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 Opening Comments

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1. Executive Summary

1.1 Background

Since 2000, the Oregon leadership has passed groundbreaking state legislation each decade that has reshaped Oregon's energy landscape. In 1999, it was SB 1149, which established the public purpose charge and created a role filled by Energy Trust of Oregon. In 2007, it was SB 838, which established a nation-leading Renewable Portfolio Standard. In 2016, it was SB 1547, which set a goal to eliminate coal from Oregon's electricity supply by 2030, doubled the state's RPS requirements, and codified energy efficiency as a least-cost resource. In 2021, it was HB 2021, which established Oregon, again, as a national leader in sustainable energy policy by requiring 100 percent reduction in baseline greenhouse gas (GHG) emissions by 2040, while also giving Oregon's communities a much greater stake and voice in the subsequent clean energy transition.

The Pacific Power (PacifiCorp, PAC, or Company) 2023 Integrated Resource Plan (IRP) is the Company's first IRP since the passage of HB 2021. Much like the Portland General Electric Company's IRP/Clean Energy Plan (CEP) (LC 80) it reflects both the promise and uncertainty of meeting all the goals of HB 2021.

Beyond HB 2021's ambitious decarbonization and community involvement goals, PacifiCorp's 2023 IRP must account for:

- Multiple federal bills creating unprecedented access to funding to spur the nation's energy transition to cleaner sources of power and more efficient end-use technology.
- Rules proposed by the US EPA—that will most likely go into effect in the Spring of 2024—that will dramatical shift how thermal generation can operate in less than a decade.
- The Oregon DEQ's Climate Protection Program, which will could accelerate electrification through its cap on most fossil fuel emissions in the state.
- Large, nascent utility markets pooling diverse sets of generation resources across the western US to improve reliability, meet environmental goals, and reduce operational costs.
- Climate change repercussions, including unpredictable weather patterns, deadly heat domes, and a stressed grid which Oregonians will rely on even more as the state decarbonizes.

Finally, the recent suspension of the 2022 All Source Request for Procurement (2022 AS RFP), has, to some extent, upended the nearly 18 months spent by the Company developing this IRP's Action Plan and much of the supporting analysis.[1]

The repercussions of the RFP suspension may also impact PacifiCorp's ability to meet HB 2021's 2030 GHG reduction goals as it suspends the process that could lead to the acquisition of the

[1] *See* UM 2193, PacifiCorp's 2022 All Source RFP, Notice, September 29, 2023 (suspending the 2022 AS RFP due to a variety of "key drivers," including wildfire liability, and noting that no final shortlist will be announced why the RFP is "paused").

first tranche of non-emitting resources since the passage of HB 2021. This raises the risks for the Company for later into the 2020's to acquire even more non-emitting resources.

Thus, Staff's and Stakeholder opening comments arrive under unprecedented circumstances that make navigating the uncertainties of this IRP and CEP challenging and call upon stakeholders for a higher degree of collaboration than ever before.

1.2 House Bill 2021

In 2021, Oregon passed House HB 2021 directing electric utilities to reduce GHG emissions associated with Oregon retail sales. Specifically, emissions must be 80 percent below the utility's baseline levels by 2030, 90 percent by 2035, and 100 percent by 2040. Beyond setting specific emissions targets, the bill also requires electric utilities to incorporate a more diverse set of resources to reach these targets. This includes a requirement that 10 percent of all Oregon generation come from small-scale renewable energy projects and that community-based renewable energy projects be actively evaluated by the utility and whether the cost and benefits of these projects account for the offsetting fossil fuel use.

Utility actions must also account for the resulting community impacts and benefits including:

- Providing environmental justice communities equitable access to affordable and clean energy;
- Addressing energy burden; and
- Helping communities through job creation, community ownership of clean energy resources, and realization of potential health benefits from reduced greenhouse gas emissions.

All these considerations, and more, must result in an electric utility resource plan, termed CEP, that the utility develops in collaboration with stakeholders, including representatives of environmental justice communities. The CEP must set forth a plan to meet emissions reduction targets by making continual progress while striking a balance between cost, risk, and community impacts and benefits for the utility's customers.

Oregon Public Utility Commission Staff (Staff) and stakeholders collaborated in Docket No. UM 2225 to develop HB 2021-based guidelines for the utility's first CEP filing. The Oregon Public Utility Commission (the Commission) adopted and memorialized these guidelines in Orders No. 22-206, No. 22-390, and No. 22-446.

1.3 Introduction to PacifiCorp's 2023 IRP/CEP

PacifiCorp filed its amended 2023 IRP and Oregon CEP as separate documents on May 31, 2023. PacifiCorp did not file a draft IRP, however the Company allowed for Round 0 comments, which largely mimicked the draft IRP process, giving stakeholders 30 days to file initial comments and PacifiCorp 30 days to respond.[2]

[2] Two orders issued by the Commission impacted the timing of PacifiCorp's IRP. First, that the IRP and CEP must be filed concurrently. Second, that the overall IRP process would include a Round 0 set of comments. *See In the Matter of PacifiCorp's*

Staff acknowledges the challenges involved in addressing HB 2021 requirements and appreciates PAC's efforts to engage stakeholders and add new voices to its planning process. The Company has gone to great lengths to begin the dialogue with stakeholders regarding community impacts and benefits, assessing GHG emission reduction pathways within the framework of the Multi-State Protocol (MSP) and in Oregon, acknowledging the need to consider and promote community scale and customer-sited resources in attempting to develop an overall strategy to balance and meet HB 2021 goals in a least-cost least-risk manner, while operating a multi-state utility. These efforts are important considerations in the Commission's acknowledgment decisions.

Staff's opening comments are meant to evaluate PacifiCorp's IRP and CEP through the lens of HB 2021. Staff's overall goal in this docket is to locate areas where the plans meet IRP guidelines and CEP requirements and guidance, assess where the plan falls short, and provide critical insights as all parties attempt to learn from this first and important attempt. Much like the PGE IRP/CEP comments Staff filed in Docket No. LC 80, Staff will note low regret actions or opportunities, key challenges possibly preventing implementation of planned actions, and key vulnerabilities that must be addressed.

1.4 Plan Overview

PacifiCorp's 2023 IRP stakes out an ambitious plan for the future. A brief summary of the supply-side acquisitions forecasted over the IRP's 20-year planning include: 9,100 MW of new wind; 7,900 MW of new solar; 8,100 MW of new storage; 1,500 MW of nuclear; 1,200 of non-emitting peakers; and over 1,100 miles of new transmission lines.[3]

Just within the 2024 to 2025 timeframe, PacifiCorp's originally-filed IRP proposes to secure approximately 1,800 MW of wind, and 500 MW of solar with 200 MW of battery storage capacity.[4] Beyond 2025, the preferred portfolio adds near-term, proxy resource selections, reflective of recent transmission cluster studies, so as to take advantage of PacifiCorp's expanding transmission system.[5] The IRP identifies resource economics and portfolio reliability as the two main drivers behind the proposed acquisition plans,[6] while various state climate policies influence resource selection.[7]

Underlying PacifiCorp's push for new resources are continued population growth, electrification, and large, new commercial loads.[8] Specifically, the Company forecasts Oregon's load to increase at five percent compounded annual load growth over the next ten years due

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2023 Integrated Resource Plan, Docket No. LC 82, Order No. 23-131 (April 6, 2023); *In the Matter of PacifiCorp's 2021 Integrated Resource Plan*, Docket No. LC 77, Order No. 23-011 (January 26, 2023).

[3] LC 82 PacifiCorp 2023 IRP, Executive Summary, May 31, 2023, page 2.

[4] LC 82 PacifiCorp 2023 IRP, Executive Summary, May 31, 2023, page 35. Staff notes that this is all now called into question.

[5] LC 82 PacifiCorp 2023 IRP, Modeling and Portfolio Selection Results, May 31, 2023, page 274.

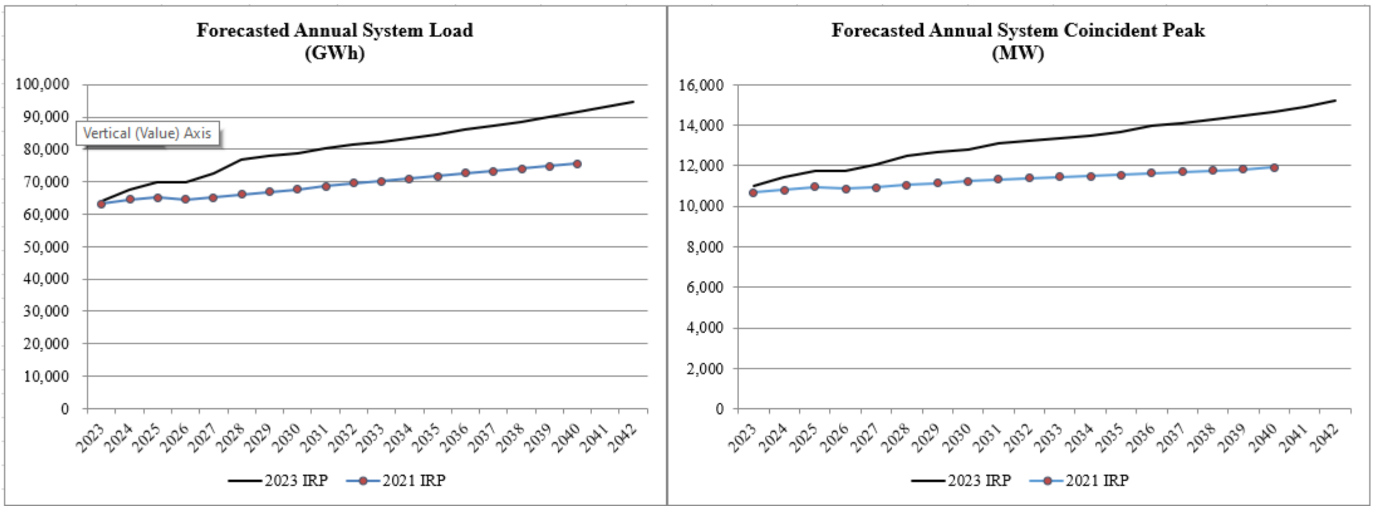
[6] LC 82 PacifiCorp 2023 IRP, Action Plan, May 31, 2023, page 367.

[7] LC 82 PacifiCorp 2023 IRP, Action Plan, May 31, 2023, page 367.

[8] See LC 82 PacifiCorp 2023 IRP, Figure 9.52, May 31, 2023, page 314; see also LC 82 PacifiCorp response to Staff DR 67, August 15, 2023.

almost entirely to the arrival of large, new commercial loads beginning in 2024.[9] PacifiCorp's system will grow at compounded annual growth rate of 2.69 percent over the next ten years.[10] Consequently, Oregon's share of the PacifiCorp system load will rise from about 25 percent in 2023 to over 30 percent by 2030. Given HB 2021's GHG reduction targets, along with the bill's 10 percent SSR requirements, this new growth creates planning complexities and opportunities, beyond typical financial and reliability concerns.

Figure 1: Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings) – PacifiCorp Workpapers.[11]



Amidst this forecasted growth, the 2023 IRP also proposes changes to PacifiCorp's fleet of coal generating facilities compared to the plan outlined in 2021. Four more coal plants will join Jim Bridger units 1 and 2 in converting to natural gas by 2030. Of PacifiCorp's 22 coal units, the 2023 IRP details the retirement or gas conversion of 13 units by 2030 and 20 units by 2032.[12] While the sum total of these activities will reduce the forecasted overall emissions of the PacifiCorp system, near-term emissions will increase. [13] The Company notes that emissions reductions in the 2023 IRP are ultimately driven by PacifiCorp's economic decisions to eventually replace its fossil fuel fleet; state carbon policies only influence resources selected.[14] Ultimately, the decisions to replace, convert, and/or retire fossil fuel generation is driven by economics and reliability, which raises questions about the costs of HB 2021 compliance.

PacifiCorp's CEP and resulting CEP Portfolio build upon the 2023 IRP preferred portfolio and action plan.[15] Notable from an analytic and cost perspective, the CEP Portfolio stacks Oregon's

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[9] LC 82 PacifiCorp 2023 IRP, Volume II, Appendix A, May 31, 2023, page 2; LC 82 PacifiCorp 2023 IRP, Modeling and Portfolio Selection, May 31, 2023, page 314; see also PacifiCorp response to Staff DR 69, August 15, 2023, combined with LC 82 PacifiCorp 2023 IRP, Workpapers Chapter 1, Figure 1.7, May 31, 2023.
[10] LC 82 PacifiCorp 2023 IRP, Volume II, Appendix A, May 31, 2023, page 1.
[11] LC 82 PacifiCorp 2023 IRP, Workpapers Chapter 1, Figure 1.7, May 31, 2023.
[12] LC 82 PacifiCorp 2023 IRP, Modeling and Portfolio Selection Results, May 31, 2023, page 252.
[13] LC 82 PacifiCorp 2023 IRP, Executive Summary, May 31, 2023, page 20.
[14] LC 82 PacifiCorp 2023 IRP, Executive Summary, May 31, 2023, page 367
[15] LC 82 PacifiCorp 2023 CEP, Resource Planning, May 31, 2023, page 55.

ten percent small scale renewables (SSR) mandate atop the 2023 IRP's preferred portfolio. The addition of these new SSR resources, however, does not lead to an 80 percent reduction in GHG emissions by 2030. PacifiCorp must take an additional step of reallocating its resource portfolio to achieve HB 2021's goals.[16] The 2023 CEP illustrates "pathways" that undergird the CEP Portfolio and are designed to demonstrate how particular assets—and its costs—could be assigned to Oregon to achieve HB 2021 compliance. In fact, the CEP Portfolio itself raises the NPVRR cost to Oregon ratepayers by an additional $268 million (M) over the IRP's non-CEP preferred portfolio.[17] The reallocation pathways further increase costs to Oregon customers for Pathways 1 and Pathways 2 by $1,030M to $616M respectively.[18]

PacifiCorp notes that nearly all low-regrets near-term actions lead back to a robust, near-term procurement strategy; the greatest risk to the IRP is under procurement. Accordingly, PacifiCorp's amended IRP from May 2023 pointed to the conclusion of the 2022 AS RFP and the launch of the 2024 AS RFP as critical. The recent pause of the 2022 AS RFP, therefore, raises substantive questions about the continued relevancy of several elements of the 2023 IRP's action plan and form the basis of many of Staff's Round 1 comments.[19]

1.5 Low Regrets, Near-term Actions

In LC 80, OPUC Staff articulated the characteristics of "Low Regrets, Near-Term" actions expected from IRP/CEPs to meet HB 2021's goals.[20] In summary, they are:

1. A flexible approach towards acquiring energy and capacity resources.
2. Pursuing all energy efficiency and demand response resources that minimize long-term cost and risk.
3. Pursuing the full CBRE potential resources through a range of actions and finding opportunities to incorporate resiliency-focused projects.
4. Pursuing a broad range of options to overcome constraints and offer creative solutions and alternatives.

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[16] LC 82 PacifiCorp 2023 CEP, Greenhouse Gas Emissions, May 31, 2023, page 73.
[17] See LC 82 PacifiCorp 2023 CEP, Clean Energy Plan Data Templates, Feb. 22, 2023, page 52.
[18] Originally these figures were $394 million and $530 million per the 2023 PacifiCorp CEP, page 67, and the 2023 PacifiCorp Clean Energy Plan Data Template. However, per an October 18, 2023 errata filing, the prices were significantly raised. Staff issued a DR on October 20, 2023, to determine the reason for the increase and timing.
[19] See generally, UM 2193 PacifiCorp's 2022 All Source RFP, Notice, September 29, 2023.
[20] LC 80 Portland General Electric 2023 IRP/CEP, Staff Round 1 Comments, July 27, 2023, page 4.

As shown below, the 2023 IRP Action Plan details broad categories of near-term actions that have direct impacts on Oregon ratepayers.

Coal Plant	Acquisitions	Transmission Investments	DSM
• Four additional Coal-to-Gas conversions • Six emission reduction investments for OTR Compliance**	• Complete 2022 All-Source (AS) in 2023** • Post 2024 AS RFP in Q3 2024** • Continue Natrium permitting	• EGS Segment F placed into service • EGW Segment D.1 placed into service • B2H continued support • Conduct local reinforcements • Initial permitting and development of other investments	• 5,000 MW of energy efficiency capacity savings • 929 MW of demand response capacity savings

***- Impacted by recent events. These Action Plan items from the May 31, 2023 IRP may need to be changed or removed.*

1.6 Key Challenges

Staff has identified several key dependencies to the 2023 IRP's preferred portfolio that pose challenges to the success of the IRP's near-term resource strategy and general implementation.

Community Engagement

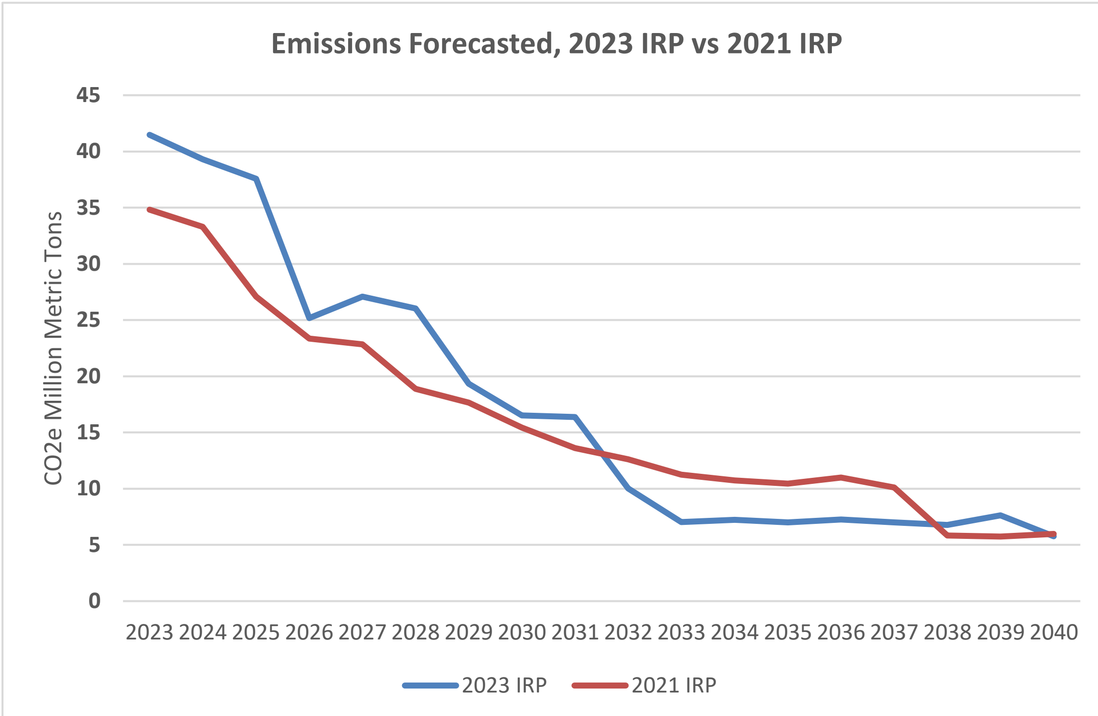
PacifiCorp continues to engage community on its CEP. Staff is concerned that the level of engagement shared in the CEP is not compliant with Commission Order No. 22-390 and HB 2021. The Company has made efforts to enhance transparency through consolidated information hubs and a recently published Feedback Tracker, but it has not articulated how community feedback translates into actionable plans, including portfolio selection. While, the Company has been making progress engaging with tribal communities, the Company has had difficulty incorporating the perspectives of these communities into the CEP. These deficiencies result in the absence of any tribal representation to inform planning. Staff is concerned that these gaps indicate a lack of accountability, community-centered planning actions, and essential perspectives.

Risk of Implementation and Costs to Meet Emissions Targets

Oregon's path to compliance rests on the success of the Company's strategy to acquire the necessary resources to reduce overall system emissions. As seen below, near-term emissions in the 2023 IRP increase compared to the emissions forecast in the 2021 IRP.[21] Despite this increase, PacifiCorp forecasts a relatively steep decline in emissions so that by 2032 the 2023 IRP's emissions are lower than those forecast in the 2021 IRP. Given the new uncertainty around the 2022 All-Source RFP, in addition to the vast near-term acquisitions and reliance on emerging technologies, Staff is concerned about the implementation and cost risks associated with achieving emission reductions.

[21] See LC 82, PacifiCorp 2023 IRP, Executive Summary, May 31, 2023, pages 17-18; LC 82 PacifiCorp 2023 IRP, Figure 1.8, May 31, 2023, page 17.

***Figure 2:* Forecasted Emissions between PacifiCorp IRPs**



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

HB 2021 requires certain amounts of Small-Scale Renewables (SSR) and encourages Community-Based Renewable Energy (CBRE) development. PacifiCorp's CEP identifies the need for 490 MW of new incremental resource to meet HB 2021's 10 percent SSR requirement by 2030.[22] PacifiCorp also presents the possibility of adding 100 MW of CBRE projects—in the form of proxy solar (80 MW) and proxy hydro (20 MW) resources—installed as early as 2027.[23] Staff greatly appreciates how clearly the Company articulates its SSR needs, the CBRE potential for this IRP, and the costs, benefits, and risks associated with these projects. Nevertheless, Staff comments seek to clarify what constitutes an SSR and CBRE, if more channels could be explored to acquire these, and how strategic investments in the Oregon transmission and distribution system could lower the costs of these projects.

1.7 Key Vulnerabilities

Below are the key vulnerabilities to PacifiCorp's IRP and CEP that Staff has identified. Without further discussion in this IRP process, Staff may be unable to recommend acknowledgment of the IRP, CEP, and/or resource actions. They will be explored in more detail in subsequent sections. Staff seeks to work with PacifiCorp and other stakeholders to address these issues.

[22] LC 82 PacifiCorp 2023 CEP, Resource Planning, May 31, 2023, page 63.
[23] LC 82 PacifiCorp 2023 CEP, Community-Based Renewable Energy, May 31, 2023, page 50.

State Policy Compliance in IRP Portfolios

Staff is concerned that the IRP Preferred Portfolio does not meet Oregon state energy policies and does not clearly demonstrate that PacifiCorp can simultaneously comply with GHG and clean energy policies in Oregon, Washington, and California. Staff recommends that PacifiCorp update its portfolio optimization modeling in the future to ensure that simultaneous compliance with all state GHG and clean energy policies, including HB 2021, is feasible in all IRP portfolios. In the current plan, Staff requests that PacifiCorp re-optimize the IRP Preferred Portfolio and other top performing IRP portfolios to incorporate Oregon's SSR requirement and provide additional information to demonstrate that the updated Preferred Portfolio can simultaneously comply with GHG and clean energy policies in Oregon, Washington, and California.

CEP Pathways

Staff understands that demonstrating future compliance with HB 2021 requires PacifiCorp to make assumptions about future allocation strategies. Staff finds the concept of allocation pathways in the CEP to be an acceptable way to demonstrate how the Company might achieve compliance with the HB 2021 GHG targets. However, Staff requests that PacifiCorp apply this concept in a way that provides more useful information for evaluating its resource plan. Staff would like more transparency into how other top performing portfolios compare to the Preferred Portfolio with respect to HB 2021 compliance and how flexible or rigid allocation must be to ensure HB 2021 compliance in each portfolio. For example, some portfolios may require more stringent allocation strategies to achieve HB 2021 compliance than others and this is information that Staff would find useful for understanding the implications of selecting one portfolio over another. Staff requests that PacifiCorp report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (re-optimized to reflect Oregon's SSR requirement) under various allocation pathways and that PacifiCorp answer some specific questions regarding portfolio selection and allocation in the context of HB 2021 compliance, especially given the recent errata filing which greatly impacted CEP Pathways costs.

Emerging Tech

The preferred portfolio relies on the availability of both nuclear power and non-emitting, peaking technologies to provide over 1,000 MW of capacity by 2030. Staff appreciated the inclusion of multiple portfolios – including two "no Natrium" portfolios – to illustrate the increased costs if these technologies were not included in the preferred portfolio. However, Staff still seeks to better understand how the Company is using this insight to inform its portfolio strategy. What does PacifiCorp plan to do if these technologies do not materialize? What milestones are the Company tracking so as to understand when a course correction is necessary? Additionally, the Oregon CEP Portfolio Pathway 2 includes the development of a large, non-emitting resource prior to 2030 under CEP Pathway No. 2.[24] Staff seeks to better understand what specific activities are being undertaken during the Action Plan time horizon to have some sort of new technology in place by 2030 and at what point PacifiCorp proposes to pivot from emerging technology to more conventional technology (i.e., solar and storage) to

[24] LC 82 PacifiCorp 2023 CEP, Greenhouse Gas Emissions, May 31, 2023, page 81.

meet CEP Pathway No. 2 emission reductions. Further, Staff seeks to understand why alternatives such as medium-term (5 to 10 year), bilateral contracts for slices of hydro capacity—that can function as a type of capacity bridge, if not a hedge from implementation risks—are not being actively explored in the Action Plan to reduce the near-term risks around deploying emerging technology.

Coal-to-Gas Conversions

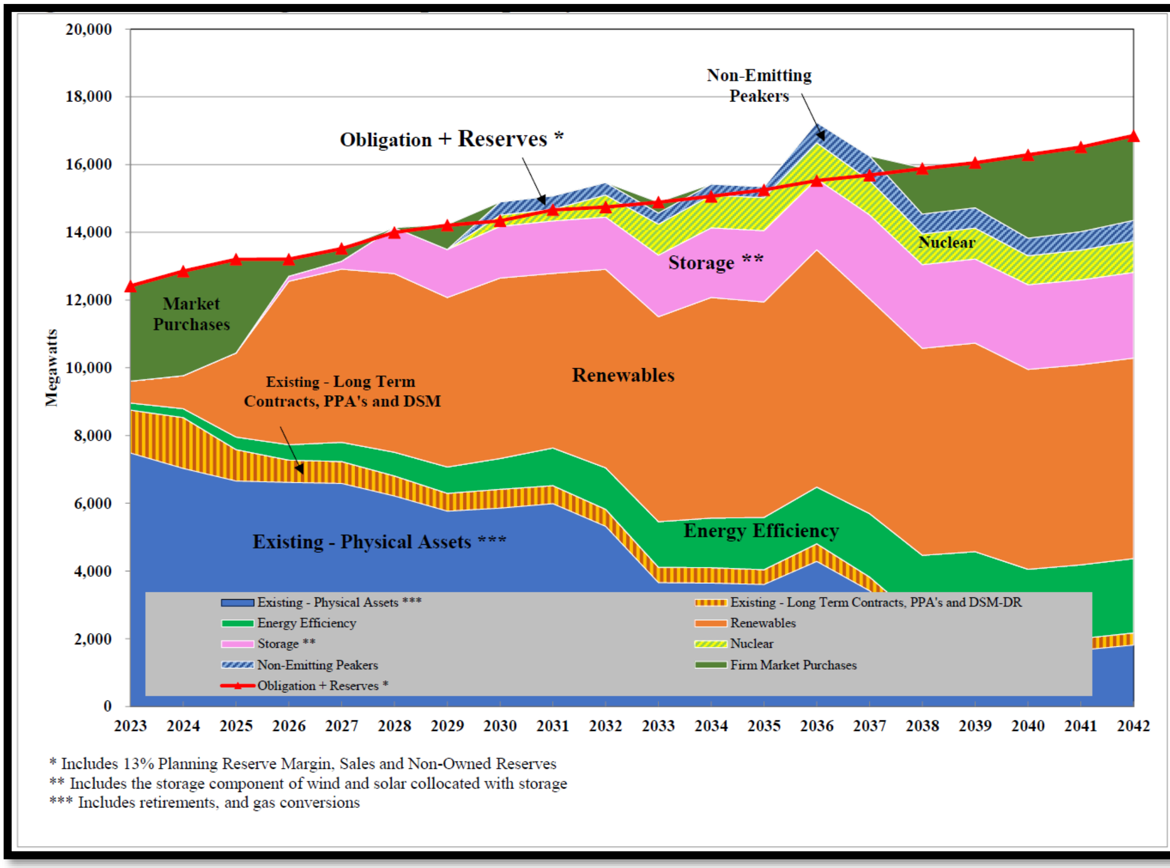
The Preferred Portfolio relies on the conversion of Jim Bridger units 1-4 and Naughton units 1 and 2 from coal to gas (amounting to 1,769 MW[25]) between 2024 and 2030.[26] Staff understands that coal-to-gas conversions may support resource adequacy while reducing the emissions intensity of the Company's thermal fleet. However, Staff is concerned that the Company's strategy deviates so significantly from PacifiCorp's 2021 plan, which only called for coal-to-gas conversion of Jim Bridger units 1 and 2 and called for the retirement of Naughton units 1 and 2 in 2025. PacifiCorp claims that these coal-to-gas conversions will serve as a bridge to cleaner alternatives, like nuclear and non-emitting peakers, and has the gas units scheduled to retire by 2038, leaving only 8-14 years to recover the associated costs. Staff requests additional analysis on coal-to-gas decisions and seeks further explanation from PacifiCorp on: why coal-to-gas conversions arose so prominently in this plan, but not in the 2021 IRP; how the Company evaluated the risk of regret for the coal-to-gas conversions; how the Company took into account HB 2021's GHG targets in the coal-to-gas conversion planning decisions; and given how quickly its coal retirement plans have changed, under what future circumstances the Company might expect to expand upon or pull back from the coal retirement and coal-to-gas conversion plans or extend the lives of the converted gas units.

RFP Suspension

As noted in several places previously, the 2023 IRP Preferred Portfolio seeks to add sizeable amounts of new generation over the next decade and beyond. The economic, reliability, and emission reduction benefits from adding so many resources over the next twenty years was so pronounced that PacifiCorp identified that the main procurement risk to this IRP was not over procurement, but rather the inability to procure enough resources in the required timeframe.[27] The Company's recent suspension of the 2022 AS RFP casts a shadow of uncertainty over the action plans, much of the IRP's supporting analysis, and the CEP compliance pathways put forth.[28] Further, the near-term acquisition of new resources also reduced one of the IRP's greatest sources of risk: market reliance to meet increasing load.[29]

[25] LC 82 PacifiCorp 2023 IRP, Table 9.12, May 31, 2023, page 266.
[26] LC 82 PacifiCorp 2023 IRP, Executive Summary, May 31, 2023, pages 18-19.
[27] LC 82 PacifiCorp 2023 IRP, Action Plan, May 31, 2023, page 375.
[28] UM 2193, PacifiCorp's 2022 All Source RFP, Notice, September 29, 2023.
[29] LC 82 PacifiCorp 2023 IRP, Figure 9.60, May 31, 2023, page 322.

Figure 3: **Meeting PacifiCorp's Capacity Needs with Preferred Portfolio Resources – *PacifiCorp Integrated Resource Plan*.**[30]



Staff's requests that PacifiCorp's reply comments describe how this delay impacts such things as the Preferred Portfolio's composition and NPVRR; the risk to HB 2021 compliance by 2030, if other investments are being similarly delayed; and if/when the RFP will move forward. Further, Staff hopes to better understand how realistic is this level of reliance on near-term renewables; what is the impact to such avoided cost elements as capacity for DSM and PURPA resources; the consequences of prolonged market purchases continuing past 2025; and, what alternatives should arise given these risks.

Action Plan Changes

As noted in the RFP Suspension subsection above, PacifiCorp reply comments will need to identify and explain changes to the following Action Plan items before Staff will be able to consider a position on acknowledgement:

- Action Plan Item 1h: Per the non-confidential response to Sierra Club Information Request (IR) No. 37, the proposed selective, non-catalytic reduction (SNCR) installations in this IRP is being reevaluated. PacifiCorp should clarify if this Action Plan Item should

[30] LC 82 PacifiCorp 2023 IRP, Figure 9.60, May 31, 2023, page 322.

be updated and run the analysis to comment on how this impacts the NPVRR and any emissions.

- All Action Plan Items Under Category 2: Please comment on the extent to which all New Resource Action Plan items need to be amended or changed. Please also comment on how the RFP pause impacts the pace of procurement in Preferred Portfolio's action plan. Please specifically address changes to Table 9.31.
- Action Plan Item 3e: Given the financial concerns raised in pausing the RFP in Docket UM 2193, please describe whether the preliminary permitting and planning for new transmission, as described in this action plan item, is impacted.

1.8 Conclusion

Staff commends PAC for its efforts in developing its 2023 IRP and first CEP following the passage of Oregon HB 2021. Clean energy policies, growing electrification, rising competition for renewable energy resources, considerations of community based and customer-sited resources and other resource-specific constraints—for example, transmission availability—are a few factors that have introduced new dimensions and challenges in utility resource planning. PAC has shown creativity in addressing these challenges. Staff identified several areas for improvement in PAC's current and future IRP and CEP and discusses them in the independent sections below.

2. Clean Energy Plan

2.1 Introduction

HB 2021 requires PacifiCorp and PGE to decarbonize their retail electricity sales with consideration for direct benefits and impacts to local communities. Running through the statute's language, as well as its legislative history, is the objective to minimize burdens for environmental justice communities as these utilities decarbonize. The foundation of HB 2021's decarbonization framework is the CEP. Within the CEP, utilities must consider an extensive list of equity benchmarks and community resource requirements to incorporate into their respective decarbonization plan.[31] The Commission has anticipated that it, stakeholders, and utilities will learn about the feasibility of these expectations after review of this first CEP.[32]

Staff's comments below address PacifiCorp's HB 2021 compliance pathways; responses to the Commission's Strategic Decarbonization Questions for long-term planning; proposed Community Benefit Indicators (CBIs) and metrics; Community-Based Renewable Energy (CBRE) acquisition, including small scale renewables; Community Engagement progress; and the new Resiliency Framework. In sum, while recognizing this is the first CEP, Staff requests key information to understand the implications of HB 2021 on PacifiCorp's resource plans and whether Staff can recommend CEP acknowledgment.

2.2 HB 2021 Compliance Pathways

PacifiCorp's CEP presents two illustrative pathways to bring Oregon into compliance with HB 2021 emissions standards. Both pathways represent alternative allocation strategies for the same system-wide resource portfolio, the CEP Portfolio. The CEP Portfolio is based on the IRP preferred portfolio, but with adjustments to meet Oregon's small-scale renewables (SSR) requirements. The Company reports that the CEP portfolio increases costs to Oregon customers relative to the Preferred Portfolio by $268M, under the 2020 Protocol.[33] The HB 2021 compliance pathways impact Oregon-allocated costs and Oregon-allocated GHG emissions, but do not impact system-wide costs or GHG emissions. In Pathway 1, PacifiCorp caps the allocation of thermal resources to Oregon in order to achieve DEQ reported emissions levels that comply with the GHG targets in HB 2021. This re-allocation increases costs to Oregon customers by $1,030M relative to the 2020 Protocol.[34] In Pathway 2, PacifiCorp assumes that new large commercial load in Oregon is met through voluntary renewables and these costs are allocated

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[31] Utilities must account for the resulting community impacts and benefits, including providing environmental justice communities equitable access to affordable and clean energy, addressing energy burden, helping communities through job creation, community ownership of clean energy resources, and realization of potential health benefits from reduced greenhouse gas emissions. See ORS 469A.425(2)(a).

[32] *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 at 1 (Oct. 25, 2022) *corrected,* Order No. 22-470 (Dec. 5, 2022).

[33] See LC 82 PacifiCorp 2023 CEP, Clean Energy Plan Data Templates, Feb. 22, 2023, page 52.

[34] Originally this amount was $394 M in the 2023 PacifiCorp Clean Energy Plan Data Template. See LC 82 PacifiCorp 2023 CEP, Clean Energy Plan Data Templates, Feb. 22, 2023, page 52. The October 18, 2023 errata filing raised this amount by over $600M to $1,030M. See LC 82 PacifiCorp Errata Filing for Clean Energy Plan, October 18, 2023, page 68.

to Oregon, increasing costs by $616M over the 2020 Protocol.[35] Staff is concerned about the very recent jump in the cost of each compliance pathway and is seeking to find out more about the reasons for this increase and its calculation.

In its response to OPUC Staff DR 131, PacifiCorp notes that the allocation pathways presented in the CEP "were not derived through an optimization process" and "are suggestions made to illustrate how compliance could be achieved."[36] Ultimately, as PacifiCorp notes, matters related to allocation will be resolved in "Oregon and downstream processes, such as ongoing Multi-State Process (MSP) and request for proposals (RFP) proceedings."[37] Staff discusses the Company's approach to the SSR requirements in Section 3.7.4. In this section, Staff focuses on PacifiCorp's approach to achieving its Oregon GHG targets. Further the increased compliance pathway costs underscores Staff's position that PacifiCorp's allocation methodology needs to be refined in relation to both the IRP and MSP.

2.3 DEQ Review

ORS 469A.420(b) states that DEQ "shall use the method of measuring greenhouse gas emissions set forth in ORS 468A.280 to verify the projected greenhouse gas emissions reductions forecasted in a clean energy plan of an electric company or the information provided by an electricity service supplier under subsection (3) of this section." DEQ verification is currently in progress.

2.4 State Policy Compliance in IRP Portfolios

Staff is concerned PacifiCorp has not incorporated HB 2021 requirements into its IRP analysis in a holistic fashion and has instead treated HB 2021 compliance as an after-the-fact exercise in the CEP. Under HB 2021, the two plans must be developed concurrently.[38] And, under some circumstances, this sequential approach could lead to higher system-wide costs. However, in this plan, PacifiCorp asserts that they can meet its Oregon GHG targets through allocation, rather than incremental resource actions, beyond SSRs, because they are already planning to bring enough non-emitting resources into its IRP preferred portfolio on the basis of economics to meet Oregon's requirements. In other words, even if they were to apply the HB 2021 GHG constraints in its portfolio optimization, those constraints would not bind. This is an important finding from the Company's IRP, if it in fact holds. It would effectively mean that Oregon's GHG constraints would not increase PacifiCorp's system-wide costs.

Staff is further concerned that PacifiCorp's after-the-fact approach could lead to an IRP Preferred Portfolio that cannot simultaneously meet PacifiCorp's various state-level GHG and clean energy policy requirements. From Staff's perspective, demonstrating that HB 2021

[35] Originally this amount was $530 M in the 2023 PacifiCorp Clean Energy Plan Data Template. See LC 82 PacifiCorp 2023 CEP, Clean Energy Plan Data Templates, Feb. 22, 2023, page 52. The October 18, 2023 errata filing raised this amount by over $86M to $616M. See LC 82 PacifiCorp Errata Filing for Clean Energy Plan, October 18, 2023, page 68.
[36] PacifiCorp response to Staff DR 131, Aug. 23, 2023.
[37] PacifiCorp response to Staff DR 131, Aug. 23, 2023.
[38] ORS 469A.415(1).

compliance is feasible requires PacifiCorp to demonstrate that it is feasible while also complying with other state policies to ensure that its plan is internally consistent.

Staff recognizes that it may not be trivial for PacifiCorp to bring Oregon's GHG constraints into its portfolio optimization in the IRP because Oregon's DEQ-reported GHG emissions will depend on allocation. Staff agrees that the IRP/CEP is not the appropriate venue for determining or estimating future allocation and that this poses challenges for PacifiCorp in both considering Oregon GHG constraints in the IRP and reporting out Oregon-specific information in the CEP. However, this does not absolve PacifiCorp from responsibility for meaningful consideration of HB 2021 within the IRP itself. Staff believes that, even without presuming an allocation strategy, the IRP can still ensure that compliance with state-level GHG and clean energy policies is feasible under one or more internally consistent allocation strategies. Furthermore, Staff believes that the IRP can determine whether HB 2021 compliance requires additional resources or different resource actions than would not otherwise be needed to meet system needs. Staff views this information as foundational to understanding the implications of HB 2021 on PacifiCorp's resource plans.

Requests:

1. **In Reply Comments, PacifiCorp should confirm whether compliance with the HB 2021 GHG targets is feasible with the Preferred Portfolio and should clarify whether any additional resources or different resource actions are/were needed in the Preferred Portfolio to comply with the HB 2021 GHG targets.**

   In answering these questions, PacifiCorp should make it clear whether the small-scale renewables in the CEP Portfolio are needed solely to meet its Oregon Small-Scale Renewable requirement or whether some portion of them is also needed to ensure that meeting the HB 2021 GHG targets is feasible. Note that "feasible" in this context means that there are one or more allocation strategies that result in DEQ-reported GHG emissions that hit the reduction targets while also complying with other state GHG and clean energy policies.

2. **In the next IRP, PacifiCorp should incorporate a constraint in its portfolio optimization to ensure that each portfolio can feasibly meet Oregon's GHG targets while also meeting requirements for other state GHG and clean energy policies. This constraint should not necessarily presume a specific future allocation approach, but should, at a minimum, ensure that simultaneous compliance with all state policies is feasible under one or more allocation strategies.**

2.5 CEP Compliance Risks

Staff is concerned that PacifiCorp's allocation pathway analysis obscures potential compliance risks. The CEP compliance pathways presented in the CEP amount to an allocation exercise that only remove emissions from Oregon rates. For example, it is not clear what the consequences for HB 2021 compliance would be if the Company is unable to procure non-emitting generation at the pace reflected in PAC's preferred portfolio. If the system-wide emissions do not fall as rapidly as projected by the Company, at what point would PacifiCorp need to take incremental action (beyond re-allocation) to comply with HB 2021 while also meeting other state GHG and clean energy policies? And what would be the cost impact of these actions to Oregon customers?

To the extent that incremental resource actions (beyond re-allocation) may be needed in the future to specifically meet Oregon's GHG targets, Staff would like to encourage the Company and stakeholders to begin discussing how this might be achieved. Staff suggests that the Company and stakeholders discuss the potential opportunities and tradeoffs in pursuing Oregon-specific non-emitting resources with additionality, whether for voluntary customers or for Oregon customers as a whole.

Request:

3. **In Reply Comments, PacifiCorp should show what portion of its non-emitting generation additions in the Preferred Portfolio is needed for compliance with HB 2021 GHG targets, what portions are needed for compliance with other state GHG and clean energy policies, and what portion contributes to the remaining system mix. PacifiCorp should identify the circumstances in which incremental action (beyond re-allocation) would be required to comply with the HB 2021 GHG targets.**

2.6 CEP Cost Allocation

Staff appreciates the difficulty in commenting on Oregon allocated costs and emissions in the CEP without presuming a future allocation strategy. Considering this, Staff appreciates that PacifiCorp's allocation pathways approach provides the opportunity for additional understanding and transparency into future HB 2021 compliance once the threshold questions, including Staff's question regarding HB 2021 feasibility, have been answered in the IRP.

From Staff's perspective, PacifiCorp's pathways approach could provide value to the planning process to the extent that it:

- Identifies where there might be constraints related to allocation that would affect the Company's ability to comply with HB 2021;
- Weighs tradeoffs in the pace of GHG reductions and cost impacts to Oregon; and
- Provides transparency into the potential implications of alternative IRP portfolios for HB 2021 compliance and Oregon-allocated costs and GHG emissions.

For example, the explorations described above could be undertaken for the Preferred Portfolio and a set of variant portfolios to understand whether some portfolios have more stringent allocation requirements to comply with HB 2021 or to achieve various paces of Oregon-allocated GHG reductions.

However, Staff does not gain these insights from the two illustrative pathways that PacifiCorp presents in the CEP. PacifiCorp's CEP pathway analysis—built atop of and essentially independent from the Preferred Portfolio and variants— are too limited to provide insights into

HB 2021 compliance. Opportunities and risks, tradeoffs between cost and the pace of GHG reductions, and potential implications for future cost allocation cannot be gleaned from an approach outside of an optimized portfolio that is also built explicitly to meet forecasted GHG reduction requirements.

Staff is also concerned that PacifiCorp's Oregon-allocated cost calculations are incomplete and potentially misleading, especially in light of the recent errata filing. Staff understands why adding small-scale renewables to the IRP Preferred Portfolio would increase costs to Oregon customers, but does not believe that allocation to achieve the GHG target should necessarily increase costs to Oregon customers. PacifiCorp states multiple times in the IRP that HB 2021's GHG constraint ***is not*** driving resource additions in the Preferred Portfolio. In principle, if the HB 2021 GHG constraint can be met without incremental resources or resource actions relative to the Preferred Portfolio (after accounting for SSRs), then the system-wide incremental cost of that constraint should be zero and meeting it should not increase costs to the system or costs to Oregon customers. Staff understands theoretically that reducing GHG emissions at a more rapid pace through allocation could result in additional costs to Oregon customers, but it is not clear if this is what's causing the cost increases the PacifiCorp is reporting.

Staff notes that the cost differences between the 2020 MSP Protocol and the two CEP pathways could also be in part due to incomplete cost accounting. PacifiCorp notes in its response to AWEC DR No. 2 that, "The IRP does not include the embedded costs of existing owned resources, so a lower allocation of existing resources, where embedded costs are not represented, and more new proxy resources that incur capital investment costs, will naturally result in higher estimated PVRR."[39] Staff questions how the Oregon-allocated cost estimates for Pathways 1 and 2 can be meaningful without accounting for the full cost of existing resources.

Another area regarding CEP pathways and MSP that Staff believes warrants further explanation is the impact of market-based solutions on HB 2021 compliance given PacifiCorp's forecasted mix of resources. Staff believes that some cost allocation could be avoided if the market dispatch can sufficiently and accurately price emissions compliance. CAISO may be able to identify the cheapest resource mix to achieve HB 2021 compliance. Accordingly more information from PacifiCorp about how market participation and market design might impact the Company's Oregon-allocation emissions would be helpful. Participation in a large regional market may be a lower cost solution that provides market-based incentives to clean energy. Staff believes participating in a day-ahead market could promote an even more rapid lowering of emissions overall, beyond those seen int this IRP's preferred portfolio, as opposed to shuffling resources such that emissions are only impacted on an accounting basis.

<u>Requests:</u>

4. In Reply Comments, PacifiCorp should clearly identify the system-wide NPVRR impacts of meeting the SSR requirement.

[39] PacifiCorp response to AWEC DR 2, July 6, 2023.

5. **In Reply Comments, Staff requests that PacifiCorp describe the extent to which system-wide cost increases would be needed relative to the Preferred Portfolio to achieve Oregon's GHG targets (excluding the SSR requirement).**
6. **In Reply Comments, PacifiCorp should update the Oregon-allocated Pathway 1 and Pathway 2 costs to account for any benefits associated with reducing the allocation of existing resources to Oregon.**
7. **In Reply Comments, PacifiCorp should state how it anticipates EDAM participation might affect its Oregon-allocated emissions, and if there are any specific market mechanisms that the company is advocating for that would promote GHG reductions on its system to help meet HB 2021 targets.**
8. **In Reply Comments, PacifiCorp should provide quantitative answers to the following questions, to the extent possible:**
    - **Are there any existing or potential constraints related to allocation that would affect the Company's ability to comply with HB 2021?**
    - **What are the tradeoffs between the pace of GHG reductions and cost impacts to Oregon under different types of allocation strategies?**
    - **What are the potential implications of adopting alternative IRP portfolios on HB 2021 compliance and Oregon-allocated costs and GHG emissions under different types of allocation strategies?**

2.7 Hourly Analysis

In LC 80, Staff has requested that Portland General Electric conduct hourly system balancing analysis to ensure that the forecasted GHG emissions are achievable under reasonable operating assumptions. Upon preliminary review, Staff does not see this issue arising with PacifiCorp's IRP/CEP. Staff's understanding is that the system-wide GHG emissions in PacifiCorp's IRP are based on the Short Term (ST) model run and that Oregon-allocated emissions are based on these dispatch results and DEQ's PacifiCorp-specific GHG accounting rules. PacifiCorp explains that "[t]he ST model accounts for resource availability and system requirements at an hourly level."[40] While no issues with PacifiCorp's approach have been identified at this time, Staff will continue to look into PacifiCorp's GHG calculations to ensure that they reflect achievable emissions under reasonable operating assumptions.

2.8 Strategic Decarbonization Questions

Commission Order No. 22-446 posited five high level planning questions to be addressed in the CEP.[41] These questions provide an opportunity for the Commission to understand the big picture implications of planning under HB 2021, gain key insights into potential obstacles inherent to the utility's plan, and understand what can be done to address those obstacles now and in the future. The goal of these questions was to reconcile the limited time available to develop the first CEP with concerns about how useful the traditional IRP approach could be within the current landscape of uncertainty and resource need.

[40] LC 82 PacifiCorp 2023 IRP, Resource Options, May 31, 2023, page 215.

[41] *In the Matter of Near-term Guidance on Analytical Improvements in the First Clean Energy Plans and Associated Integrated Resource Plants*, Docket No. UM 2225, Order No. 22-446, Appendix A at 30 (Nov. 14, 2022).

PacifiCorp's CEP is upfront about the challenge of complying with HB 2021 in 2040. The Company notes that both new technologies and new markets will be needed to meet the GHG target in 2040 in a manner that is not cost prohibitive. PacifiCorp points to its pursuit of new technologies, like advanced nuclear, and its participation in WRAP and EDAM as examples of how it is engaging around potential solutions in the near term. PacifiCorp also highlights load growth as a potential risk to future HB 2021 compliance, especially the addition of large un-forecasted loads.[42]

Notably, the Company's plan relies on resources in 2030 that have large implementation risks and/or could carry a significant risk of regret, including nuclear, non-emitting peakers, and coal-to-gas conversions. Staff appreciates that PacifiCorp's IRP quantitatively addresses these risks by testing alternatives in portfolio analysis (including, but not limited to P05, P06, P12, P23, and P24), but the Company does not bring these insights into the CEP to shed light on how these risks could affect PacifiCorp's HB 2021 compliance strategy and the associated Oregon-allocated costs and GHG emissions. To this end, PacifiCorp states that the near-term advancement of emerging technology, such as nuclear and non-emitting peaking resources is critical to the transition of the PAC coal fleet.[43] It is therefore not clear to Staff whether certain elements of PacifiCorp's preferred portfolio are needed for HB 2021 compliance or at what junctures deviations from PacifiCorp's plans could compromise the Company's ability to comply with HB 2021 or have material impacts to the cost of compliance.

Requests:

9. **In lieu of a more holistic treatment of HB 2021 within PacifiCorp's IRP analysis, Staff urges PacifiCorp to amend its CEP with a report of the Oregon-allocated annual GHG emissions, Oregon-allocated annual costs, Oregon-allocated NPVRR, and the CBIs for the best performing Preferred Portfolio Variants listed in Table 9.13 of the IRP. Staff requests that the Company report this information, at a minimum, using the same allocation pathways that were used in the filed CEP (2020 Protocol, Pathway 1, and Pathway 2); and clearly explain any alternative allocation pathways that may be used to comply with HB 2021 or any updates to the Company's allocation strategies since filing the CEP. Staff also requests that this information be provided in an updated CEP Data Template to support transparency and accessibility.**
10. **Staff also urges PacifiCorp to use the IRP portfolio analysis and amended CEP information described above to directly address the following questions in its Reply Comments:**
    - **How have major IRP and CEP near-term action items been assessed for risk? Which action items have larger risks than others?**
    - **Discuss and describe any possible future events that would likely cause the CEP Portfolio to significantly change.**
    - **To what extent does PacifiCorp's ability to meet Oregon's 2030 GHG target rely on emerging technologies, such as nuclear and non-emitting peakers?**

[42] LC 82 PacifiCorp 2023 CEP, Introduction, May 31, 2023, page 4.
[43] LC 82 PacifiCorp 2023 IRP, Modeling and Portfolio Section Results, May 31, 2023, page 313.

- **When are there timing junctures or what are key milestone events at which the Company might consider material changes in strategy, such as changes to coal retirement and coal-to-gas conversion plans, changes to nuclear plans, adopting operating constraints on emitting resources, joining an RTO, or other alternatives?**
- **What feedback will the Company use to determine whether a change in course may be warranted? Will the Company adjust its strategy based only on the progress of procurement, or will PacifiCorp examine additional data, like actual GHG emissions, power costs, load forecasts, and load forecast uncertainties, as the Company executes its strategy?**

2.9 Community Benefit Indicators

Staff is concerned that PacifiCorp's interim CBIs do not provide incremental information for evaluating the Company's IRP or CEP portfolios and do not materially affect its plans. Staff proposes that the Company add interim CBIs within this CEP that address local non-GHG emissions from PacifiCorp facilities, community benefits of energy efficiency, and local impacts of CBREs.

In Order No. 22-390, the Commission adopted Staff's recommendation in Docket No. UM 2225 that the utilities should adopt CBIs that address five areas:

- Resilience (system and community),
- Health and community well-being,
- Environmental impacts,
- Energy equity (distributional and intergenerational equity), and
- Economic impacts.

Further, Staff recommended in UM 2225 that the utilities should include at least one metric in each of the following categories:

- Portfolio CBIs, which address the impacts of the utility's portfolio on communities, may or may not be tied to CBREs, and should be reflected in IRP portfolio scoring.
- CBRE-focused CBIs, which are used to inform and track progress on CBRE actions and should be reflected in the CBRE potential study and in the IRP portfolio scoring; and
- Informational CBIs, which may or may not directly inform portfolio scoring in the IRP.

Staff discusses PacifiCorp's interim CBIs by category in the following sections. Staff understands that the Company is currently in the process of further developing PacifiCorp's CBIs for future planning decisions. Staff is engaged in those conversations and sees many important opportunities for the Company to advance its consideration of community impacts through that process. For the purposes of informing acknowledgement decisions for this IRP and CEP, Staff is framing these comments around expectations for PacifiCorp's first CEP. Staff notes that the implementation of CBIs is an emerging area that is also an issue of interest in Portland General Electric's IRP/CEP docket, LC 80, and any conflicting recommendations between the two dockets should be viewed as an evolution of Staff's thinking rather than a set of inconsistent recommendations.

Presentation of CBIs

Based on what Staff has reviewed in both this docket and LC 80, Staff feels it worthwhile to suggest a preferred way to present the CBIs. Throughout the Company's CEP filing, the Company reports the CBIs as goals or targets rather than an indicator. As an example, one of the CBIs in Table 1 is "Decrease proportion of households experiencing high energy burden", and the metrics to measure this are various measures of energy burden contained in Table. 2.[44] While Staff takes no issue with the goals in Table 1, Staff wants to establish that the CBI itself is a metric and should be presented as such in a future filing. For the remainder of these comments, Staff will refer to any recommendations on CBIs as recommendations to the metric rather than the goal or target.

<u>Request</u>:

11. In Reply Comments, PacifiCorp should express CBIs as metrics rather than goals.

Portfolio CBIs

PacifiCorp lists two desired outcomes as Interim Portfolio CBIs: Increasing Energy from Non-Emitting Resources and Reducing CO_2 Emissions to meet HB 2021 Targets. To measure progress toward these outcomes, the Company reports the GHG emissions associated with the CEP portfolio and alternatives.

PacifiCorp's Interim Portfolio CBI does not provide additional information or influence the Company's planning beyond factors that the Company should already be taking into account outside of the community benefits evaluation. The Company is already expected to reduce Oregon GHG emissions to achieve the GHG targets set forth in HB 2021. Furthermore, in Order No. 23-060, the Commission waived compliance with IRP Guideline 1I 1(c) and directed PacifiCorp to consider the following revised planning guidance:

> The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers, the pace of greenhouse gas emissions reductions, and community impacts and benefits.[45]

PacifiCorp's approach effectively consolidates the two new considerations (i.e., the pace of GHG reductions and community impacts and benefits) into a single metric.

PacifiCorp's interim portfolio CBI also fails to directly address the local impacts of PacifiCorp's resource planning decisions related to emitting resources, such as local health impacts of non-

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[44] LC 82 PacifiCorp 2023 CEP, Executive Summary, May 31, 2023, page 16.

[45] *In the Matter of Request to Waive IRP Guideline 1(c) for Pacific Power and Portland General Electric for the First Clean Energy Plans*, Docket No. UM 2225, Order No. 23-060, Appendix A at 5 (Feb. 23, 2023).

GHG emissions and both health and local economic impacts of building energy efficiency measures.

<u>Requests</u>:

12. **Staff requests that before the next IRP, PacifiCorp adopt one or more interim portfolio CBIs that address local non-GHG emissions from PacifiCorp facilities, regardless of whether those facilities sit within PacifiCorp's service area.**
13. **Staff requests that before the next IRP, PacifiCorp adopt one or more interim portfolio CBIs that address community benefits of energy efficiency.**

CBRE-focused CBIs

PacifiCorp lists two desired outcomes as interim CBRE-focused CBIs: reducing frequency and duration of energy outages and improving resilience of vulnerable communities during energy outages. To measure progress toward these outcomes, the Company reports the energy not served (ENS) associated with the CEP portfolio and alternatives.

Staff appreciates that PacifiCorp intends to consider the potential impacts of outages on local communities as part of its CBRE planning. However, Staff believes that the Company's choice of CBRE-focused CBIs does not provide any meaningful information about CBRE impacts, nor does it impact IRP portfolio scoring. The ENS metric provides information about the resource adequacy of each portfolio, not the impact of outages on customers or communities. Theoretically, if portfolios are being compared on the basis of cost, risk, and GHG emissions, then they should be achieving the same level of resource adequacy. The Company's observation that the CEP portfolio achieves lower ENS than the Preferred Portfolio is simply an indication that the Company has not fully backed out the equivalent amount of capacity from other sources after adding small scale renewables (SSRs) in Oregon. Similar to the Company's portfolio CBI, the CBRE-focused CBI does not provide any new information to planning decisions beyond what should already be considered in an IRP.

Staff agrees with the Company that one of the benefits of CBREs is increased community resilience. However, community resilience is a function of many interconnected aspects of utility planning that extend far beyond CBREs, and CBREs likely have local economic and health benefits that extend beyond resiliency.

<u>Request</u>:

14. **Staff requests that before the next IRP/CEP, PacifiCorp adopt one or more interim CBRE-focused CBIs that directly affect the Company's planned CBRE actions.**

Informational CBIs

PacifiCorp lists three desired outcomes as interim Informational CBIs and intends to track several metrics associated with these objectives (in parentheses): decrease number of residential disconnections (number of residential customer disconnections); decrease proportion of households experiencing high energy burden (energy burden by census tract and energy burden for low-income customers, bill assistance participants and Tribal members); and

increase community-focused efforts and investments (headcount of DSM program delivery staff and grants, public charging stations, pre-apprenticeship/educational program participation, and resource development workforce and spend).
The Company also intends to track SAIDI, SAIFI, and CAIDI including major events by census tract. In some parts of the CEP, these metrics are associated with the CBRE-focused CBI objective "Reducing Frequency and Duration of Energy Outages." However, PacifiCorp does not address these metrics in its CBRE analysis or plans, so they are effectively informational.

Staff does not object to PacifiCorp's Informational CBIs at this time, but encourages the Company to both continue to inform this list with input from communities and the CBIAG and to explore options for using these metrics to more directly inform planning in future cycles.

2.10 Community Based Renewable Energy

CBRE Acquisition Targets

In Order 22-390, the Commission adopted Staff's recommendation that that the utilities should establish acquisition targets for community based renewable energy (CBRE), beginning with a potential analysis which, "should inform or directly identify annual acquisition targets (e.g., MW, MWh) for CBREs. PacifiCorp identified 95 MW of CBRE potential by 2030, sorted into two groups. Group 1 includes 92 MW of CBRE potential from existing programs, 65 MW of which is Oregon Community Solar Program (OCSP). Group 2 is an annual 700 kW of anticipated small-scale community solar + storage facilities starting in 2025.

Staff appreciates PacifiCorp's detailed, bottom-up accounting of CBRE resources in the potential study. The total, 95 MW potential of CBRE resources, is a reasonable initial target, and Staff anticipates most identified resources to come online, because PacifiCorp added up potential CBRE resources that are in some degree of consideration today. For example, 52 MW of Oregon's Community Solar Program is already subscribed.

Due to PacifiCorp's focus on a CBRE inventory from existing programs, Staff has concerns that the potential study does not anticipate a future reimagined by HB 2021 and stakeholders. PacifiCorp only projects the growth of one program, the Community Resilience Battery Storage Pilot, which was prioritized for enhancing resilience over capacity. That program is identified as Group 2 in the CEP, and the Company assumes two 350 kW projects of community solar + storage will come online annually starting in 2025. Staff highlights that the cumulative Group 2 potential of 3.5 MW by 2030 is modest and may not meet community appetite for resiliency or CBRE.

Request:

15. **Staff encourages PacifiCorp to consider whether additional CBRE capacity could be available beyond the inventory exercise considering the observed demand for resiliency and recent growth of distribution-sited resources. Based on the organic growth of net metering projects in the Company's territory, PacifiCorp should study whether a CBRE**

program could leverage the existing demand and access new markets and opportunities with modest co-funding, including significant sources, such as the Inflation Reduction Act and Portland Clean Energy Fund.

CBRE Portfolio Analysis

For the purposes of scenario analysis in the CEP, PacifiCorp rounded up the potential study's 95 MW to 100 MW and broke up the capacity into five, 20 MW blocks of available CBRE. Four blocks were proxy southern OR solar resources with a capacity of 29.33 percent and variable price of $87.30/MWh.[46] One block was hydro with a capacity factor of 45 percent and variable price of $76.50/MWh.[47] The Company had to force the model to acquire CBRE resources in the CBRE sensitivity portfolio because the model would not have otherwise selected the resources at the assigned cost.

In the CBRE sensitivity portfolio, the CBRE resources only replace small-scale renewables (SSR), and therefore the emissions reduction and energy not served are the same. In other words, PacifiCorp's modeling suggests there is no additional emissions reduction benefit resulting from CBRE acquisition. Rather CBRE simply displace SSR acquisition.

During the development of near-term CEP guidance, Staff believed that including CBREs in portfolio analysis would help satisfy the HB 2021 requirement to, "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy."[48] PacifiCorp's analysis does not enable insight into whether CBRE resources directly impact the dispatch of emitting resources nor the impacts to costs, risks, and benefits. Staff requests the Company respond to insight limitations of CBREs' contributions to emissions reductions.

Staff finds the treatment of CBRE in IRP analysis to be problematic because many of the inventory-identified CBRE resources can be expected to come online absent PacifiCorp's implementation of a CBRE strategy. As an example, the Oregon Community Solar Program can grow to 65 MW and is an established, existing program in the state. PacifiCorp should have included this program in its baseline, IRP preferred portfolio scenario. Further, the lack of inclusion of existing programs in the IRP analysis unfairly portrays the CBRE scenario as higher cost.

While staff understands the need for simplification of cost due to uncertainty, the assigned cost of CBRE appears high without any averaging of cost from co-funding sources or netting of cost due to benefits from energy, capacity, avoided transmission, and distribution. Further, it is unclear that CBIs capture community benefits in portfolio analysis which drive CBRE strategy.

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[46] See PacifiCorp response to Staff DR 160, Aug. 30, 2023. A ten-percent cost reduction benefit was applied to the proxy solar CBRE based on a Company decision to use such a credit to be consistent with the Northwest Power Act's treatment of energy efficiency.
[47] See PacifiCorp response to Staff DR 160, Aug. 30, 2023.
[48] ORS 469A.415(4)(d).

CBRE Acquisition Coordination

PacifiCorp outlines multiple action items for bringing CBRE online, including leveraging existing programs, issuing a small-scale RFP, and offering a CBRE grant pilot straw proposal. Staff appreciates the multiple strategies to acquire CBRE resources as it recognizes the communities seeking CBRE are not homogenous. However, there has been much progress since the CEP was filed, across various types and levels of organizations, that could greatly assist local communities in developing CBRE projects that are at much lower costs.

PacifiCorp's perspective on enabling infrastructure to support groups of varying size and sophistication can help bring together local, state, and federal resources to inform local communities about identifying outstanding CBRE projects that could receive funding.

In addition to the variety of entities which may benefit from CBRE, Staff also recognizes a variety of potential CBRE resources beyond those modeled in the CEP. Staff encourages the Company to not limit resources to the inventory provided and to make space for resources not identified in the CEP such as community-led, targeted EE and DR programs.

Small Scale Renewables Connection to CBRE

PacifiCorp identified a need for 490 MW of SSR by 2030, growing to 802 MW of SSR by 2037. The Company will host a separate SSR RFP to specifically target these resources. The volume of SSR needed by 2030 means there is significant compliance risk. A robust CBRE strategy could reduce this risk as it opens more pathways for resources to interconnect and an ability to leverage outside expertise and funding. The 95 MW of CBRE can contribute to the 2030 need of 490 MW and as discussed earlier, much of that capacity exists in existing program pipelines.

PacifiCorp should continue to consider how outside funding may reduce the total cost to ratepayers and subsequently reduce the cost of compliance. PacifiCorp can help the market respond to the RFP process by making certain qualities explicit such as outlining preferred zones for resource siting or offering reduced interconnection costs and timing for projects meeting pre-identified criteria.

In addition, Staff's experience with project development and project interconnection in Oregon's Community Solar Program leads Staff to see a connection between the cost and extent of CBRE adoption and project access and stakeholder insights into the local transmission and distribution network. A reduction in the length of time and costs, along with greater insights into local transmission and distribution system bottlenecks, will be critical to PAC meeting and/or exceeding this IRP's CBRE target of 95 MW.

Further, Staff is left to assume PAC must make substantial local transmission and distribution system upgrades in Oregon given the commercial and residential load growth in certain areas (e.g., the Walla Walla Oregon and Central Oregon load pockets per DR response No. 69). A CBRE acquisition strategy with a pre-2030 goal of 95 MW should seek to identify how to best leverage these investments so that the interconnection upgrade costs for CBRE projects is only incremental to the system upgrades required by increased demand.

<u>Request:</u>

16. In Reply Comments, PacifiCorp should describe the estimated cost and growth of planned local transmission and distribution system upgrades to accommodate load growth in Oregon load pockets (e.g., per DR Response No. 69, Walla Walla Oregon, Central Oregon, etc.). Staff requests the Company address how these investments could be a foundation upon which to stack CBRE projects for only the marginal cost, rather than the entire cost, of a new substation and/or feeder.

2.11 Community Engagement

Transparency, Accessibility, and Incorporating Feedback

In Order No. 22-390, the Commission adopted the expectations for PacifiCorp and PGE to furnish details on community engagement. In the order, the Commission prioritized transparency and accessibility, stating:

> The utility should report the following information regarding community engagement in developing the plan: what opportunities were provided for input and how was accessibility prioritized across those channels, what input was received through each channel, how was input incorporated into the IRP/CEP, what input was not incorporated into the IRP/CEP and why was that input not incorporated, and what plans does the utility have for modifying the engagement strategy in future planning cycles.[49]

PacifiCorp's filed CEP asserts a commitment to increasing access and opportunities for historically marginalized communities and strengthening existing partnerships to promote engagement. According to the Company, these efforts are intended to facilitate a two-way flow of information and enable stakeholder input to influence PacifiCorp's strategic priorities. Staff recognizes PacifiCorp's efforts to incorporate practices into its Community Engagement Strategy (CES) that improve transparency and accessibility. The CEP highlights various engagement channels[50] and the use of consolidated information hubs to provide access to resources and materials from past and scheduled engagement opportunities. PacifiCorp has also developed a Feedback Tracker,[51] which the Company published online in October 2023, with the intent of further enhancing transparency and accountability to public input.

In addition to the various CES venues, PacifiCorp continues to engage its Community Benefits and Impacts Advisory Group (CBIAG)[52] to provide community representatives a dedicated venue to provide input on utility processes, including the CEP. According to the Company, the

[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 54 (Oct. 25, 2022) *corrected,* Order No. 22-470 (Dec. 5, 2022).
[50] LC 82 PacifiCorp 2023 CEP, Figure 1, May 31, 2023, page 9.
[51] PacifiCorp Response to Staff DR 55, Aug. 14, 2023.
[52] Section 6 of HB 2021 requires each utility to establish a Utility Community Benefits and Impacts Advisory Group. The advisory group must increase the engagement and enhance the equal protection of communities traditionally underrepresented in the utility's processes. See, generally, ORS 469A.425.

CBIAG continues to discuss CEP-related issues to refine and improve the Company's plan and planning process while providing insights and understanding of its respective communities. PacifiCorp is finalizing the CBIAG's charter[53] and has committed to reviewing its engagement practices during a CBIAG end-of-year review.[54]

Staff appreciates PacifiCorp's work to enhance the accessibility of its engagement and leverage learnings from previous and ongoing community forums into the CEP. Staff understands that the Company is continuing to evolve its community engagement strategy through the CBIAG engagement series and other feedback channels. Staff is concerned, however, that PacifiCorp has not met the community engagement expectations of Order No. 22-390.

PacifiCorp's filed CEP did not include a clear path from engagement and input to planning and action. Further, while the Company did provide a link to its Feedback Tracker[55] as a supplemental response to Staff's specific request,[56] the noted impacts are generally deferred in terms of action and fail to rise to the level of establishing accountability to community. In both the filed CEP and responses to data requests, Staff finds PacifiCorp has not sufficiently articulated how it has incorporated stakeholder and community feedback into the IRP and CEP planning process. Staff shares the Oregon Citizens' Utility Board's (CUB) reflections that:

> [a]s filed, the CEP reads as if community engagement consisted primarily of participation in the PUC's HB 2021 investigative dockets and traditional IRP engagement strategies with the inclusion of the Utility Community Benefit Impacts & Advisory Group (UCBIAG). While PAC discusses that this engagement occurs, the CEP contains little if any explanation of how it took that feedback, considered it, or an explanation of why it made the decisions it did regarding whether or not to accept or reject that information.[57]

In this regard, Staff is concerned that that the CES and CEP are weighted in favor of extractive engagements of demographic information rather than participatory decision making that could leverage the expertise and assets of community members, including environmental justice communities, in the Company's planning decisions.

Staff believes that setting clear, actionable expectations for accessibility and engagement in the development of the next IRP/CEP should be a priority for the Commission's investigation into planning and procurement reforms expected in 2024. Staff also believes that this element of planning will benefit from a dedicated forum for utilities, Staff, Stakeholders, and representatives of communities to develop recommendations to improve the next CEP process. This working group would consider what constitutes successful engagement by identifying standards, metrics, and benchmarks for transparency, accessibility, and accountability. It would

[53] *See* PacifiCorp response to Staff DR 62, Aug. 14, 2023.
[54] *See* PacifiCorp Response to Staff DR 55, Aug. 14, 2023; PacifiCorp Response to Staff DR 56, Aug. 14, 2023.
[55] The CEP feedback tracker / matrix can be accessed utilizing the following website link to PacifiCorp's Oregon CEP webpage, under "Oregon feedback tracker."
[56] See PacifiCorp response to Staff DR 34 1st SUPP, Oct. 10, 2023.
[57] LC 82, CUB Round 0 Comments, June 30, 2023, page 4.

explore and articulate standards and guidelines that can be considered for codification and/or provide a structured framework for community engagement and consider where change in current processes or regulatory frameworks may be necessary to achieve the desired outcomes. Staff has discussed this concept in more detail in its Round 2 comments within PGE's IRP/CEP process, LC 80, and believes that this working group will provide valuable insights, perspectives, and solutions on how to address many of the shared transparency, accountability, and accessibility issues flagged in both utilities' CEP reviews to date.

Staff appreciates the intent of the Feedback Tracker proposed by the Company and sees this as a key step in meeting the expectations in Order 22-390; however, Staff is interested in understanding how the Company plans to continue to develop and refine the tracker in the interest of transparency and accountability.

<u>Requests</u>:

17. **Staff suggests that PacifiCorp update and publish the Feedback Tracker at timely, regular intervals, such as after PacifiCorp receives comments or following a public workshop. Staff believes this will support the utility's effective reflection of feedback and provide additional transparency.**
18. **In the Company's Reply comments and going forward, Staff suggests that the Company provide the following additions and enhancements to the Feedback Tracker:**
    - **Organization/entity attribution or affiliation.**
    - **Flag for whether and where PacifiCorp incorporated the feedback into utility planning or actions.**
    - **Clear description of why feedback was or was not included.**
    - **Where, by topic, PacifiCorp is able to engage with community along the spectrum of engagement.**[58]
19. **Staff would like PacifiCorp to provide feedback on the Company's perspective with regard to the suggested working group aimed at improving and standardizing elements of community engagement in CEPs going forward.**

Accountability

Order No. 22-390 set forth the expectation that utilities would "survey participants who provided input on their experiences participating in the utility's process and their perspectives on how their input influenced the plan." Order No. 22-390 further stated that survey responses should be included with the utility's plan.[59] PacifiCorp did not provide these survey results with the Company's plan.

In Round Zero comments, CUB and Sierra Club made three requests that were not included in the Company's Reply Comments. First, CUB raised concerns that environmental justice voices

[58] See <u>The Spectrum of Community Engagement to Ownership</u>; Rosa Gonzalez, Facilitating Power. Available at https://movementstrategy.org/resources/the-spectrum-of-community-engagement-to-ownership/.

[59] *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 54 (Oct. 25, 2022) *corrected,* Order No. 22-470 (Dec. 5, 2022).

were left out of the Company's engagement conversations.[60] CUB also requested information on how PacifiCorp planned to identify environmental justice communities in future engagement practices.[61] In Reply Comments, the Company reiterated that it has recurring engagement series meetings and that it continues to engage with the CBIAG for input and feedback into the development of its resilience analysis. However, the Company did not provide a direct response to CUB's specific concern regarding the identification of environmental justice communities going forward.[62]

Second, Sierra Club and CUB questioned whether PacifiCorp had maximized state and federal incentives and Inflation Reduction Act (IRA) financing opportunities within the action plan.[63] Similarly, CUB asked which communities the incentives would impact and whether there were Justice40 Initiative opportunities available to disadvantaged communities.[64] Although the Company noted that PacifiCorp's Demand-Side Management (DSM) Potential Report included details on IRA optimization, Staff does not believe this sufficiently reconciles CUB's request. Staff is still unclear whether or not there are additional IRA or Justice40 opportunities that should be considered for the CEP. Additionally, Staff is unclear how PacifiCorp determined what and how the Company's decisions "optimize" these financing opportunities or what those opportunities might look like.

Third, CUB requested information about CBIs related to energy burden.[65] Specifically, CUB asked about how the Company plans to share the burden of investment in the Company's Low Income Discount (LID) program when looking at the customer rate impacts of a mature program.[66] In Reply Comments, the Company notes that it intends to have discussions with stakeholders and work towards incremental progress in achieving HB 2475 goals, but does not share how it is looking at the customer rate impacts of a mature program.[67]

Staff views the participant survey as one means for the Commission to get direct feedback from community members on how they are being engaged by the utility and the extent to which community members see its input impact the utility's plans.

That being said, Staff shares stakeholders' concerns and requests that the Company articulate specific, direct, and comprehensive responses to Round 0 and Round 1 comments in Reply Comments. For example, Staff is concerned that the Company has not verified that it has meaningfully included informed environmental justice priorities and input within planning conversations. Membership affiliation across CBIAG membership alone does not evidence community centered planning and to the extent that the Company's responses simply point to

[60] LC 82, CUB Round 0 Comments at 6 (filed June 30, 2023).
[61] See LC 82 CUB Round 0 Comments at 5-6 (filed June 30, 2023).
[62] See LC 82, PacifiCorp Reply comments at 43 (filed July 31, 2023).
[63] See LC 82, Sierra Club Round 0 Comments at 4-6 (filed June 30, 2023); see also LC 82, CUB Round 0 Comments at 5 (filed June 30, 2023).
[64] See LC 82, CUB Round 0 Comments at 5 (filed June 30, 2023).
[65] Energy burden is defined as the percentage of gross household income spent on energy costs.
[66] See LC 82, CUB Round 0 Comments at 6 (filed June 30, 2023).
[67] See LC 82, PacifiCorp Reply comments at 43 (filed July 31, 2023).

existing documentation rather than providing additional insights and evidence, Staff's concerns remain.

<u>Requests</u>:

20. **In Reply Comments, PacifiCorp should provide responses from any community or stakeholder surveys that the Company conducted to inform the CEP. If PacifiCorp has not conducted the type of survey outlined in Order No. 22-390, the Company should describe its plans to conduct this survey.**
21. **In Reply Comments, PacifiCorp should articulate a plan to actively increase environmental justice community priorities and impacts in planning conversations and resource decision-making beyond CBO recruitment goals. Staff would like to see specific actions that the Company plans to take rather that lists of engagement workshop opportunities.**
22. **In Reply Comments, PacifiCorp should provide additional clarity on the Company's optimization strategy relative to federal programs and incentives and further articulate the specific federal incentives PacifiCorp has looked at applying for. Staff requests the Company provide any applicable timelines, discuss which communities these incentives will impact and how, and include sources that have been excluded and why. In response to this request, the Company should include, but not limit to, any IRA and Justice40 Initiative incentives.**
23. **In Reply Comments, Staff requests that PacifiCorp explain how the Company plans to use CBI metrics to inform how it will share the burden of investment in the Company's Low-Income Discount (LID) program and other types of direct assistance rates or programs when looking at the customer rate impacts of a robust energy burden mitigation strategy.**

Community Demographics

In the CEP and CES, as well as at CBIAG meetings, PacifiCorp documents that it has collected extensive data on social and systemic issues its customers and local communities prioritize. For example, the Company has distributed clean energy surveys, hired regional business managers, and solicited feedback at CBIAG meetings and engagement workshops in the interest of elevating community perspectives and promoting informed planning. The Company also stated that it is currently evaluating how to shift from data gathered at the census tract level to more granular metrics.[68]

Staff recognizes that identifying community issues is an important first step to establish an effective and inclusive CBIAG and also to build trust with communities in the utility's service territory. Staff would like to understand how PacifiCorp intends to use this collected demographic data to inform CBIs, CBI metrics, CBREs, and resource acquisition or portfolio decision making.

[68] LC 82, PacifiCorp Reply comments at 43 (filed July 31, 2023).

Staff appreciates that the Company is pursuing a move to more granular metrics than that provided by census tracts. Staff finds that this approach can provide more accurate data as the Company's service territory does not align with census tracts.[69] In this regard, Staff would like to know what venues, metrics, maps, methodologies, or other data PacifiCorp has considered or is exploring. For example, has the Company utilized data and maps developed in the DSP proceedings; used more granular census data such as census blocks; or considered alternative tools and metrics developed by outside parties to collect socioeconomic data?

<u>Requests</u>:

24. In Reply Comments, Staff would like the Company to articulate how it intends to use the community data is has collected to inform CBIs, CBI metrics, CBREs, and resource acquisition or portfolio decision making.

25. In Reply Comments, Staff would like the Company to discuss its progress identifying and utilizing granular data in addition to census tract level, or other metrics and tools that can provide socioeconomic data. Additionally, in reply comments, Staff would like the Company to articulate how it intends to use the community data is has collected to identify how the utility's actions have benefited and impacted communities. Staff is looking for connections, specifics, and metrics of the effect of the utility's actions that can aid in the development of CBIs and also inform its portfolio selection or planning decisions.

Tribal Engagement

The Company states that it created the CEP Engagement Series for Oregon Tribal Nations "to respect the unique needs, interests and requests of the representatives from Tribal Nations and is one of several ways the Company is working to seek input and share information with Tribal Nations."[70] PacifiCorp models these Tribal Engagement Sessions similar to CBIAG meetings.[71] According to the Company, an end-of-year planning session in the Tribal Engagement sessions will slightly differ from the CBIAG as the Tribal Engagement group is less formalized.[72] The Company states that expanded engagement with the Tribal Nations includes adding meetings with individual Tribal Nations based on topic interest.[73]

Staff recognizes 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 efforts to explore the necessary learnings and engagement practices with intentionality and deference. Staff acknowledges the challenges the Company has flagged with regard to representing tribal perspectives in the CBIAG and in

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[69] For example, the Company proposes to measure outages at the census tract level divided by PacifiCorp's customer count. Staff shares Energy Trust of Oregon's concern, raised at the July CBIAG Meeting, that this data will include outages within the census tract but outside of PacifiCorp's service territory.

[70] PacifiCorp response to Staff DR 64, Aug. 14, 2023.

[71] PacifiCorp response to Staff DR 55, Aug. 14, 2023.

[72] PacifiCorp response to Staff DR 55, Aug. 14, 2023.

[73] PacifiCorp response to Staff DR 55, Aug. 14, 2023.

launching the Clean Energy Plan Engagement Series for Oregon Tribal Nations that cultivates a robust dialogue on CEP planning and action.

That said, Staff is interested in seeing meaningful progress in this space and wishes to emphasize the importance of the inclusion of perspectives from tribal community members in the CEP process and community engagement. Staff is concerned, for example that when considering the proposed CBIs from the Joint Advocacy Group participating in UM 2225, PacifiCorp excluded all the Tribal Benefits and Priorities listed. According to PacifiCorp, "many CBIs/metrics proposed by the Joint Advocates were affiliated with topics that require thoughtful discussion with broader group of stakeholders."[74] PacificCorp explains that this is why it omitted the proposed tribal CBIs from the CEP. [75] Staff would like to better understand the Company's plan for how its engagement with tribal community members will lead to a CBI for Tribal Benefits given that this was not included in the CEP.

Request:

26. In Reply Comments, Staff would like PacifiCorp to provide an explanation for how and when the Company envisions its tribal engagement leading to the development a Tribal CBI. In this explanation, please detail how PacifiCorp will solicit and use input from stakeholders in the Tribal Engagement to develop and approve any resulting Tribal CBI. Also, include an explanation for how the timing of the finalized Tribal CBI will impact the next IRP and CEP.

2.12 Resiliency Framework

Section 4 of HB 2021 requires that a CEP include "a risk-based examination of resiliency opportunities that includes costs, consequences, outcomes and benefits based on reasonable and prudent industry resiliency standards and guidelines established by the Public Utility Commission." Regarding resiliency, PacifiCorp states that its long-term goal is to "include resilience risk scores in project and program prioritization."76 The Company describes a future process that identifies and prioritizes census tracts for targeted resiliency analysis. The Company proposes to base this analysis on both community resilience data (SOVI and BRIC scores from the National Risk Index data) and local electric reliability data (SAIDI, SAIFI, and CAIDI by census tract). The Company would then select and prioritize resiliency solutions based on risk-spend efficiency or cost-benefit analysis. PacifiCorp provides a schedule with milestones for standing up this process in Table 9 of the CEP, which would have the Company "[i]ncorporat[ing] community-utility resilience scores and risk drivers into CEP program planning" by March 1, 2024. PacifiCorp also states that the process will "inform project planning and prioritization processes recurring periodically under resiliency related programs such as DSP or IRP."77 The Company also reiterates the importance of community input in

[74] LC 82, PacifiCorp Reply comments at 34 (filed July 31, 2023).
[75] LC 82, PacifiCorp Reply comments at 34 (filed July 31, 2023).
[76] LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 29.
[77] LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 31.

resiliency analysis and planning and suggests that it will seek feedback on resiliency-related topics at future stakeholder meetings.

Staff appreciates PacifiCorp's proposal to prioritize resiliency solutions based on community resiliency information, utility data, and risk-spend efficiency or cost-benefit analysis. Staff notes that SOVI and BRIC scores are well known indices. Staff is not aware of whether census-level SAIDI, SAIFI, and CAIDI data has been successfully used in the past for resiliency-related planning. Staff also appreciates PacifiCorp's proposal to incorporate resiliency-based risks into both existing and new decision-making processes (e.g., the IRP, DSP, and CEP). Staff seeks clarification from the Company on items discussed below.

Like CUB, Staff would like to better understand how PacifiCorp plans to incorporate community input in the Company's resiliency analysis and planning. Staff appreciates that PacifiCorp intends to look to guidance from Docket UM 2225,[78] but would like to know how the Company will include stakeholder feedback received from its CBIAG and other engagement processes into resilience analysis and planning. Staff would also like to know how the Company intends to make the resiliency analysis accessible to community members who will be affected by the utility's plans.

Regarding risk evaluation, the Company's process appears to rely solely on National Risk Index data as a measure of community vulnerability. As a result, Staff questions whether and how community input will be considered when identifying and/or prioritizing resiliency-based risks. Regarding potential solutions, it is not clear what role the Company envisions local communities taking in determining potential resiliency solutions in high-risk areas. Staff also notes that community members have raised concerns of wildfire risk. Accordingly, Staff would like to further the wildfire discussion with PacifiCorp, beyond FEMA's wildfire metrics,[79] to understand how the Company has considered the encroachment of wildfires on vulnerable populations and critical energy infrastructure as a contributor to increased risk exposure within the Company's CEP resiliency analysis and planning.[80]

Staff would also like to better understand how the process that the Company describes for resiliency-based decision making would flow into and be reflected in the IRP, CEP, and/or DSP. Specifically, Staff is curious if and how this process will affect IRP portfolios (including CBREs and SSRs) and CBIs in future IRPs and CEPs. By extension, Staff would like to understand how the Company has ensured that any cost-benefits analysis used to prioritize resiliency solutions will distribute resources, benefits, and burdens equitably.[81]

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[78] See LC 82, PacifiCorp Reply comments at 44 (filed July 31, 2023).

[79] See LC 82, PacifiCorp Reply comments at 44-45 (filed July 31, 2023), (noting the community resilience part of the utility-community composite risk scores includes the potential probability and impact of wildfires through FEMA NRI data).

[80] Staff notes a recent publication on the vulnerability of populations exposed to wildfires in the U.S. West Coast states may contribute to this discussion. *See generally,* Arash Modaresi Rad et. al., Social Vulnerability of the People Exposed to Wildfires in U.S. West Coast States, SCIENCE ADVANCES (Sept. 20, 2023), https://www.science.org/doi/10.1126/sciadv.adh4615.

[81] *See* Arash Modaresi Rad et. al., Social Vulnerability of the People Exposed to Wildfires in U.S. West Coast States, SCIENCE ADVANCES (Sept. 20, 2023), https://www.science.org/doi/10.1126/sciadv.adh4615 ("Many national disaster mitigation and

Finally, Staff seeks clarity on how the Company uses the two terms "reliability" and "resiliency" when discussing its resilience frameworks. While PacifiCorp discusses the difference between resiliency and reliability, the terms are used interchangeably in the CEP. For example, in the CEP the Company states "[o]nce PacifiCorp formalizes a framework for identifying vulnerable communities experiencing the greatest impact from outages, the Company will then develop a proposal for how to prioritize communities for further reliability analysis." The Company goes on to state that it "foresees the application of this reliability framework in a variety of scenarios" and notes that a reliability framework could supply valuable information for CBRE development and project prioritization. In fact, the Resilience CBI "Reduce Frequency and Duration of Energy Outages" relies on the Energy Not Served metric, which the Company states shows the reliability of a portfolio. Notably, Staff seeks clarification beyond semantics. Staff recognizes that guidance in Order No. 22-390 provided that the Company use measurable historical reliability performance measures as one component of its resiliency-related analysis. Staff is concerned, however, that by focusing the score on reliability over resiliency the Company may over procure resources or overlook non-energy solutions to improving resilience.

Requests:

27. **In Reply Comments, the Company should provide status updates for the milestones listed in Table 9 of the CEP and provide the Company's most recent update to the schedule.**
28. **In Reply Comments, the Company should explain how it intends to incorporate community input into its future resiliency analysis and planning.**
29. **In Reply Comments, the Company should explain how it intends to consider the encroachment of wildfires on populations and critical energy infrastructure as a contributor to increased risk exposure within the Company's CEP resiliency analysis and planning. The Company should reference or incorporate specific items from its wildfire protection and mitigation plans as necessary.**
30. **In Reply Comments, the Company should clarify whether it intends to conduct resiliency analysis and planning in the DSP, IRP, and/or CEP and how this analysis will affect both IRP and CEP portfolios.**
31. **In Reply Comments, the Company should clarify why it has used the terms resilience and reliability interchangeably; explain why and how it is using reliability metrics to measure resilience; and articulate how using a reliability metric to measure resilience impacts costs, consequences, outcomes, and benefits.**

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prevention programs use cost-benefit analyses to allocate resources, which can skew benefits toward wealthy people.") (*citing,* Eric Tate, et al., *Flood Exposure and Social Vulnerability in the United States*, NAT HAZARDS 106, 435–457 (2021), https://doi.org/10.1007/s11069-020-04470-2. ("[S]electing structural mitigation projects based on benefit-cost ratio may preferentially allocate resources to places with low social vulnerability, while at the same time lead[ing] to funding denials or delays in socially vulnerable neighborhoods.").

3. Integrated Resource Plan

3.1 Portfolio Development

PacifiCorp develops portfolios in the IRP by optimizing resource additions, retirements, and conversions and transmission based on economics and subject to reliability requirements to determine a Preferred Portfolio, and then testing variations (Preferred Portfolio Variants) on this portfolio by manually adjusting specific decisions or input assumptions. PacifiCorp then tests the Preferred Portfolio and a subset of the Variant portfolios across different gas and CO_2 price assumptions. PacifiCorp did not include HB 2021-specific modeling in its IRP portfolio optimization. PacifiCorp addresses HB 2021 compliance in its CEP with an outboard addition to the Preferred Portfolio to include Oregon's SSR requirement and analysis of illustrative allocation pathways in HB 2021 Compliance Pathways.

Staff commends PacifiCorp on continuing to innovate in its portfolio development process, including expanding functionality to endogenously represent coal retirement and conversion decisions with more flexibility. Staff also raises some concerns regarding PacifiCorp's portfolio development approach, which are described in the following sections.

3.2 HB 2021 Requirements

As discussed previously in HB 2021 Compliance Pathways, Staff is concerned that IRP modeling does not account for HB 2021 compliance. If PacifiCorp needs to take incremental action to comply with HB 2021, then incorporating those constraints directly into IRP modeling will help to ensure that they are met in a manner that minimizes system-wide costs. Staff appreciates that modeling the HB 2021 GHG constraints in the IRP may be complex, given that DEQ reported emissions will depend on future allocation strategies. However, as discussed in HB 2021 Compliance Pathways, Staff believes that PacifiCorp can examine within the IRP whether HB 2021 compliance is at least feasible with the Preferred Portfolio and/or what is needed in the Preferred Portfolio to ensure that compliance is feasible, while also meeting all GHG and clean energy policy requirements in other states. Staff views this as a threshold question for the IRP and urges PacifiCorp to implement this functionality in its portfolio optimization model for the next IRP.

For this IRP, Staff interprets the pathways analysis in the CEP to mean that HB 2021 compliance is feasible when Oregon's SSR requirements are taken into account (the CEP Portfolio). The Company has shown two of the many allocation strategies that could result in compliance with Oregon's GHG targets in its CEP. Staff is, however, unable to understand whether the CEP Portfolio achieves the lowest system-wide costs given the SSR additions.

Request:

32. PacifiCorp should re-optimize the Preferred Portfolio and the best performing Preferred Portfolio Variants listed in Table 9.13 of the IRP (including P04 and P17, at a minimum) to incorporate Oregon's SSR requirement.

- **PacifiCorp should account for cost and performance of SSRs in the IRP in a manner that appropriately reflects the opportunities to meet a portion of this requirement with Qualifying Facilities.**
- **The Company should report out the resulting annual portfolio additions, retirements, and conversions, annual costs, PVRR, risk adjusted PVRR, ENS, and cumulative GHG emissions in its Reply Comments. The Company should use these portfolios for the additional CEP analysis and reporting requested by Staff in the section [HB 2021 Compliance Pathways](#).**

3.3 Carbon Price Path

In Round 0 Comments, Sierra Club recommends increasing the medium CO_2 price path because of the many recent proposed climate policies.[82] Staff is supportive of using a medium CO_2 price path that reflects a best estimate of the risks of future carbon policies. Because these policies are proposed but not yet enacted, Sierra Club's argument that they increase regulatory risk has merit. For example, PacifiCorp has not included EPA's proposed carbon standards in the IRP. It seems appropriate to revise the medium CO_2 price path to reflect this increased risk.

3.4 Capacity Additions

Staff notes that the Preferred Portfolio suggests that significant additional capacity (beyond the coal-to-gas conversions) will be needed to meet capacity needs in 2030. The Preferred Portfolio includes 7,560 MW of battery additions through 2030, as well as 500 MW of nuclear and 606 MW of non-emitting peakers.[83] In P05, which excludes nuclear, the portfolio replaces the 500 MW nuclear addition with 289 MW of additional non-emitting peakers as well as limited quantities of additional EE and DR by 2030.[84] However, in P06, which excludes both nuclear and non-emitting peakers, there is no substantial replacement capacity for the 500 MW of nuclear and 606 MW of non-emitting peakers beyond the limited additional EE and DR.[85] As shown in Figure 9.11 of the IRP, P06 does not see material replacement capacity until 2032, when battery additions begin to exceed those in the Preferred Portfolio.[86] Staff interprets this finding to mean that the nuclear and non-emitting peaker additions in the Preferred Portfolio may not be needed to ensure resource adequacy through 2030 and seeks further clarification from the Company on this finding.

Request:

33. In Reply Comments, PacifiCorp should explain whether or to what extent the 500 MW of nuclear and 606 MW of non-emitting peakers in the Preferred Portfolio are needed for resource adequacy in 2030 in light of the P06 portfolio composition. If these resources are not needed, PacifiCorp should explain why they arise in the Preferred Portfolio.

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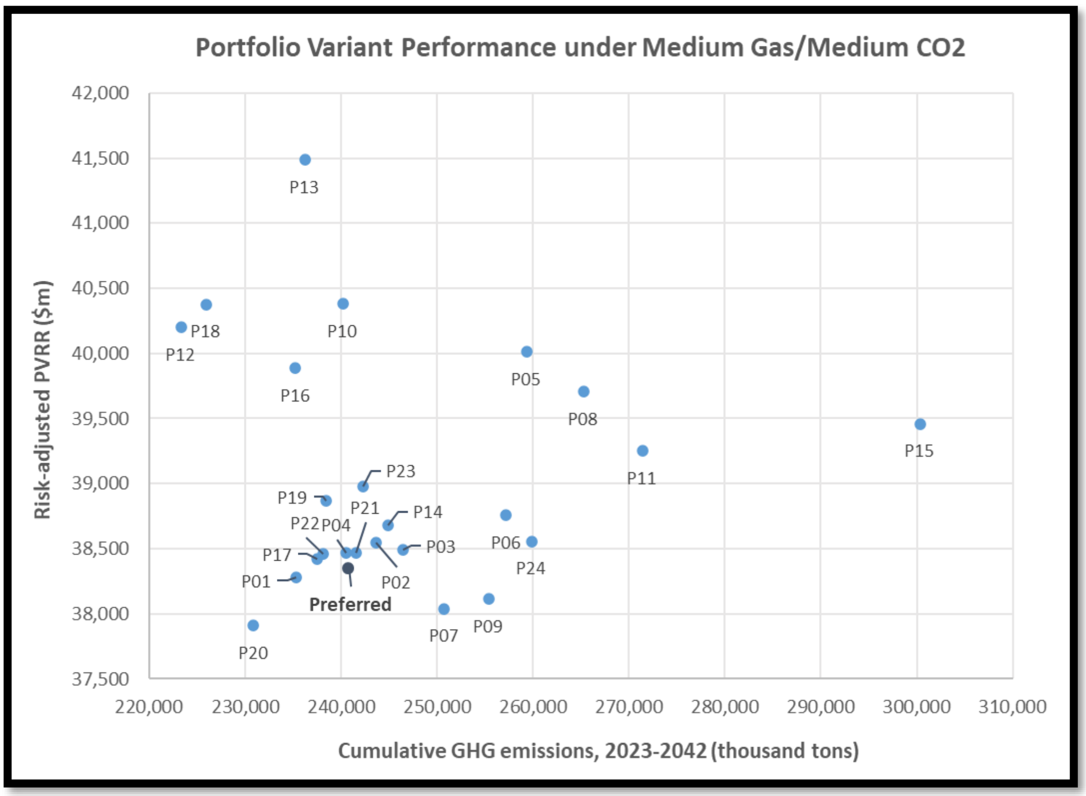
[82] LC 82, Sierra Club Round 0 Comments, May 31, 2023, page 1.
[83] LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, Tables 9.1-9.12, pages 255-265.
[84] *Ibid*.
[85] *Ibid*.
[86] LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, page 277.

3.5 Portfolio Scoring and Selection

The IRP provides analysis of 24 Preferred Portfolio variants that test alternative strategies for coal (retirement, conversion to gas, and retrofit with CCUS) and reliance on nuclear, non-emitting peakers, offshore wind, transmission, and DSM. PacifiCorp also tested six sensitivities with varying load growth and private generation forecasts. The Company presented key scoring metrics, including PVRR, risk-adjusted PVRR, cumulative Energy Not Served (ENS), and cumulative GHG emissions for each portfolio under Medium Gas/Medium CO_2 price assumptions and a subset of the portfolios under alternative gas and GHG price assumptions. Figure 4 below shows the performance of the variant portfolios under medium gas and CO_2 prices based on information in Table 9.14 of the IRP.[87] Only two of the variant portfolios (P01 and P20) achieve both lower risk adjusted PVRR and cumulative GHG emissions relative to the Preferred Portfolio. P01 reflects early coal-to-gas conversion of Jim Bridger units 3 and 4 (2026, rather than 2030), and P20 reflects conversion of Jim Bridger units 3 and 4 to CCUS in 2028.

Figure 4: Portfolio Variant Performance



With regard to Jim Bridger 3 and 4, under Medium Gas/Zero CO_2 price assumptions, accelerating coal-to-gas conversion from 2030 to 2026 increases the risk adjusted PVRR by $152M, relative to the Preferred Portfolio.[88] PacifiCorp therefore does not consider P01 to be preferred over the Preferred Portfolio and states that because of this finding, "future policy risk

[87] *Ibid*, p. 268.
[88] *Ibid*, Table 9.16, p. 269.

and other factors must be evaluated as an earlier conversion is considered."[89] PacifiCorp also lists a number of reasons why CCUS at Jim Bridger 3 and 4 is not preferred over the Preferred Portfolio at this time, including uncertainty in CCUS technology costs and the unprecedented scale of CCUS that would be needed at Jim Bridger 3 and 4 among other implementation challenges.[90] PacifiCorp notes that in response to an RFP for amine-based CCUS retrofit options at Jim Bridger Units 3 and 4, the Company received one proposal in March 2023, which they are still evaluating.[91] Staff does not, at this time, dispute PacifiCorp's decision to exclude P01 and P20 from consideration for the preferred portfolio given the technology uncertainty in CCUS and the potential risk of regret for accelerated coal-to-gas conversion.

Staff notes that the following additional portfolios yield performance under the Medium Gas/Medium CO_2 price assumptions that are similar to the Preferred Portfolio in terms of risk adjusted PVRR and GHG emissions:

Figure 5: Variant Portfolios with Performance Similar to Preferred Portfolio

Variant Portfolio	Description	Risk Adjusted PVRR relative to Preferred Portfolio ($m)	Cumulative GHGs (thousand tons)
P04-Huntington RET28	Early retirement of Huntington 1 in 2028	+$118	-289
P17-Col3-4 RET25	Colstrip units 3 and 4 retire end of 2025	+$69	-3,314
P22-DJ4-CCUS	DJ4 converts to CCUS in 2028	+$111	-2,662

PacifiCorp does not present results for these portfolios across the various gas and CO_2 price assumptions and does not bring these portfolios into the CEP for Oregon-specific analysis. It is difficult for Staff to understand how sensitive these cost, risk, and GHG emissions results are to gas and CO_2 price assumptions and under what circumstances, if any, these portfolios might outperform the Preferred Portfolio in the IRP. While Staff appreciates the Company's reasoning regarding CCUS portfolios, it is not clear why the Company has not further explored portfolio P04 and P17, especially given that they examine coal retirements on a timeline that could affect Oregon GHG emissions in and before 2030.

<u>**Requests:**</u>

34. PacifiCorp should evaluate portfolios P04 and P17 under the alternative gas and CO_2 price assumptions and report the resulting scoring metrics in the Company's Reply Comments.

[89] *Ibid*, p. 270.
[90] *Ibid* p. 296-297.
[91] *Ibid*, p. 296-297.

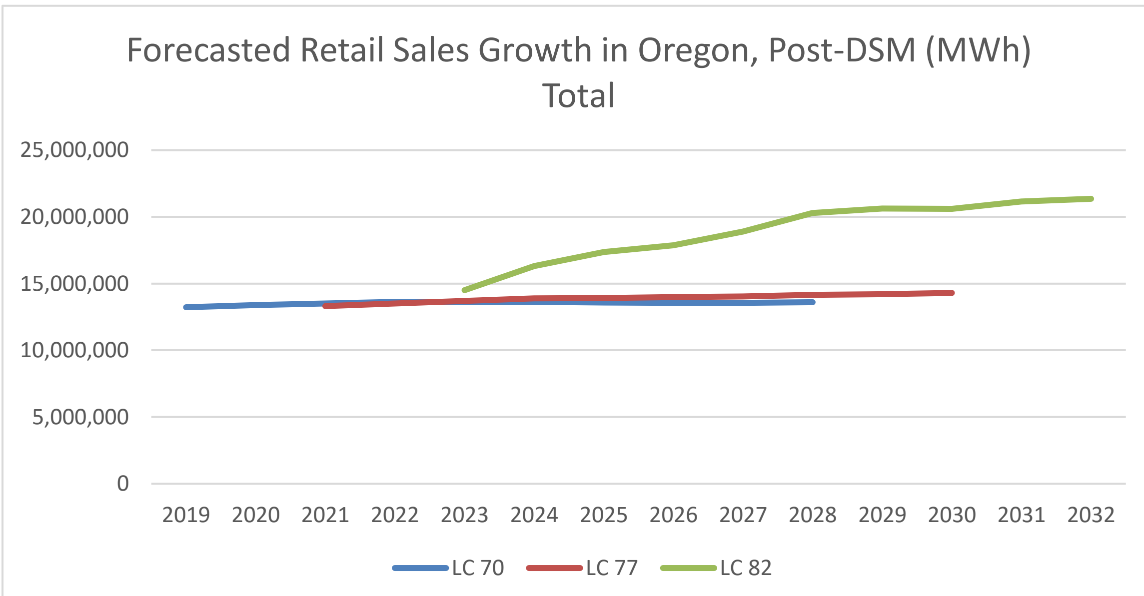
35. **PacifiCorp should include P04 and P17, at a minimum, in the CEP evaluation of alternatives to the Preferred Portfolio within the CEP (see recommendation in the Strategic Decarbonization Questions section).**

3.6 Load Forecast

Commercial Load Growth

Between 2023 and 2032, PacifiCorp has forecast load to increase by 47 percent within its Oregon service territory. This forecast represents a stark deviation from the trend of forecasted load growth presented by the Company in previous year's IRPs (Figure 6).

Figure 6 Forecasted Retail Sales Growth in Oregon, Post-DSM (MWh) Total



The most significant factor driving the increased load is the Company's commercial load forecast which estimates commercial load in Oregon to increase 88 percent by 2032. This forecasted increase estimates that commercial retail sales will become 61 percent of total retail sales in Oregon by 2032, up from 48 percent in 2023 (Figure 2). The Company states in the IRP that "Changes to PacifiCorp's load forecast are driven by higher projected demand from new large customers driving up the commercial forecast and an increased residential forecast."[92] Beyond this statement, the Company offers no further detail within the text of the 2023 IRP Appendix A to explain why such an increase can be reasonably expected through 2032.

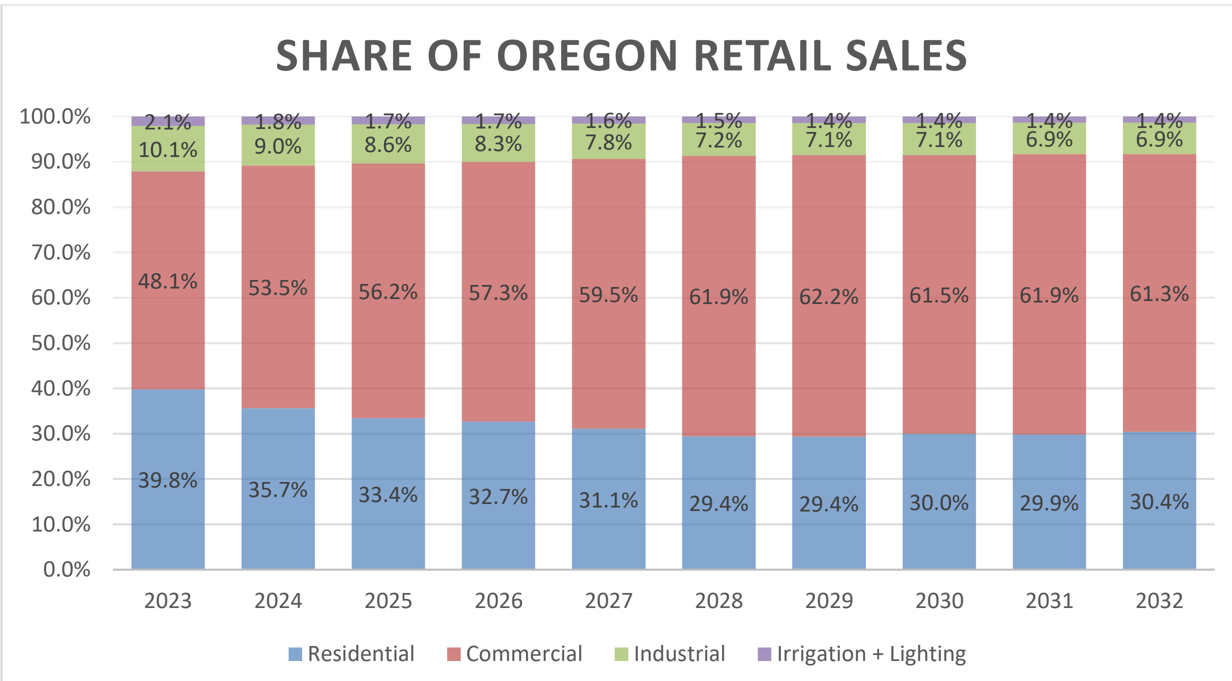
The Company's forecast of monthly sales for the commercial class are forecast directly from historical sales volumes, not as a product of the use-per customer and number of customers model as is done with the residential class. The Company also states that as an additional step for the commercial sales forecast "to reflect the addition of a large "lumpy" change in sales

[92] LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, page 277.

such as a new data center, monthly commercial sales are increased based on input from the Company's [Regional Business Managers] RBM's".

PacifiCorp fails to provide sufficient detail on how exactly input from RBMs are incorporated into the commercial sales forecast, and whether these "lumpy" changes in commercial sales such as new projects can be reasonably expected to come online over the period put forth by the Company in the commercial forecast.

Figure 7: Forecasted Share of Oregon Retail Sales



Given that the expected increase in commercial load is the most significant factor driving the increase in the Company's overall load forecast, Staff is concerned with the lack of detail provided by the Company on the exact nature of this load growth. Staff finds it difficult to determine whether the Company is overestimating or underestimating its load forecast. To better assess the accuracy of the forecast Staff would need greater detail on how these projects are incorporated into the model and whether they can be reasonably expected in the time frame laid out by the Company.

__Requests__:

36. In Reply Comments, PacifiCorp should provide greater detail on how the Company incorporates input from Regional Business Managers into the Commercial Load Forecast

37. In Reply Comments, PacifiCorp should provide greater detail on the expected commercial load growth anticipated within Oregon, and whether this load can be reasonably expected within the timeframe put forth by the Company.

Electrification Adjustments and Sensitivity Analysis

The Company's load forecast accounts for expected transportation and building electrification trends based on current and expected electric vehicle (EV) adoption rates and building electrification initiatives. Various adoption curve sources are calibrated to reflect market conditions across each jurisdiction.

To consider the impact of electric vehicle adoption on energy demand, the Company uses a model to assess trends for light-duty and medium-duty EVs. The model incorporates various national data sources and assumptions to project EV adoption rates, which can be adapted to reflect state-level market conditions.[93] The Company states that building electrification is a relatively minor share of load in the near-term but that it is expected to grow as policies encourage fuel substitution and electrification. The Company's forecast for building electrification is based on expected replacement fuel shares for space and water heating equipment at the end of its useful life, as well as new construction shares of electric fuel for these end-uses over time. This is calibrated with assumptions about equipment turnover and new construction rates.

Staff believes that the pace of electrification will likely have a significant, yet uncertain, impact on load growth in the coming years. However, in its initial IRP filing, the Company did not perform any analysis of high or low electrification assumptions. After an initial review of the IRP, Staff asked the Company to develop an aggressive electrification load forecast. The Company agreed and provided an aggressive electrification forecast of annual energy demand in MWh to Staff. The forecast was reasonably in-line with the energy demand in the Company's "High Load Forecast Scenario," which helps ease Staff's concern that the Company would be unprepared to serve energy needs in an aggressive electrification future.

Staff appreciates the Company's willingness to look into a high electrification load forecast. However, so far, the Company has only looked at annual energy demand in MWh and did not examine the impact of an aggressive electrification scenario on the peak load in MW. Given that both building and transportation electrification are likely to add significant load during peak hours, Staff believes a thorough examination of an aggressive electrification peak load scenario is necessary.

Requests:

38. In Reply Comments, provide a forecast of peak load under aggressive electrification assumptions.

39. In Reply Comments, conduct a sensitivity analysis of an aggressive electrification scenario in PLEXOS. Include the expected effects of building and transportation electrification on the Company's peak load.

Climate Change

PacifiCorp's load forecast uses historical actual weather data from 2002 through 2021 and then adjusts for expectations and impacts from climate change. The Company's climate change

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[93] LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, page 12.

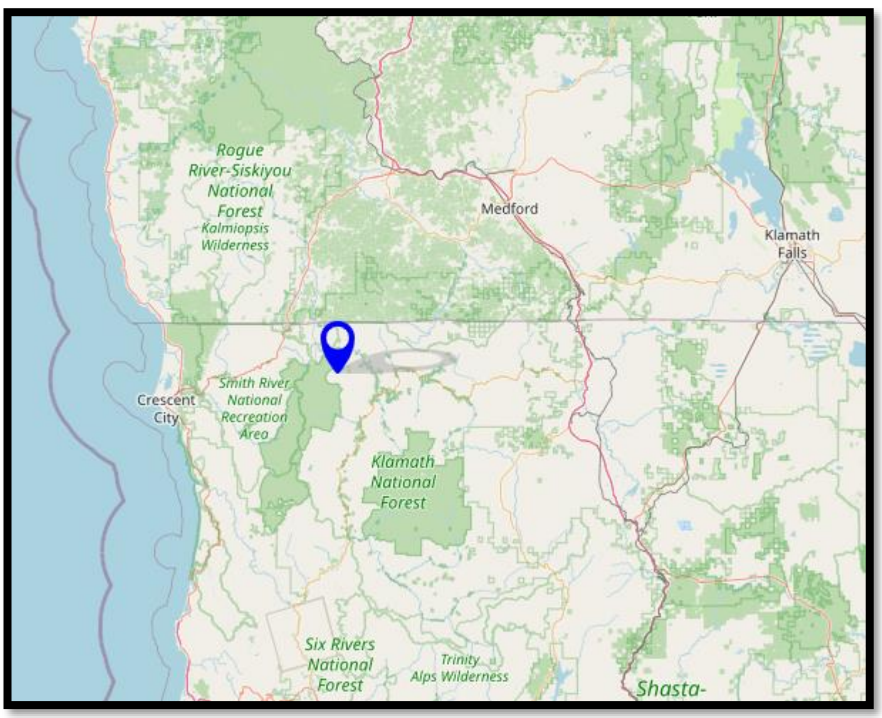
model adjusts the percentile of the historic weather data to achieve the expected target average annual temperature and calculate the HDD and CDD impacts and peak producing weather impacts within the energy forecast and peak forecast, respectively.

The Company uses temperature changes projected by the United States Bureau of Reclamation in the West-Wide Climate Risk Assessment: Hydroclimate Projections Study (Study) to determine daily average temperatures and peak producing temperatures.

The Company uses the "Klamath River near Seiad Valley" Bureau of Reclamation Site for its projected range of temperate changes associated with Oregon. Staff notes, however, that this site is not located within Oregon (Figure 3).

Staff understands the Study estimates temperature and hydrologic impacts broadly across regions and that while this specific site may not be within Oregon it could still generally represent climate impacts in the west. However, Staff finds the Company's selection of this site to represent projected temperature changes in Oregon odd, especially given the Company's wide ranging service territory throughout Oregon (Figure 4).

Figure 8 United State Bureau of Reclamation Site – "Klamath River near Seiad Valley"



Additionally, the Study uses a global climate model (GCM) which is a computer-based simulation that uses mathematical equations to predict Earth's future climate by representing various physical processes in the atmosphere, oceans, land and ice. The Study then takes the global predictions and down-scales them to produce regional estimates across the west. There are inherent uncertainties in downscaling these models that could lead to biases for certain areas, the 2021 Study states "some GCMs may not capture the orographic effects associated with certain mountain ranges (e.g., the Cascade Mountains of Washington)."[94] Given the varying topography within Oregon, estimates of temperature and hydrologic impacts could vary widely across the state and have greater variability at local levels. Changes in regional temperature and weather patterns within Oregon could influence heating and cooling demand in unanticipated ways.

Staff struggles to see how the projected temperature changes for a single reclamation site in Northern California can accurately assess the impacts of climate change for all of PacifiCorp's customers in Oregon.

<u>**Requests**</u>**:**

40. In Reply Comments, evaluate whether the Company's approach for incorporating Climate Change impacts accurately reflects temperature changes across the Company's Oregon service territory.

41. In the next IRP, examine alternative climate modelling approaches which account for more localized effects.

Figure 9: PacifiCorp Service Territory

[94] LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, 2021 West-Wide Climate Risk Assessment: Hydroclimate Projections Study, Page 357.

3.7 Supply / Candidate Resources

The candidate resources in PacifiCorp's 2023 IRP include technologies with diverse supply chains reflecting the varied chemistries of batteries, solar panels, nuclear fuels, etc. These supply chains have seen disruptions due to issues including outbreaks of war in Europe, Withhold Release Orders (WROs) blocking the import of certain goods due to forced labor inputs used in their production, and increased market volatility for commodities such as steel. With these pressures and uncertainties at top of mind, it is important to use the most accurate assumptions when evaluating these alternatives, as the forecast horizon is lengthy, and each supply chain is likely to continue to evolve. The Company performed a commendable job with regard to estimating these inputs. However, Staff has concerns ranging from the issues of availability and price assumptions of nuclear fuels, coal to gas conversion costs, to the modelling of anticipated transmission costs associated with candidate resources such as offshore wind.

3.7.1 Nuclear

The IRP relies in part on emerging technologies, largely Natrium nuclear and hydrogen peakers, to meet demand beginning in 2030. These non-emitting technologies will provide value and cost savings to customers by allowing for flexible, dispatchable, non-emitting capacity. Importantly, the IRP also considers variant portfolios that do not rely on these technologies. These variants are important because they help assess risks and potential actions if these technologies do not become available. Staff appreciates the 24 variant portfolios that allow for comparison of a wide variety of costs and risks under different assumptions in this IRP.[95]

Staff has concerns regarding the PLEXOS cost inputs assumed for the Natrium nuclear resource. The company states in OPUC Data Request 198 that the costs are the same as the 2021 IRP save for an adjustment to reflect the Production Tax Credits (PTC) from the Inflation Reduction Act (IRA). In addition to Staff's concerns from the 2021 IRP that Natrium cost estimates are not well supported, it is also unclear whether these costs have been escalated appropriately, or whether they reflect the supply shortages in production of the reactor's fuel. The Natrium's projects developers announced efforts to expand domestic production of the reactor's HALEU fuel, but it remains unclear if there are associated cost impacts from these developments that would affect the project's economics.

In addition to the above emerging technology concerns, the reactor's atypical permitting timeline expectations remain somewhat opaque to Staff. A critical path item is Nuclear Regulatory Commission (NRC) Construction Permit Application (CPA). This permitting process takes approximately 36 months.[96] Per an August filing with the NRC, the Natrium contractor TerraPower, plans to submit the project's Construction Permit Application in March 2024.[97] TerraPower originally thought the company would submit the Natrium CPA to NRC to begin the

[95] LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, page 267.
[96] LC 82, PacifiCorp Information Request Response No. 118, Aug. 8, 2023.
[97] *Ibid.*

construction permitting process in June 2023.[98] This example underscores Staff's concerns about additional unforeseen permitting delays that may materialize and, as such, are not adequately addressed in the Company's scenario analysis, especially if PacifiCorp plans for Natrium to become a component of the eventual Oregon portfolio to achieve the HB 2021 emission reduction goals.

Request:

42. PacifiCorp should revise Action Plan Item 1g to go beyond monitoring to include tracking and reporting annually on key milestones, including TerraPower's NRC Construction Permit Application, and updating Natrium commercial online date (COD) as appropriate.

3.7.2 Non-Emitting Peaking Resources

In each candidate portfolio, save for the P11-Max NG variant, the Company seeks to procure a significant amount of non-emitting peaking generation. These resources are assumed to use a non-CO_2 emitting fuel such as hydrogen or even solar and storage,[99] with most portfolios targeting acquisitions of 606 MW by year end 2029,[100] with additional large acquisitions expected by year end 2036. In the preferred portfolio, 606 MW is selected in 2030, with a cumulative total acquisition of 1,240 MW selected to come online through 2037. Staff is concerned about the timeline for procuring these resources in the next seven to nine years, and is also concerned that the scale of non-emitting peaking generation selected for the preferred portfolio is so large given that these are emerging technology resources with fuel and fuel transmission yet to be developed.

Request:

43. In Reply Comments, PacifiCorp should discuss how it could identify key events and milestones around the costs and availability of non-emitting peak resource technology in order to better inform the next IRP's preferred portfolio resource mix and associated Action Plan.

3.7.3 Private Generation Forecast

The Company's private generation forecast, performed by DNV, includes tax credits in the base case scenario that creates favorable conditions for PG adoption. DNVs high case scenario includes lower technology costs and higher retail electricity rates that result in just 0.5 percent greater cumulative installed capacity forecasted over the 20-yr forecast horizon. Staff would like to understand why PG adoption, as modelled, is sensitive to tax credits and seemingly less sensitive to other favorable economic conditions, such as reduced technology costs and higher retail electricity prices, and would like to understand what data informs these modelled sensitivities.

[98] *See* TerraPower letter to U.S. Nuclear Regulatory Committee, August 2, 2023. Can be found on the U.S. NRC website at https://adamswebsearch2.nrc.gov/webSearch2/main.jsp?AccessionNumber=ML23214A199.

[99] LC 82, PacifiCorp Information Request Response AWEC IR No. 2, July 6, 2023.

[100] LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, page 313.

Further, due to the timing of the IRP relative to the passage of the IRA, the Private Generation forecast does not include the impact of the IRA tax credits, which creates favorable economics for adoption.[101]

Lastly, PAC appears to be experiencing strong growth in private generation that involves batteries. Since 2020, PacifiCorp has seen over 400 new batteries installed with annual capacity growing at over 40 percent annual and with a cumulative installed capacity of over 4.3 MW by July 2023.[102] Staff sees the growing adoption of solar as stimulating greater deployments of behind-the-meter battery technology. However PacifiCorp does not link the growth potential of battery demand response to increasing levels of behind-the-meter solar installations.[103] We would like PAC to explore the relationship between solar and battery adoption as it could have an impact on forecasted capacity need and local area reliability.

Requests:

44. **Staff requests that given the delay in the 2022 AS RFP and the 2024 AS RFP, the Company update the forecast of private generation factoring in the IRA tax credits for both solar and for battery technologies and apply that to the load forecast and overall capacity need used by the 2023 IRP preferred portfolio.**
45. **Staff requests that by the next IRP, the Company study the correlation between Private Generation solar installations and the installation of battery technology and, if applicable, use it in the next IRP's forecast of battery technology.**

3.7.4 SSRs

Per HB 2021, the Company faces a requirement to obtain 10 percent of its capacity from Small Scale Renewables (SSRs). SSRs must be less than or equal to 20 MW in size, certified by the Oregon Department of Energy, and registered in the Western Renewable Energy Generation Information System.[104] Qualified SSRs do not need to be located in Oregon. PacifiCorp identified that, based on Oregon load growth, it would need 860 MW of SSRs by 2030. The Company estimates 370 MW of this requirement can be met through existing and already-planned capacity.[105]

[101] LC 82, PacifiCorp Information Request response to Staff DR No. 154, August 24, 2023.
[102] LC 82, PacifiCorp Information Request response to Staff IR No. 155 Excel Attachment, August 24, 2023.
[103] LC 82, PacifiCorp Information Request response to Staff IR No. 129, August 21, 2023.
[104] ORS 469A.210(2); OAR 860-091-0030.
[105] LC 82, PacifiCorp CEP, May 31, 2023, page 63.

Figure 10: Existing and Planned Resources to Meet SSR Requirement by 2030

Fuel Type	Estimated Existing and Planned and Planned Capacity in 2030 (MW)
Solar	156.1
Wind	109.5
Water	58.9
Biomass	40.7
Geothermal	2.8
Methane	1.9
Total	**370**

PacifiCorp estimates it will need an additional 490 MW of SSRs by 2030 and add an estimated $268 M, in net-present value terms, to the cost of the preferred portfolio for Oregon ratepayers.[106] The acquisition of SSRs, as part of the underlying CEP Portfolio, only reduces PacifiCorp's emissions approximately 3 percent.[107]

Due to cost considerations with this obligation, Staff is interested in exploring options that would facilitate the development of these resources in a cost-effective manner. One possibility Staff would like to explore with the Company and stakeholders would be the identification and evaluation of the barriers, or costs and any informational challenges, that small renewable projects face in the RPS certification process that might be relieved through changes in statute, rules, or through minimal additional informational resources.

And while Staff greatly appreciates the candor with which PacifiCorp discusses the urgency to begin the SSR acquisition process[108] (also discussed "RFP Section" of these comments) Staff would also appreciate insights from the Company on how PURPA could be better leveraged to bring on new SSRs, in addition to the proposed RFP.

<u>Request</u>:

46. **In reply comments, PacifiCorp should identify barriers that SSR projects face in RPS certification process that might be relieved through changes in statute, rules, or through minimal additional informational resources.**
47. **In reply comments, detail how PacifiCorp could improve the PURPA process to facilitate the rapid acquisition of new SSRs, in addition to the proposed SSR RFP.**

3.7.5 Coal

Coal to Gas Conversions

The 2021 IRP introduced gas conversion of Jim Bridger units 1 and 2 in 2024. The 2023 IRP adds coal-to-gas conversions of Jim Bridger 3 and 4 by 2030 and Naughton 1 and 2 by 2026. Some

[106] LC 82, PacifiCorp CEP, May 31, 2023, pages 55 and 67.
[107] LC 82 PacifiCorp 2023 CEP, Resource Planning, May 31, 2023, page 65.
[108] LC 82, PacifiCorp CEP, May 31, 2023, page 89.

participants have raised concerns about coal to gas conversions, including CUB and OSSIA. Staff understands that coal-to-gas conversions may support resource adequacy while reducing the emissions intensity of the Company's thermal fleet. However, Staff is concerned that the Company's strategy deviates so significantly from PacifiCorp's 2021 plan and from the Company's 2020 Inter-Jurisdictional Protocol, which recommended Oregon exit dates for Jim Bridger 1 by December 31, 2023, and Jim Bridger 2, 3, and 4 along with Naughton 1 and 2 by December 31, 2025.[109]

PacifiCorp claims that these coal-to-gas conversions will serve as a bridge to cleaner alternatives, like nuclear and non-emitting peakers, and has the gas units scheduled to retire by 2038, leaving only 8-14 years to recover the associated costs. Staff is concerned that this assumption may be unreasonable and that future decisions to extend the lives of converted gas units could risk HB 2021 compliance. Staff is also concerned that high gas prices could affect the economics of the converted units and make them less competitive than cleaner alternatives.

<u>Requests</u>:

48. In Reply Comments, Staff seeks further explanation from PacifiCorp on:

- **Why coal-to-gas conversions arose so prominently in this plan, but not in the 2021 IRP;**
- **How the Company evaluated the risk of regret for the coal-to-gas conversions;**
- **How the Company took into account HB 2021's GHG targets in the coal-to-gas conversion planning decisions; and**
- **Given how quickly PacifiCorp's coal retirement plans have changed, under what future circumstances the Company might expect to expand upon or pull back from the coal retirement and coal-to-gas conversion plans or extend the lives of the converted gas units.**

Staff would also like PacifiCorp to test a variant on the Preferred Portfolio that does not allow coal-to-gas conversions beyond Jim Bridger units 1 and 2, to test this portfolio across the various gas and CO_2 price assumptions, and to report on this portfolio in the CEP alongside the Preferred Portfolio and other high performing variant portfolios referenced in these comments. Finally, Staff appreciates that the Company will assess the impact of the U.S. EPA's recently proposed GHG standards for fossil fuel-fired power plants in the IRP update, but also encourages the Company to share any initial assessment it has conducted in Reply Comments.[110]

Coal and New Emissions Control Technology

In the 2023 IRP Action Plan, PacifiCorp proposed upgrading six coal units with emissions control technology by 2026 despite proposing that five of the six plants be retired by 2032. This

[109] UM 1050 – 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol, December 3, 2019, pages 21-22.

[110] LC 82, PacifiCorp Information Request response to OPUC IR #137, August 23, 2023.

technology – Selective Non-Catalytic Reduction (SNCR) was being installed for the purpose of meeting the Ozone Transport Rule.[111] However, these plans are now being reconsidered.[112]

In addition, CUB noted in its Round 0 comments that investments in SNCR emissions equipment for coal plants may not be reasonable for inclusion in Oregon rates, given that Oregon must exit coal plants by 2030.

Despite PAC's assurances that the SNCR investments were warranted,[113] it is not clear that any future installation of SNCR would be the least cost and risk choice given the eminent retirement dates and Oregon's required coal exits. Additionally, as discussed below, the Inflation Reduction Act's (IRA) Energy Infrastructure Reinvestment (EIR) Program presents a new alternative to consider when assessing the economics of any action, including retirement, for these facilities.

Requests:

49. **In Reply Comments, Staff requests that PacifiCorp detail when it expects the reconsideration of SNCR investments to be concluded. If the date is uncertain, the Company should articulate at what point in the future the benefit of emission reductions from SNCR is no longer worth the cost given the IRP's proposed, near-term retirement dates for five of the six plants.**
50. **In Reply Comments, PacifiCorp should address the steps it will take in analyzing whether any of these six coal facilities could be leveraged to take advantage of the IRA's $250 Billion EIR program.**[114]

Coal Modeling

One concern Staff has identified is that the IRP fuel cost and generator dispatch do not appear to reflect the recent distress in the Utah coal market, which has made coal less accessible and more expensive, affecting the Company's two Utah coal plants. This disruption may result in higher dispatch at other available thermal units.

In the 2024 power cost forecast filing, PacifiCorp reported serious issues with coal supply for Utah coal plants, including a mine fire and other supply and demand changes. IRP Guideline 1b says that utilities should address fuel price uncertainty in the IRP. Utah market disruption is a major source of uncertainty that has not been adequately assessed in this IRP.

The Company's 2024 TAM testimony stated that impacts from the Utah mine fire are expected to persist into the foreseeable future.[115] Staff is concerned that failure to consider recent coal market issues in the IRP could result in missed opportunities to optimize procurement and retirement decisions.

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[111] LC 82, PacifiCorp Information Request response to OPUC IR No. 181, August 31, 2023.
[112] LC 82, PAC response to Sierra Club IR #37, September 26, 2023.
[113] LC 82, PacifiCorp Round 0 Reply Comments, July 31, 2023, page 40.
[114] See https://www.energy.gov/lpo/energy-infrastructure-reinvestment for additional information.
[115] *See* UE 420, September 15, 2023, PAC/200, Owen/4

Staff is also concerned that PacifiCorp is modeling coal units as must-run units with no minimum take agreement.[116] Both of these assumptions introduce inaccuracies in coal modeling. First, given that economic cycling is a possibility, the Company should allow economic cycling on any coal unit. Second, the complete removal of minimum take agreements from IRP modeling is unrealistic. Existing minimum take agreements should be modeled accurately. After the existing contracts end, Staff expects that units should be modeled as having no minimum take.

Requests:

51. In its IRP Update, the Company should include a variant portfolio that optimizes the system resource buildout under conditions of continuing Utah coal market disruption and elevated gas prices through 2030. PacifiCorp should discuss the implications of this future for coal to gas conversion decisions and other significant resource decisions.

52. In Reply Comments, PacifiCorp should provide a discussion of whether existing minimum take agreements are modeled for the Company's coal plants. If not modeled, include an explanation of why not.

Coal and Inflation Reduction Act's Energy Infrastructure Reinvestment Program

The IRP's preferred portfolio includes retirement or gas conversion of many coal units by 2032.[117] While the economics and performance of new resource alternatives drives much of this activity, relatively late breaking developments around Federal Clean Energy Financing could play an outsized role in retiring or repurposing coal plant.

The EIR can finance projects that retool, repower, repurpose, or replace energy infrastructure that has ceased operations or enable operating energy infrastructure to avoid, reduce, utilize, or sequester air pollutants or greenhouse gas emissions. The EIR support a wide range of projects that utilize existing energy infrastructure and revitalize communities, including:

- Upgrading or uprating energy infrastructure so it can restart or operate more efficiently, at higher output, or with lower emissions.
- Replacing retired or soon to be retired (by 2031) energy infrastructure with clean energy infrastructure.
- Building new facilities for clean energy purposes that utilize legacy energy infrastructure.

Additionally, the scope of a project receiving EIR financing may include remediation of environmental damage associated with legacy energy infrastructure.

To this end, in Round 0 Comments, Sierra Club shared a study estimating that $2.1 billion could be saved by retiring four PacifiCorp coal plants using EIR loans. In PacifiCorp's Round 0 Reply

[116] LC 82, PacifiCorp response to Sierra Club Information Request 08, August 29, 2023.
[117] LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, Figure 1.11, Page 19.

Comments, PacifiCorp did not discuss the EIR or the potentially huge benefit to customers from pursuing this option.
If the opportunity exists to reduce customer rates through a program to retire coal plants, and replace them with non-emitting resources, PacifiCorp must not ignore this important opportunity. Staff understands that conditional commitments of available funding must be issued by DOE by September 30, 2026, so waiting to analyze how this program could impact PacifiCorp's portfolio and resource acquisitions by the next IRP is not a reasonable option.

Requests:

53. Staff requests PacifiCorp respond in Reply Comments regarding how it plans to ensure it is effectively pursuing the potential benefits of the EIR program to support a plan that best balances cost and risk for customers.

54. Staff requests that PacifiCorp perform Sierra Club's recommended variant analysis in this IRP to study the possibilities of the EIR. A variant study can help inform the value of pursuing EIR loans, as well as potential effects of EIR loans on resource buildout.

3.7.6 Offshore Wind

Staff greatly appreciates PacifiCorp devoting a variant portfolio (P10) to exploring the addition of 1,000 MW of offshore wind. Additionally, the 2023 IRP included this portfolio in the IRP's published sensitivity analyses so that this portfolio can be easily compared to the preferred portfolio and other portfolio variants. The IRP also explores the benefits and challenges to this portfolio in Chapter 9, Modeling and Portfolio. Overall, Staff think this addition and overview of Oregon offshore wind shows PacifiCorp's responsiveness to stakeholder feedback and should be very helpful to advancing the regional dialogue around this topic.

PacifiCorp states that the costs of onshore transmission upgrades associated with offshore wind projects is not included in modelling as those costs are location dependent.[118] For the sake of realistic comparison with other resource options in modelling, Staff would like to see some approximation of these transmission upgrade costs included with Offshore Wind options. This would be similar to how the Company was able to internally develop proxy resource costs for confidential pumped-hydro storage projects for use in resource option comparisons.

Beyond the transmission upgrade issue, Staff would note that offshore wind continues to be identified as key component to recent regional decarbonization studies and several studies have directly addressed the value of offshore wind to the Oregon grid, ratepayers, and economy.[119] As a supplement to PacifiCorp's helpful analysis in this IRP, Staff requests the Company, in the IRP update, identify the near-term actions and investments the region would need to make for a utility, like PacifiCorp, to begin actively considering the addition of 500 MW to 1,000 MW Oregon offshore wind by 2035 through RFPs or bilateral contracts, like Natrium.

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[118] LC 82, PacifiCorp response to Sierra Club Information Request 08, August 29, 2023, pp. 175 and 194.
[119] See Net-Zero Northwest Technical Report, June 21, 2023; WECC 2040 Clean Energy Sensitivities Study, January 28, 2022; Renewable Northwest, "Oregon Clean Energy Pathways," June 15, 2021; PNNL "Exploring the Grid Value Potential of Offshore Wind Energy in Oregon," PNNL-29935, May 2020; and, Oregon Department of Energy report to the Oregon Legislature, "Floating Offshore Wind: Benefits & Challenges for Oregon," September 15, 2022.

Requests:

55. **In the IRP Update, please provide a general estimate transmission upgrade costs for the 1,000 MW of offshore wind modeled in P10. This estimate should be similar to proxy resource costs for confidential pumped-hydro storage projects used in other resource option comparisons.**
56. **Additionally, in the IRP Update, please identify the other near-term actions and investments the region would need to make for PacifiCorp to consider the addition of 500 MW to 1,000 MW Oregon offshore wind by 2035 through RFPs or bilateral contracts, like Natrium.**

3.8 Resource Adequacy

Although the Company does not appear to do a dedicated assessment of resource adequacy (RA), it appears that the Company has utilized various features of PLEXOS to analyze reliability concerns. Staff appreciates the work that the Company has done to model RA up to this point, but recommends that the Company's methods should be updated for its next IRP to incorporate more weather years, to incorporate WRAP benefits, and to report out the primary metric of interest to WRAP and Oregon's RA program, the loss of load expectation (LOLE). Staff would like to begin these comments by first summarizing what is happening in UM 2143, the Commission's investigation into resource adequacy, and the associated rulemaking in AR 660. In those dockets, Staff has recommended that all Oregon-regulated IOUs include an informational filing in their IRP that addresses peak load growth, strategies to meet the load, and transmission strategies to meet any RA needs over a four-year period.[120] Staff also recommends that the utilities include any public program output from the Western Resource Adequacy Program (WRAP) so that the Company's RA strategies and methods can be placed in a regionwide context. The proposed rule language was made to be flexible enough that a load-responsible entity could implement their own RA methodology or update the methodology with newer data or industry best practices that may not perfectly align with WRAP without running afoul of any Oregon rules.

The best practices for RA analysis have changed drastically over the last decade to better accommodate Variable Energy Resource (VER) penetration, transmission constraints, and extreme weather conditions due to climate change. A 2021 ESIG report outlines shortcomings of commonly used approaches and makes recommendations on how to improve RA analysis.[121] In short, the ESIG report points out that RA risk was traditionally driven by discrete, probabilistic and uncorrelated outages at dispatchable thermal plants, therefore the resulting RA analysis methodology treats load and weather as uncorrelated with generation shortfalls.

However, the modern power system relies heavily on VERs whose generation correlates with weather and load. Dispatchable thermal resources are also being displaced by dispatchable but energy-limited resources, such as batteries or demand response programs that cannot necessarily be relied upon in all instances. ESIG asserts that the traditional probabilistic

[120] See UM 2143 Staff report for the September 21, 2023 Public Meeting.
[121] See *Redefining Resource Adequacy for Modern Power Systems.* Energy Systems Integration Group, 2021. Last accessed, September 11, 2023 here.

modeling of resource generation that does not take into account the realities of operating energy-limited resources or the correlation between VER generation and load should be updated for the modern RA landscape. Of note, ESIG recommends:

- Modeling chronological dispatch at all hours using many weather years;
- Quantifying the size, frequency, and timing of capacity shortfalls;
- Modeling resource sharing between Balancing Authority Areas (BAAs);
- Recognizing new load flexibility and that not all capacity resources are created equal.

Staff believes that the recommendations in the ESIG report are particularly relevant given recent developments in Oregon and the Western US generally. Since 2020, Oregon has seen multiple heat dome events that led to calls for conservation and exceptional transmission constraints, extreme wildfire conditions that have led to public safety power shutoffs,[122] and a cold snap event in 2021 that led to extended outages across the Willamette valley. Oregon is also embarking on a path to decarbonize the electric sector after the passage of HB 2021. Aiding in this energy transition amidst increasingly common extreme weather events, the WRAP's tariff has been approved by FERC, thus allowing for increased coordination between BAAs both when planning for RA concerns and addressing them in the moment.[123] Given all these changes, Staff believes it to be the utmost importance that the Company's RA methods evolve to meet these new challenges and opportunities.

According to the Company's IRP filing, the Company implements a chronological dispatch in its short-term and medium-term models through PLEXOS over a twenty year horizon.[124] By Staff's understanding of Appendix K, the Company is using only three weather-years from 2016 to 2019 to study the correlation between load and renewable energy output.[125] When doing stochastic evaluation of resources to determine capacity contribution, the Company chose to use only a single 8760 hourly wind and solar resource shape using 2018 data. The days within each month were varied so as to match intramonth variability observed in the 2016-2019 sample.[126] The Company states that it believes more work is needed in this area in a future IRP.[127]

The Company uses PLEXOS to quantify reliability shortfalls at the hourly level in the short-term model.[128] In particular, the short-term model calculates total shortfalls by hour of the portfolio selected by the long-term model, which is then used to inform the value of a new resource added to the portfolio.[129] The Company's capacity contribution methodology calculates a "Capacity Value" based on weighted average of the resource's expected generation, where hours with a higher Loss-of-Load-Probability (LOLP) are given greater weights.[130] Simulations

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122 PGE, Pacific Power start public safety power shutoffs in Oregon | kgw.com.
123 See FERC's approval of the WRAP tariff here.
124 LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, page 232.
125 LC 82, PacifiCorp Amended IRP Filing, May 31, 2023 Appendix K of PAC's IRP filing, Appendix page 246.
126 *Ibid* page 248.
127 *Ibid*.
128 LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, page 218.
129 LC 82, PacifiCorp Amended IRP Filing, May 31, 2023page 232.
130 LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, Appendix K of PAC's IRP filing, Appendix page 244.

for LOLP and renewable energy generation appear to use the same 2016-2019 study data and 2018 8760 shape discussed above.

Staff agrees that the data and methodology used to determine the Company's RA position and the capacity contribution of each resource needs improvement in a future IRP and strongly recommends that the Company continue to improve its modeling and data integration. In particular, Staff is worried by the Company's choice to use only data from the 2016-2019 time period when determining the relationship between load and renewable energy generation and the choice to only base its modeling off of a single load year. This is inconsistent with the ESIG recommendation that RA modeling should be done using many weather years. Beyond that though, the Company's omission of more recent data means that many extreme weather events such as the Labor Day 2020 wildfires, the February 2021 ice storms, and the multiple extended heat domes since June 2021 are not included in this analysis.

Staff also believes that the Company should model more than a single year when doing a stochastic evaluation of RA and capacity contributions. While there is some value of shifting around the days within each month as the Company does, the Company's method still would still likely omit possible extreme weather events that are not expected to occur every year. As climate change increases the likelihood of extreme weather events, Staff believes it to be of the utmost importance to model as many possible load-shortfall scenarios as is practicable.

Requests:

57. **For the next IRP, Staff recommends that the Company update its methodology and data to reflect the impact of several years of potential weather conditions on the Company's RA position and resource capacity contributions.**
58. **PacifiCorp should account for the benefits of the WRAP program in future IRPs if it plans to continue as a participant in the program.**
59. **In the next IRP, PacifiCorp should calculate and report the LOLE of the Preferred Portfolio in each year and explain why it chose to plan for that level of reliability.**

3.9 Transmission

PacifiCorp has proposed an ambitious set of transmission investments in this IRP. However, PacifiCorp is not planning transmission in a vacuum. Not only is BPA undergoing a large planning effort, per a recent presentation to the Committee on Regional Electric Power Cooperation, eight different studies on the Western Region's transmission needs and obstacles have been completed recently.[131] Another ten are underway. It would be helpful to understand how PacifiCorp plans to optimize its transmission investments relative other important, large-scale, regional transmission planning activities. Further, Staff seeks to better understand how the 2022 AS RFP suspension could impact the economics of current and proposed transmission investments.

[131] CREPC-WIRAB Meeting, Fall 2023 Joint Meeting, "Making Sense of Other Transmission Studies Underway in the West," Keegan Moyer from Energy Strategies, October 5, 2023.

Request:

60. In Reply Comments, PacifiCorp should discuss how its ambitious transmission plans are coordinated with and through other regional planning activities and how the 2022 AS RFP suspension may impact the economics of any planned transmission.

3.10 Major Transmission Project Modeling

PacifiCorp has modeled the B2H transmission line as a transmission resource that displaces the need for 725 MW of battery storage if not constructed.[132] This appears to be similar in principle to the cost offset applied to Energy Gateway South in the 2021 IRP. PacifiCorp has not provided any explanation for the assumption that 725 MW of battery storage would be needed in the absence of B2H.

Request:

61. In Reply Comments, PacifiCorp should discuss and provide justification for the assumption that 725 MW of battery storage would be needed in the event that B2H were not constructed.

3.10.1 Transmission Alternatives and Grid Enhancing Technology

Staff supports RNW's recommendations that PacifiCorp better assess non-wires alternatives to transmission investments. RNW's Round 0 Comments mentioned several technologies that could potentially defer or reduce the need for transmission investments. PacifiCorp's reply comments did not explain how the Company has considered the potential benefits of these technologies to customers. These technologies include:

- Non-wires solutions.
- Grid Enhancing Technologies (GET) including dynamic line ratings, and advanced power flow and topology control.

RNW notes that recent Washington legislation will likely require the Company to consider non-wires solutions and GETs in transmission planning, and recommends that PacifiCorp begin to study GETs more seriously. Staff is supportive of the Company taking a close look at any technologies that could make more efficient use of transmission resources.

Request:

62. In the next IRP, Staff requests PacifiCorp include a discussion of how it has considered non-wires solutions and Grid Enhancing Technologies to make the most effective use of its existing transmission system before choosing transmission expansion options.

3.10.2 Transmission and Interconnection in Oregon

HB 2021 has created a need to consider interconnecting many small-scale renewable resources and CBRE resources in Oregon. PacifiCorp's CEP has looked at the cost of adding SSRs to meet

[132] LC 82, PacifiCorp Information Request response to Staff IR No. 191, September 6, 2023.

the 10 percent requirement, but has made simplified assumptions that leave many questions about how these resources can best be added to the grid.

Staff would like to discuss the potential for improving the granularity and accuracy of Oregon transmission and interconnection modeling. Staff would note that the data from PacifiCorp's response to IR 158, mapping substations to load bubbles, was very helpful. Staff continues to analyze this data as further improvements in understanding the relationship between load, distributed resources, and constraints within local areas could enable a more informed process for valuing the addition of new, local resources to serve Oregon load. Currently, there is limited visibility into how and where the grid can be optimized so that the 10 percent SSRs serving Oregon customers may in fact originate in Oregon. Considering Oregon transmission on a more granular scale will help to answer questions like whether SSRs are being added at locations that most benefit the grid by increasing reliability at the most reasonable cost.

Request:

63. Staff requests PacifiCorp respond in Reply Comments regarding its ability to model Oregon transmission on a more granular scale to help inform the best way to build out SSR and other resources in Oregon. The Company should indicate whether it can provide this type of analysis in the IRP Update or the next IRP or whether there is another open docket that is more appropriate.

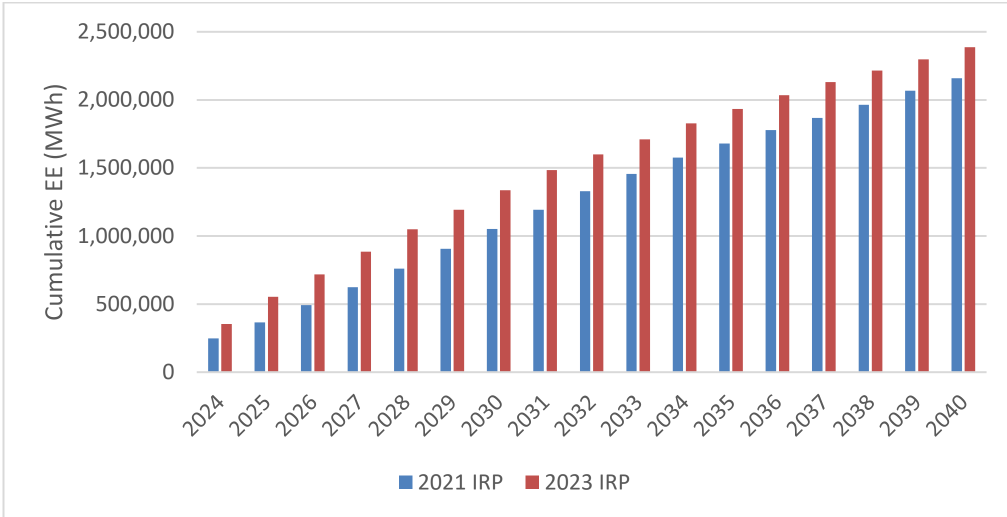
3.11 Demand Side Management (DSM)

3.11.1 Energy Efficiency in Portfolio Analysis

PacifiCorp identifies a sharp, near-term increase in the need for cost-effective energy efficiency (EE) in the Company's preferred portfolio. EE selection in the preferred portfolio is driven primarily by elevated and volatile forward market prices for electricity in the next three years. Cumulative EE acquisition between 2024 and 2030 increased by 28 aMW in the 2023 IRP compared to the Company's 2021 IRP.[133] Figure compares the Oregon acquisition of EE between the two IRPs. Notably, the 2023 IRP identifies a 61 percent greater EE need in the 2024 and 2025 EE acquisition. In response to identified needs, Energy Trust of Oregon is planning to scale investment and infrastructure to acquire higher levels of EE this decade.

[133] LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, Table D.4. Appendix D, page 116 and Table D.4. PacifiCorp 2021 Integrated Resource Plan. Appendix D. Docket No. LC 77. Page 110.

Figure 11: Comparison of Oregon EE Acquisition in Preferred Portfolios from 2021 and 2023 IRPs[134]

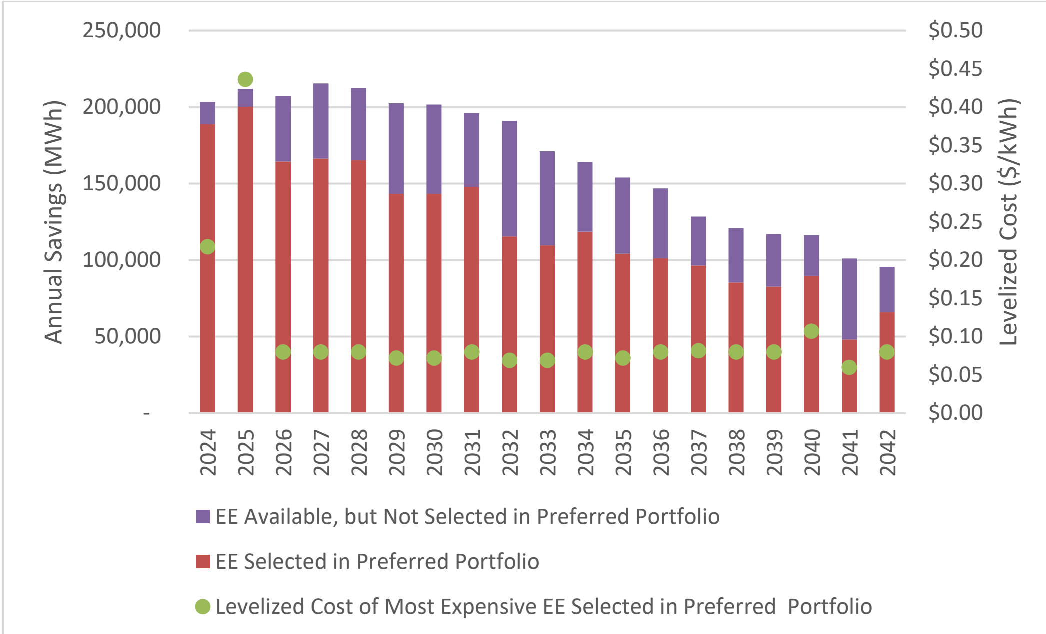


Staff is encouraged to see PacifiCorp identify the significant short-term EE need, but concerned that the long-term acquisition is insufficient to meet the requirements of HB 2021.

[134] LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, Table D.4. Appendix D, page 116.

Figure demonstrates how over the planning period, PacifiCorp's preferred portfolio selects a lower percentage of available EE, with a low levelized cost for the highest cost EE resource. For example, in 2025 PacifiCorp identifies a need for 95 percent of the available EE, with the highest bin of EE selected having an average levelized cost of $0.44/kWh. This compares to most subsequent years procuring maximum cost EE at an average levelized cost of less than $0.10/kWh. This long-term decrease stands in stark contrast to the increasing resource needs in the IRP and steeply increasing costs associated with the CEP's compliance pathways. Staff finds that improvements to avoided costs may address this decline along with different assumptions about EE technology development curves.

Figure 12: PacifiCorp's Preferred Portfolio EE Acquisition and Cost[135]



Staff appreciates that PacifiCorp included a scenario that maximizes DSM resources, however Staff arrives at different conclusions than the Company. Staff takes issue with PacifiCorp's use of the Max DSM scenario as an add-on to what is selected in the preferred portfolio (P-MM). PacifiCorp notes that the scenario does not change any other resource selections, indicating that all other supply side resources are still pursued as well as the additional DSM measures. Without consideration of avoided supply side investments as a result of the additional 4 GW of cumulative DSM identified by 2042, the scenario incorrectly evaluates cost relative to the preferred portfolio.

In the Max DSM scenario, PacifiCorp cites "much higher DSM costs" after 2027 as the reason why that scenario starts increasing cost compared to the preferred portfolio. Staff does not agree with the characterization of much higher DSM costs as the driver limiting EE selection. Rather, Staff is concerned that what is avoided is not properly valued. As one example, PacifiCorp provides optimistic forecasts of where market prices for electricity will be in 2027 and beyond. If those forecasts are inaccurately low, then DSM measures will not receive its proper valuation nor optimal selection in modeling.

Staff recommends PacifiCorp rerun the Max DSM scenario or generate multiple additional DSM scenarios. Such an effort should seek to resolve issues of avoided cost, reduced supply-side buildout, and the additional benefits of EE to HB 2021 compliance. A sole alternative EE scenario which forces in all DSM, may reflect costs that are unfairly skewed by the most expensive measures. Instead, testing key tranches of additional EE may be more insightful. According to the Company's response to Staff DR 80, OPUC DR 80-1, Staff finds that 74 percent of Oregon's available EE is selected in the preferred portfolio. Staff would like to understand

[135] LC 82, PacifiCorp Information Request response to OPUC IR No. 80-1, Attachment, August 17, 2023.

the costs and benefits of portfolio runs that select 80 percent, 90 percent, and 95 percent of all available EE.

3.11.2 Energy Efficiency Strategy in Response to HB 2021

The availability of relatively low-cost EE to the portfolio raises questions around why the model did not select as high levels of EE beyond 2025, despite significant new decarbonization constraints imposed by HB 2021 in 2030, 2035, and 2040. Staff is concerned that PacifiCorp did not optimize EE considering the full suite of HB 2021 requirements. For example, PacifiCorp expresses concern around increased cost of procuring CBRE SSR resources to meet the 10 percent requirement. Meanwhile, EE is an emission-free resource that reduces the system load and thus proportionately reduces PacifiCorp's SSR requirement.

In response to OPUC DR 193, PacifiCorp indicated that EE was not an additionally available resource in CEP analysis. Rather, the optimal EE acquisition was determined in IRP analysis and copied over to the CEP, which layered on additional SSR resources without considering additional EE. Moving forward, the emissions-free and potentially low-cost availability of additional EE should be considered as a resource option in CEP portfolio analysis and explicitly recognized in annual goals for emissions reduction.

Request:

64. **Staff requests the Company allow optimization of EE in the CEP to inform how increased amounts of EE could help meet HB 2021 requirements in a least cost manner.**
65. **The Company should also update the CEP's annual acquisition targets in light of updated analysis.**

3.11.3 Valuation of Avoided Costs

PacifiCorp's EE selection in the preferred portfolio, which is notably higher than prior forecasts, suggests potential flaws in the current method for approximating avoided costs. This challenge has also been discussed in Portland General Electric's 2023 IRP.[136] The use of optimization models for resource selection in the IRP may include a level of sophistication not captured in existing avoided costs. Optimization modeling can include constraints such as those imposed by HB 2021. Because this IRP/CEP is the first that PacifiCorp has produced since the law was enacted, it is unclear to Staff how a reliable, carbon-free resource such as EE is optimized and whether avoided costs can be properly calculated as a result of the analysis.

In this section, Staff outlines several factors related to avoided costs and the associated impact of EE selection. First, Staff requests the Company address the calculation of avoided costs considering the additional constraints of HB 2021. Due to the increased role of non-emitting capacity on a decarbonized grid, staff would like to understand how the net cost of capacity of EE resources is derived, and to what extent that value represents EE avoided costs.

[136] LC 80, PGE, Staff's Round 1 Comments, July 28, 2023, page 28 and 31.

Second, Staff would like to understand how portfolio analysis may drive selection of EE resources with more energy savings during capacity constrained periods compared to lower levelized cost efficiency with savings at less valuable times. To the extent that the Company forecasts negative pricing in the future, Staff requests PacifiCorp summarize whether some EE was considered a cost due to savings energy during negative price periods.

Third, Staff requests the Company address how portfolio analysis considers a changing cost of capacity. In the current avoided cost framework, the cost of capacity is assigned a single, present-day value. However, that value may change, even dramatically, over the planning horizon where there is increasing need for non-emitting capacity. It is worth noting how the cost of HB 2021 compliance ratchets up very quickly toward the end of the planning horizon. **Figure** from PacifiCorp's 2023 CEP demonstrates how average annual cost increases significantly over the planning period.

Figure 13: Annual Cost Presented by PacifiCorp in 2023 CEP [137]

Table 16 – Average Annual Cost Compared to the 2023 IRP Preferred Portfolio ($millions)

	Years 2023-2029	Years 2030-2039	Years 2040-2042
2023 IRP Preferred Portfolio	-	-	-
Base Cost Allocation Compared to Preferred Portfolio			
CEP Portfolio	$3	$36	$103
CBRE	$15	$51	$109
SSR 15%	$3	$54	$154
SSR 2028	$20	$74	$137
No Purchases 2040	($2)	$30	$218
Pathway 1 Cost Allocation			
CEP Portfolio	$3	$212 ~~$81~~	$394 ~~$352~~
CBRE	$15	$227 ~~$96~~	$399 ~~$358~~
SSR 15%	$3	$232 ~~$103~~	$444 ~~$402~~
SSR 2028	$20	$251 ~~$121~~	$427 ~~$386~~
No Purchases 2040	($2)	$201 ~~$72~~	$515 ~~$473~~
Pathway 2 Cost Allocation			
CEP Portfolio	$12 ~~$30~~	$143 ~~$94~~	$204 ~~$292~~
CBRE	$24 ~~$41~~	$158 ~~$110~~	$209 ~~$298~~
SSR 15%	$12 ~~$29~~	$162 ~~$117~~	$254 ~~$343~~
SSR 2028	$29 ~~$46~~	$182 ~~$134~~	$237 ~~$326~~
No Purchases 2040	$7 ~~$24~~	$135 ~~$88~~	$297 ~~$385~~

Staff requests PacifiCorp respond to whether portfolio analysis includes and considers an avoided capacity cost that varies over the planning horizon, especially with regard to the optimal pathway for CEP compliance.

Fourth, Staff requests PacifiCorp address whether forward market prices used for avoided cost reflect the need for the Company to purchase increasing shares of non-emitting market purchases, not simply the least cost market resource. PGE refers to this challenge in its IRP as

[137] LC 82, PacifiCorp Amended IRP Filing, Errata Filing, October 18, 2023, page 3. Originally found in the PAC CEP, May 31, 2023, page 68.

the "cost of clean energy".[138] Staff seeks to understand how reliant PacifiCorp will be on clean market purchases and how the Company is forecasting the availability of such resources during periods of constraint.

Fifth, Staff highlights that the current avoided cost framework may not capture the Company's planning reserve margin requirement despite the fact that additional EE can proportionately reduce the company's overall reserve margin and associated cost. Staff requests PacifiCorp discuss how an avoided planning reserve margin cost is considered in portfolio analysis.

Staff appreciates PacifiCorp's engagement on the topic of avoided costs and looks forward to the Company's responses to address these factors in reply comments.

Requests:

66. Staff requests that, in Reply Comments, PacifiCorp:

- **Address the calculation of avoided costs considering the additional constraints of HB 2021.**
- **Respond to whether portfolio analysis includes and considers an avoided capacity cost that varies over the planning horizon, especially with regard to the optimal pathway for CEP compliance.**
- **Address whether forward market prices used for avoided cost reflect the need for the Company to purchase increasing shares of non-emitting market purchases, not simply the least cost market resource.**
- **Discuss how an avoided planning reserve margin cost is considered in portfolio analysis.**

3.11.4 Collaboration with Energy Trust Budget Process

In the absence of updated avoided costs in the 2024-2025 Energy Trust budget planning cycle, we direct PacifiCorp to collaborate with Energy Trust to plan for a sufficient acceleration in EE acquisition as that demonstrated in the IRP. If a sufficient acceleration is not possible to meet PacifiCorp's EE needs in 2024, we recommend PacifiCorp support Energy Trust efforts to maintain EE acquisition at a high enough rate to meet the cumulative 2030 acquisition targets.

Additionally, the Company should collaborate with Energy Trust on the types of EE selected in the preferred portfolio. PacifiCorp created 27 bins of available energy efficiency based on temperature dependency and seasonality. Each profile has a different capacity contribution and may be selected by the PLEXOS model for qualities not directly reflected in avoided costs. As a result, we request PacifiCorp summarize which types of EE are most valuable to the system and compare that to anticipated near-term acquisition from Energy Trust in reply comments.

3.11.5 Electrification Impacts

As Staff suggests in these comments, the coincidence of EE savings with peak periods is of increasing importance. Measures that relate to space conditioning, both HVAC and envelope,

[138] LC 80, PGE Clean Energy Plan and Integrated Resource Plan 2023, March 31, 2023, page 244.

can have an outsized contribution to savings during capacity constrained periods. More efficient buildings and HVAC systems require less power to deliver equivalent comfort and can also ride-through events, maintaining comfortable temperatures even without active space conditioning.

For these reasons, Staff is concerned that in response to OPUC DR 172 the Company stated an assumption of "low to moderate conversion of HVAC, and hot water end uses from oil, propane, wood, and natural gas fuels." Staff requests the Company be more specific about the assumptions used in modeling. Building electrification driven by tax credits and programs from the Inflation Reduction Act (IRA), the Portland Clean Energy Fund (PECF), or Oregon's Climate Protection Program (CPP) compliance collectively could influence PacifiCorp's load forecast, but also its EE potential. Due to the coincidence with capacity constraints, the efficiency of electrifying loads is critically important, and Staff requests PacifiCorp detail how it considered this challenge and opportunity.

Requests:

67. In Reply Comments:

- **Provide details about the assumptions used in modeling HVAC and hot water end uses.**
- **Provide details on how PacifiCorp is considering the efficiency of electrifying loads in relation to capacity constraints and the increased demand from such activities above and beyond ETO, like IRA, PECF, or the CPP.**

3.11.6 Demand Response Strategy

PacifiCorp's acquisition strategy of demand response (DR) is reasonable and reflects near-term consistent, achievable growth. Staff commends the Company for efforts over the past three years to implement meaningful DR programs. The preferred portfolio reflects near-term DR potential that can be met by growth within existing programs. Staff highlights that the 2023 IRP reflects a marked decrease in DR potential and acquisition compared to the 2021 IRP, which was a result of double counting DR potential from the 2021 conservation potential assessment and PacifiCorp's 2021 DR request for proposals.[139]

Beyond 2025, PacifiCorp must consider additional strategies, programs, and methods for shifting load. The Company's preferred portfolio includes electric vehicle direct load control (DLC), distributed battery DLC, and grid interactive water heaters.[140] Staff finds the IRP, as a long-term plan, should include a broader suite of DR resources to reduce NPVRR.

For example, in the Northwest Power and Conservation Council's (Council) 2021 Power Plan, the Council recommended regional utilities pursue cost-effective time-of-use (TOU) rates and demand voltage reduction (DVR).[141] These DR resources benefit ratepayers and the system by being frequently deployable, low-cost, and having minimal customer impact. PacifiCorp's DR

[139] LC 82, PacifiCorp Information Request Response OPUC IR No. 87, August 17, 2023.
[140] *Ibid* IR 88.
[141] See 2021 Northwest Power Plan. Page 47. https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf.

strategy relies on direct load control measures which can have a higher customer impact and are less frequently deployed. Staff request that PacifiCorp investigate DVR and Class 3 DSM, of which TOU rates are one tool.

PacifiCorp's portfolio analysis did not consider alternative types of DR nor alternative means of deploying existing DR. Electricity price forecasts illustrate a future with predictable extremes, periods of high cost and periods of low cost. Frequently dispatchable resources and durable shifts in periods of consumption, such as those driven by class 3 DSM and DVR may result in a least cost system that is not currently considered in PacifiCorp's portfolio analysis or action plan. Staff requests the Company specifically evaluate further how additional DR, like the type captured in the Council's 2021 plan, could lead to lower costs and lower risks over the planning horizon by the IRP update.

3.12 New Resource Acquisition Strategy

As noted previously, PacifiCorp recently suspended the Company's 2022 AS RFP right before announcing the Final Short List of projects.[142] This RFP planned to have 1,800 MW of wind, 500 MW of solar, and 200 MW of battery storage operational between 2024 and 2026.[143] The RFP was also soliciting and evaluating resources to meet the preferred portfolio's near-term proxy resource selections. PacifiCorp has stated that the Final Short List will be brought back for an acknowledgement decision in the second quarter of 2024, but has yet to give further details.

It is hard to overstate the importance of the 2022 AS RFP. The RFP suspension calls into question the following elements of the IRP analysis, Action Plan, and CEP.

- The Preferred Portfolio's near-term resource targets, which were by 2026 to:
    - Add ~2,100 MW of wind.
    - Add ~4,000 MW of solar.
    - Add ~3,100 MW of batteries.
    - Conduct a cumulative ~2,100 MW of Summer Front Office Transactions.
- Every Action Plan item under category No. 2 "New Resource Additions", which includes posting a new all-source RFP by Q3 2024 with contracts executed by Q1 2025.
- The impact to Action Plan item No. 5 "Market Purchases".
- Issuing a targeted small-scale renewable resource RFP by Q4 2023 per the CEP.[144]
- The capacity to execute cluster study requests in the past two years that support transmission projects in the 2023 preferred portfolio.
- Emission reductions and the overall risk to meeting several GHG reduction goals simultaneously, including HB 2021's 80 percent reduction by 2030.

With regard to issuing an SSR RFP, the Company has noted that it is uncertain whether it will receive an adequate amount of reasonably priced SSR bids and has suggested that it may

[142] UM 2193 PacifiCorp 2022 All Source Request for Approval, Notice, September 29, 2023.
[143] LC 82, PacifiCorp Amended IRP, May 31, 2023, pages 10 and 92.
[144] LC 82, PacifiCorp CEP, May 31, 2023, page 90.

include benchmark bids into the SSR RFP to improve competitiveness.[145] PacifiCorp's candor about the urgency of new SSR projects coming forward by the next cluster study deadline of May 15, 2024, was very helpful. Staff greatly appreciates PacifiCorp's work toward helping to procure SSRs at a reasonable cost and seeks to understand what activities the Company plans to conduct in the near-term to raise awareness and interest among potential SSR project developers.

Requests:

68. In Reply Comments, Staff requests that the Company:

- **Share an update on the 2022 AS RFP suspension and the current resource acquisition plans for the Company. Please note key dates in the future that may provide clarity on lifting the RFP suspension, such as the adoption of the U.S. EPA GHG standards for power plants and the end of wildfire litigation.**
- **Discuss the impact of pausing the 2022 RFP to Preferred Portfolio's near-term resource targets. To this end, please update Table 9.31 to reflect the shift in resources by type and year. As part of this please comment on the feasibility and risks associated with moving these targeted resource activities and how this may impact coal retirements and overall portfolio annual reliability.**
- **Submit a revised set of Action Plan items for all items under category No. 2 that reflects the 2022 AS RFP suspension.**
- **Discuss the impact of the 2022 AS RFP suspension and the anticipated delay to the other RFPs on market purchases and executing upgrades and/or contracts from cluster study requests. To this end, please update load resource balance tables 6.11 and 6.12 along with Figures 6.4 through 6.7 and Figure 9.60.**
- **Discuss the near-term actions to issue an SSR RFP by Q4 2023 and if an RFI, prior to issuing an RFP, could be helpful.**
- **The impact on annual system emissions. To this end, please provide an updated Figure 1.12 detailing the Preferred Portfolio's CO_2 equivalent emissions trajectory.**

This concludes Staff's Comments.

Dated at Salem, Oregon, this 25th of October, 2023.

JP Batmale

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JP Batmale
Administrator
Energy Resources and Planning Division

[145] LC 82, PacifiCorp CEP, May 31, 2023, page 90.