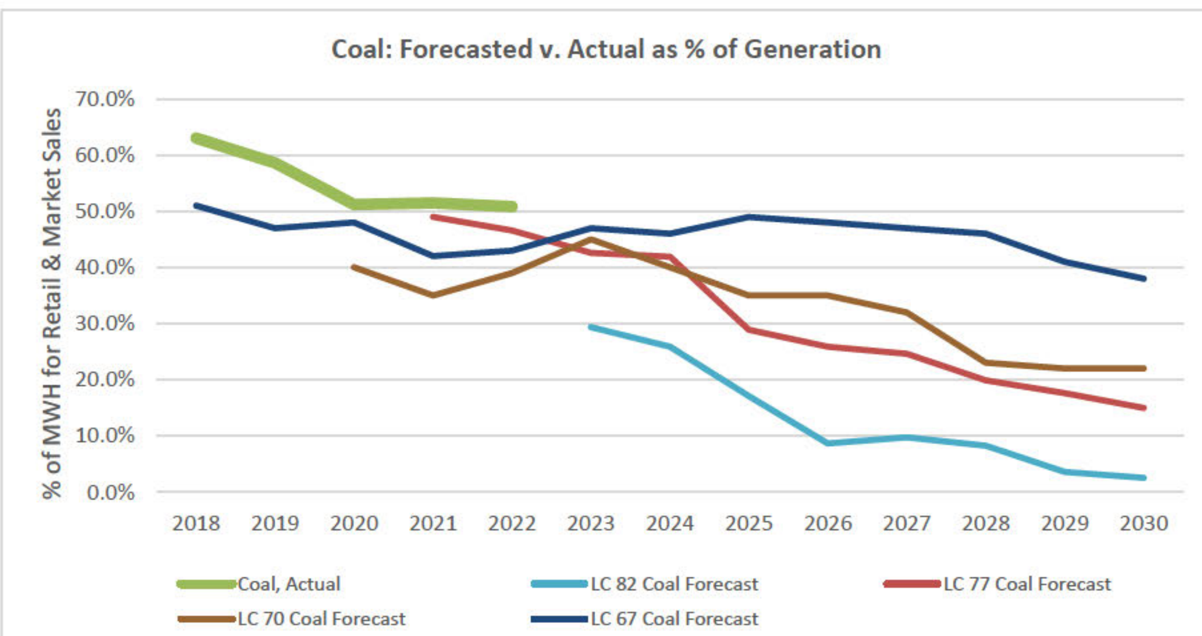
- Utilize coal prices for Jim Bridger that are reflective of actual costs from the Long-Term Fuel supply contract.
- Provide a full update on Utah coal supply issues.

Carbon Price Path

At the LC 82 Special Public Meeting on December 12, 2023, Bob Jenks of CUB raised an interesting point regarding PacifiCorp's use of carbon pricing. He noted that PacifiCorp's IRPs generally begin to apply a price to carbon two years after the IRP. This has the effect of reducing forecasted emissions in the IRP, especially from coal plants, as PacifiCorp's models internalized this carbon price into simulated, future operations. CUB suggested that because a true carbon price has never actually internalized into operations, real-life emissions are systematically higher than IRP modeled GHG emissions. CUB also noted in its Round 1 comments that an effective GHG price could be developed by forecasting, "…the annual cost of carbon from wildfires (prevention and insurance), divide that by its carbon emissions, and allocate the costs of emissions directly to the emissions themselves." [93]

Staff conducted a brief analysis forecasted to actuals in an attempt to substantiate CUB's comments regarding the disconnect between planning that uses a carbon price and actual coal operations.

Figure 8: 3Comparison of Forecasted v. Actual Coal Use as Percent of Generation



Staff's simple analysis would seem to corroborate CUB's concerns regarding the realism of PacifiCorp's modeled coal dispatch in the IRP. Staff raised a similar concern in UM 2225 in discussing the role of

[93] CUB Round 1 Comments, October 25, 2023, page 8.

operational changes in achieving GHG reductions and the Commission adopted the following expectation:

> *For the first CEP and associated IRP, if the Preferred Portfolio relies on operational changes relative to expected economic dispatch to reduce GHG emissions, including, but not limited to, application of operating or emissions constraints, inclusion of a GHG emissions cost in dispatch decisions, or out-of-state sales of fossil fuel generation, the utility should:*
>
> - *Quantify the impacts of those operational changes relative to expected economic dispatch in terms of generation (curtailed, reduced, or sold) and GHG emissions (avoided); and*
> - *Describe how the utility intends to implement those operational changes (e.g. through the development of operating or emissions limits, application of GHG emissions penalties, or execution of contracts with out-of-state entities), to the extent that they impact forecasted GHG emissions in the Action Plan window.* [94]

Accordingly, if the GHG emissions reductions in the CEP depend on the reduction in coal generation that results from applying carbon prices to dispatch, Staff would expect PacifiCorp to quantify those impacts in terms of both generation and GHG emissions, relative to an assumption of economic dispatch without carbon prices.

Importantly, PacifiCorp removes all coal from Oregon rates prior to 2030 per SB 1547 and so Staff expects this issue may only affect the Oregon-allocated GHG emissions in the 2020s. Nevertheless, PacifiCorp's use of GHG prices in modeling operations could be resulting in an unrealistic trajectory of GHG emissions reductions and the lack of an operationalized carbon price could therefore affect PacifiCorp's ability to demonstrate continual progress in the 2020s.

Staff fully supports PacifiCorp's use of GHG prices in portfolio design to capture the risk of future GHG policies. However, Staff is concerned that including GHG prices in the dispatch simulation that informs the Company's Oregon-allocated GHG emissions could be resulting in an unrealistic GHG reduction trajectory.

Staff Expectation:
In the next IRP/CEP PacifiCorp should:

- Recreate the chart above for (a) coal and (b) Oregon allocated GHG emissions comparing past IRP forecasts to actuals.
- Provide a sensitivity that calculates Oregon-allocated GHG emissions under the assumption of no carbon prices operationalized in dispatch. This sensitivity should still be based on the Preferred Portfolio, which considers a carbon price in investment decisions.
- Propose a PacifiCorp specific carbon price that layers atop the medium carbon price the Company's annual cost from wildfires as described by CUB.

[94] Order No. 22-446, Appendix A at page 21.

Candidate Resource Costs

In Round 1 comments, stakeholders raised concerns that PacifiCorp incorporated unreasonable price escalations for renewable resources. RNW's Round 1 Comments raised concerns on the cost assumptions PacifiCorp applied to its clean energy and energy efficient technologies, which include solar, wind (land-based and offshore), and storage resources.[95]

PacifiCorp sourced its cost data from WSP, an engineering and professional services firm, and later made some adjustments to the cost data to align with its view of future renewable resources market conditions.[96] WSP had relied primarily on the 2022 NREL ATB study to formulate renewable cost forecasts. The IRP states that PacifiCorp's cost-escalation curve differs from the NREL ATB forecast to account for observed market conditions, such as supply chain issues and long construction lead times.[97] RNW found that the company's ambiguous modifications to WSP's renewable resource cost estimates results in cost escalations that are 15-50 percent higher through the years 2023-2030.[98] PacifiCorp's sources or methodology behind large price escalations remain unclear. PacifiCorp has not clearly explained its resource cost modifications besides the "recent tighter trade tariff and inflation" observed in 2022.[99]

Staff agrees with RNW that the long duration of these high prices assumptions are concerning and not well proven. Manual adjustment of cost assumptions most likely affects resource selection and the preferred portfolio's economics.[100, 101] Due to the high capital cost forecast for renewable resources in PacifiCorp's IRP, the model selects over a GW of nuclear and non-emitting peaking resources through the years of cost escalations.[102]

While it is reasonable to assume cost escalations due to recent market conditions, PacifiCorp's estimates are far above the consensus. Compared to other studies that have adjusted for the recent market changes in renewable energy, PacifiCorp's adjustments have overstated the effects of inflation. Recently published studies have shown that cost increases may not be as persistent as PacifiCorp assumes. Lazard's most recent Levelized Cost of Energy Analysis from 2023 provides recent capital cost comparisons for renewable energy technologies based on a detailed analysis of observed new renewable builds across best-in-class renewables companies. This source provides a thoroughly vetted set of actual costs from newly installed projects. [103] Lazard's report states that "Even in the face of inflation and supply chain challenges, the LCOE of best-in-class onshore wind and utility-scale solar has declined at the low-end of our cost range, the reasons for which could catalyze ongoing consolidation across the sector—although the average LCOE has increased for the first time in the history of our studies."[104]

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95 Renewable Northwest, Round 1 Comments, page 31.

96 *Ibid.*

97 *Ibid.*

98 Renewable Northwest, Round 1 Comments, page 31.

99 LC 82, PacifiCorp Reply Comments, page 47.

100 Renewable Northwest, Round 1 Comments, page 32.

101 *Id,* page 32.

102 *Id,* page 32.

103 https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

104 Lazard. Levelized Cost of Energy Analysis-version 16.0. April 2023. Available at: https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

Regulators in other states are also assessing the reasonableness of using NREL ATB studies for the purposes of resource planning.[105] One South Carolina study found that relying on NREL ATB was reasonable and anticipates, "…a gradual decline in real-dollar costs due to industry learning curves and economies of scale, especially as renewable adoption accelerates. Therefore, we encourage Santee Cooper to remain open to upward adjustments in future procurement targets to capitalize on these anticipated cost reductions."[106] Staff finds this sentiment to be similarly relevant to PacifiCorp's resource cost methodology and would also encourage the Company to reassess overly conservative costs and monitor the market for anticipated cost reductions.

For example, PacifiCorp estimates a 34 percent increase in the cost for solar starting in 2023 and persisting for five years after, until cost declines in 2029. This results in a projected cost of $1,533/kW for a 200MW PV installation in Utah for 2023 through 2028.[107]

PacifiCorp's capital cost forecast for land-based and offshore wind is also unsupported by the 2023 NREL ATB and Lazard. For 2023 through 2028, PacifiCorp assumes roughly $2,000/kW for land-based wind and $5,900/kW for offshore wind. According to Lazard's 2023 Levelized Cost of Energy Analysis, capital costs for land-based and offshore wind reaches a high of $1,700/kW and $5,000/kW, respectively. [108]

Finally, PacifiCorp's resource storage assumptions are also significantly higher than NREL's projections. PacifiCorp's battery storage capital costs estimates are $454 and $477/kWh in 2022 and 2023 respectively, with no projected cost declines until 2029.[109] NREL 2023 study estimates capital cost of approximately $470/kW but assumes step cost decline afterwards with capital cost reaching a low $320/kW in 2032.

Staff, through its consultant, Synapse, conducted a high-level analysis to estimate the difference in the Preferred Portfolio's build costs if the utility had instead relied on NREL's 2023 ATB. This analysis relies on the current levels of near-term renewable builds presented in the 2023 IRP Preferred Portfolio and does not attempt to re-optimize the renewable builds based on these lower costs. This analysis reflects the situation where PacifiCorp conducts resource planning using elevated prices, and is able to procure renewable resources for lower cost in actuality.

Additionally, we highlight here that if PacifiCorp had incorporated supply-side costs for renewables that were more in line with PGE, CPUC, and NREL ATB, it is likely that PLEXOS LT would select more of these resources ***instead of*** higher-cost alternatives, such as nuclear, non-emitting peakers, and fossil units. It is important to note that the build costs shown in the PLEXOS LT outputs are shown pre-tax credits and without annualization, rate of return, or depreciation. This means that the final impact on the Preferred Portfolio revenue requirement will be different than the total cost delta presented below.

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105 See South Carolina Public Service Commission, Report by PA Consulting *Independent Review of Santee Cooper's 2023 Integrated Resource Plan*. December 2023.
106 *Ibid.*
107 PacifiCorp file "(P)-Figure 7.3-7.5 History of IRP Renewables Cost Curves 2023 0119.xlsx".
108 https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.
109 Renewable Northwest, Round 1 Comments, page 38.

Table 9: Renewable Build Costs Summary Results

Category	Resource Type	NPV (2023-2030) ($M)	2023	2024	2025	2026	2027	2028	2029	2030
Capacity (MW)	Solar	n/a	-	-	1,069	2,524	483	1,907	-	-
2023 IRP Build Costs ($)	Solar	$7,037	-	-	$1,687	$4,020	$790	$2,946	-	-
ATB Build Costs ($M)	Solar	$6,034	-	-	$1,474	$3,440	$650	$2,530	-	-
Delta ($M)	Solar	$1,003	-	-	$213	$580	$140	$416	-	-
Capacity (MW)	Wind	n/a	-	43	296	-	100	300	1,900	-
2023 IRP Build Costs ($M)	Wind	$3,317	-	$85	$644	-	$212	$613	$3,394	-
ATB Build Costs ($M)	Wind	$2,427	-	$59	$405	-	$138	$414	$2,631	-
Delta ($M)	Wind	$890	-	$26	$240	-	$75	$199	$763	-
Capacity (MW)	BESS	n/a	-	-	754	2,929	628	1,900	1,149	-
2023 IRP Build Costs ($M)	BESS	$9,594	-	-	$1,364	$5,300	$1,136	$3,416	$2,009	-
ATB Build Costs ($M)	BESS	$8,590	-	-	$1,240	$4,767	$1,010	$3,018	$1,800	-
Delta ($M)	BESS	$1,004	-	-	$124	$533	$126	$398	$209	-
Total Delta ($M)	All	**$2,897**								

Staff Expectation:

- As part of the IRP update and future IRP processes, PacifiCorp should update its renewable cost assumptions based on more recently available information.

Natrium and Non-Emitting Peaking Resources

In Opening Comments, Staff raised concerns about the permitting timeline and fuel availability of nuclear resources in the Company's preferred portfolio.[110] Staff concerns about reactor fueling risks and permitting were shared in comments from the Sierra Club,[111] NewSun,[112] and Renewable Northwest.[113] As an example RNW documented the lengthy six-year timeline to final approval by the NRC of the only other small modular reactor (SMR) design to date, developed by TerraPower competitor NuScale Power Company.[114] RNW follows this discussion with a request for the Company to identify offramps that would provide adequate lead time for replacement of the Natrium facility with clean energy resources with comparable attributes, a request that Staff finds to be reasonable.

[110] LC 82 – Staff's Round 1 Comments, page 44.
[111] LC 82 – Sierra Club's Round 1 Comments, page 58.
[112] LC 82 – NewSun Energy's Round 1 Comments, page 5.
[113] LC 82 – Renewable Northwest's Round 1 Comments, page 21-22.
[114] Id.

In PacifiCorp's December reply comments, the Company stated that its consideration of nuclear resources in the 2023 IRP are consistent with Oregon IRP Guidelines 1(a), 1(b), and 1(c), and therefore those resources are limited to years outside of the action plan and CEP planning windows and require continued evaluation of their potential.[115] The Company further stated that it "cannot provide meaningful tracking and reporting" on the Natrium facility's NRC Construction Permit Application due to there being no commercial agreement with the facility's developer, TerraPower. The Company did provide that a construction permit (CP) is targeted for submission to the Nuclear Regulatory Commission (NRC) by Q1 2024, stating a generic timeframe for issuance of the CP by the NRC is 36 months.[116] Staff, assuming a similar 36-month timeline for issuance of the separate operating license (OL) for the Natrium facility from the NRC, contemplates substantial risk in selecting this resource in the preferred portfolio for inclusion in the year 2030. Staff finds comments from the Sierra Club, NewSun, and RNW regarding fueling cost and risk, permitting timeline risks, and the lack of adequate alternatives should permitting issues arise, to be compelling.

The Company's timelines for the availability of non-emitting peaking resources and nuclear resources have both been modelled for portfolio consideration in the year 2030 or beyond, intentionally outside of the action plan window and the current CEP compliance window.[117] As the Company states that it anticipates that non-emitting peaking resources will improve in performance and cost-effectiveness, Staff believes that the Company should also prepare for the possibility that both non-emitting peaking resources and nuclear resources may potentially fail to materially improve in those regards before the year 2030.[118]

In short, Staff finds that the overly optimistic timeline for both the Natrium nuclear technology and any potential non-emitting peaking technology - given both what is known and unknown - requires planning more reflective of implementation risks. Staff is not opposed to either technology per se and believes they may both be necessary to achieve HB 2021's 2040 target and for the broader region to decarbonize. However, we agree with RNW's observation that the 2021 IRP selection of Natrium in 2028, which was due in part to overly optimistic assumptions, impacted both the action plan and the scope of the subsequent RFP (UM 2193).[119] Staff finds that PacifiCorp appears to be repeating the same process in LC 82 with these long lead time resources. An additional implication of this approach in LC 82 is that it puts Oregon's decarbonization efforts at risk.

Per a December filing, NRC has scheduled a readiness assessment meeting for the TerraPower permit application on January 10, 2024.[120] The process to conduct the assessment will take four weeks and 45 calendar days, following which NRC staff will issue a public report on their findings. The approximate date for the publication of this report will be approximately around March 20, 2024. At the point of the NRC report's publication, the Company should have a clear understanding if the Natrium project is on track to begin construction under the very tight timelines found in LC 82.

In variant portfolio P06 – No Forward Tech, PacifiCorp explored the risk of neither the nuclear facility ***nor*** the non-emitting peaker being operational by the end of 2030. This portfolio showed no impact to

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[115] LC 82 – PacifiCorp Reply Comments, page 94-95.
[116] PacifiCorp response to Staff DR No. 118.
[117] LC 82 – PacifiCorp Round Reply Comments, page 93-95.
[118] LC 82, PacifiCorp Reply Comments, page 93.
[119] Renewable Northwest, Opening Comments, page 20.
[120] *See Filing in NRC Docket 99902087, "Preapplication Construction Permit Readiness Assessment Plan," December 20, 2023.*

the timing of the planned retirements of approximately 2.5 GW of coal generation capacity between 2028 and 2032. Instead this variant portfolio showed more some additional solar and wind but most notably an additional 1.2 GW of batteries by 2033. This portfolio had some of the highest emissions compared to all other portfolios.[121]

As RNW notes, the Company's plan to replace SMRs should they not be viable is to largely replace them with non-emitting peakers.[122] The Company states that non-emitting peakers' limited presence in the 2023 IRP preferred portfolio supports the Company's position that the risks associated with these resources are reasonable.[123] Given the potential for neither to emerge and both the higher cost and higher emissions associated with this outcome – as evidenced by P-06 – the Preferred Portfolio's reliance on emergent nuclear and non-emitting peaking resources may prove to be an outsized risk.

Staff would note that in LC 80 the procurement of long lead time (LLT) resources posed a similar set of risks and procurement challenges for PGE. Given the uncertainty around timelines for both nuclear and non-emitting peaking resources, Staff believes that the Company should issue a request for information (RFI) for LLT resources. The RFI should be used to inform placement of LLT emergent resources in a preferred portfolio more realistically by accurately comparing them against more traditional, matured, resources. To gain a more accurate view of the entire resource landscape, the Company's RFI could also study advanced geothermal, pumped hydro storage, transmission costs associated with offshore wind, and any other resources identified by the Company or stakeholders. The Company might even coordinate with PGE in developing this RFI for a streamlined approach.

Staff Recommendation 11. Direct PacifiCorp to update Action Plan Item 1g to reflect actual events since the IRP/CEP was filed in May 2023.

Staff Expectations:

- Inform the Commission in the IRP Update whether the TerraPower permit application passed the U.S. NRC's readiness assessment for Natrium's construction permit and the estimated timeline for the project following that decision.
- In the next IRP, utilize a ten-year buffer between the date of the issuance of the Natrium CP and when that resource may appear in the Company's preferred portfolio.
- In the next CEP, more directly address the high-level planning questions from Order No. 22-446 regarding the critical junctures, dependencies, and barriers to nuclear and any non-emitting peaking technology as part of a preferred portfolio.

Small Scale Renewables

In Opening Comments, Staff expressed an interest in exploring options to facilitate the development and acquisition of small scale renewables (SSRs) in a cost-effective manner, highlighting the RPS certification process in particular.[124]

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[121] LC 82, PacifiCorp 2023 IRP, page 268, Table 9.14.
[122] Renewable Northwest, Opening Comments, page 22.
[123] LC 82, PacifiCorp Reply Comments, page 93.
[124] LC 82 – Staff's Opening Comments, page 46.

Staff greatly appreciates the Company's efforts to offer regulatory recommendations toward easing the acquisition of SSRs in its reply comments. Regarding the Company's recommendation that the OPUC amend or waive OAR 860-091-0030(1), Staff finds that this may be an unnecessary solution to a barrier that remains, in Staff's view, to be largely informational. The Company specifically cites an additional ODOE regulation, OAR 330-160-0035(2), that "may require…an explanation of the relationship between the applicant and the WREGIS account holder."[125] Staff does not understand how this requirement, nor RPS certification as a whole, are meaningful barriers to potential SSR project financing.

Staff agrees with the Company's recommendation that incentives might be refined or updated to better reflect system SSR needs through updated PURPA policies in the OPUC's UM 2000 proceeding.[126] Should these policies be updated to better reflect SSR acquisition costs, Staff would urge the Company to utilize PURPA policies to the greatest extent possible to streamline its SSR acquisition process, and additionally facilitate modelling of SSR acquisition in portfolio modelling as the SSR mandate will remain an ongoing compliance obligation. The ability to model SSR acquisition costs reliably and accurately will facilitate the modelling of marginal SSR needs and associated costs when system capacity acquisitions are made.

Resource Adequacy Modeling, Front Office Transactions, and WRAP

In Opening Comments, Staff found that the Company's current resource adequacy and capacity valuation approaches are lacking necessary sophistication and should be updated with both more data and methodologies that better conform to best practices. Staff recommended that the Company incorporate WRAP into its next IRP, update its resource capacity contribution methodology, add more weather data, and perform a Loss of Load Expectation (LOLE) analysis on the preferred portfolio.[2]

RNW has a host of recommendations for the Company to modernize its reliability and resource adequacy modeling that are largely in line with Staff's opening comments. Among them, RNW recommends that the Company move beyond its current capacity factor method to something an Effective Load Carrying Capability (ELCC) method or something similar, such as the "Global Slicing Block" that is available in PLEXOS.[3] RNW also believes that the Company's 13 percent Planning Reserve Margin is unfounded.[4] Of greater concern to them, RNW finds that the Company's deterministic look at Loss-of-load-probability (LOLP) modeling is lacking and recommends that the Company incorporate stochastic parameters for weather risk factors that correlate with supply and demand.[5] Given that the Western Resource Adequacy Program (WRAP) may become binding as early as 2026, RNW also advocates that the integrate WRAP into the IRP process.[6]

The Company responded to comments made by both Staff and RNW in its Round 1 Reply Comments. Staff recommended that the Company update its capacity valuation methodology to incorporate multiple years of weather data, calculate and report the LOLE of the preferred portfolio in each year and explain why the Company chose to plan to its current level of reliability.
PacifiCorp agrees with Staff and RNW that incorporating stochastic conditions is a necessary part of identifying supply and demand risks and notes that neither wind nor solar nor energy efficiency savings were modeled stochastically in the 2023 IRP. The Company also agrees that the value of stochastic analysis is higher when multiple years of data are used but also notes that incorporating this is a significant undertaking. The Company states that it looks forward to further improvements to the LOLP and that it is always open to improvements in its RA modeling.[7] In response to Staff's and RNW's

[125] LC 82 – PacifiCorp Reply Comments, page 85.
[126] Id, page 86.

comments on WRAP, the Company states that it is actively evaluating the WRAP program and considering how to implement it in the IRP as early as 2026.[8] The Company did not appear to directly respond to RNW's recommendation to conduct an ELCC style analysis.

Staff recognizes that updating LOLP, capacity valuation, and RA modeling is a large undertaking that may take many months. While Staff continues to advocate for the use of more years of weather, load and generation data, Staff is supportive of these things being included in the Company's next IRP. Staff also agrees with RNW's comments advocating for stochastic modeling of supply and demand variable in LOLP analysis and recommends that wind and solar resources be modeled stochastically using observed weather and load correlation. Staff also agrees with RNW that switching to an ELCC style analysis of capacity valuation is a necessary modeling improvement that should be integrated into the next IRP. Staff reiterates its past recommendation that the Company model and report the LOLE of the preferred portfolio in a future IRP.

Staff continues to recommend that PacifiCorp consider WRAP participation, including potential future obligations and benefits, in the next IRP. Staff notes that another Oregon-regulated utility, Idaho Power, has chosen to model the benefits of WRAP in its current IRP, LC 84, and assumes that WRAP's operational program would provide some system capacity benefit starting in 2027.[127] While Idaho Power presents this merely as a first attempt at modeling WRAP benefits, Staff feels it necessary to point out that one of the Company's Oregon peer utilities has already begun incorporating WRAP into its IRP.

Front Office Transactions

Staff is concerned by the Company's reliance on FOTs in its IRP.[128] PacifiCorp's IRP allows for a certain amount of market purchases to contribute to system capacity needs. These purchases are referred to as Front Office Transactions (FOTs) and they have limits as shown in Table 5.8 in the IRP and reproduced below as Table 10.

Table 10: Reproduction of Table 5.8 of IRP[129]

Market Hub	Availability Limit (MW)				
	2023 IRP			2021 IRP	
	Short-term (2023-2027)	Long-term (2028-2042) Summer	Long-term (2028-2042) Winter	Summer	Winter
Mid-Columbia (Mid-C)	1979	500	350	500	350
California Oregon Border (COB)	424	0	250	0	250
Nevada Oregon Border (NOB)	200	0	100	0	100
4 Corners (4C)	398	0	0	0	0
Mona	325	0	300	0	300
Total	**3326**	**500**	**1000**	**500**	**1000**

In the IRP, FOTs are modeled as short-term purchases that can be made with little or no notice. However, this may be an oversimplification. Staff also notes that in order to demonstrate compliance with WRAP, an entity has to secure resources and contracts with a lead time of multiple months,

127 LC 84, Idaho Power IRP Initial Filing, page 8.
128 LC 82, PacifiCorp 2023 IRP, page 33, Action item 5a.
129 2023 IRP at 126.

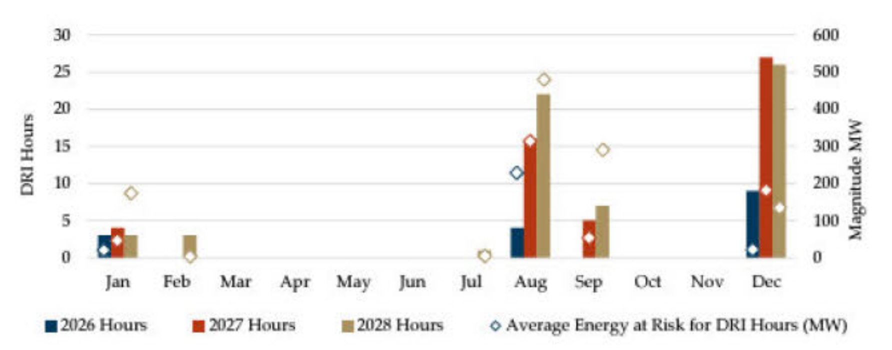
meaning that the Company's choice to rely on short-term purchases may lead to the Company being out of compliance with WRAP's forward showing requirements. Further, given the suspension of the Company's RFP, UM 2193,[130] Staff anticipates that the Company will need to rely further on FOTs to offset resources that may come on later than what was expected at the beginning of LC 82.

In other proceedings, the Company has noted that the volume of transaction in regional wholesale markets has been steadily declining in recent years.[131] The Company models a constant level of FOT availability at its main five market hubs through 2027, which is incongruous with its operational realities of the last few years. Staff worries that the failure to align its action plan assumptions with the operational realities it uses as evidence in its power cost dockets could lead to a situation in which it neither has resources available to meet its load nor a viable counterparty to buy energy in a peak load hour.

Renewable Northwest also expressed concern with PacifiCorp's assumptions regarding future reliance on regional markets. RNW notes that near-term reliance on market purchases for capacity in this IRP is high. In addition, RNW notes that the Load and Resource Balance table in the IRP includes market purchases well above the stated FOT limits in Table 5.8. RNW notes, "regional markets are likely to experience increasing uncertainty in both depth and availability due to environmental policies and regional market initiatives, which increases the importance of hedging against the continued risk of high market reliance in the future." RNW recommends that PacifiCorp work with other regional planning organizations such as the Western Power Pool (WPP) to develop "a detailed, quantitative analysis on the likelihood of regional markets to provide reliable power at non cost-prohibitive prices." Staff acknowledged that a regional study could provide value in long-term planning, but notes that there are currently multiple organizations that already look at resource adequacy to assess whether there is a surplus of energy available in the region. For example, WECC releases frequent studies of regional capacity availability. The 2023 WECC Western Assessment of Resource Adequacy (WARA) finds that total planned resources in the WECC are not adequate to prevent substantial "Demand at Risk" hours in 2026-2028.[132] Demand at risk hours are defined as the number of hours in a year that are at risk for loss of load exceeding the one-day-in-ten-year outage threshold. As Figure 9 below shows, in August 2028, the WARA finds on average about 500 MW of Demand at Risk over 25 hours.[133] We note, however, that shortage predictions five years out can often change, as both demand and supply side resources respond in advance to potential shortfalls with incremental development activity.

Figure 9: Mid-term DRI Hours and Magnitude for the Western Interconnection

[130] See the Company's September 29, 2023 filing in UM 2193.
[131] See UE 420, PAC/400, Mitchell/59 here.
[132] WECC. 2023 Western Assessment of Resource Adequacy, page 17.
[133] WECC. 2023 Western Assessment of Resource Adequacy, page 16.



The WARA finds that a significant increase in Demand at Risk hours in December can be attributed to increased load forecasts in the Northwest, while there are relatively few utility-scale resource additions planned in the Northwest. The WARA concludes that load serving entities may need to delay resource retirements if they cannot mitigate these risky hours in the next two years. However, we note that WARA may have less visibility into local small-scale supply and demand resource activity that could reduce the at-risk hours in those out years.

Notably, PacifiCorp's IRP relies on 944 MW of summer market purchases in 2027 and 493 MW in 2028.[134] Given WECC's showing of regional resource adequacy risk during August in those years (red bars in Figure 4 above), the expectation of nearly 1 GW of market energy being available for purchase during summer peak hours seems potentially risky. Further, PacifiCorp has suspended the 2022AS RFP that would have brought resources online from 2025 through 2027, further increasing the region's resource adequacy risk.

These findings are concerning and indicate that PacifiCorp should look seriously at reducing market reliance in the near term, whether through longer-term contracts or resource procurements. If PacifiCorp continues to plan its system around procuring capacity from the market that may not be available and is forced to delay fossil retirements as a result, the Company could be at risk for failing to meeting its HB 2021 Oregon emissions reductions targets and much higher power costs. To address this, PacifiCorp should consider actions to reducing near-term market reliance in the next IRP.

Staff also expects PacifiCorp to consider how WRAP participation might affect the Company's reliance on FOTs in the next IRP. The WRAP forward showing program will require PacifiCorp to secure enough resources to meet their obligations seven months in advance. Staff's understanding is that this requirement may limit FOTs to transactions that can be secured on that timeline. Staff also expects that information from the WRAP program may bring additional transparency into the depth of regional markets during constrained periods and that this information could help to inform future assumptions regarding FOT availability.

Staff Expectations:
By the next IRP, PacifiCorp should:

- Include more years of weather data in its resource adequacy modeling.
- Change its capacity valuation to an ELCC or ELCC-adjacent methodology that has weather-correlated stochastic modeling.

[134] LC 82, PacifiCorp 2023 IRP, page 325.

- Calculate and report the LOLE of the Preferred Portfolio in each year.
- Model the benefits of WRAP to the Company's system and compliance hurdles in addition to any requirements that arise from the ongoing resource adequacy rulemaking in AR 660.
- Account for the benefits of WRAP in future IRPs if it plans to continue as a WRAP participant.
- Update FOT availability assumptions based on insights from regional analysis and the WRAP program.
- Restrict the modeling of FOTs to contracts that can be obtained seven months ahead of need.

Transmission

Transmission & Storage

In Round 1 Comments, Energy Advocates recommends, "PacifiCorp should expand future CEP/IRP's to look beyond storage co-location near generation sites and to identify substations and transmission lines that can use storage to flatten load peaks and avoid congestion and costly transmission and distribution upgrades."

In Reply Comments, PacifiCorp responded that the 2023 IRP allows standalone storage to be selected at generator and load locations, in addition to co-location near generation sites. PacifiCorp states, "Additionally, storage options that were not part of a cluster study were considered unconstrained by transmission requirements, such that any amount could be placed anywhere on the system."[135]

PacifiCorp also notes that "[t]he specific substation and transmission would be identified in the request for proposals process after the 2023 IRP."[136] We note, however, that PacifiCorp should reconcile this statement with its unambiguous indication in the IRP itself that battery storage resource options are limited to co-location at generation sites.[137]

PacifiCorp's explanation partially addresses Energy Advocates' recommendation, although it does not directly explain how PacifiCorp considers the ability of storage to avoid transmission and distribution upgrades. PacifiCorp applies a Transmission and Distribution deferral credit to DSM resources in the IRP; however, it does not appear that PacifiCorp has used a T&D deferral value for storage in PLEXOS IRP modeling.

In evaluating PacifiCorp's consideration of T&D deferral value, it may be valuable to consider transmission deferral separately from distribution deferral. Regarding transmission, the PLEXOS modeling logic should be able to assess the potential for storage to reduce or defer the need for endogenously selected transmission resources. The model can generally make economic decisions about whether to upgrade the system with storage or to select a major new transmission investment.[138] However, there may be some transmission deferral value that is not considered in the IRP PLEXOS modeling. For transmission system investments that cannot be selected by the model, and are instead hard-coded, the model will not be able to see any opportunities to defer these resources by acquiring storage.

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[135] LC 82, PacifiCorp Reply Comments, page 73.
[136] LC 82, PacifiCorp Reply Comments, page 72.
[137] LC 82, PacifiCorp 2023 IRP, Chapter 8, page 233: "Batteries are assumed to **always** be co-located with other resources, enabling them to shift energy…". Emphasis added.
[138] PacifiCorp response to OPUC DR 190.

The IRP generally states that transmission resources are available for endogenous selection.[139,140] However, further clarification from PacifiCorp to verify whether this applies to all or only some planned transmission resources that could be deferred by storage would be valuable. There may be some transmission expenses that can be deferred by strategically located storage but are not included in the PLEXOS model. If these costs are significant, then applying a transmission deferral credit to storage resources in the IRP could be appropriate.

Staff Expectation:

- In the next IRP, develop a transmission deferral credit for storage resources.

Demand Side Management

Staff's Round 1 Comments supported PacifiCorp's plan to include near-term cost-effective EE in the Company's preferred portfolio. The long-term EE modeling however, appeared insufficient. Staff's analysis found that PacifiCorp had not included available and low-cost EE in the preferred portfolio after 2025.[141] Accordingly, Staff requested that PacifiCorp allow optimization of EE in the CEP to inform whether EE could reduce HB 2021 costs allocated to the CEP portfolio. Staff also requested PacifiCorp reoptimize the Max DSM scenario. Additionally, Staff found opportunities to improve PacifiCorp's avoided costs, such as including avoided planning reserve margin costs and considering HB 2021's emissions constraints.[142] Finally, Staff found PacifiCorp's short-term DR acquisition strategy reasonable but recommended additional measures to reduce NPVRR.

In Round 1 Comments CRITFC, CUB, Energy Advocates, and Sierra Club saw room for additional DSM measures in the preferred portfolio. By extension, they questioned whether PacifiCorp's long-term planning recognized the full implications of HB 2021. CRITFC, CUB, and Energy Advocates voiced concerns that the existing cost-effectiveness tests overlooked EE's non-energy values of improved community resiliency and reduced environmental and ratepayer burdens.

In Round 1 Reply Comments PacifiCorp did not allow the Max DSM Scenario to reoptimize the resource selections around the additional EE. PacifiCorp also declined to reoptimize EE in the CEP. According to PacifiCorp, this request was unnecessary because the model had selected an average of 91 percent of potential EE between 2023 to 2030, with few remaining potential EE measures to meet system needs. PacifiCorp further argued there is no statutory or regulatory mechanism requiring the Company to optimize EE for CEP requirements. Similarly, PacifiCorp argued it lacked Commission guidance to include HB 2021's constraints in avoided cost data. PacifiCorp stated that the Company's method is like the traditional concept of "capacity cost" with the added component of renewable energy compliance. PacifiCorp's standard renewable avoided costs reflect the cost of a renewable wind proxy starting in 2026; prices after that date would not include a forward market component. PacifiCorp further explained that calculating the avoided planning reserve margin cost was difficult due to the addition of

[139] LC 82, PacifiCorp 2023 IRP, page 221.
[140] LC 82, PacifiCorp 2023 IRP, page 213.
[141] LC 82, Staff Round 1 Comments, October 15, 2023, page 58, Figure 12.
[142] For example, in using the existing avoided cost method, Staff found the Company overlooked the need to purchase non-emitting resources rather than the least-cost market resources. These comments mirrored Staff's comments to PGE in LC 80. *See In the Matter of Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Corrected Opening Comments at pages 27-30 (July 27, 2023).

variable energy resources. Finally, PacifiCorp provided an update on its electrification modeling and agreed to consider DR measures encouraged by Stakeholders.

Staff's review of OPUC DR 80-1 found that the preferred portfolio selected only 80 percent of available EE between 2023 and 2030, which contradicts PacifiCorp's claim of 91 percent.[143] In either case, the model selected EE *without considering HB 2021,* which suggests that the model would select more EE once HB 2021 strategy is considered. Staff requests that the 2024 IRP Update address the discrepancy in EE acquisition and ensure that the model considers HB 2021 compliance in the preferred portfolio.

Further, PacifiCorp's 2023 IRP analysis relied on an Energy Trust potential study which used avoided costs from the 2019 IRP.[144] If the Company's long-term planning were to indicate that greater amounts of efficiency at higher avoided costs would benefit the system, Energy Trust could perform a new potential estimate that would likely result in a higher amount of available efficiency in Oregon. Therefore, Staff concludes that PacifiCorp's least cost, preferred portfolio likely includes more EE from the previously identified potential, plus additional new23 potential that may have been screened out of Energy Trust's potential study.

Given the impactful new requirements of HB 2021, the value of efficiency in Oregon should diverge substantially from the value of efficiency to some other states on PacifiCorp's system. Under Senate Bill 1547 (2016) and codified in ORS 757.054(3)(a), investor-owned utilities are required by law to acquire all cost-effective energy efficiency and demand response prior to acquiring new generating resources.[145] To meet this requirement, new approaches to avoided costs must be explored and Staff expects PacifiCorp to help update the accounting in UM 1893 to reflect current state policy. Staff expects that Oregon-specific avoided cost analysis will be included in PacifiCorp's IRP Update and future IRPs. The acquisition of higher-value Oregon EE in light of HB 2021 requirements, should be part of PacifiCorp's preferred portfolio in both IRP and CEP planning, not relegated to one or the other.

Staff will consider approaches to avoided cost valuation from other regions, such as the method used by New England energy efficiency program administrators.[146] PacifiCorp's current IRP modeling approach for calculating avoided energy costs has similarities with the New England AESC modeling construct and could be improved to better represent Oregon-specific benefits.
Staff reiterates prior recommendations from Round 1 Comments regarding demand response resources. Staff recommends acknowledgement of DR acquisition to 2026, but encourages the Company to consider additional classes of DR as part of the least cost, least risk portfolio in future analysis. Staff again cites the Northwest Power and Conservation Council's 2021 Power Plan recommendations for utilities to pursue frequently deployable, low-cost measures with minimal customer impact, including time-of-use rates and demand voltage reduction.[147] PacifiCorp did not respond to this request in Round

143 See PacifiCorp response to Staff DR No. 80-1.

144 Under OAR 860-030-011(2), utilities must provide energy efficiency avoided cost data based on the utility's most recently acknowledged IRP or update, or from the energy utility's most recent general rate case that has been resolved by a final order of the Commission.

145 ORS 757.054(3)(a), https://oregon.public.law/statutes/ors_757.054.

146 For every planning period (3 years), the efficiency program administrators sponsor an avoided energy supply components (AESC) study to determine the value of energy efficiency and other demand-side measures. Avoided costs are calculated for each New England state under a hypothetical future in which New England program administrators do not install any new demand side measures in future years.

147 See 2021 Northwest Power Plan, page 47. https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf.

1 Reply Comments. Staff expects future IRP analyses will consider these two resources to help manage power costs and reduce emissions.

Staff Recommendation 12. Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.

Staff Recommendation 13. Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.

Staff Expectations:

- In the IRP update, PacifiCorp should address the discrepancy in EE acquisition and ensure that HB 2021 compliance is considered in the preferred portfolio.
- In the next IRP, PacifiCorp should model a counterfactual case in which utilities install no new energy efficiency in Oregon in 2025 or later years.
- In the next IRP, PacifiCorp should include the HB 2021 emissions requirement and SSR/CBRE requirement based on the load forecast without new EE.
- In the next IRP, analyze the role of frequently deployable, low-cost DR measures with minimal customer impact, including but not limited to time-of-use rates and demand voltage reduction.

Conclusion

Despite the good work and hard effort of PacifiCorp staff, the decisions to both suspend the 2022 AS RFP **and** push all necessary revisions of LC 82 analysis to the IRP Update mean Staff and stakeholders lack the shared analytic understanding for making many of the needed acknowledgement recommendations required of this IRP/CEP. Until additional analysis is done, and the Preferred Portfolio is revised, many aspects of this IRP and the CEP cannot be acknowledged.

Staff proposes to truncate the LC 82 review process. Staff will file a motion to update the schedule so as to bring the recommendations from these comments forward for acknowledgement at the public meeting on February 20, 2024. Staff will seek a Commission order on those items that it believes can be acknowledged **and** on minimum analytic requirements for the IRP Update. Further, we recommend that the CEP be revised and resubmitted, per Staff's suggestions, with the IRP Update so that it has the potential to be acknowledged.

Dated at Salem, Oregon, this January 24th, 2024.

JP Batmale

JP Batmale
Administrator
Energy Resources and Planning Division

Appendix A: Summary of Recommendations

RFP Suspension
Staff Recommendation 1. Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan**.**

Staff Recommendation 2. Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.

Staff Recommendation 3. Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.

Action Plan Changes
Staff Recommendation 4. Do not acknowledge Action Plan items 1h and 2a.

CEP Comments:
Community Benefit Indicators
Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

CBRE Resource Potential
Staff Recommendation 7. Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

Community Engagement
Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Resiliency Analysis Framework
Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

IRP Comments:
Preferred Portfolio Modeling Process

Staff Recommendation 10. Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.

Natrium and Non-Emitting Peaking Resources

Staff Recommendation 11. Direct PacifiCorp to update Action Plan Item 1g to reflect actual events since the IRP/CEP was filed in May 2023.

Demand Side Resources

Staff Recommendation 12. Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.

Staff Recommendation 13. Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.

Appendix B: Staff Expectations

State Policy Compliance in IRP Portfolios

- In the next IRP, PacifiCorp should demonstrate that simultaneous compliance with all state-level policies is feasible with the Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP.
- In the next CEP, PacifiCorp should transparently explore and describe constraints that HB 2021 compliance potentially places on allocation.

CEP Compliance Pathways

- PacifiCorp should utilize its 2025 IRP public input workshops to clarify with stakeholders the relationship between MSP, IRP "actions", Oregon's CEP requirements, and Oregon's DEQ compliance methodology and explore improvements such that HB 2021 targets and activities are informative to and reflected in MSP decisions. As part of this process, changes to MSP disclosure rules should be explored to increase transparency.
- To improve an understanding of tradeoffs in the IRP Update and/or as part of the revised CE, the Company should report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (inclusive of Oregon's SSR requirement) under various allocation pathways and that PacifiCorp.

Coal-to-Gas Conversions

- PacifiCorp should provide analysis around risk of regret for coal to gas conversions in its 2023 IRP Update.
- PacifiCorp remove Action Items 1c and 1d from the action plan because the Company has already taken these actions.

CEP Comments:

Community Benefit Indicators

- In the next IRP/CEP, Staff expects PacifiCorp to:
  - Adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.
  - Better inform CBIs and methods with input from stakeholders and community.
  - Enhance tribal-focused CBIs.
  - Use CBIs to better reflect the health impacts of EE.
  - Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios.
  - Enhance the ability of CBIs to better reflect the resiliency benefits of actions.
  - Incorporate CBIs reflecting community-level impacts of non-GHG emissions, energy efficiency, and the Company's CBRE actions.

CBRE Activities

- Report regularly to the CBIAG on development including concrete and proactive activities PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

CBRE Inclusion in Preferred Portfolio

- In the IRP/CEP update:
  - Include at least 92 MW of CBRE in the preferred portfolio, depending on the current pipeline of existing programs.

- By the next IRP/CEP:
  - Highlight and communicate the relative benefits of CBRE in load pockets.
  - Quantify the costs and benefits of CBRE for meeting HB 2021 guidance to "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy."[148]
  - Identify one or more new, specific CBRE resource opportunities in Oregon and report on findings regarding specific costs and benefits.

CBRE Program Design

- Engage the CBIAG on potential program designs that can scale quickly to meet community and system needs.

Community Engagement

- Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document Environmental Justice community priorities.
- In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in related dockets and venues to inform CBIs, CBREs, and portfolio decisions.
- PacifiCorp should include the following additions and enhancements to the Feedback Tracker:
  - o Organization/entity attribution or affiliation.
  - o Flag for whether and where PacifiCorp incorporated the feedback into specific utility planning, actions, resource selection, and project prioritization.
  - o Clear description of why feedback was or was not included.
- Staff encourages PacifiCorp to report on its Tribal engagement strategy by December 31 of each year to the CBIAG. The review should include successes, opportunities for improvement, feedback received, a discussion of Tribal CBIs and CEP/DSP project development, and any work to involve Tribal Nations in planning and resource decision-making.
- PacifiCorp to conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts.

Resiliency Analysis Framework

- PacifiCorp should specify how it intends to incorporate CBIAG feedback and other community input into the community-utility resilience scores and risk drivers by March 1, 2024.
- By the next IRP, PacifiCorp should explain how it will use the Resiliency Analysis Framework in IRP and CEP resource planning, project prioritization, and portfolio selection considering HB 2021's requirement that resiliency planning consider costs, consequences, outcomes and benefits.
- Prior to the next CEP, Staff expects the Company to open discussions with stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework; work with Stakeholders to

[148] ORS 469A.415(4)(d).

identify gaps in comprehension of the Resiliency Analysis Framework; and identify the vulnerabilities and complexities of SAIDI/SAIFI/CAIDI data sets and NRI values as a measure of community level impacts. The Company is encouraged to discuss how it can incorporate the lived experiences of communities into the community-resiliency score. The results of these discussions should be included in the next CEP.

- By next CEP, PacifiCorp should be able to articulate further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.
- At a CBIAG meeting before the next CEP and prior to any CBRE Grant Pilot project selection, provide details for how a completed Resiliency Analysis Framework will be used to impact project selection. Staff expects to work with PacifiCorp in helping to craft this presentation and what will be covered.

<u>Acquisition of Federal Incentives</u>

- The IRP Update includes two variant portfolios that directly reflects Sierra Club's suggested analysis around reduced upgrade costs and early retirements using the EIR program.
- PacifiCorp details in the IRP Update the timeline for submitting an EIR application and the scope of the projects it is seeking to be financed through the U.S. Department of Energy Loan Program Office's EIR program.
- PacifiCorp provides a brief update at every IRP public input meeting and every CBIAG meeting leading up to the 2025 IRP that details the Company's activities to apply for federal incentives and detailing any funding secured.

IRP Comments:

<u>Preferred Portfolio Modeling Process</u>

Before the next IRP PacifiCorp should:

- Work with interested participants from the IRP Public Input process to develop and publicly produce a granularity adjustment methodology.
- Increase transparency around reliability adjustments by stating which resources will be eligible to be included as reliability adjustments in the next IRP and how each one will be valued. Further, it should clarify its modeling approach around how to limit the magnitude of the reliability adjustments that it must make.
- Solicit suggestions through the IRP Public Input process and as part of the Draft IRP of variant portfolios.

As part of the next IRP PacifiCorp should:

- Adjust its modeling approach to better capture resource adequacy needs and the capacity contributions of resource options to reduce the need for and magnitude of reliability adjustments to portfolios.
- Reoptimize variant portfolios that add resources to the preferred portfolio unless there is a clearly explained reason to study an un-optimized portfolio of resources.

<u>Coal Strategy</u>

In the next IRP, PacifiCorp should:

- Utilize coal prices for Jim Bridger that are reflective of actual costs from the Long-Term Fuel supply contract.
- Provide a full update on Utah coal supply issues.

Carbon Price Path

In the next IRP/CEP, PacifiCorp should:

- Recreate the chart above for (a) coal and (b) Oregon allocated GHG emissions comparing past IRP forecasts to actuals.
- Provide a sensitivity that calculates Oregon-allocated GHG emissions under the assumption of no carbon prices operationalized in dispatch. This sensitivity should still be based on the Preferred Portfolio, which considers a carbon price in investment decisions.
- Propose a PacifiCorp specific carbon price that layers atop the medium carbon price the Company's annual cost from wildfires as described by CUB.

Candiate Resource Costs

- As part of the IRP update and future IRP processes, PacifiCorp should update its renewable cost assumptions based on more recently available information.

Natrium and Non-Emitting Peaking Resources

- Inform the Commission in the IRP Update whether the TerraPower permit application passed the U.S. NRC's readiness assessment for Natrium's construction permit and the estimated timeline for the project following that decision.
- In the next IRP, utilize a ten-year buffer between the date of the issuance of the Natrium CP and when that resource may appear in the Company's preferred portfolio.
- In the next CEP, more directly address the high-level planning questions from Order No. 22-446 regarding the critical junctures, dependencies, and barriers to nuclear and any non-emitting peaking technology as part of a preferred portfolio.

Resource Adequacy Modeling, Front Office Transactions, and WRAP

By the next IRP, PacifiCorp should:

- Include more years of weather data in its resource adequacy modeling.
- Change its capacity valuation to an ELCC or ELCC-adjacent methodology that has weather-correlated stochastic modeling.
- Calculate and report the LOLE of the Preferred Portfolio in each year.
- Model the benefits of WRAP to the Company's system and compliance hurdles in addition to any requirements that arise from the ongoing resource adequacy rulemaking in AR 660.
- Account for the benefits of WRAP in future IRPs if it plans to continue as a WRAP participant.
- Update FOT availability assumptions based on insights from regional analysis and the WRAP program.
- Restrict the modeling of FOTs to contracts that can be obtained seven months ahead of need.

Transmission

- In the next IRP, develop a transmission deferral credit for storage resources.

Demand Side Resources

- In the IRP update, PacifiCorp should address the discrepancy in EE acquisition and ensure that HB 2021 compliance is considered in the preferred portfolio.
- In the next IRP, PacifiCorp should model a counterfactual case in which utilities install no new energy efficiency in Oregon in 2025 or later years.
- In the next IRP, PacifiCorp should include the HB 2021 emissions requirement and SSR/CBRE requirement based on the load forecast without new EE.
- In the next IRP, analyze the role of frequently deployable, low-cost DR measures with minimal customer impact, including but not limited to time-of-use rates and demand voltage reduction.

PacifiCorp
2024 Oregon Small-Scale Renewable Request for Proposal

Pre-Issuance Bidder Workshop

January 24, 2024

    

PACIFICORP

POWERING YOUR GREATNESS

2024 Oregon Small-Scale Renewable RFP

Logistics

Workshop Date and Time

- Wednesday, January 24, 2024
- 2:00 – 4:00 PM (Pacific Standard Time)

Location

- Microsoft Teams meeting
- Join on your computer or mobile app
- Click here to join the meeting
- Or call in (audio only)
- tel:+15632755003,,979257373# United States, Davenport
- Phone Conference ID: 979 257 373#

2024 Oregon Small-Scale Renewable RFP

Agenda

- Purpose/Resource Types
- Eligibility Requirements
- Contract Considerations
- Interconnection and Transmission Requirements
- Proposed RFP Schedule
- Evaluation and Selection Methodology
- Role of Independent Evaluator (IE)
- Next Steps
- Questions and Comments

2024 Oregon Small-Scale Renewable RFP

Purpose of Request for Proposal (RFP)

- To enable PacifiCorp to obtain, by 2030, approximately 490 megawatts (MW) of additional electrical capacity from small-scale renewable energy projects.
- The RFP supports PacifiCorp compliance with Oregon House Bill 2021 (OR HB2021) Section 37 and furthers PacifiCorp's Clean Energy Plan goals.

Energy sources accepted into the 2024 Oregon Small-Scale Renewable RFP must

- **Have a nameplate capacity of at least 3 MW but no greater than 20 MW *and***
- **Generate electricity utilizing one of the following sources:**
    - Wind energy
    - Solar photovoltaic and solar thermal energy
    - Wave, tidal and ocean thermal energy
    - Geothermal energy
    - Hydroelectric energy
    - Biomass that generates thermal energy for a secondary purpose
        - Biomass energy sources larger than 20 MW will be accepted, but only the first 20 MW of the energy source counts toward OR HB2021 requirement.
    - Energy sources listed above will be accepted to the 2024 Oregon Small-Scale Renewable RFP only if they meet the Renewable Portfolio Standard (RPS) criteria outlined in ORS 469A.025.

Note: Information in this presentation is subject to further change until RFP is issued.

2024 Oregon Small-Scale Renewable RFP

Minimum Resource Eligibility Requirements

- Eligible technologies consistent with ORS 469A.025.
- Eligible resources cannot be behind-the-meter, energy storage, microgrids or demand response technologies.
- Minimum 3 MW (ensures Energy Imbalance Market (EIM) eligibility); maximum 20[1] MW (supports Oregon HB2021 compliance).
- Possess Oregon Department of Energy Renewable Portfolio Standard (RPS) certification at time of commercial operation for contract effectiveness.
- Off-system bids not accepted; projects must be planned to interconnect to PacifiCorp transmission or distribution system in Oregon, Washington, California, Idaho, Utah or Wyoming.
- Completed interconnection study, confirming ability to interconnect to PacifiCorp's transmission or distribution system.
    - https://www.oasis.oati.com/ppw/index.html; https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Transmission_Wall_Map,_E-Size.pdf
- Site control required.
- Commercial Operation Date (COD) by December 31, 2028.
- Comply with co-location/proximity criteria based on Oregon OAR 860-089-0100, applied to a 20 MW threshold level.
- Bids for new and existing resources will be accepted provided the existing resources are not obligated in a contract effective as of the COD date above.
- Bid fee will be required for each bid proposal. Details provided at RFP issuance.
- All PPA bids must be fixed-price for the full term.

[1] As previously noted, Biomass resources larger than 20 MW *will* be considered, but only the first 20 MW will count toward OR HB2021 capacity requirement.

2024 Oregon Small-Scale Renewable RFP

Minimum Eligibility Criteria

1. Receipt of bid by deadline
2. Receipt of bid fee by deadline
3. Completed provided Bid Summary and Pricing Input Sheet, without modification
4. Capacity interconnected to PacifiCorp's transmission or distribution system
5. Completed PacifiCorp Transmission Interconnection Study or signed PacifiCorp Transmission Interconnection Study Agreement
6. Interconnection study results and/or executed Large Generator Interconnection Agreement (LGIA) consistent with and supports bid
7. Demonstrated ability to achieve COD deadline
8. Execute Confidentiality Agreement and allow appropriate disclosures to agents, contractors, regulators, etc.
9. No attempts to influence PacifiCorp
10. Entire bid held firm through Q2 2025
11. No commitments of all or part of bid to another entity
12. Must disclose real parties of interest
13. Compliance with Prohibited Vendors List (see pro forma PPA)
14. Bidder’s credit information
15. Ability to meet credit security requirements
16. Non-modifiable standard pro-forma contract
17. Bidder not in bankruptcy proceedings
18. Proposal cover letter signed by authorized officer
19. Renewable Portfolio Standard (RPS) certification from Oregon Department of Energy
20. Performance report and model output including hourly output values; bid resource assumption (12X24 or 8760) includes all planned outages and losses, including planned and maintenance outages and curtailment due to protected species such as bats; third-party provided performance report preferred
21. Adherence to all applicable permits prior to and after construction. If applicable, Seller will also agree to Eagle Take Permit or alternative mitigation measures
22. Ownership of, leasehold interest in, or right to develop site, or valid title to property
    https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230823_OATTMaster.pdf
23. Oregon bidder agrees to the contractor labor standards attestation in OR HB2021, Section 26
    https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
24. Compliance with OR HB2021 reporting requirements, including contractor diversity reporting requirement
    https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

2024 Oregon Small-Scale Renewable RFP

Key Contract Considerations

- **Contract form**. PacifiCorp's pro forma power purchase agreement (PPA) will be provided.
  - Standard-form power purchase agreement (PPA). **The PPA will be standard for all bidders with no individual form modifications permitted.**
  - Seller develops, operates and owns resource; PacifiCorp buys the output for a specific term.
- **Ownership.** PacifiCorp takes ownership of all capacity, energy and associated environmental attributes after delivery to PacifiCorp.
- **Contract pricing**. Fixed pricing for term of contract (flat or on-peak/off-peak).
- **Credit requirements.** Letter of credit or approved parental guarantee will be required.
  - **Project development security**. Seller security is required to support delay damages and/or default damages for failure to reach commercial operation date (COD).
  - **Default security.** Seller security is required to support default damages in the event of breach of contract.
- **Commercial Operation Date delay.** Seller will have up to 365 days to cure a delay in scheduled commercial operation date; delay damages will be assessed.
- **Post-execution Condition Precedent.** Agreement language will ensure PacifiCorp's ability to obtain designated network resource (DNR) transmission service at no additional cost.
- **Annual Performance Guarantee.** Agreement will require annual resource mechanical availability guarantee and threshold percentage.
- **Benchmarks.** To support 2030 OR HB 2021 compliance PacifiCorp may offer benchmark bids.
  - PacifiCorp develops, constructs, owns and operates a bid project.
  - Benchmark bids will be evaluated using methodology consistent with market bid evaluation.

2024 Oregon Small-Scale Renewable RFP

Interconnection and Transmission

On-system resources (Off-system resources not accepted)

- PacifiCorp Transmission interconnection studies and agreements should be consistent with the bid proposal's technology, size and commercial operation date. If studies and agreements are not consistent with the proposal, bidder will provide documentation from PacifiCorp Transmission that a material modification to their interconnection documentation is not required.
- Bidders are financially responsible to PacifiCorp Transmission for all interconnection costs as identified in their generator interconnection agreement.
- After a PPA is executed, PacifiCorp's merchant function is responsible for requesting and arranging transmission from the Point of Interconnection (POI) to load.

Acceptable Documentation of Interconnection

- Completed PacifiCorp Transmission Interconnection Study (system impact study and/or facilities study) or signed PacifiCorp Transmission Interconnection Agreement is due when bid is submitted.
- An *Informational* Interconnection Study is NOT sufficient interconnection documentation to be considered eligible for the 2024 SSR RFP.

Questions

- For questions regarding PacifiCorp Transmission's interconnection study process, please visit the PacifiCorp Transmission website and contact Generation Interconnection at: www.pacificorp.com/transmission/transmission-services.html

2024 Oregon Small-Scale Renewable RFP

Equity Questionnaire

Facility proximity to community
Census track in which facility is located
Distance from facility to nearest residential home
Number of residential homes within 1 mile of facility
Number of residential homes within 6 miles of facility
How does this resource serve or otherwise impact vulnerable populations?
Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels?
Distance to nearest existing generation sources by fuel source within 6 miles of proposed facility;
Will the proposed facility replace/supplant identified generation sources?
If "yes," provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much megawatt-hour ("MWh")/year), and avoided emissions released into the community (within 6 miles of the project).

Population characteristics of community where facility is proposed
To be completed based on census track in which facility is located
Race and ethnicity
White (%)
Black or African American (%)
Amercan Indian and Alaska Native (%)
Asian (%)
Native Hawaiian and Other Pacific Islander (%)
Two or More Races (%)
Hispanic or Latino (%)
Population 25 years and over with no high school diploma
Unaffordable housing
Population five years and older that speak English less than "very well" and "not at all"
Population with income 185% below poverty
Population 16 years and older unemployed

Facility Job Creation
Total hires (number of jobs)
Will there be an apprenticeship or training program?
Will there be a project labor agreement (PLA)?
Will Bidder have a plan for outreach, recruitment and retention of women, minority individuals, veterans and people with disabilities to perform work under the contract?
Projected local hires from nearby communities (number of jobs)
Expected total employment (hires) of fossil fuel construction workers (number of jobs)
Duration of work (months of construction / years of operation)
Total Recordable Incident (TRI) of Bidder
Industry Average TRI for type of business (OSHA)
Bidder agrees to use Veriforce, or equivalent, to report safety
Estimate projected economic benefits to the local economy (direct and indirect) (annual $ from payroll taxes, property taxes, other taxes, services)
Minority-owned businesses (percentage of contractors and subcontractors) Woman-owned businesses (percentage of contractors and subcontractors) Service-disabled veteran-owned businesses (percentage of contractors and subcontractors) LGBT firms (percentage of contractors and subcontractors)
What percent of total work hours does Bidder target to be performed by women, minority individuals, veterans and people with disabilities?

Local Impacts
Is Facility a distributed energy resource?
Duration of construction
Source of water used during construction
Source of water used during operations
Is water a permitted or public source
Site disturbance - amount of disturbed soil during construction
Tree and pollinator seed re-planting after construction

Note: Above questionnaire was requested in the 2022AS RFP.

2024 Oregon Small-Scale Renewable RFP

Proposed RFP Schedule

Event	Date
Pre-issuance bidder workshop	1/24/2024
Independent Evaluator (IE) hired	2/16/2024
RFP issued to market and publicized	3/29/2024
PacifiCorp OATT[1] cluster study window open	4/1/2024
PacifiCorp OATT[1] cluster study window closed	5/16/2024
Bidder workshop No. 1	6/27/2024
Bidder workshop No. 2	TBD (September 2024)
Last day for bidder questions to PacifiCorp and IE	11/1/2024
Cluster study results posted to OASIS	~11/12/2024
Benchmark bid submissions due	11/15/2024
Benchmark final bid financial analysis provided to IE	12/20/2024
Market bid submissions due	12/23/2024
Bid eligibility screening complete	1/17/2025
Market bid evaluations complete	2/14/2025
IE final report	3/17/2025
Potential 2025 SSR RFP	3/28/2025
Contracts finalized and executed	TBD (June 2025)
Guaranteed commercial operations date (COD)	12/31/2028

[1] PacifiCorp's Open Access Transmission Tariff (OATT)

POWERING YOUR GREATNESS

2024 Oregon Small-Scale Renewable RFP

Price Proposal – Bidder Inputs

Each Proposal is required to include a completed Bidder Inputs form, which provides PacifiCorp a "numbers based" overview of the bid offering:

Price Proposal - Bidder Inputs (Required for Bid Submittal)	**Location**
➢ Bid Summary ▪ Type of Bid: PPA or Benchmark ▪ Project Specifics (Generator Type, location, capacity, annual degradation) ▪ Bidder Contact Information ➢ PacifiCorp Interconnection/Transmission Information ▪ Queue Number or Cluster Study ▪ Cost of Interconnection Facilities and Network Upgrades ➢ Purchase Power Agreement Terms ▪ Start/End Dates ▪ $/MWh Price[1] (Flat or On- and Off-Peak Pricing) ➢ Benchmark Terms ▪ Date Operational ▪ Initial Capital Cost (Detail on Tab 3) ▪ ITC/PTC Qualification Questions	Tab 1
Expected First-Year Generation Inclusive of Degradation – 50th Percentile Estimate ➢ 8,760 hourly generation profile, OR ➢ 12 month by 24-hour generation profile ("12X24")	Tab 2a, or Tab 2b
Benchmark Pricing (Not Applicable to Market Bids)	Tab 3
Benchmark Additional Information (Annual Operating and Capital Costs)	Tab 4

[1] Bid prices include direct interconnection costs. PacifiCorp includes network upgrade costs from PacifiCorp Transmission interconnection studies in the financial valuation model.

2024 Oregon Small-Scale Renewable RFP

Evaluation and Ranking of Bids

- Objective is to acquire 490,000 kilowatts (490 MW) of new capacity from small-scale renewable energy projects at the lowest cost to Oregon customers
- Acceptable Bid Criteria:
  - Power purchase agreement and benchmark bids
  - Fixed pricing for Term of PPA (flat or on-peak/off-peak)
- Bids will be ranked based on the LOWEST Real Levelized Cost per Kilowatt of installed Capacity

Cost to PacifiCorp of Bid
PPA Cost or Revenue Requirement of Benchmark Bid
(Present Value)
+
Network Upgrade Cost
(Present Value)

−

Value of Generation Based on Oregon Avoided Costs. Includes Value of Capacity Contribution.
(Present Value)

=

Net Cost / (Benefit) of Installed Capacity
(Present Value)

Net Cost / (Benefit) of Installed Capacity
(Present Value)

÷

Installed Capacity (kW) over PPA Term or Asset Life.
(Real[1] Present Value)

=

Cost / (Benefit) Per Kilowatt-Year
(Real Levelized)

[1]Discussion of Real Levelized valuation methodology will be provided in June bidder workshop.

2024 Oregon Small-Scale Renewable RFP

Role of the Independent Evaluator (IE)

PacifiCorp is seeking the services of an Independent Evaluator to provide independent validation that:

- PacifiCorp’s screening of eligible bidders based on published minimum eligibility requirements was consistently applied to all submitted market and benchmark bids; and
- PacifiCorp’s cost valuation of all submitted market and benchmark bids was consistently applied.

2024 Oregon Small-Scale Renewable RFP

Next Steps

1. Questions or comments regarding this pre-issuance bidder conference should be sent to the following mailbox, even if an answer was provided verbally in today's meeting, to ensure all bidders receive responses: **2024SSR_RFP@pacificorp.com.**
2. Responses to questions (Q&As) received will be posted anonymously on PacifiCorp's 2024 Small-Scale RFP website.
3. 2024 Small-Scale RFP information will be provided it is developed and Q&As will be posted to: www.pacificorp.com/suppliers/rfps/2024-small-scale-renewable-rfp.html.

Supporting Materials

2024 Oregon Small-Scale Renewable RFP

PacifiCorp Transmission OASIS Interconnection Requests

Information on new generator interconnection requests and general interconnection and cluster study information please visit: https://www.oasis.oati.com/ppw/index.html

Question & Comments

To: PacifiCorp SSR RFP Team (2024SSR_RFP@pacificorp.com)
Subject: Oregon PUC Staff Initial Comments on SSR RFP

PUC Staff appreciates PacifiCorp releasing a draft of the Small Scale Renewable request for proposal (SSR RFP) for comments and the speed with which the Company is pursuing these resources. Staff's comments are organized around two themes. First, PacifiCorp's chosen SSR project characteristics are too narrow, leaving value on the table, driving up project costs, and failing to leverage the RFP as a market discovery mechanism. Second, Staff has suggestions for the structure of the RFP itself, based on our experience, that should help the Company meet its goals and the goals of the state while also assisting potential bidders.

Project Characteristics

Issue: Energy storage ineligibility
Staff position: Energy storage paired with renewable energy projects should be eligible.
Staff rationale:

- Allowing for the pairing of energy storage with renewables and dispatched as a single project enhances capacity value of SSR projects to system peak. Barring energy storage from SSRs appears to make projects less economic than other renewable systems and potentially drives up total costs of CEP compliance for Oregon ratepayers.
  - Energy storage allows for renewable projects to be dispatched in a way that better aligns with system need and to offset fossil fuel use (i.e., summer peak, after 6pm).
- PAC has outstanding capacity need that SSR projects with energy storage can help meet. Evidence:
  - Per the 2023 IRP, the Company has a 2028 summer capacity deficit over 6,000 MW.[1]
  - Per the Draft IRP Update, peak capacity will grow at an average annual rate of 1.7%.[2]
  - Company is seeking 100s of MW of energy storage by 2026 through bilateral contracts in wake of UM 2193 RFP suspension.

Given the outstanding capacity need, Staff questions why PacifiCorp would limit dispatchable load.

- PacifiCorp staff stated on the January 24, 2024 conference call that the Company had determined that the economics of SSR projects with energy storage would be uncompetitive. There is no data to substantiate this argument. Further, the purpose of an RFP is to discover what is available in the market. If project bids are uneconomic due to inclusion of energy storage that should be apparent in their RFP score.
  - Based on PacifiCorp's evaluation and ranking of bids, projects paired with storage will most likely provide more value and thus provide a higher benefit to ratepayers.
- CAISO and WREGIS allow for renewable projects to be paired with energy storage and to be dispatched as a single system.
- ODOE certifies RPS projects paired with energy storage.

[1] LC 82, PacifiCorp IRP, May 31, 2023, pgs. 165 – 172, specifically Table 6.11 and Figure 6.4.
[2] LC 82, Draft IRP Update, January 31, 2024, pg. 2.

Issue: 3 MW floor
Staff position: Allow for project sizes down to 25 kW.
Staff rationale:

- 25 kW is smallest size for Community Solar Program. A lower bid threshold allows for projects such as those waitlisted in the CSP to participate in the SSR RFP.
- Based on the size of PacifiCorp's CSP queue there are clearly many projects less than 3 MW in size that could submit viable bids.
- Function of an RFP is to discover what is available in the market. If project bids are uneconomic due to their smaller size, that will be apparent in the RFP scoring.
- WREGIS allows for renewable projects of any size to be registered.

Issue: CAISO EIM eligibility
Staff position: Should be optional for projects, not a requirement.
Staff rationale:

- Eliminates the potential for smaller projects.
- Imposes unnecessary costs on all projects.
- Reinforces need to allow batteries to be paired with projects as it would increase value of projects to ratepayers.

Issue: Required ODOE RPS Certification at time of commercial operation date (COD)
Staff position: Should be required only after COD and should be optional for projects, not a requirement.
Staff rationale:

- Timing is off. ODOE does not issue RPS certifications until after COD.
- Project does not need ODOE certification to be considered renewable energy resource. Just needs to be one of the technologies listed in ORS 469A.025. Imposes unnecessary costs on all projects.
- ODOE RPS certification requires WREGIS issuing a generating unit id. This requires equipment that is expensive for smaller projects. It also requires more time and raises project costs.
    - o The largest benefit to registering with WREGIS is the ability to generate RECs. As HB 2021 does not require REC retirement to demonstrate emission reductions – and as PacifiCorp will have over 50 million RECs in excess of its Oregon RPS needs by 2030[3] – Staff finds little to no value in requiring PAC SSRs to be WREGIS certified, even if the ODOE RPS verification is waived.

Issue: Contract pricing limited to flat or on-peak/off-peak.
Staff position: Contract pricing should include flat, on-peak/off-peak, or premium peak hours
Staff rationale:

- Projects with associated storage should have a contract pricing structure which incentivizes and rewards its dispatchable nature. More targeted hours will maximize the capacity value derived from these projects at little to no cost to the project.
- Hour derivation could be based on projected market prices or utility capacity needs.
- Structure could follow UM 1729 Solar+Storage rate with minor modifications.

[3] LC 82, PacifiCorp IRP, May 31, 2023, pg. 321, Figure 9.59.

RFP Structure Issue

Issue: Lack of non-price scoring.
Staff position: Include non-price scoring that captures information about benefits to Oregon communities.
Staff rationale:

- Staff appreciates the inclusion of the Equity Questionnaire from the 2022 AS RFP. However, the equity questionnaire is not mandatory in the SSR RFP and answers do not impact project selection.
- Elements should be improved *(see below)* and converted into non-price scoring or sensitivity that captures community benefits.
- The Commission stated that it will want information about direct benefits to communities in Oregon.[4] In fact, capturing more information about benefits and impacts to Oregon communities was identified as a necessary first step in impacting near-term decisions around utility procurement.[5]
- PacifiCorp and Oregon PUC staff agree that many projects could easily qualify as both SSR and as Community Based Renewable Energy (CBRE) projects, under HB 2021.

Issue: Equity questionnaire
Staff position: Equity questionnaire needs more explicit linkages to PacifiCorp's CBIs and reflect input from the Company's CBIAG.
Staff rationale:

- Staff appreciates the inclusion of the 2022 AS RFP Equity Questionnaire. However, the equity questionnaire does not necessarily reflect the Company's evolving CBIs from LC 82 and input from community members in both LC 82 and in the CBIAG.
- Some portion of the equity questionnaire should become the non-price scoring element to the RFP. *(See above.)*
    - These can reflect the Company's evolving CBIs and/or attempt to capture insights into elements like positive impacts to community resiliency or the offsetting of fossil fuels.
    - HB 2021 requires consideration of community benefits in meeting the emissions reduction targets, vis-à-vis offsetting fossil fuels, increasing community resiliency, and even economic development.[6]

Issue: Lack of locational value in evaluating and ranking of bids.
Staff position: PacifiCorp's evaluation and ranking of bids needs to explicitly take into account the locational value of capacity and energy from proposed SSR projects when assessing bids.
Staff rationale:

- Given that PacifiCorp has multiple load pockets across its system (e.g., five in Oregon) and uneven growth across its system (e.g., northeast Oregon load will grow incredibly fast over the next five years), the methodology to determine net cost/benefit of installed capacity needs to explicitly account for locational value.

[4] UM 2273, Order No. 24-002, January 3, 2024, pg. 23
[5] *Ibid.* Pg. 24-25.
[6] ORS 469A.400(2)(a),(b) and 469A.415(4)(d)

- This will encourage the selection of bids with the lowest realized cost to Oregon ratepayers while better capturing the value to the PacifiCorp system.

Issue: No contract negotiations or redlines
Staff position: Redlines should be allowed.
Staff rationale:

- In UM 2274, contract redlines will be used by IE to illuminate bid nuances and pricing so as to make project selection more transparent and so the IE can comment around tradeoffs or irregularities in ISL or FSL project selection. [7]
- Contract redlines allows for projects with more unique attributes to potentially offer lower cost bids and provide necessary flexibility.

Issue: IE Scope
Staff position: Include information that compares and contrasts IE scope and staff interaction in the SSR RFP to UM 2193.
Staff rationale:

- Staff appreciates the inclusion of an IE for this RFP but needs a clearer understanding of the IE's scope and ability to interact independently with stakeholders, and how similar the role will be to an IE selected for a procurement under Oregon's competitive bidding rules.
- Will the IE be responsible for responding to bidder questions?
- Will the IE be responsible for establishing the scoring rules, as well as scoring all, or a subset of bids?
- Will the IE be working for/reporting to PAC or OPUC staff?

Issue: Separation of PacifiCorp RFP and Benchmark staff in establishing scoring system, reviewing bids and contract negotiations.
Staff position: The final RFP needs to clearly state how PacifiCorp RFP and Benchmark staff will be entirely screened from one another throughout this RFP process. This includes naming all employees working as part of the RFP team or the Benchmark team, including their roles and associated dates of their work; ensuring Benchmark staff have had no access to 3rd party project information during this RFP and for at least two years after bids are submitted; and developing and enforcing separation protocols to ensure no confidentiality breech or anti-competitive use of confidential data.
Staff rationale:

- If PacifiCorp's SSR benchmark project development team has any access to RFP bidder information they will have an unfair advantage in their bids.
- All other RFPs require a separation of staff.
- It is standard practice in Oregon to name utility staff on RFP and Benchmark teams so the IE, Staff, and/or stakeholders can verify that a separation between RFP and Benchmark teams was maintained.
- Bidders who receive confidential utility information are embargoed from using it for two to five years after an RFP. The same should be true for utility staff.

[7] UM 2274, Order No 24-011 at 1.

In closing, an RFP functions as a market discovery mechanism. In Staff's experience, an RFP with too many restrictions on project eligibility limits the Company's and stakeholder's insights into available, competitive options. And for this RFP, Staff finds no downside to removing many restrictions (e.g., energy storage, RPS certification, size limit, two-types of pricing, etc.,) if project selection still rests mainly on price and the determination of value as proposed in the RFP's evaluation and ranking methodology. If acquiring 490 MW by 2030 is truly an "all hands on deck" moment, restricting participation – as this RFP currently does – would appear to be counterproductive.

Further, HB 2021's direction to consider community benefits by understanding what they are necessitates some evaluation of a bid's community benefits and impacts. However, the equity questionnaire does not reflect recent developments and is not mandatory. Without some sort of non-price scoring or sensitivity that attempts to capture/understand community benefits we lose a unique opportunity in this RFP to understand and learn while also undermining a key rationale for including SSRs in HB 2021.

Finally, Staff encourages the utility to adopt the changes proposed above and to make any additional improvements necessary to clarify the community benefits and impacts of SSR procurement and ensure a fair, competitive process that reflects HB 2021's evolving approach to the public interest, especially with regards to technical and economic feasibility. Such efforts will be necessary for the Commission to evaluate the prudence of any acquisition and to evaluate the steps PacifiCorp is making to demonstrate continual progress towards the HB 2021 reduction targets at reasonable costs to customers.

ITEM NO. RA1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: MARCH 5, 2024

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** ______N/A______

DATE: March 1, 2024

TO: Public Utility Commission

FROM: JP Batmale

SUBJECT: PACIFICORP:
(Docket No. LC 82)
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP). Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Adopt Staff's recommendations for additional direction to PacifiCorp as outlined in this memo.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (PUC or Commission) should acknowledge PacifiCorp's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PacifiCorp's CEP or decline to acknowledge the CEP.

Whether the Commission should adopt Staff's recommendations for additional direction to PacifiCorp.

Applicable Law

See Staff's February 20, 2024 public meeting memo for a full description of the Applicable Law to this docket.

Analysis

Purpose of Memo
The memo provides a final set of Staff recommendations to aid in Commissioner deliberation at the March 5, 2024 public meeting. These final recommendations are informed by the February 20, 2024 public meeting, the discussion of the Commissioners in that meeting, and subsequent review of the issues. For more background information behind these recommendations, please see Staff's previous public meeting memo, filed February 7, 2024, and associated comments from Stakeholders and PacifiCorp.

The approach guiding Staff's final suggested recommendations for Commissioner consideration are as follows:

- Elements of the IRP can be acknowledged in part.
- Based on Staff's interpretation of statute, the CEP cannot be acknowledged – in whole or in part – due to the CEP's failure to meet the standard in ORS 469A.420 to be in the public interest and consistent with the emissions reduction targets.
- Based on comments made by PacifiCorp at the February 20, 2024 public meeting, the April 2024 IRP/CEP Update is not a viable vehicle for any substantial new or revised analysis.
- All recommendations for any new or revised IRP/CEP analysis should focus on the 2025 IRP/CEP, which PacifiCorp plans to file in April 2025, and are based on an expectation that that IRP/CEP will be timely filed.
- Recommendations for the 2025 IRP/CEP should be kept to a minimum. The focus is on identifying the least number of analytic improvements or qualitative additions necessary to develop an IRP/CEP that leads to an acknowledgeable CEP.
- Additional recommendations are not new to this proceeding, but instead are drawn from previously stated expectations or stakeholder comments. Staff will continue to work with the Company and Stakeholders in the lead up to the 2025 IRP/CEP to implement the expectations identified in Staff's Round 2 comments.

Staff's final, suggested recommendations for Commissioner consideration are organized into two parts:

1. **Original Recommendations**: These come from Staff's Round 2 Comments. They are also included as Attachment A to Staff's February 20, 2024 public meeting memo. The recommendations include suggested strike throughs.

2. **Additional Recommendations**: There are three sources for these new recommendations. The first is Staff's stated expectations. The second is utility and stakeholder final comments and/or suggestions at the February 20, 2024 Public Meeting. The final source is the PacifiCorp IRP/CEP.

Original Recommendations
Table 1 below details Staff's original thirteen recommendations and includes Staff's suggested redlines as of the date of this memo.

Table 1, Revised Original Recommendations from Staff

Recommendation Description	Suggested Commissioner Action on March 5
# 1: Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.	Retain in full.
~~#2: Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.~~	Remove in full
#3: Do not acknowledge the LC 82 CEP ~~and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update~~.	Change.
#4: Do not acknowledge Action Plan item~~s 1h and~~ 2a.	Change.
#5: Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.	Retain in full.
#6: Direct PacifiCorp to provide specific baseline metrics ~~prior to filing its next~~ in the 2025 IRP/CEP to allow for measured progress towards CBI goals. ~~If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.~~	Change.

Recommendation Description	Suggested Commissioner Action on March 5
#7: Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG and environmental justice groups.~~in Q1 2024~~	Change.
#8: Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, environmental justice groups, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.	Change.
#9: The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.	Retain in full.
~~#10: Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.~~	Remove in full. *Staff will have more specific directions in next table.*
#10 (Formerly #11): ~~Direct PacifiCorp to update Action Plan Item 1g (Natrium) to reflect actual events since the IRP/CEP was filed in May 2023.~~ In the 2025 IRP/CEP, direct PacifiCorp to update Natrium assumptions to reflect actual events.	Revise.
#11 (Formerly #12): Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.	Retain in full.
#12 (Formerly #13): Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.	Retain in full.

Additional Recommendations

Table 2 below details additional recommendations Staff believes the Commissioners should consider in the acknowledgement order. Recommendations number 13 and 14 are recommendations that should have been included with the original thirteen but were not due to a Staff oversight. We apologize for the error and seek to correct that by including those recommendations below.

The other seven remaining recommendations are all forward looking. They are designed to help the PacifiCorp IRP team by providing clear expectations for the 2025 IRP/CEP.

The table below also includes the source of the recommendation and a short summary of the rationale behind the recommendation's inclusion. While the text may not exactly match a recommendation attributed to a stakeholder, Staff sought to capture the essence of the recommendation. Finally, many stakeholders made outstanding contributions to this IRP/CEP in written and verbal comments, which Staff greatly appreciates. Staff apologizes in advance for any potential oversights in recognizing the contribution of a stakeholder organization toward these additional recommendations.

Table 2, Additional Recommendations

New Recommendation Description	Source and Rationale
#13: Do Not Acknowledge Action Items 1c and 1d from the action plan because the Company has already taken these actions.	**Source**: Staff expectations. **Rationale**: Should have been included in original recommendation. Do not acknowledge action items already undertaken and not already acknowledged.
#14: Acknowledge Action Plan Items 3a through 3e, 5a, 6a, and 6b.	**Source**: PacifiCorp IRP Action Plan. **Rationale**: Should have been included in original recommendation.

New Recommendation Description	Source and Rationale
# 15: In the 2025 IRP/CEP model, PacifiCorp must: (1) demonstrate that simultaneous compliance with all state-level policies is feasible with the least-cost, least-risk Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP under multiple allocation paradigms; (2) include expected CBREs in the Preferred Portfolio and ensure that the Preferred Portfolio meets Oregon's Small Scale Renewable Requirement; (3) adopt best practices in resource adequacy modeling, including consideration of load and resource performance under multiple weather years and calculation of loss of load expectation and capacity contributions using probabilistic analysis.	**Source**: Staff's expectations; CUB, Sierra Club, and RNW comments. **Rationale:** An optimized preferred portfolio that reflects law and best practices.
#16: In the 2025 IRP/CEP, PacifiCorp shall include an analysis of forecasted costs and annual emissions of the Preferred Portfolio using only actual carbon prices in effect in 2025 through the 20-year planning horizon.	**Source**: CUB comments. **Rationale**: Better forecast of actual emissions. Provides insight into the potential continuation of historical underperformance of the fleet's emission reductions relative to IRP forecasts.
#17: In the 2025 IRP/CEP, PacifiCorp shall calculate and report the costs and GHG emissions associated with each portfolio assuming that GHG prices are not reflected in dispatch decisions but still included in investment and retirement decisions.	**Source**: Staff expectations. **Rationale**: Improve understanding of tradeoffs in CEP construction.
#18: In the 2025 IRP/CEP PacifiCorp shall provide an explanation of renewable cost assumptions and a comparison to recent pricing information from such organizations as National Renewable Energy Lab and Lazard.	**Source:** RNW comments **Rationale:** Improve transparency of resource costs in portfolio development.

New Recommendation Description	Source and Rationale
#19: In the 2025 IRP/CEP, PacifiCorp shall confirm that coal generator cost assumptions reasonably reflect the structure and terms of any associated fuel supply agreements or fuel supply plans. Categorize variable costs that affect dispatch as variable costs in the model with as much accuracy as reasonably possible.	**Source:** Sierra Club **Rationale:** Improved transparency in pricing of coal resources.
#20: In the 2025 IRP/CEP PacifiCorp shall report on steps that the Company took to reduce the magnitude of reliability and granularity adjustments, how the Company engaged with stakeholders on adjustments, and describe the methodology and report the resulting reliability and granularity adjustments by resource. Include any supporting work papers demonstrating the granularity/reliability adjustments in the Data Disk.	**Source:** Sierra Club, RNW, and Staff **Rationale:** Improve modeling and portfolio transparency.
#21: In the 2025 IRP/CEP PacifiCorp shall provide an update on PacifiCorp's efforts to secure Energy Infrastructure Reinvestment (EIR) financing from the DOE Loan Program Office. Assume EIR financing through the DOE Loan Program Office in the Preferred Portfolio or include a variant portfolio that optimizes resource additions and retirements under the assumption of EIR financing.	**Source:** Sierra Club **Rationale:** Very low-cost financing for renewables should be pursued. Future resources – for either the System or for Oregon ratepayers – will be less costly due to EIR financing.

<u>Conclusion</u>

The twenty-two final proposed recommendations above are designed to aid in Commissioner deliberation at the March 5, 2024 public meeting. The memo includes updated recommendations from Staff's previous memo ***and*** updated recommendations based on various sources and in response to learnings from the February 20, 2024 public meeting.

PROPOSED COMMISSION MOTION:

Acknowledge in part and not acknowledge in part PacifiCorp's 2023 IRP, per Staff's recommendations. Decline to acknowledge PacifiCorp's CEP. Adopt Staff's recommendations for additional direction to PacifiCorp as outlined in this memo.