PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
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December 1, 2023

VIA ELECTRONIC FILING

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

RE: LC 82—PacifiCorp's Round 1 Response Comments

PacifiCorp d/b/a Pacific Power submits for filing its Round 1 Response Comments in the above-referenced docket.

Informal inquiries may be directed to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

LC 82

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2023 Clean Energy Plan and Integrated Resource Plan	PACIFICORP ROUND 1 RESPONSE COMMENTS

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I. INTRODUCTION AND SUMMARY

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) filed its Amended 2023 Integrated Resource Plan (IRP) and 2023 Clean Energy Plan (CEP) with the Public Utility Commission of Oregon (Commission) on May 31, 2023. On June 30, 2023, PacifiCorp received Phase 0 comments on the 2023 IRP and 2023 CEP from Commission Staff (Staff), Renewable Northwest (RNW), the Cascade Policy Institute, the Citizens' Utility Board of Oregon (CUB), Sierra Club (SC), the Oregon Solar + Storage Industry Association (OSSIA), and Swan Lake North Hydro, LLC and FFP Project 101, LLC (Swan Lake). PacifiCorp submitted reply comments on July 31, 2023.

Thereafter, the Company submitted a substantive errata to the Company's CEP on October 18, 2023 (Errata), and subsequently received Phase 1 comments from: Staff, RNW, CUB, Community Advocates Cohort (Community Advocates), Energy Advocates, Alliance of Western Energy Consumers (AWEC), SC, Columbia River Inter-Tribal Fish Commission (CRITFC), Swan Lake, Fervo Energy Company (Fervo), and NewSun Energy LLC (NewSun).

The Company continues to appreciate the feedback received through the IRP and CEP development process, and Round 0-1 stakeholder comments, and responds to specific comments below.

II. RESPONSE TO ROUND 1 COMMENTS

Overall, the Company represents that PacifiCorp's IRP and CEP, either together or individually:

- Involved an unprecedented amount of stakeholder engagement and process improvements compared to previous Oregon planning efforts. PacifiCorp's first CEP provides a substantial foundation for successive CEPs to build from and identified many opportunities to incorporate feedback where appropriate in future CEPs.

- Do not result in merely an "an allocation exercise" with "no net change in PacifiCorp's carbon emissions;" nor are they "simply a transfer of wealth from Oregon to non-Oregon jurisdictions in return for greenwashing Oregon energy."[1] The Company plans to procure over 3,140 megawatts (MWs) of renewable, non-emitting, and storage resources to meet Oregon needs, and *another* 802 MWs of small-scale resources. This is a historic level of resource investment for the next two decades and should temper stakeholder concerns that PacifiCorp's CEP is largely a paper exercise.

- Comply with House Bill (HB) 2021 and Oregon's small-scale renewable mandate on a least-cost, least-risk basis. Several stakeholders recommend the Company rely less on certain technologies (like nuclear or non-emitting peakers), or build out more small-scale renewables (SSR), or require Oregon-only IRP or CEP modeling (or system-wide small-scale renewables modeling for that matter). The Company considered many of these alternative scenarios—and appropriately rejected them—because compliance pathways 1 and 2 provide at least two strategies that allow the Company to comply with HB 2021 without requiring back-breaking costs to Oregon customers.

[1] AWEC Round 1 Comments, at 3.

- Provide appropriate certainty on the Company's strategies to achieve HB 2021's emissions reductions, without unnecessarily limiting the Company's compliance strategies based on now-current assumptions and information.

- Take an appropriately measured and incremental approach to investigating CBREs (and to a lesser extent, SSR). Unless and until these resources can provide comparable benefits to more economic renewable or storage resources that are larger than 20 MWs, the Commission's prudency standards and least-cost and least-risk planning principles require modest procurement strategies.

- Finally, the Company is confident this suspension will not impact our ability to meet emissions reduction targets or procurement of sufficient resources to meet these targets. Any impacts of PacifiCorp's suspension of the 2022AS RFP have not yet materialized, and the Company continues to proactively identify issues for inclusion in PacifiCorp's off-year cycle resource planning during the preparation of its 2023 IRP Update. PacifiCorp hopes to share updated findings following the finalization of 2023 IRP Update, scheduled to be published on April 1, 2024.

The sections below provide additional detail on these and other important stakeholder comments, including: PacifiCorp's responses to stakeholder engagement and community benefit indicator (CBI) concerns; how the CEP is consistent with HB 2021 requirements; how the IRP and CEP modeling processes, assumptions, and resource selections are reasonable; and how the Company's procurement strategies are properly aligned with PacifiCorp's planning efforts. The Company appreciates the Commission's, Staff's, and stakeholders' consideration of these responses.

A. PacifiCorp's stakeholder engagement, development of CBIs, and transparency and process improvements were incremental and appropriate.

The Company represents that its stakeholder engagement, CBIs, and metrics represent an incremental and well-considered approach to the inaugural Clean Energy Plan.

1. Stakeholder Engagement

As discussed below, while the Company can always improve its stakeholder engagement, PacifiCorp represents that its stakeholder engagement meets the letter and the spirit of the requirements of HB 2021. The sections below summarize some of the Company's efforts regarding distribution system planning, tribal engagement, environmental justice, participation and influence, and data.

a. Distribution System Planning (DSP)

The Community Advocates have several questions and recommendations regarding the Company's distribution system planning community engagement strategy and recommend that the CEP include more information regarding attendance, participation, main takeaways from meetings and public workshops, and how the utility is considering points raised.[2]

PacifiCorp responds that its community engagement strategy has been informed by soliciting survey feedback from a random sample of residential and small business customers within Oregon. Additionally, the survey was made available and accessible in English and Spanish. Furthermore, at least 30 frontline customers were surveyed, which the Company has defined as meeting certain low-income thresholds, language limitations or having an underlying medical condition on file. In addition to querying Distribution System Planning (DSP) topics within the survey, PacifiCorp also outlined the survey methodology for public comment at the Distribution Planning Public Workshop on January 13, 2022.[3]

The Company surveyed over 4,600 Oregon customers to: better understand and prioritize the benefits associated with cleaner energy and concerns about energy transition; identify challenges facing communities and individuals; measure awareness of Company communications; and measure satisfaction with the Company's level of outreach and engagement; among other topics. Survey participants included residential and business customers, frontline customers, and stakeholders. The study was conducted using online and

[2] Community Advocates Round 1 Comments, at 1.
[3] The DSP survey predates the formation of the Community Benefits and Impacts Advisory Group (CBIAG), and therefore the CBIAG could not be consulted at that time.

phone surveys in English and in Spanish. The survey was conducted between February 1 and February 28, 2022, with 130 completed phone surveys, 4,497 completed web surveys and 24 interviews conducted with stakeholder organizations.

Although the survey was designed to help inform PacifiCorp's DSP efforts, key findings have also guided the Company's evolving community engagement strategies on several topics, including CEP engagement more specifically. A summary of the survey results was provided to stakeholders in the May 5, 2022, DSP meeting and is publicly available online at: Pacific Power-DSP 2022 Survey Results - Presentation (5.5.22).

According to the survey results, the top challenges facing communities within the Company's service area are affordable housing and the high cost of living. Residential customers' primary challenges include high cost of living, climate change, and healthcare, although noticeable differences were identified in the challenges facing communities across the state. The most important benefits participants noted related to a cleaner energy future are reducing the impact of climate change, preparing for natural disasters, decreasing reliance on fossil fuels, spending less on energy bills, and reducing the environmental impact of the electric system. Those customers located in Portland are more likely to consider the impacts of climate change and environmental issues as highly important. Costs and potential bill increases are the primary concerns with the transition to cleaner energy. The dependability of renewable sources and the potential impact of materials required for clean energy technology also concern more than half of the surveyed participants. These results mirror topics of concern to Staff, stakeholders and PacifiCorp, and are manifest in the IRP and CEP in climate change modeling assumptions, reliability assessment of the evolving resource mix, and least-cost least-risk analysis.

b. Tribal Engagement

Columbia River Inter-Tribal Fish Commission, CRIFTC, comments that PacifiCorp should "include specific plans for tribal engagement that recognize sovereignty of tribal nations and meaningfully incorporate tribal input."[4] This could include: initial recognition and acknowledgment of tribal government sovereignty and authority to govern activities occurring within reservation boundaries; meeting tribal elected officials with equivalent and appropriate PacifiCorp leadership; maintaining open and organic lines of communication with affected tribes and their elected officials; respecting appropriate timing of utility-tribal engagement to ensure pre-decisional engagement; and working directly with the Warm Springs and Umatilla Tribes to deliver demand side and fish-friendly resources.[5] PacifiCorp continues to pursue a substantive and transparent dialogue with its sovereign tribal partners across its six-state service area. To enhance these relationships, the Company has established a full-time tribal affairs representative position to serve as a corporate liaison to help foster meaningful partnerships with indigenous organizations. This position will also serve a key role in communicating PacifiCorp's unwavering commitment to environmental stewardship when deploying or modifying infrastructure within ceded areas. With the above considerations in mind, PacifiCorp will continue to incorporate tribal input in the pursuit of fair, just, and reasonable rates and the development of a comprehensive CEP.

PacifiCorp has also established a CEP engagement series for Oregon tribal nations. Through these external engagements, PacifiCorp continues to seek tribal nations, Native persons and tribal organization feedback to build an inclusive and accessible process for consultation, collaboration and co-creation. An Oregon CEP, tribal-relations-centered web page has also gone

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[4] CRIFTC Round 1 Comments, at 1.
[5] *Id.* at 2-4.

live and can be reviewed at: Tribal Relations (pacificorp.com). This webpage is specifically designed to complement and support transparency and the access of information under the Oregon CEP. This webpage houses content and updates related to the tribal engagement series which is open to all. PacifiCorp continues to work with tribal representatives to develop CBIs that reflect agreed-upon desirable outcomes, and to identify opportunities for specific projects or program activities that will deliver demand-side resource and other benefits to tribes.

Regarding tribal engagement, Staff requests PacifiCorp discuss its strategy for a tribal CBI (including tribal engagement processes, and timing for next IRP and CEP).[6] PacifiCorp continues to seek input and co-develop the tribal engagement process with Native persons, tribal nations and tribal organizations, in order to establish more equitable CBI dialogues. Tribal representatives have expressed interest in establishing partnerships in transportation electrification. Co-developed work on programs and projects may foster the development of additional CBIs. Further, PacifiCorp is in the process of organizing a listening tour in which the Company intends to discuss with tribal organizations their objectives and goals related to transportation electrification. RNW similarly recommends PacifiCorp's community engagement be more meaningfully and thoughtfully focused. For example, "while there are spaces for community input and guidance such as the CBIAG, we recommend that PacifiCorp also hold space for participants to share feedback on the effectiveness of the CBIAG. PacifiCorp agrees with the importance and need to continue growing opportunities for additional community input and guidance through stakeholder engagement and continues to focus on building an inclusive and accessible process of consultation and collaboration. Examples of current methodologies employed to foster input include the public comment period during the CBIAG meetings, direct

[6] Staff Round 1 Comments, at 31.

outreach by PacifiCorp and subject matter experts, interactive content in engagement spaces to foster and support dialogue and feedback and collaboration with other utilities to surface best practices and a more recent addition of a post engagement participant survey promoted by the third-party facilitator at the close of several of the Company's engagement spaces.

c. Environmental Justice

CUB notes that environmental justice considerations are a critical component of CEP acknowledgement, and CUB "continues to hear frustrations from energy justice advocates about whether their engagement in the CEP and IRP are being meaningfully considered."[7] The Company has previously responded to CUB's concerns in Phase 0 comments, but CUB expressed concern with how these actions are informing PacifiCorp's CEP. Instead, CUB recommends the Company describe how it is complying with environmental justice requirements that entails "equal protection from environmental and health hazards and *meaningful public participation in decisions* that affect the environment in which people live, work, learn, practice spirituality and play."[8] This would address concerns where advocates wonder whether their respective investments in CEP and IRP processes are meaningful.[9]

Initial CBIAG meetings required an educational component focused on a common understanding of equity values, perspectives, and community needs and viewpoints. To receive input on programs and processes, PacifiCorp has provided information to the CBIAG to foster shared understanding of the electric industry including CEP requirements and regulatory processes.

[7] CUB Round 1 Comments, at 8.
[8] *Id.* at 9 (citing ORS 469A.400(4)) (CUB emphasis).
[9] *Id.*

The Energy Advocates have several suggestions: the CEP should better discuss community engagement,[10] collaborate with energy justice stakeholders,[11] evaluate the effectiveness of its efforts,[12] and should have improved readability and better publication of its existence.[13]

PacifiCorp is exploring the formation of a community engagement workgroup in collaboration with Portland General Electric to standardize elements of community engagement. As proposed by Staff, this group would include external stakeholders and Staff, and serve to surface and develop engagement methodologies, approaches for best practices, help to maximize accessibility, and improve participation and the engagement experience.

PacifiCorp has taken steps to meet the parameters of this request, demonstrated by its participation in meetings with environmental justice advocates alongside Portland General Electric and Staff. The Company remains committed to continuing future outreach to environmental justice stakeholders. PacifiCorp will also continue to solicit feedback in good faith to enhance accessibility and readability of our materials amongst frontline community members.

d. Participation and Influence

Staff is concerned that the community engagement strategy 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."[14]

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[10] Energy Advocates Round 1 Comments, at 5-6.
[11] *Id.* at 6.
[12] *Id.* at 6-7.
[13] *Id.* at 7.
[14] Staff Round 1 Comments, at 26.

To improve and incorporate feedback from the Company's stakeholder engagement, Staff recommends PacifiCorp: (1) update and publish the feedback tracker at timely intervals to support reflective PacifiCorp comments; (2) expand the feedback tracker to describe entity affiliation or attribution, flag whether PacifiCorp incorporated feedback into utility planning or actions, describe why feedback was or was not included, and detail where PacifiCorp engaged with the Community "along the spectrum of engagement;" and (3) provide feedback on the suggested working group aimed at improving and standardizing elements of community engagement going forward.[15]

Regarding participation and influence generally, PacifiCorp supports the development of data gathering and interactive engagement, both of which influence decision- making. PacifiCorp is implementing the process of the feedback tracker to have the information available on its webpage as soon as possible following the engagement space from which the feedback was provided to the Company. Currently, the Company identifies the feedback received in the engagement spaces to indicate the source of the input. Additional information regarding each of the engagement spaces' attendance is listed in the notes posted on each space's corresponding webpage. The Company considered the idea of an affiliation-based tracker but felt that identifying the engagement space for the feedback is an acceptable level to share the information publicly. PacifiCorp follows a scrupulous internal review process of all stakeholder feedback received and encourages the continued participation of our valued partners in the communities we serve. As addressed above, PacifiCorp is developing a process with environmental justice advocates, Portland General Electric, and Staff to assist with the evaluation on how to improve and standardize elements of community engagement.

[15] Staff Round 1 Comments, at 27.

To foster accountability, Staff recommends PacifiCorp: provide responses from any community or stakeholder surveys that informed the CEP as recommended by Order No. 22-390 (or discuss future plans to do so); and articulate a plan to increase environmental justice priorities and impacts in planning conversations and resource decision-making beyond community based organization recruitment goals (for example, with specific actions). PacifiCorp will share the results of the clean energy benefits survey at the CBIAG meeting in December 2023. To bolster the visibility into this process and provide resources for stakeholders who cannot attend, the Company also plans to publish these materials for the benefit of customer and community stakeholders.

e. Data

Regarding community demographics, Staff recommends PacifiCorp: describe how it intends to use community data to inform CBIs, CBI metrics, CBREs, and resource acquisition or portfolio decision making; and discuss progress identifying and using granular data (in addition to census tract level) that can provide socioeconomic data (and how PacifiCorp intends to use this data to identify how utility actions have benefited and impacted communities).[16]

Since filing the CEP on May 31, 2023, PacifiCorp has continued to explore data availability and is considering ways to incorporate data into the CEP. In addition to the American Community Survey data from the United States Census Bureau, the Company is evaluating Federal Emergency Management Agency National Risk Index data, United States Department of Agriculture Economic Research Service data, Economic Department of Energy Low-Income Energy Affordability Data tool, Council of Environmental Quality Climate Economic Justice Screen Tool and Justice40 data. Further, PacifiCorp has recently completed its clean energy

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[16] *Id.* at 30.

benefit survey and is in the process of conducting its 2023 residential survey.

At this stage, the Company intends to use demographic data from the 2023 residential survey to monitor progress at achieving each CBI's desired outcome. Other data sources are expected to help PacifiCorp understand the geographic distribution of vulnerable communities in its service territory, with the goal of helping PacifiCorp focus its actions further.

While the Company can always improve its stakeholder engagement, the Company represents that its engagement for its first CEP more than satisfies the requirements of HB 2021.

2. Community Benefit Indicators (CBIs)

NewSun comments that the Commission should decline to acknowledge PacifiCorp's CEP until it provides additional direct benefits to Oregon communities.[17] PacifiCorp's CEP will result in substantial benefits to Oregon communities. To highlight one example, the Company's portfolio optimization processes determined that the "most current cost-effective locations for small-scale renewable (SSR) resources are located in Oregon," and that this outcome "aligns well with Oregon energy policy objectives and allows more non-economic project benefits to accrue to Oregon customers."[18] and points to the Company's SSR procurement strategies, that assume some of the more cost-effective SSR resources may be Oregon based.

The Community Advocates have several comments and recommendations regarding the Company's CBIs: the advocates are discouraged about benefits actually reaching communities who need it the most; the CBI to "Improve Resilience of Vulnerable Communities During Energy Outages" should be broadened to include other strategies besides CBREs, including those that better incorporate stories from members that experience outages, and what resilience means to them; PacifiCorp should explain SAIDI, SAIFI, and CAIDI scores, and what they will

[17] NewSun Round 1 Comments, at 6.
[18] PacifiCorp CEP, at 65.

be used for; PacifiCorp should explain how it will address vulnerability to outages; and comments that the CBI to "Increase Energy from Non-Emitting Resources and Reduce CO2 Emissions to Meet HB 2021 Targets" should not be a CBI as it is already required by HB 2021.[19]

In response, PacifiCorp intends to use the CBI and metric framework as a tool to ensure that the utility is appropriately targeting its activities to benefit underserved areas. CBIs are intended to be a holistic representation of all Company activity to increase community benefits—not only those activities added after a certain date or as a result of a certain regulatory action. Baseline measurements for each CBI metric provide a foundation for monitoring the Company's forward progress. The Company continues to work with stakeholders to refine and expand the CBI framework. Under this process, PacifiCorp recently added two new draft CBIs and is currently reviewing its own programs and working with partners such as Energy Trust of Oregon to identify activities and metrics to drive progress under these CBIs and measure impacts. PacifiCorp is also currently evaluating how to apply its initial resilience analysis to inform programs and activities that will support greater resilience in vulnerable communities, such as a CBRE program. PacifiCorp intends to provide additional information on its planned application of resilience analysis in its next CEP.

Additionally, SAIDI, SAIFI, and CAIDI are electric system reliability metrics used to measure system performance. SAIDI is the System Average Interruption Duration Index, calculated by dividing the total number of outage minutes by the total number of customers within a given period and geographic area. SAIFI is the System Average Interruption Frequency Index, calculated by dividing the total number of outages by the total number of customers within a given period and geographic area. CAIDI is the Customer Average Interruption

[19] Community Advocates Round 1 Comments, at 2.

Duration Index, calculated by dividing the total number of outages by the total number of customers who experienced an outage within a given period and geographic area. SAIDI and SAIFI provide a measurement of the total amount of outage time and number of outages the average customer experiences while CAIDI measures the average length of an outage when a customer experiences a service interruption. Together, these metrics indicate average system performance and the amount of time required to restore an outage if one occurs. PacifiCorp reviews this data including and excluding large interruptions classified as major events to assess both system reliability during day-to-day operations and system resilience during major events such as large winter storms or wildfires.

Next, CRIFTC recommends PacifiCorp amend its CBIs and IRP to meaningfully reflect tribal energy visions.[20] Specifically for CBIs, PacifiCorp should: (1) integrate tribal energy metrics (for example, by reducing peak loads; maximizing energy efficiency; strategically siting renewable resources; reducing over-reliance on federal hydroelectric resources; and minimizing transmission and distribution systems); and (2) take specific steps to implement these metrics (for example, by reviewing avoided cost inputs to better incorporate climate change; accelerate process for updating avoided costs for Energy Trust use; not use cost-effectiveness tests at the project level; enhance low-income investments with other energy resource investments; and quantify more non-energy benefits of efficiency; and use a societal test instead of the total resource cost test).[21]

The Energy Advocates have several CBI-related suggestions. As an initial matter, the Energy Advocates suggests PacifiCorp should consider increased CBI granularity.[22] Regarding

[20] CRIFTC Round 1 Comments, at 4-12.
[21] *Id.* at 5-9.
[22] Energy Advocates Round 1 Comments, at 7-8.

resiliency, PacifiCorp should: discuss services that the Company would provide during power interruptions;[23] look at resiliency more broadly in future CEPs;[24] explain increases or decreases in reliability in future CEPs, overlay reliability data with other vulnerability measures, and consider CBIs and metrics related to community resilience and system resilience.[25]

PacifiCorp responds that it intends to continually refine its approach to resilience in future CEPs. This will include the addition of its initial community and utility resilience analysis in the next CEP with descriptions of the selected resilience metrics and how those are applied. Specific attention is paid to topics of interest in tribal energy metrics to ensure these challenges are fully considered. For analysis of reliability trends, the Company encourages interested stakeholders reference the annual reliability report.[26] PacifiCorp currently offers a host of proactive outreach strategies during power interruptions. In conjunction with PacifiCorp's internal communications and customer care teams, the Company provides regular customer updates including estimated time of restoration for affected areas.

The Energy Advocates also comment that: the health and community well-being CBIs should be tied to specific actions to reduce disconnections;[27] PacifiCorp should adopt meaningful environmental CBIs beyond simply tracking carbon dioxide (CO2) emissions;[28] PacifiCorp's energy equity CBIs should include distributional and intergenerational equity;[29] and PacifiCorp's economic impacts CBI should increase community-focused efforts and investments with a focus on environmental justice communities.[30] RNW recommends that PacifiCorp provide more detail

[23] *Id.*
[24] *Id.*
[25] *Id.* at 10.
[26] Available here: PaciCorp Annual Reliability Report for Calendar Year 2022.
[27] Energy Advocates Round 1 Comments, at 10-11.
[28] *Id.* at 11-12.
[29] *Id.* at 12.
[30] *Id.* at 12-13

regarding why PacifiCorp selected the seven CBIs and 17 metrics that it selected, and recommends adopting an additional environmental CBI, as greenhouse gas reductions are already required by HB 2021.[31]

PacifiCorp recognizes there is additional work necessary in the development of its CBIs, metrics and actions. Over the coming months, PacifiCorp will be working with stakeholders to develop and formalize its CBIs and the actions it can take to incentivize and influence positive outcomes.

To the point, for its first CEP, PacifiCorp relied largely on its prior experience in completing the Clean Energy Implementation Plan (CEIP) for Washington. Given CEP timeline considerations, and that the CBIs for the CEP must address a variety of topics including resilience, health and community well-being, environmental impacts, energy equity and economic impacts, PacifiCorp prioritized those CBIs/metrics in Oregon that demonstrated a relationship with these same topic areas within the Washington CEIP. Over the coming months, PacifiCorp will undertake a thoughtful approach to better consider, understand and develop additional CBIs and metrics, of which some could be environmental CBIs.

Generally, Staff recommends that CBIs should be reported as metrics rather than goals.[32] And prior to PacifiCorp's next IRP or CEP, Staff recommends PacifiCorp should: (1) incorporate 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; (2) adopt one or more interim portfolio CBIs that address community benefits of energy efficiency; and (3) adopt one or more interim CBRE-focused CBIs that directly affect the Company's planned

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[31] RNW Round 1 Comments, at 65-66.
[32] Staff Round 1 Comments, at 20.

CBRE actions.[33] Staff also recommends PacifiCorp explain how CBI metrics will "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 mitigation strategy."[34]

PacifiCorp defines CBIs as the desired outcome that utility actions could either incentivize, influence, or cause. Each CBI identifies a desired outcome, while metrics allow for PacifiCorp to monitor progress at achieving these outcomes. PacifiCorp will consider referring to CBIs in future filings as metrics but anticipates this may result in unneeded confusion between the CBIs themselves and their associated metrics.

The actions taken by PacifiCorp will be targeted and influenced by the outcomes (i.e., CBIs) desired by PacifiCorp's stakeholders. For example, stakeholders have indicated that decreasing the proportion of households experiencing high energy burden is an important outcome for the Clean Energy Plan, Therefore, PacifiCorp will consider how to focus programs so that they can decrease the proportion of households experiencing high energy burden.

3. Transparency and Process Improvements

The Community Advocates comment that the CEP is not written in a way that is geared towards the general public, and recommends that the CEP be drafted to a 6th grade level.[35] Similarly, the Community Advocates recommend PacifiCorp use more accessible language in community engagement meetings, and should make targeted actions to translate materials not only to accommodate different languages, but also for clarity and accessibility.[36] The Company

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[33] *Id.* at 21.
[34] *Id.* at 29.
[35] Community Advocates Round 1 Comments, at 2.
[36] *Id.* at 2-3.

appreciates this feedback, and will endeavor to improve its readability and accessibility of CEP meetings and associated materials to ensure more equitable outcomes for all parties involved.

RNW recommends PacifiCorp publicly disclose additional information from its modeling assumptions, and hold technical workshop series on these assumptions and processes to improve transparency into PacifiCorp's IRP and CEP modeling processes.[37] This could include providing a public version of the Company's PLEXOS XML datafile; providing parties with a detailed description of cost assumptions for all proxy resources that are active in the 2023 IRP; and better describe the Company's transmission assumptions and constraints and how each affects selection of proxy resources.[38] RNW also recommends PacifiCorp consider reprioritizing work efforts, for example by enhancing "the depth of its reliability studies by narrowing the scope of the analysis."[39] As RNW notes: "By reducing the number of portfolios analyzed in the MT Model, PacifiCorp can allocate resources to conduct sensitivity analyses on different cost curve projections and forecasted market prices, which will facilitate informed decision-making when addressing economic risk factors."[40]

Regarding transparency, the requested PLEXOS XML formatted data is third party proprietary intellectual property of Energy Exemplar. Pursuant to the contract terms between PacifiCorp and Energy Exemplar, the Company is prohibited from providing the requested information outside of PacifiCorp unless otherwise ordered by a relevant state or federal authority. However, the Company is exploring alternative data export methodology, and will notify RNW and other 2023 Integrated Resource Plan (IRP) parties if an appropriate alternative method is determined and agreed upon with Energy Exemplar. With regard to providing the

[37] RNW Round 1 Comments, at 11-12, 61-63.
[38] *Id.* at 62-63.
[39] *Id.* at 64.
[40] *Id.*

same data in another format, this is already accomplished through the public data disk and materials supporting the public input meeting series, available through PacifiCorp's website.[41]

In the 2023 IRP, in response to stakeholder feedback and IRP commitments stemming from the 2021 IRP, PacifiCorp enhanced its reporting to enable a broader range of publicly available workpapers, and to allow for more stakeholders to access confidential workpapers by creating a "highly-confidential" category to capture materials of particular commercial sensitivity. PacifiCorp also leveraged its new RFP price-scoring methodology as a part of its reporting, building upon work done to determine the net value of every resource in each portfolio. The 2023 IRP also makes available workpapers used to translate hourly model output into resource selections for reliability, flexibility and cost effectiveness. As remarked in round zero comments, publicly available workpapers increased by more than three-fold over the 2021 IRP, in the form of model reports from all three PLEXOS models and representing the complete range of portfolio studies. Model input and output data is represented on a vastly more comprehensive scale, and what is not immediately represented can be supplied in the discovery process, as appropriate to the purpose of discovery.

PacifiCorp appreciates suggestions regarding work prioritization and the balance between breadth and depth in conducting its IRP analysis. The Company's experience has been that additional studies are continually requested, and sometimes required in accordance with commission orders given in past IRPs.[42] At the same time, the desire for increased analytical depth is continually stressed, with prescribed requirements often dictating the approach. PacifiCorp's 2023 IRP was conducted under a careful and balanced consideration of available

[41] Integrated Resource Plan (pacificorp.com)
[42] *See, e.g.,* 2023 IRP cases P02-JB3-4 EOL, P09-No WY OTR, P10-Offshore Wind, P20-JB3-4 CCUS, P21-DJ2 CCUS, P22-DJ4 CCUS, P23-RET Coal 30/33, P24-Gas 40-year Life.

resources, requirements, deadlines and stakeholder's expressed interests. The 2023 IRP greatly expanded access to data, added many requested studies and also introduced tremendous new analytical depth, particularly in the arena of thermal and storage resource option modeling.[43]

With regard to accessibility of writing style not being geared toward the general public, PacifiCorp is conscientious about framing its communications to strike an appropriate balance between the depth and breadth of subject matter, clarity and usefulness. As the combined CEP and IRP approach 1,000 pages of material, it is the company's intent that interested members of the public participate in equitable public processes, especially during the development of materials that will find their way into the finished documents. Public meetings, workshops and other stakeholder engagement opportunities lay the groundwork for an informed reading of the filed documents. The IRP also includes chapter summaries, a glossary and numerous references to assist with accessibility of these materials. Lastly the Company also encourages participants to review press releases and brochures when provided, which succinctly describe the tenets of PacifiCorp's long-term planning objectives in order to keep individuals apprised of notable IRP and CEP developments.

B. <u>The CEP is consistent with HB 2021 requirements and Commission guidance.</u>

This section provides the Company's responses to stakeholder comments that question whether PacifiCorp's CEP satisfies HB 2021 requirements. This includes discussions regarding the incremental treatment of the CEP Portfolio, the treatment of incremental costs, how the CEP allocates resources between jurisdictions, several action plan issues, and whether the CEP is "consistent with" a Commission-approved cost allocation methodology.

[43] As discussed in the 2023 IRP September1-2 public input meeting.

1. Incremental Treatment of the CEP Portfolio

Staff recommends PacifiCorp confirm whether compliance with HB 2021 is feasible with the IRP Preferred Portfolio, and whether any additional resources or different resource actions are needed in the Preferred Portfolio to comply with HB 2021.[44] To the point, 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."[45] Relatedly, CUB reiterates its concern that layering PacifiCorp's CEP on top of the Company's six-state IRP does not result in least-cost, least-risk, procurement planning that complies with HB 2021.[46] This concern is driven by the Company's conversion of coal to natural gas assets, that the CEP does not lead to binding emissions reduction targets, and that this sequential process does not give full credit to the requirements of HB 2021, especially where other PacifiCorp states do not have carbon emissions reduction requirements.[47] As a result, CUB "fails to understand why it is appropriate to assume that a preferred portfolio that does not reflect any binding carbon reduction is the correct starting point for determining the optimal portfolio in Oregon where significant carbon reduction is mandated."[48]

In response, PacifiCorp asserts that it is not feasible to comply with HB 2021 with just the IRP preferred portfolio for at least three reasons: an additional two percent of emissions reductions were necessary to meet Oregon's emissions reductions requirements; the IRP does not include the SSR mandate; and different Oregon resource allocation assumptions are needed

[44] Staff Round 1 Comments, at 14.
[45] *Id.*
[46] CUB Round 1 Comments, at 2-3.
[47] *Id.*
[48] *Id.* at 3.

beyond what is included in the 2020 Protocol. Additionally, while energy from small-scale renewable proxy resources potentially offsets a small amount of emitting generation (referring to Table 14 in the CEP report, the inclusion of the small-scale resources offset 1,752 thousand tons of carbon dioxide equivalent (CO_2e) emissions to Oregon over the planning horizon), even with the small-scale resources included in the CEP portfolio the Oregon-allocated emissions exceeded GHG targets in certain years. This means additional steps (relevant here, Pathways 1 and 2), are required to reach ultimate compliance with HB 2021. These additional pathways, as discussed under section 3.b. PacifiCorp Response, below, are not the primary means by which PacifiCorp meets CEP targets. Rather, PacifiCorp's systemwide modeling under its current IRP strategy accomplishes nearly all of the CEP's emissions reduction targets, and the pathways are needed to close the last two-percent gap.

Focusing on the SSR mandate, simply put, small-scale resources are uneconomic and inadequate to achieve compliance with HB 2021. Their required adoption can either be allowed to disrupt the least-cost least-risk optimization of the system or can be layered on incrementally. If allowed to disrupt, there are inevitable resource conflicts with other states, and subsequent adjustments will render a final portfolio with increased costs compared to the incremental approach. Even when layered on incrementally, additional action is still required to achieve compliance. This fact indicates that an incremental treatment was the best analytical approach at the time of filing.[49] The Company is committed to continually improving its methodologies, however the Company represents that its current incremental approach to the SSR mandate is sound.

[49] *See also,* Section B.3. and related footnotes.

For the next IRP, Staff also recommends PacifiCorp constrain its modeling to "ensure that each portfolio can feasibly meet Oregon's GHG targets while also meeting requirements for other state GHG and clean energy policies."[50] PacifiCorp responds that any given portfolio must ultimately meet all requirements, and that given competing interests across the multistate system there is no feasible single-pass modeling solution that guarantees Oregon compliance while simultaneously meeting all other portfolio requirements. Given Oregon's continued participation in the benefits of PacifiCorp's multi-jurisdictional structure, the Company anticipates that it must continue to defer to some form of iterative modeling and adjustment design to determine final compliance with every state's requirements. PacifiCorp would also like to emphasize that the modeling requirements for Oregon are not completely compatible with the interests and requirements of other states with whom Oregon shares the wider system.

Staff also recommends PacifiCorp demonstrate what portion of non-emitting generation "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."[51] This should include identifying where incremental actions (beyond re-allocation) would be required to comply with HB 2021.[52]

PacifiCorp responds that this request is not feasible under current PLEXOS modeling capabilities. Further, emissions tied to individual state jurisdictions have not been incorporated into PLEXOS, as it would require individual resources to be allocated to individual states. While PacifiCorp continues to lead MSP negotiations in conjunction with regional parties, the Company has not reached a definitive conclusion for resource allocations to each state.

[50] *Id.*
[51] Staff Round 1 Comments, at 15.
[52] *Id.*

2. Incremental Costs

AWEC comments that, for several reasons, the cost impacts of the CEP are unclear, and as a result it is "likely that Pathway 1 and 2 exceed HB 2021's incremental cost cap."[53] These include: assumed allocation of emitting resources appear incorrect; the impacts from the Company's Errata that impacted the costs of Pathways 1 and 2; compliance years 2030 and 2040 appear to indicate annual cost increases well above the six percent cost cap; and that PacifiCorp should present costs on a nominal basis, instead of as levelized costs.[54]

The Company appreciates AWEC's concerns regarding the potential for PacifiCorp's future actions to exceed HB 2021's cost cap, though for several reasons believe it is premature for the Commission to consider this issue.

As a question of law and policy, it is unclear to what extent the Commission should consider cost cap issues when reviewing utility CEPs. While the cost cap generally permits investigation of "forecasted costs" used to comply with HB 2021 (and PacifiCorp's current CEP includes forecasted HB 2021 proxy compliance costs), the cost cap appears more relevant for actual costs and investments that are typical to ratemaking proceedings.[55] This narrower interpretation is encouraged by the Company for several reasons (among likely many others), because CEP forecasted HB 2021 compliance costs: (1) do not reflect cumulative rate impacts, which is the standard of decision required by the cost cap statute;[56] (2) are based on proxy resources, locations, and costs that will necessarily differ from actually procured resources; (3) for PacifiCorp's initial CEP, are based on multiple compliance strategies that inhibit any

[53] AWEC Round 1 Comments, at 5-7.
[54] *Id.*
[55] ORS 469A.445(1) (allowing utilities or organizations to request OPUC to "open an investigation" to consider cost cap issues, though focusing primarily on "investments made" and "costs incurred," and reviewed with similar rate making methodologies, to determine "cumulative rate impact").
[56] ORS 469A.445(3) ("The commission shall use the actual or anticipated rate impact of each investment or cost to calculate the cumulative rate impact . . .").

definitive application of the cost cap at this stage; and (4) are based on market and multi-state resource allocation assumptions that may eventually differ materially from current facts and circumstances.

Under this narrower and more practical interpretation supported by PacifiCorp, existing cost assessments such present value revenue requirement (PVRR) can serve as a guide to relative overall costs, and there are perhaps specific narrow cost cap questions that can be raised in individual CEPs. However, the bulk of these analyses should be reserved for investigations in ratemaking-type proceedings. The Company represents that the circumstances warranting a ratemaking-style cap assessment are not present here, as: (1) AWEC lacks standing to raise this issue because it has not petitioned the Commission for a cost cap investigation as required by ORS 469A.445(1), nor does the cost cap statute provide AWEC with the relief it requests;[57] and (2) AWEC's assumption that PacifiCorp's 2022 revenue requirement is the reasonable baseline to calculate HB 2021 compliance costs for years 2030-2040 (resulting in a cost cap calculation based on a revenue requirement that is either one or two decades old) is untenable and renders their analyses meaningless."[58]

To the extent the Commission wants to address these opportunities, PacifiCorp represents that UM 2273 presents the more appropriate approach.

3. The CEP Allocations of Resources are Optimal and Compliant

Specific concerns are raised in comments regarding the appropriateness of PacifiCorp's approach to resource allocations for this first CEP, particularly with regard to the Company's

[57] *Compare* ORS 469A.445(4) (allowing for a narrow and time-limited exemption of HB 2021 requirements if the cost cap is exceeded, and silent regarding any Commission powers regarding review of utility CEPs) *with* AWEC Round 1 Comments, at 2 (requesting the Commission either decline to acknowledge PacifiCorp's CEP, or acknowledge portions and direct PacifiCorp to resolve deficiencies).
[58] AWEC Round 1 Comments, at 6-7.

two compliance pathways. The CEP compliance pathways offer material emissions reductions that comply with HB 2021 on a least-cost, least-risk basis.

a. Stakeholder Comments

Staff recommends PacifiCorp update Pathways 1 and 2 to account for any benefits associated with reducing the allocation of existing resources to Oregon.[59] Staff also requests PacifiCorp provide quantitative answers, to the extent possible, to demonstrate: any existing or potential constraints related to allocation that would affect 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; and what are the implications of adopting alternative IRP portfolios on HB 2021 compliance and Oregon-allocated costs and GHG emissions under different types of allocations strategies.[60]

AWEC comments that there are two issues with PacifiCorp's proposed pathways: first, PacifiCorp can guarantee neither outcome, because Pathway 1 requires resolution with additional PacifiCorp service territories, and Pathway 2 requires customers to participate in voluntary programs; second, PacifiCorp's proposed compliance paths do not result in any measurable reduction in carbon emissions relative to PacifiCorp's baseline IRP, but will result in material cost increases for Oregon customers.[61] Relatedly, AWEC notes that PacifiCorp's allocations have illogical and unlawful results, because AWEC alleges that PacifiCorp has allocated more than 100 percent of the cost of certain non-emitting peaker plants to Oregon under Pathway 1.[62] Similarly, AWEC comments that it is unclear why PacifiCorp modifies the allocation of all emitting plants equally, "when it may be more cost effective to reduce only the allocation of the

[59] Staff Round 1 Comments, at 17.
[60] *Id.*
[61] AWEC Round 1 Comments, at 2-4.
[62] *Id.* at 7-8.

most costly emitting plants."[63] AWEC then requests PacifiCorp to provide analyses that determines "the most cost-effective allocation scheme for Oregon."[64] As a result, AWEC asserts PacifiCorp's compliance positions are "an allocation exercise" with "no net change in PacifiCorp's carbon emissions," and is "simply a transfer of wealth from Oregon to non-Oregon jurisdictions in return for greenwashing Oregon energy."[65]

The Energy Advocates comment that the proposed compliance pathways have significant hurdles. Regarding Compliance Pathway 1, while re-allocating coal and gas assets is a simple conceptual exercise, PacifiCorp "does not explain in the CEP how this allocation methodology would be accomplished or whether other states within PacifiCorp's service territory would likely agree to its implementation," nor does PacifiCorp provide estimated costs of this re-allocation to other states.[66] Regarding Compliance Pathway 2, the Energy Advocates believe this option is overly optimistic, and PacifiCorp has not provided any details on what incentives would be offered to encourage 100 percent opt-in, and this pathway could raise double-counting issues if PacifiCorp claimed the non-emitting attributes for HB 2021 compliance purposes.[67] The Energy Advocates seek to underscore the importance of a CEP that complies with HB 2021 "without assuming that current emission levels can simply be reallocated to another state, which ultimately reduces emissions reduction to a paper exercise."[68]

Similarly, RNW is concerned that neither of PacifiCorp's pathways "represents a technical or engineering analysis of the portfolio, and neither strategy appears to have any impact on the resource portfolio as a whole," and if so, it "is unclear what HB 2021 compliance

[63] *Id.* at 8.
[64] *Id.* at 10.
[65] *Id.* at 3.
[66] The Energy Advocates Round 1 Comments, at 26.
[67] *Id.* at 26-27.
[68] *Id.* at 27.

represents beyond a shifting of emissions and cost accounting between PacifiCorp customer groups with and without emissions policy requirements."[69] Instead, RNW recommends PacifiCorp develop a more robust analysis of what resources would be required to reliably serve Oregon customer loads without fossil fuel resources, and not resort to re-allocation exercises,[70] and reject Pathway 2.[71] This could be accomplished witha production cost model (either a simple spreadsheet tool like that used by the CPUC or more sophisticated modeling approach).[72] RNW is optimistic that, "whether now or later (after markets are established and operational), interested parties can ensure both robust emission reductions and a strong market that facilitates regional emission reduction at the least cost to utilities and customers."[73]

b. PacifiCorp Response

As an initial matter, PacifiCorp would like to frame stakeholder concerns regarding the two example pathways with several points to hopefully provide a more complete perspective on the Company's CEP.

First, the Energy Advocates observation is correct that Pathway 2 is making a core assumption that there would be an interest in opting into customer enabled programs. That said, the DEQGHG accounting would recognize the non-emitting nature of the resource used to serve this load, and there is no double counting concern as the load and resources are all attributed to Oregon and no other entity can claim the same non-emitting attribute than the customer.

The Company plans to procure over 3,140 MWs of renewable, non-emitting, and storage resources to meet Oregon needs, and *another* 802 MWs of small-scale resources. This is a

[69] RNW Round 1 Comments, at 9, 43-46.
[70] *Id.* at 9, 44-46.
[71] *Id.* at 44.
[72] *Id.* at 45-46.
[73] *Id.* at 46.

historic level of resource investment contemplated for the next two decades, and should temper stakeholder concerns that PacifiCorp's CEP is largely a paper exercise. The Company has, for at least the past several IRP cycles, been a front-runner in decarbonization and continues in this trend, as put forth in the executive summary of the 2023 IRP. Because of this several year trend, PacifiCorp's systemwide modeling under its current IRP strategy accomplishes nearly all of HB 2021's emissions reduction targets.

Second, the compliance pathways are necessary to close a small gap in achieving HB 2021 emissions reduction targets compared to what resulted from PacifiCorp's optimally determined 2023 IRP Preferred Portfolio. The 2023 IRP Preferred Portfolio results in significant emissions reductions for its six-state system (i.e., 90 percent reduction from 2005 baseline emissions by 2035), and would achieve Oregon's 80 percent emissions reduction target by 2032, and 90 percent reduction target by 2037. The CEP compliance pathways were only necessary to accelerate the timeline of emissions reduction for each HB 2021 target by two years. Yet as discussed below, even just this two percent additional emissions reduction requires substantial investments if the Company does not consider re-allocating existing Oregon emitting assets. This is most certainly a case where the path to achieving the first 98 percent of the path to success is more straightforward than achieving the last two percent.

Third, PacifiCorp's Oregon load is projected to increase by 60 percent by 2030, and nearly 80 percent by 2040 compared to loads when baseline emissions were established. This growth impacts our compliance strategies, because our analysis indicated it is unduly expensive to meet HB 2021's emissions reductions requirements by simply increasing the amount of non-emitting resources. This load growth also increases PacifiCorp's emissions. Under the existing 2020 Protocol, system resources are allocated to states in proportion to load. Therefore, when load grows in one state (as is expected for Oregon), the allocation of all system resources, including thermal resources, similarly increases. Pathway 1 assumes a cap on thermal resource allocation but does not make assumptions around specific resource selection.

Fourth, as a result of each of these factors, PacifiCorp cannot cost effectively comply with HB 2021 without re-allocating existing Oregon resources. Yet the Company's allocation protocols are not intended to favor least-cost alternatives for only one state (as is suggested or recommended by several advocates), but rather fairly shares costs and benefits across six states for the mutual benefit of allstates. Viewed together, PacifiCorp's anticipated load growth over the CEP planning horizon requires re-allocating existing resources to comply with HB 2021. Yet these protocols can only be addressed with MSP stakeholders, where Commission and Staff leadership and collaboration will be vital.

With these points in mind, the Company will highlight several alternative HB 2021 compliance strategies, suggested or recommended in comments, but which are ***not*** suitable paths for the Company to pursue to comply with HB 2021. The Company has investigated and discussed the merits of these considerations internally, in public meetings, in the IRP and CEP, and each concluded that these alternative paths are either unsupportable for implementation or unduly expensive compared to Pathway 1 and 2. Hopefully these alternative strategies, which are another way to explain the detailed points made in round zero comments, will effectively highlight the merits of the Company's decision to present the two HB 2021 compliance pathways. These alternative strategies included:

- Pathway 0 – Forever 2020 Protocol. This pathway examined CEP strategies where the 2020 Protocol and relevant allocation assumptions remained in place for the entire compliance period. In this scenario, Oregon would be served by the current natural gas resources until those resources are retired (e.g., Hermiston). Yetit is not possible to comply with HB 2021 under this pathway, because thereare no non-emitting solutions (i.e., build more non-emitting resources or turn off emitting resources) that could remotely satisfy HB 2021's cost cap based on using the PVRR result as a gross indicator as previously described. This approach is also flawed because the 2020 Protocol is set to expire on December 31, 2025. Note, this approach is labeled Pathway 0 (zero) because it is the allocation approach used to determine the extent to which an optimal systemwide portfolio could meet all CEP targets without diverging from current methodology (even recognizing that the current methodology is set to expire).

- Pathway 3 – Oregon-only IRP. This pathway analyzes whether it is reasonably possible to comply with HB 2021 by modeling Oregon load, resources, and requirements distinct from the rest of PacifiCorp's system. This pathway would remove Oregon customers from receiving the benefits of systemwide planning. PacifiCorp considers this both unwise and outside of its authority under any reasonable least-cost least-risk obligation. This approach would require substantial additional Oregon-situs investments in non-emitting dispatchable resources. Similar to Pathway 0, it is not possible to comply with HB 2021 under this pathway because costs would be excessive. This pathway would also require substantial re-allocation of existing Oregon resources under the 2020 Protocol to effectively separate Oregon's resource participation from the rest of the system. Additionally, this modeling exercise introduces a number of challenges, including the division of existing resources that are currently co-allocated, the division of transmission rights, the de-optimization of market access implicit in dividing transmission rights, the changing nature of actual requirements over time, and the loss of systemwide diversity. Most of these challenges can only be overcome by the creation of new assumptions which are likely to be contentious. If these steps are nonetheless taken, resulting flaws in the analysis may render it valueless beyond providing a rough indicator of the magnitude of increased costs. In particular, the artificially smaller or more restrictive system will not dispatch in a manner reflective of system operations.

- Pathway 4 – Small-Scale Systemwide Portfolio. This pathway would incorporate Oregon's 10 percent small-scale mandate into PacifiCorp's systemwide initial portfolio development requirements, either as shared resources, or situs to Oregon. As explained thoroughly in PacifiCorp's round zero reply comments, this pathway will increase costs to other states because it would require those states to purchase more expensive SSR compared to assets larger than 20 MWs. This cost impact is currently unsupportable and would also require re-allocating these assets under future protocols. The pathway also results in reliability concerns (larger resources displaced by smaller-scale resources in the modeling would likely have to be re-added, under less optimal conditions, during reliability assessments), cost concerns (similar to Pathway 0, as just increasing the amount of small-scale renewables cannot comply with HB 2021's in a cost-effective manner), and compliance concerns (e.g., PacifiCorp's small-scale mandate quadruples if compliance was applied to PacifiCorp system-load, using a much larger denominator, as opposed to being Oregon-specific). Further, this pathway is impractical as an optimal modeling exercise unless the amount of the 10 percent requirement can be determined in advance. This is because the 10 percent requirement is recursive as described in law, such that every portfolio requires not a set amount small-scale renewable resource, but rather an amount proportional to the energy distribution specific to the portfolio. Given these issues, the Company concluded and represented that this pathway was unwarranted, and that an incremental approach mitigates identified problems.

Given these alternatives, PacifiCorp maintains that its two compliance pathways are valid, because they provide at least two strategies to achieve HB 2021's emissions reductions requirements that could meet the small remaining compliance gaps, even remotely satisfy the potential cost cap, and not force undue resource allocations or costs onto other states. These strategies preserve the system-wide benefits that Oregon customers receive from PacifiCorp's existing IRP processes and minimize rate impacts to customers consistent with least-cost, least-risk systemwide planning. While PacifiCorp is always open to improving and expanding these analyses and seeks ongoing feedback from stakeholders and guidance from the Oregon Commission, the Company affirms that its initial CEP compliance pathways are appropriate.[74]

That said, PacifiCorp is sensitive to stakeholder concerns that the CEP presents compliance pathways that appear to result in accounting exercises that re-allocate existing Oregon allocated emissions to other states, perhaps leading to less overall emissions reductions on PacifiCorp's total system than what several advocates would prefer. This is an essential point that the Commission will need to consider in this and future CEPs: Is the Commission willing to acknowledge alternative stakeholder CEP compliance pathways that will result in substantial additional costs to Oregon customers, in an attempt to regulate more emissions across PacifiCorp's system that are more appropriately regulated by those respective states, or consider PacifiCorp's strategies that nonetheless comply with HB 2021, while at the same time minimizing costs to Oregon customers to the extent possible?

[74] After the filing of the CEP, and in consideration of the currently suspended 2022 All-source RFP, PacifiCorp has continued efforts to develop a conceptual approach to achieve a 'unified' preferred portfolio which integrates all state requirements.

Given that PacifiCorp's CEP and IRP planning already call for 3,140 MW of new standalone wind, solar, and battery, or co-located solar and battery new resources over the next two decades, and that the final gap resolved through allocations is relatively small, PacifiCorp's position is that the IRP and CEP are very well-aligned. To that end, the Company does not believe the Commission needs to resolve this question of allocations in this CEP cycle, and the Commission should not foreclose any compliance pathways at this early stage. However, PacifiCorp believes this will be a recurring theme in future CEPs and will require final resolution at some point.

4. Action Plan Issues

The Energy Advocates have several comments regarding the Company's Action Plan. These include: include more specific community engagement actions, including targeted outreach to tribal communities and governments; more assertive action that leads to progress on PacifiCorp's six CBIs; go beyond defining and establishing goals and metrics for resiliency, and actually increase resiliency; include procurement steps and more comprehensive CBRE analyses; evaluate total-system decarbonation (as opposed to re-allocating resource strategies) to eliminate greenhouse gas emissions and not simply shift emissions to other states; resume the 2022 AS RFP, and complete a new 2023-2024 AS RFP; and procure small-scale resources and provide more detailed transmission project development plans.[75]

With regard to total-system decarbonization, PacifiCorp is explicitly on this path, and describes this path in the 2023 IRP. Per Volume I, Chapter 1 – Executive Summary, page 1, "This IRP provides an update on our progress toward decarbonization and lays out our roadmap for the work still ahead of us." This decarbonization pathway, in which the Company is fully

[75] The Energy Advocates Round 1 Comments, at 30-32.

engaged, provides the foundation for the CEP. Decarbonization has been an accelerating effort over each of the past three IRP long-term planning cycles, is based upon least-cost least-risk analysis and predates the existence of the CEP. To the extent that states hold different views regarding the ideal path to decarbonization, and these states express an interest in emphasizing selected aspects of their resource mix going forward, PacifiCorp is committed to providing an optimal path forward for all of its customers. This includes the consideration of allocation options that better respond to the Oregon Commission's preferences. The 2023 IRP presented its systemwide decarbonization plan at the time of filing, and the CEP presents its first plan for achieving HB 2021 with important options, under fluid conditions, directed towards achieving this goal.

5. The CEP is consistent with a Commission-approved Cost Allocation Methodology

AWEC comments that, because both Pathway 1 and 2 require a reallocation of resources that differs from the Commission-approved 2020 Protocol, that it does not comply with HB 2021's requirement that CEP's "must be based on or contained in other information developed consistent with a cost-allocation methodology approved by the commission."[76] As a result, AWEC concludes that the Commission should not approve an alternative cost-allocation method in this CEP.[77] Relatedly, CUB notes that the Company's proposed compliance pathways reflect a material change in the currently approved 2020 Protocol (largely based on the planned conversion of several coal assets to natural gas).[78] While CUB "is not arguing that this fundamental change in the compliance pathway is not in the best interest of Oregon customers,"

[76] AWEC Round 1 Comments, at 4.
[77] *Id.* at 5.
[78] CUB Round 1 Comments, at 3-5.

it nonetheless notes this change "has neither been acknowledged nor analyzed as it pertains to Oregon," and requests PacifiCorp to respond to this concern.[79]

As an initial response, PacifiCorp disagrees, because its CEP is consistent with the current Commission-approved cost-allocation methodology. HB 2021 requires that PacifiCorp's CEP must "be based on or contained in other information developed consistent with a cost-allocation methodology approved by the Commission."[80] The Commission's most recently approved cost-allocation methodology is the 2020 Protocol,[81] which was initially contemplated to terminate no later than December 31, 2023.[82] When approving the 2020 Protocol, the Commission declined to address certain issues that would be resolved with future MSP proceedings.[83] This was based on the Commission precedent that has noted that "as a quasi-legislative body," the Commission has "no authority to bind this Commission on such future decisions."[84] Accordingly, the CEP is "consistent with" the 2020 Protocol for purposes of compliance with ORS 469A.415(3)(b), because it incorporates the relevant cost-allocation methodologies for the relevant CEP time period.

More materially, PacifiCorp's CEP is consistent with the intention of HB 2021: It is not possible to comply with HB 2021 under the existing 2020 Protocol. Despite removing coal-fired resources from Oregon's resource mix by 2030, Oregon's share of the emissions from natural gas-fired generation within PacifiCorp's existing fleet (including both existing generators and those pending conversion from coal) were forecasted to exceed the level required for compliance with HB 2021. PacifiCorp's CEP acknowledges this reality, and instead provides two different

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[79] *Id.* at 5.
[80] ORS 469A.415(3)(b).
[81] *In re PacifiCorp's MSP Petition,* Docket No. UM 1050, Order No. 20-024 (Jan. 23, 2020).
[82] *In re PacifiCorp's MSP Petition,* Docket No. UM 1050, PAC/100 Lockey Direct Testimony at 11 (Dec. 3, 2019).
[83] *Id.* at 9 ("We emphasize that this determination does not bind future Commissions, particularly if circumstances change, or if evidence is later presented that leads to different conclusions.").
[84] *Id.* at 4, n. 11.

compliance pathways (including relevant cost-allocation assumptions) that directly implicate the level of emitting resources used to serve Oregon customers and could be considered in future MSP discussions. Respectfully, PacifiCorp represents its CEP not only complies with the law but results in a more helpful and instructive planning document than what would otherwise result if the Commission accepted AWEC's interpretation of ORS 469A.415(3)(b) that would require the use of the 2020 Protocol through the entire CEP planning period.

Moving to CUB's concerns, PacifiCorp wholeheartedly agrees that the Company's CEP compliance pathways embody material cost-allocation assumptions that could impact Oregon rates. The CEP's allocation methods represent the types of considerations that will be critical in ongoing MSP negotiations, while at the same time ensuring there are adequate solutions for MSP discussions to consider (and for future Commissions to adopt), without unnecessarily limiting those discussions by presenting a single compliance pathway in PacifiCorp's inaugural CEP. Yet PacifiCorp disagrees that these compliance pathways were not thoroughly analyzed for CEP purposes; this is explicitly what the CEP portfolio development stages and sensitivities provide,[85e] and these analyses explicitly recognize the kinds of changes that must find support in MSP negotiations to succeed.

While the Company anticipates more discussions and analysis in future MSP negotiations and OPUC proceedings, the Company believes its CEP portfolio development, sensitivities, and analyses provide the appropriate detail to ensure stakeholders can thoroughly review the Company's current CEP compliance strategies.

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[85] *See, generally, 2023 IRP and Clean Energy Plan workpapers* (specifically portfolio outcomes of each examined case, noting that into each distinct case, portfolio comparison and analytics are core model functions).

C. <u>The Company's 2023 IRP and CEP modeling processes and assumptions were legitimate and improved from previous approaches.</u>

This section provides the Company's responses to stakeholder comments that allege that the IRP and CEP modeling processes were either incorrect, unacceptable, or could be improved upon. The stakeholder comments are broken into several sections, including: reliability and granularity adjustments; resource adequacy and regional integration; renewable cost assumptions; resiliency; pace of emissions reductions; transmission considerations; alternative portfolio variants and cluster results; carbon assumptions; market assumptions; federal and state incentives; and avoided costs.

1. Reliability and Granularity Adjustments

Sierra Club recommends the Company consider several reliability and granularity adjustments, as PacifiCorp's manual adjustments to ensure reliability "are quite significant and merit particular attention."[86] These include: further clarify its methodology for reliability adjustments, specifically regarding resource additions and modifications to the timeline of optimally selected asset retirements; explain in the next IRP why the long-term model produces significant energy shortfalls in the short-term model, that must be manually addressed; provide opportunity to recommend alternative reliability adjustments to the 2023 Preferred Portfolio, and for PacifiCorp to evaluate those alternatives in the IRP Update; further clarify the Company's granularity adjustments, especially for coal unit total fuel costs, rather than incremental or marginal fuel costs.[87]

RNW recommends PacifiCorp replace its legacy capacity accreditation method (the capacity factor method) with an effective load carrying capability method (ELCC) or something

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[86] Sierra Club Round 1 Comments, at 14.
[87] *Id.* at 14-42.

comparable.[88] This would "not only improve the performance of the models but also assist the company in identifying an optimal level of planning reserves that provides ratepayers with reliable retail electric service," as PacifiCorp uses a 13 percent planning reserve margin but "hasn't provided stakeholders with any analysis that supports this value."[89] RNW provides additional examples if an ELCC is not feasible or recommended at this time.[90]

In response to concerns regarding additional detail, PacifiCorp represents it has complied with Commission Order 22-178.[91] The 2023 IRP explicitly explained the differences between its models, why there are shortfalls measured in the ST model, why the LT model does not solve the entire problem, how and where the MT and ST models each provide specific additional value, and how each model's data outcomes are used to improve portfolio development.[92] In addition, the Company has provided this information in public input meeting series, stakeholder feedback forms, data disks, and data requests.[93]

Turning to specific stakeholder comments, because both the reliability assessment and granularity adjustments are specific measures to address specific enhancement to achieve superior modeling results, there are no logical alternatives because both procedures are dictated by model math.

[88] RNW Round 1 Comments, at 10, 47-55.
[89] *Id.* at 10.
[90] *Id.* at 51-53.
[91] LC 77, Order 22-178, Recommendations 27, 28.
[92] PacifiCorp's 2023 IRP, Chapter 8 –Modeling and Portfolio Evaluation, at 217-224.
[93] Inclusive of references to stakeholder feedback forms received from Sierra Club: April 7, 2022 Public Input Meeting pp31, 51 discussing granularity adjustment and reliability assessment; June 10, 2022 Public Input Meeting p58, discussing reliability assessment; October 13, 2022 Public Input Meeting pp41-42, 44 discussing granularity adjustment and reliability assessment; Dec 1-2, 2022 Public Input Meeting p53, 54, 67, including a full analytical plan for reliability assessment; January 12-13 Public Input Meeting, p28 discussing reliability assessment; February 23, 2023 Public Input Meeting, pp 13, 26, discussing reliability assessment; 2023 IRP Volume I, Chapter 1 – Executive Summary; Volume I, Chapter 8 – Modeling and Portfolio Evaluation, pp 217-219, 223, 233.

For example, the granularity adjustment is the calculated difference in resource value between the long term (LT) and short term (ST) models, using the LT initial portfolio. Because the portfolios are identical, the differences in resource value are driven by differences in the two models. Chief among the differences, overwhelmingly, is granularity. This difference is applied as an adjustment to the less granular model. Any other approach would be a different type of adjustment, not suited to the measured model differences.

Similarly, regarding the reliability assessment, resource adjustments are made on the basis of measured deficiencies and applying calculated resource values to determine the appropriate action to cover those deficiencies. While a different approach may be envisioned and nuanced considerations can occur, this approach is specific to the goal and again, is an application of model outcomes to improve results, and not the result of arbitrary PacifiCorp tinkering.

Moving on, the claim that PacifiCorp has not presented analysis to support its 13 percent planning reserve margin is untrue. It may be that RNW views the 13 percent planning reserve margin as something other than a minimum "floor" value as presented and explained by the Company in the 2023 IRP.[94] The 13 percent planning reserve margin is not the final margin required to meet all requirements. It is rather the logical minimum required to guide the LT capacity expansion model to select portfolios appropriate to the model's degree of granularity.

To the point, with the advent of the PLEXOS model, the Company more accurately evaluates reliability in terms of resource availability to meet requirements in all modeled periods. This method accounts for a planning reserve margin that realistically changes across years, seasons, months and days based on resource availability in any timeframe being examined. This

[94] 2023 IRP Volume I, Chapter 6 – Load and Resource Balance; 2023 IRP Volume I, Chapter 8 – Modeling and Portfolio Evaluation, at 219-220, 223.

floor is established and known, and assumes PacifiCorp must hold approximately six percent of its resources in reserve to meet contingency reserve requirements and an estimated additional 4.5 percent to 5.5 percent of its resources in reserve, depending upon system conditions at the time of peak load, as regulating margin. This sums to 10.5 percent to 11.5 percent of operating reserves before even considering longer-term uncertainties such as extended outages (transmission or generation) and customer load growth. These figures initially imply a 12 percent margin; however, we know that the PLEXOS LT model exhibits shortfalls in the more granular ST model; we also know that the 13 percent margin has been consistently supported by 2017, 2019 and 2021 IRP planning. These facts establish 13 percent as a reasonable planning reserve margin assumption for capacity expansion.

2. Resource Adequacy and Regional Integration

Staff recommends PacifiCorp 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 not needed, explain why they are in preferred portfolio).[95] Similarly, for the next IRP Staff recommends PacifiCorp: update its methodology and data to reflect several years of potential weather conditions on the Company's resource adequacy position and resource capacity contributions; account for the benefits of the WRAP if PacifiCorp plans to participate in the program; and calculate and report the LOLE of the Preferred Portfolio in each year and explain why it chose to plan for that level of reliability. Relatedly, RNW discusses steps PacifiCorp can take in its next IRP to more effectively implement the WRAP into future planning processes, including: how PacifiCorp should analyze and report on its WRAP position in future filings, how the Commission can establish clear

[95] Staff Round 1 Comments, at 35.

guidelines for filling gaps in PacifiCorp's WRAP compliance position, and opportunities to leverage insights from WRAP modeling to address gaps in PacifiCorp's IRP process.[96]

RNW recommends that, to account for weather-related risk factors, PacifiCorp should "conduct Loss-of-Load-Probability (LOLP) studies that incorporate stochastic parameters for critical inputs while addressing weather-correlated risks affecting both supply and demand variables."[97] RNW recommends these studies should encompass multiple years of historical weather data and also heightened risks with extreme weather events linked to climate change.[98] This would allow PacifiCorp to "comprehensively capture variability in all relevant risk factors, including those related to unit availability or derating risks associated with prevailing weather conditions."[99]

In response, PacifiCorp notes that perceived misalignments between preferred portfolio and P06 variant results are due to intertemporal effects, i.e., the cost-effectiveness of resource timing. Optimization modeling provides a comparison of portfolio-to-portfolio and not individual resources compared to each other in an otherwise locked environment. This means that while no resource changes are indicated immediately upon changing specific resources in a portfolio, there will still be portfolio level impacts to costs and benefits realized through re-dispatch. The non-emitting baseload capability of the NatriumTM demonstration project coupled with its storage benefits make it a suitable candidate in the preferred portfolio.[100] Ultimately, the

[96] RNW Round 1 Comments, at 11, 57-61.
[97] *Id.* at 10, 53-55.
[98] *Id.*
[99] *Id.*
[100] Staff Round 1 Comments, at 53.

P06 variant, which studied the impact of removing new technologies, reported significantly higher cost than the preferred portfolio on a risk-adjusted basis.[101]

PacifiCorp agrees that LOLP studies incorporating stochastic conditions are a necessary tool for identifying risks in supply and demand. The most critical input that did not have stochastic parameters in the 2023 IRP were wind and solar generation. Similarly, for the 2023 IRP PacifiCorp enhanced the modeling of energy efficiency to ensure that heating and cooling measures produced the highest savings on the days in which the load forecast had the highest heating or cooling demand, but was not able to incorporate stochastic effects, e.g. higher than expected savings from cooling measures during an extreme high-temperature event in the summer. PacifiCorp agrees the value of stochastic analysis will be enhanced if it reflects risks that may only be apparent with multiple years of history, or which reflect ongoing evolution in climate-related effects. This is a significant undertaking, and maintaining the correlation between all of the weather-impacted parameters will be complex and a necessary part of producing valid results. PacifiCorp looks forward to advancing its LOLP analysis with feedback from stakeholders during the public input in its next IRP.

PacifiCorp also notes that it is always open to improve and update the existing methodology of how the Company evaluates inclement weather conditions on the existing RA position in subsequent IRPs. Lastly, PacifiCorp is actively evaluating the WRAP program and its potential implementation as early as 2026 but has not determined how it will be incorporated into IRP modeling at this time.

[101] *See* 2023 IRP Volume I, Chapter 9 – Modeling and Portfolio Selection Results (through 2042, the PVRR(d) shows that the portfolio without future technology is $188 million higher cost than the P-MM portfolio. On a risk-adjusted basis, considering the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without future technology is $405 million higher cost than the P-MM portfolio).

3. Renewable Cost Assumptions

RNW questions PacifiCorp's cost assumptions for solar, wind, storage, geothermal, non-emitting peakers, hydrogen fuel costs, and nuclear resources. As a result, RNW states that PacifiCorp's modeling assumptions "drive an outcome that is over reliant on emerging technologies, with approximately a fifth of PacifiCorp's capacity needs slated to come from highly uncertain resources by the mid-2030s," and this outcome appears to be driven "in large part by cost assumptions for clean energy resources, particularly solar, wind, and storage, that are far higher than comparable benchmarks in neighboring planning proceedings and is paired with overly optimistic cost assumptions for future technologies, specifically small modular nuclear reactors (SMR) and non-emitting peakers."[102] For example, unlike SMRs, "modeled at $62.05/MWh, non-emitting peakers are highly costly, with all 100% hydrogen configurations exceeding $400/MWh," and by contrast "geothermal resources, with total resource costs of $29.21/MWh for an expansion of Blundell and $42.069/MWh for a greenfield project were not selected, despite being approximately a tenth of the cost of non-emitting peakers and providing clean, firm energy."[103]

Instead, RNW recommends PacifiCorp develop a new preferred portfolio based on RNW's alternative cost assumptions for each resource, and that the Commission should view PacifiCorp's current preferred portfolio as a sensitivity case that reflects a future where "unlimited development of emerging technologies is viable."[104] Specifically, RNW recommends PacifiCorp: limiting SMR technology to a single 500 MW Natrium reactor in 2030 with potential to expand to a second in 2035, and limiting non-emitting peakers to 250 MW in 2030 and an

[102] RNW Round 1 Comments, at 7-8, 18-42.
[103] *Id.* at 25.
[104] *Id.* at 8.

additional 250 MW in 2033 and 2036;[105] use best available date for clean energy cost assumptions, as PacifiCorp's are 15-50 percent greater than cost inputs used by Portland General Electric and the CPUC;[106] or otherwise provide additional support for the Company's price assumptions and escalations.[107]

Finally, RNW does "not wish to discourage PacifiCorp from exploring emerging technologies, and supports broader efforts to commercialize emerging carbon-free technologies," however RNW "strongly encourages PacifiCorp and the Commission to avoid overreliance on a strategy which puts so many of the eggs of Oregon's energy transition into baskets which are still making their way from lab to market."[108]

In response, PacifiCorp notes that the cost of resources referenced by RNW represents the levelized cost of electricity (LCOE). This is an informative data point, bringing together the several disparate fixed and variable cost components for various resources into a single total value. Tax credits, whether production tax credits or investment tax credits, also need to be considered in the LCOE which lowers cost. However, LCOE does not distinguish the time of delivery or a resource's contribution to the reliability of the system as a whole. A non-emitting peaking resource has a lower fixed cost than a nuclear resource and comes with no obligation to generate. A nuclear resource will produce generation in every hour that it is online, whether that generation is needed or not. In many hours, that generation is not needed PacifiCorp's load varies significantly across the year. For example, while the 2023 summer peak load is 10,657 MWs, the total load in 2023 is approximately 58,671 GWh, or an average of 6,698 MWs.[109]

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[105] *Id.* at 19.
[106] *Id.*
[107] *Id.* at 32.
[108] *Id.* at 19.
[109] 2023 IRP, Volume I: Chapter 6 (Load and Resource Balance), Table 6.11 and Volume II: Appendix A (Load Forecast), Table A.9 (58,671 GWh divided by 8,760 hours yields an average of 6,698 MW).

That leaves roughly four gigawatts of resources that may only be used in half of the year, or as little as one hour per year. That four-gigawatt resource requirement also does not include operating reserves, which are held in all hours, but deployed relatively infrequently, and additional resources to meet planning reserve requirements, which may only need to be called upon when loads are higher than expected or resource supply is lower than expected. PacifiCorp's portfolio modeling evaluates the mix of load and resources throughout the year, and while a certain amount of base load resource such as nuclear is indicated, future IRPs may be able to identify wind, solar, storage, and peaking resources that in combination are better suited than a baseload resource for a portion of the resource supply.

With regard to geothermal resources, PacifiCorp agrees that they have significant potential, in large part as a result of technological improvements that could allow for viable projects in a broader range of geographic locations. In the 2023 IRP, geothermal resource costs were projected to increase at inflation, while wind, solar, and storage resources were projected to decline or escalate at less than inflation as a result of projected technological advancement.[110] Cost declines may also be appropriate for geothermal resources. PacifiCorp would note that it has not seen interconnection requests at the scale of the 200 MW geothermal resource assumed in the supply-side table that would indicate geothermal resources would be ready to move forward in the near term. While geothermal resource potential could limit the locations and size of geothermal resources, this is certainly an area for review in forthcoming IRPs.

The "PacifiCorp 2023 Renewables IRP Report" developed by WSP provides details regarding the cost assumptions for renewables.[111] The cost forecasts in WSP's report were

[110] 2023 IRP, Volume I: Chapter 7 (Resource Options), Figures 7.3-7.5.
[111] Available here: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023-irp-support-studies/2023_Renewables_IRP_Report.pdf.

developed before PacifiCorp witnessed the impact of recent tighter trade tariffs and inflation on the utility scale market. Upon observing those impacts PacifiCorp adjusted the cost forecasts to reflect what was observed in the market in 2022.

Finally, PacifiCorp appreciates its long-standing partnership with stakeholders across its six-state service territory. In order to incrementally de-carbonize our existing portfolio, the Company evaluated the deployment of a diverse array of technologies in various stages of development. The 2023 IRP mitigates concerns of over-reliance and single-solution strategies through this diversity of options, and also by restricting when new technologies are allowed to be adopted, and by performing counterfactual analysis including studies P05, P06 and alternative acquisition path analysis. In doing so, this strategy ensures that PacifiCorp is aligned in the pursuit of resources that will provide fair, just and reasonable rates for our customers.[112]

4. Resiliency

The Energy Advocates have several resiliency suggestions. Specifically, PacifiCorp should: slightly amend the definition of resilience to ensure that it centers communities and discuss services PacifiCorp will provide during service interruptions;[113] ensure that risk analysis frameworks include three factors that focus on community (time and duration of power outages;

[112] *In re OPUC IRP Investigation*, Docket No. UM 1056, Order No. 07-002, Appendix A (Jan. 8, 2007), Errata Order No. 07-047 (Feb. 9, 2007) ("All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response."); Order No. 07-002 at 4 (in approving IRP Guideline 1, the Commission specifically rejected the consideration of all "*known*" resources to be limited to the consideration of only *"all commercially or near-commercially viable resources.*") (emphasis added); *Id*. (the Commission stated that it did "not want utilities to limit their consideration to currently available resources, but rather to include all those that are expected to become available. We prefer the IRP be inclusive of all such resources and allow the parties to debate in the planning process whether it is reasonable to rely on a new technology").

[113] Energy Advocates Round 1 Comments, at 13-14.

resources within communities during outages; and long-term comparisons of microgrids and CBRE projects).[114]

PacifiCorp intends to continually refine its approach to resilience in future CEPs. This will include the addition of its initial community and utility resilience analysis in the next CEP with descriptions of the selected resilience metrics and how those are applied. The Company expects that the definition of, and approach to, resilience will evolve as we gain experience and receive additional stakeholder input. Initial resilience metrics (as included in the inaugural CEP) are focused on helping to identify communities where resilience efforts can be most beneficial (e.g.: areas with both higher socio-economic vulnerabilities and higher than average outage levels, as measured by SAIFI, SAIDI, and CAIDI). The Company appreciates the continued engagement and dialogue as we continue to improve its resilience program.

Next, Staff recommends that PacifiCorp: (1) provide status updates regarding CEP Table 9; (2) explain how it intends to incorporate community input for future resiliency analyses and planning, wildfire encroachment concerns and CEII as a contributor to increased risk exposure (and incorporate aspects from PacifiCorp's wildfire protection and mitigation plan as necessary); (3) clarify whether PacifiCorp intends to conduct resiliency analyses and planning in DSP, IRP and or CEP processes, and how this will affect both IRP and CEP portfolios; and (4) clarify whether PacifiCorp uses "resilience" and "reliability" interchangeably, explain why and how it is using reliability metrics to ensure resilience, and describe how reliability metrics to measure resilience impacts, costs, consequences, outcomes, and benefits.[115]

PacifiCorp appreciates these comments from Staff and will incorporate these changes into its next CEP. PacifiCorp is currently evaluating expanding its initial community and utility

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[114] *Id.* at 14-15.
[115] Staff Round 1 Comments, at 33.

resilience analysis to include additional community input. For detailed information on PacifiCorp's wildfire mitigation efforts, PacifiCorp encourages interested stakeholders to review its Wildfire Mitigation Plan.[116] PacifiCorp is also evaluating how to apply its resilience analysis to DSP and CEP programs and will provide additional information in its upcoming CEP consistent with Staff recommendations. PacifiCorp does not use resilience and reliability interchangeably and will clarify its distinction between these aspects of electric system operations in its upcoming CEP. PacifiCorp is currently developing a preliminary resilience cost-benefit analysis and will include this framework in its upcoming CEP.

5. Pace of Emissions Reductions

The Energy Advocates comment that PacifiCorp's forecasted pace of emissions reductions should not be relied upon for two reasons: near-term emission reductions are much more valuable than promised emission reductions years down the road; and PacifiCorp's pause of its all-source RFP will "undoubtedly impact PacifiCorp's ability to meet its projected greenhouse gas reductions."[117]

In response, PacifiCorp notes that the pros and cons of early adoption as compared to just-in-time adoption were vigorously explored by the Company when determining which compliance pathways were the most feasible. The currently projected path forward remains in between these extremes, with resources anticipated for 2026 through 2030. While these resources are partly dependent upon the resource pool available to the 2022 AS RFP, the Company expects that its pace of emissions reductions will remain largely on track, and resources will come online prior to 2030, despite the current delay in the 2022 AS RFP.

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[116] Available here: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/wildfire-mitigation/PacifiCorp_2023_Wildfire_Mitigation_Plan_12-29-22.pdf.
[117] The Energy Advocates Round 1 Comments, at 29-30.

6. Transmission Considerations

Staff recommends that, in reply comments, PacifiCorp; (1) address how its ambitious transmission plans are coordinated with other regional planning activities, and how the 2022 AS RFP may impact the economics of any planned transmission;[118] (2) discuss PacifiCorp's justification for the assumption that 725 MWs of battery storage would be needed if B2H was not constructed;[119] (3) discuss PacifiCorp's ability to model Oregon transmission on a more granular scale to inform the best way to build out SSR and other Oregon resources (and indicate whether this analyses can be included in the IRP Update or next IRP).[120] And for the next IRP, Staff recommends PacifiCorp consider non-wires solutions and Grid Enhancing Technologies prior to considering transmission expansion options.[121]

In response, the Company notes that it participates in FERC Order 1000 Regional Planning through the NorthernGrid planning region. When a new transmission project is identified through internal transmission planning efforts, the Company submits that transmission project into the NorthernGrid planning process for evaluation at a regional level. Within each biennial planning cycle, NorthernGrid evaluates the combination of submitted projects to identify whether there may be a regional combination of projects that effectively satisfies the needs of the region. If a transmission project is selected as part of the regional combination into the regional transmission plan, then it is subsequently reevaluated as a baseline project in each successive biennial regional planning cycle until it has reached Committee Project status. This process is outlined in detail in Attachment K of the Company's Open Access Transmission Tariff. Additionally, the Company coordinates transmission plans through the Western

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118 *Id.* at 54.
119 *Id.*
120 *Id.* at 55.
121 *Id.* at 54.

Electricity Coordinating Council (WECC) project coordination path rating and progress report process. This process extends coordination beyond the NorthernGrid planning region and notifies WECC members and the broader Western Interconnection of planned projects. The WECC Project coordination path rating and progress report process also outlines the procedures for establishing or modifying path ratings for those projects that affect WECC major paths.

In response to the requested justification of battery storage assumptions, a 725 MW, eight-hour duration battery is added to the portfolio in 2027 as a requirement in Southern Oregon in the absence of B2H. A non-wires analysis performed by BPA, IPC, and PacifiCorp indicated that obtaining 680 MW of central Oregon load service capability in the absence of B2H would require dispatchable generation in Southern Oregon ranging from 725 MW to 1,450 MW to prevent impacts to other existing rated paths. Because the IRP analysis only includes PacifiCorp's transmission rights and forecasted usage, it cannot identify periods in which dispatchable southern Oregon generation would need to be deployed to address flows on regional transmission paths. As such, this battery is held available to increase the reliability of deliveries to Central Oregon loads, so it is not dispatched under the normal system conditions represented in the PLEXOS model. Additionally, this assumption was modeled in the 2021 IRP as a Boardman to Hemingway variant under (P02b-No B2H).

As it relates to the granularity of modeling Oregon transmission, the PLEXOS model allowed SSR anywhere in PacifiCorp system and was not limited to Oregon. In this analysis, potential additional transmission costs were not included, providing SSR an offsetting advantage compared to utility scale projects.

Adding more transmission areas (bubbles) can dramatically increase PLEXOS run times. A 20-MW small-scale resource is on the smaller side for a Utility scale project. BPA provides transmission rights to connect the load bubble locations in Oregon such that wheeling costs could be incurred when adding a small-scale resource.

A more judicious course of action is not to prejudge SSR but to see what the SSR RFP bids are received before conducting an analysis. Due to these modeling limitations using PLEXOS to model a more detailed transmission is unlikely for the 2023 IRP Update and future IRPs. There are other analytical methods to provide evaluations around SSR. For example, Oregon's DSP processes may provide more granular information to assist developers in their siting considerations.[122] Collating this highly site-specific information for inclusion in the IRP is difficult, but PacifiCorp hopes to learn more about the landscape and opportunities in its proposed small-scale RFP, and should be able to incorporate both the results of that RFP and lessons learned in its next IRP. Lastly, the Company appreciates the stakeholder feedback pertaining to non-wires solutions and will consider the inclusion of this topic in the 2025 IRP public input meeting series.

NewSun comments that the Company has not adequately addressed local alternatives to large out-of-state resources, or the Company's reliance on transmission capacity that have long lead-times.[123]

In response, NewSun juxtaposes local resources to large out-of-state resources. While this is an understandable differentiation in some regards, this view overlooks larger resources identified over the 20-year planning period in the 2023 IRP which are located in Oregon. A total of 3,140 MW of standalone wind, solar, and battery, or co-located solar and battery was selected in Oregon in the preferred portfolio. These resources can be both "local" and large, in the sense

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[122] *See* "Oregon UM 2000 Interconnection Data", located on PacifiCorp's website at: http://www.oatioasis.com/ppw/ (in the sidebar, select "Generation Interconnection" and then "Additional Information").
[123] NewSun Round 1 Comments, at 7.

that they are utility scale and developed within the state. As discussed in Chapter 8 of the 2023 IRP, transmission options, costs and construction lead times are developed from the best currently available information, including interconnection and Cluster study results. As identified in these studies, the non-contiguous nature of the PacifiCorp system in Oregon often results in major transmission projects to deliver local Oregon resources to local Oregon loads. An advantage of the cluster study process is that it has the potential to identify collective solutions that can allow groups of resource additions and projects to move forward together in a timelier manner. These cluster study solutions are included as transmission options in the 2023 IRP for both small and large resource additions.

This possibility aside, PacifiCorp directly examined the potential for SSR to serve local loads at a transmission discount in the CEP. PacifiCorp agrees that a chief advantage of SSR is the potential to serve local load with less transmission expense, as these resources are not anticipated to require large transmission projects to meet local load. PacifiCorp's first CEP gives SSR a conservative advantage in assuming no such transmission cost, as the transmission options were not considered required for interconnection. Despite this defrayed cost, SSR were not economic when compared to utility scale resources even in the face of the additional transmission options required to interconnect those larger resources. PacifiCorp anticipates that future analysis will include more refined accounting of both pros and cons to small-scale economics, including transmission considerations for SSR. At this time, it is clear that SSR are uneconomic and required non-endogenous handling to meet Oregon requirements.

CUB reiterates its concern that layering PacifiCorp's CEP on top of the Company's six-state IRP does not result in least-cost, least-risk, procurement planning that complies with HB

2021.[124] This concern is driven by the Company's conversion of coal to natural gas assets, that the CEP does not lead to binding emissions reduction targets, and that this sequential process does not give full credit to the requirements of HB 2021, especially where other PacifiCorp states do not have carbon emissions reduction requirements.[125] As a result, CUB "fails to understand why it is appropriate to assume that a preferred portfolio that does not reflect any binding carbon reduction is the correct starting point for determining the optimal portfolio in Oregon where significant carbon reduction is mandated."[126]

PacifiCorp would direct attention to discussion above under section B.3., "Pathway 4", wherein small-scale optimization is discussed. The Company's round zero reply comments were extensive on this point and expanded on in the above example. Simply put, SSR are uneconomic and inadequate to achieve compliance. Their required adoption can either be allowed to disrupt the least-cost least-risk optimization of the system or can be layered on incrementally. If allowed to disrupt, there are inevitable resource conflicts with other states, and subsequent adjustments will render a final portfolio with increased costs compared to the incremental approach. Even when layered on incrementally, additional action is required to achieve compliance. This fact indicates that an incremental treatment was the best analytical approach at the time of filing. Since the filing of the CEP, PacifiCorp has continued to evaluate methodologies and has envisioned another possible approach that allows for the integration of the systemwide and state-specific portfolios into a "unified" portfolio.[127] Whether this alternative is competitive with the incremental approach remains to be determined in future analysis. The Company is committed to continual improvement of its methodologies.

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[124] CUB Round 1 Comments, at 2-3.
[125] *Id.*
[126] *Id. at 3.*
[127] This method, while still in development, has been discussed with staff.

7. Alternative Portfolio Variants and Cluster Resources

Sierra Club recommends PacifiCorp complete model runs of several portfolio variants under each of PacifiCorp's price and policy scenarios. These include P01-JB3-4 GC, P04-Huntington RET 28, and P17-Col3-4 RET25. Sierra Club also recommends PacifiCorp complete portfolio variants that force the model to incrementally select additional cluster study resources from Cluster Areas 1, 2, 4, 12, and 14, and reassess variants P18-Cluster East and P19-Cluster West by re-optimizing resource selections, portfolio composition, costs, and risks throughout the LT model.[128]

In response, PacifiCorp evaluates portfolios under five price-policy scenarios with attention to heuristic value and resource availability to name two key factors. As the Company cannot evaluate all studies under all possible conditions, cases are prioritized. At the same time, PacifiCorp has been responsive to stakeholder requests, conducting additional studies as time and resources allow.[129] Regarding the three cases named as examples, the results are conclusive enough that only the heuristic value of robustness under a less likely future comes into play. P17, for example, was examined only to determine the cost effectiveness of an early retirement of both Colstrip units over the optimally selected approach of retiring one unit and continuing the other. Given that continued operation of a single unit supported renewables and increased relative benefits in the period most critically related to long-term CEP compliance, the value of a high gas price, high CO2 price (HH) analysis is reduced, and not competitive with the potential value of running other studies.

Likewise, the analysis of P18 and P19 was conducted with the understanding that additional resources would likely result in a higher cost present value of revenue requirements

[128] Sierra Club Round 1 Comments, at 47-52.
[129] E.g., P10-Offshore Wind, P23-RET Coal 30/33, P24-Gas 40-year Life.

(PVRR) outcome. The value of these studies is to assess the magnitude of that PVRR impact for determining possible least-regret paths to consider for the preferred portfolio. The results of these studies supported the selection of the preferred portfolio without the addition of marginal cluster resources in the east or west and indicated that even further additions must further deteriorate benefits. However, incremental additions are a common feature of portfolio analysis, and future filings are expected to continue with this type of analysis.

8. Carbon Assumptions

CUB comments that the Company should eliminate price-policy scenarios that assume zero carbon costs, and instead should identify the $/ton cost of carbon costs and current emissions as the minimum carbon cost price-policy scenario.[130] As a result, CUB notes by "recognizing and allocating these costs to their cause (carbon emissions) in planning, we can incentivize clean energy investments over fossil fuel investments and get to the root cause of our wildfire problem."[131] Similarly, the Sierra Club recommends the Company increase the medium carbon price policy to reflect recent federal regulations, and incorporate these developments in the 2023 IRP Update.[132]

Sierra Club and CUB misunderstand the function of the CO2 medium assumption cost. This cost does not represent current legislation, which is already modeled as appropriate methodologies and data become available. The medium CO2 policy assumption is a proxy for future drivers, continuing the already strongly established trend of decarbonization into the future. This proxy CO2 cost is therefore a forecast, representing this trend, and properly based on a survey of currently available forecasts. It is not the role of the proxy cost to drive

[130] CUB Round 1 Comments, at 7-8.
[131] CUB Round 1 Comments, at 8.
[132] Sierra Club Round 1 Comments, at 57-58.

decarbonization, rather its role is to represent drivers that can be reasonably forecast. This is why recent legislation has not replaced or eliminated the need for the medium CO2 proxy cost – the Company is forecasting that the decarbonization trend will continue into the future.

Regarding the elimination of the medium gas price, zero CO2 price (MN) price-policy scenario or zero CO2 (LN) price-policy scenarios generally, doing so would eliminate a source of information indicating robustness of portfolios and also indicating what may occur if the expected case CO2 cost forecast is not realized. While the Company's position is that the MM price-policy scenario is the most likely, eliminating alternatives such as the HH or MN scenarios seems precipitous and unnecessary. PacifiCorp considers price-policy scenarios over the course of each IRP, and they are an important subject covered in the public input meeting series.

Staff recommends PacifiCorp: (1) evaluate portfolios P04 and P17 under alternative gas and CO2 price assumptions and report the resulting scoring metrics, and include these portfolios in the CEP evaluation of alternatives to the Preferred Portfolio;[133] (2) evaluate whether PacifiCorp's approach for incorporating climate change impacts accurately reflects temperature changes across the Company's Oregon service territory;[134] and (3) in the next IRP, examine alternative climate modeling approaches that account for more localized effects.[135]

In response, the Company notes that it has applied a targeted analysis approach to P04 - Huntington Retire 2028 and P17 - Colstrip 3-4 Retire 2025 by analyzing under the expected case, medium-gas and medium CO2 price curve. Both studies reported a higher cost than the preferred portfolio. The conclusion learned from the case variant study would not have changed when analyzing under other prices curves. The company also balanced limited time and computer

[133] Staff Round 1 Comments, at 37-38.
[134] *Id.* at 42.
[135] *Id.*

resources to complete the 2023 IRP. As it pertains to climate change impacts, PacifiCorp has studied the Klamath River near Seiad Valley as the point to measure the overall impact of climate change on its service territory is based on the location's proximity to the company's largest concentration of load. The Company also notes that there is limited variability in temperature expectations between the different Oregon river basins in the study. The Company agrees that accurately reflecting the various climates across the Company's service territory is important. To account for this the Company uses seven different weather stations to reflect this variability. The Company determined the percentile of the seven weather stations' historical temperatures necessary to achieve the predicted average temperature increase on the Klamath River near Seiad Valley.[136] By applying this percentile to each of the Company's seven weather stations' 20-year history, the Company was able to capture the micro-climate embedded in the historical temperatures around each of the seven weather stations.

Lastly, in relation to alternative climate modeling approaches, PacifiCorp is proactively considering other climate modeling methodologies and intends to incorporate these methods in subsequent IRP's.

9. Market Assumptions

Staff recommends PacifiCorp 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."[137]

In response, PacifiCorp notes that the expansion of organized markets in the West is anticipated to promote broader West-wide decarbonization by optimizing resource dispatch to

[136] *See, 2023 IRP Confidential Climate Change Weather, Monthly HDD CDD workpapers*.
[137] *Id.* at 17.

serve load and reducing curtailments of renewable resources. The very existence of these markets will "promote GHG reductions on the PacifiCorp system to help meet HB 2021 targets."

For example, under the current DEQ accounting approach, PacifiCorp anticipates that it will continue to attribute Oregon's cost-allocated share of EDAM purchases to Oregon and treat them as unspecified. As such, under the current approach, these unspecified purchases would be applied the current unspecified emissions factor (0.428 MT/MWh). However, it is anticipated that as the regional mix gets cleaner, this unspecified emissions factor (roughly consistent with a gas plant) may be revisited. PacifiCorp may advocate for regulation that revisits the calculation of the unspecified emissions factor in the future, or for the organized market design to provide more granular emissions factors. While PacifiCorp may advocate for such regulatory approaches in the future, it is prioritizing the promotion of the expansion of these markets to realize broader west-wide decarbonization.

RNW recommends PacifiCorp analyze procuring resources beyond its service territory, "which could inform interregional transmission needs as well as the value proposition for regional markets which reduce procurement friction for off-system resources."[138] For example, "while PacifiCorp's solar resource is relatively strong, capacity factors and availability during critical hours for resources in Nevada, California south of the Company's territory, Arizona, and New Mexico may be preferable to (or complementary with) on-system resources."[139]

RNW is also concerned that PacifiCorp's volume of front-office transactions are unsubstantiated and present an avoidable risk to ratepayers; instead, RNW recommends the Commission examine these transactions by collaborating with regional planning organizations to develop a regional modeling study that would "assist PacifiCorp in forecasting a prudent volume

[138] RNW Round 1 Comments, at 8, 20, 39-42.
[139] *Id.* at 39-40.

of wholesale market transactions to include in its portfolio in order to meet its load obligations."[140] This could involve working with other regional planning organizations like the WPP, to "conduct a detailed WECC-wide modeling study to quantitatively estimate the timing and volume impacts of tightening regional markets and their ability to serve as reliable capacity and energy resources for utilities."[141]

With regard to off-system resources, PacifiCorp has in the past evaluated such resources under specific circumstances. Given the scope of the company's territory, accessible to some of the best solar and wind opportunities to be found anywhere, IRP may consider specific off-system resources, but it is unrealistic and unnecessary to attempt to distinguish such resources on a proxy basis. The location of off-system resources immediately entails higher costs for access to such projects in the form of additional contractual agreements and related wheeling costs.

PacifiCorp performs WECC-wide modeling as a component of other company analysis and reporting, namely, regional transmission planning cycles.

10. Federal and State Incentives

Swan Lake reiterates that PacifiCorp did not include Inflation Reduction Act tax credits for pumped storage, or any other form of storage resource.[142] Swan Lake requests PacifiCorp (1) provide an updated Table 7.2 that shows Inflation Reduction Act (IRA) tax credits and amounts that were applicable to storage resources (if any), and (2) if PacifiCorp has not analyzed storage resources with IRA tax credits, to provide updated analyses that does.[143]

CUB comments that it would like regular updates on the Company's efforts to secure government funding to support utility operations, for example including PacifiCorp's efforts with

[140] *Id.* at 10, 55-57.
[141] *Id.* at 57.
[142] Swan Lake Round 1 Comments, at 2.
[143] *Id.* at 3.

the DOE Grid Resilience Innovation Partnership grants, or PacifiCorp's successful $150 million award to improve grid infrastructure and wildfire mitigation.[144]

Sierra Club recommends PacifiCorp incorporate several opportunities from the IRA. These include financing opportunities from the Energy Infrastructure Reinvestment (EIR) program (which can enable closure of coal plants, replacement of fossil fuel resources with cleaner alternatives, and develop transmission infrastructure), that Sierra Club recommends should be included no later than the IRP Update, and should include a transmission network upgrade cost scenario for Cluster Areas 1, 2, 4, 12, and 14 that are reduced by 30 percent, and a scenario where EIR financing assumes the early retirement and replacement of Jim Bridger Units 3 and 4, Huntington, Hunter, and Wyodak.[145] The Energy Advocates also recommend the Company expand its incorporation of IRA bonus tax credits for certain energy communities (including in Oregon), and update its publicly available data to correctly reflect the incorporation of investment tax credits (ITCs) and production tax credits (PTCs) for storage and stand-alone storage resources.[146]

Staff has similar recommendations to CUB and Sierra Club,[147] and also recommends PacifiCorp address what steps it will take to analyze whether the IRA's $250 Billion EIR program could apply to any of PacifiCorp's existing coal facilities.[148] This includes detailing how PacifiCorp plans to pursue EIR programs and perform Sierra Club's recommended variant analyses of EIR benefits.[149]

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144 CUB Round 1 Comments, at 11.
145 Sierra Club Round 1 Comments, at 5-10.
146 *Id.* at 11-14.
147 Staff Round 1 Comments, at 29.
148 *Id.* at 48.
149 *Id.* at 50.

In response, PacifiCorp will continue to pursue meaningful opportunities to share government funding updates with stakeholders when appropriate. Currently, the Company does not lead a public forum that is dedicated to the disclosure of grant projects, and instead encourages stakeholders to actively monitor the PacifiCorp press releases page to remain apprised of new funding developments.[150]

Pumped hydro ITC credits were included in modeling for the 2023 IRP, which did not result in selection at this time. Any changes regarding this technology are unlikely to impact the action plan window. Also, pumped hydro will be re-assessed with any appropriate input updates in the forthcoming 2023 IRP Update.

PacifiCorp incorporated, at the time of filing, the best of the timely available information regarding IRA legislation, and as previously detailed in its Round Zero replies to comments, continues to examine evolving legislation for use in future analysis where appropriate.[151] While the publicly posted supply side table does not show the IRA, ITC or PTC factors, modeling within the PLEXOS database DID account for the above factors as appropriate (not limited to wind, solar, storage, pumped storage and other asset classes). The Company also notes that its treasury department is actively pursuing EIR programs, financing it can qualify for, and applying for grants. The details of EIR will be communicated in the next IRP as they become known. A variant study can be reported once the EIR details are better known.

11. Avoided Costs

Staff recommends PacifiCorp: (1) address the calculation of avoided costs considered additional constraints of HB 2021; (2) discuss whether the Company's analysis considers

[150] Available here: [News releases (pacificorp.com)](pacificorp.com)
[151] Refer to PacifiCorp's Reply to Comments, filed July 31, 2023, the 2023 IRP and CEP Appropriately Evaluates the Benefits of Federal Legislation, pp 41-42.

avoided capacity costs that vary over the planning horizon (especially regarding the optimal pathway for CEP compliance); (3) address whether forward market prices used for avoided costs reflect the need for the Company to purchase increasing shares of non-emitting market purchases, not simply the least cost market resource; and (4) discuss how avoided planning reserve margin costs are considered in portfolio analyses.[152]

NewSun comments that the Commission should decline to acknowledge PacifiCorp's IRP until PacifiCorp provides updated avoided cost information as required by OAR 860-029-0080(3).[153]

In response, the Company notes that the Commission has approved standard and standard renewable avoided cost methodologies and has not yet addressed how constraints associated with HB 2021 should be incorporated. For example, PacifiCorp has previously raised concerns about standard avoided costs relying upon a natural gas combined cycle combustion turbine in the current rules as this resource will not be compliant with HB 2021 and is not least-cost and least-risk given its absence from the preferred portfolio in the last several IRPs. Additionally, PacifiCorp's IRP portfolio analysis is intended to fit together the disparate capacity, energy, RPS, and greenhouse gas compliance characteristics of a multitude of resources into a portfolio that reliably and cost effectively serves customers in all hours from year to year. The resources in that portfolio are expected to provide a variety of benefits, making the determination of a single "avoided resource" something of a misnomer. PacifiCorp agrees that compliance with HB 2021 is likely to result in additional costs, for both the revised small-scale capacity standard and the greenhouse gas emissions requirements, and that the costs of meeting those requirements may be appropriate to consider when setting avoided costs. However, these examples, and others, are

[152] Staff Round 1 Comments at 61.
[153] NewSun Round 1 Comments, at 7-8.

more appropriate to address in UM 2000, and not individual utility CEPs. PacifiCorp has engaged in additional discussions with stakeholders in the UM 2000 docket and looks forward to further developments in those proceedings.

With regard to avoided capacity costs over the planning horizon, PacifiCorp agrees that this is an important consideration, and its modeling selects resources with the lowest net cost of capacity, i.e., those with the lowest cost relative to their contribution to reliability, after accounting for a resource's energy and renewable or clean energy compliance benefits. This is not quite the same as the traditional "capacity cost" which is more closely tied to the cost of building new resources, without accounting for their operational benefits. At present, PacifiCorp's standard renewable avoided costs reflect the cost of a renewable wind proxy starting 2026, so prices after that date would not include a forward market component. As discussed above, using a single resource to reflect capacity, energy, and compliance obligations is complicated, so some consideration of forward market obligations may be warranted in 2026 and beyond, but that was outside the scope of the 2023 IRP and CEP. PacifiCorp's portfolio analysis ensures that sufficient resources are included to ensure reliable operation. As discussed in section C.1., above, the analysis includes a minimum planning reserve margin "floor" from the beginning, so it is difficult to identify specific costs associated with meeting the planning reserve margin, which in any event would be unavoidable. In addition, with the increase in variable energy resources, different resources may contribute to meeting planning reserve requirements in different hours of the day and different seasons. Ultimately PacifiCorp has to ensure reliable load service throughout the year, not just during peak hours in the winter or summer.

Finally, with regard to NewSun's concerns about OAR 860-029-0080(3)(a), PacifiCorp's data disks include the assumed market prices for energy in the requisite peak and off-peak periods, consistent with the Commission's use of market prices for avoided costs during the resource sufficiency period. Similarly, for part (b), PacifiCorp's supply side table, provided in Tables 7.1-7.3 in Chapter 7 (Resource Options) contains capacity cost estimates using the traditional metric (cost per kW of installed nameplate capacity). PacifiCorp is open to direction from the Commission to the extent additional information should be made available or it should be provided in a different format.

D. The 2023 IRP and CEP resource selections are properly determined.

As discussed below, the Company's IRP and CEP: demonstrated resource needs and targets appropriate for HB 2021, developed and modeled energy efficiency and demand response, included diverse supply-side resource options, and accounted for private generation.

1. General

Staff recommends PacifiCorp "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."[154] Staff requests PacifiCorp report this information with the same allocation pathways in the CEP (2020 Protocol, Pathway 1, and Pathway 2), explain any alternative allocation pathways that could be used to comply with HB 2021 or any updates to the Company's allocation strategies since filing the CEP, and include the information in an updated CEP Data Template.[155]

PacifiCorp appreciates Staff's desire for additional IRP variant case analysis in the CEP. While the variant cases can be placed in a CEP table for a comparison of emissions, costs and CBIs, the resulting math which indicates the inferiority of these cases would remain unchanged. PacifiCorp specifically included in the CEP requested studies for analysis and will consider

[154] Staff Round 1 Comments, at 18.
[155] *Id.*

additional studies in the future. However, if subsequent additional analysis of IRP variants is intended to include the additional compliance steps used for the CEP portfolio, the resource-intensive results likely could not be provided in a useful timeframe and would still be un-useful with regard to systemwide portfolio selection. For all of the reasons established in public meetings, the IRP, the CEP, round zero comments and again in this document, the optimal systemwide solution should be honored for all states, including Oregon, as a participant in the multistate process. The Company would draw attention here to its earlier position that the systemwide preferred portfolio as optimally determined for all states achieves an overwhelming portion of HB 2021 target compliance, and that supply-side incremental adjustments are minimal. However, PacifiCorp continues to welcome input regarding additional CEP sensitivities for future filings.

In addition to the above, Staff recommends PacifiCorp describe:

- How major IRP and CEP near-term action items have been assessed for risk, and which actions have larger risk than others, and possible future events that would likely cause the CEP Portfolio to significantly change;[156]
- To what extent does PacifiCorp's ability to meet Oregon's 2030 GHG target rely on emerging technologies like nuclear and non-emitting peakers;[157]
- Key milestones or timelines when the Company might consider material changes in strategy (such as coal retirement or coal-to-gas retirements, changes to nuclear plans, joining an RTO, or other alternatives);[158]
- What feedback will the Company use to determine whether a change in course is warranted? Will PacifiCorp adjust its strategy based on procurement efforts, or examine additional data, like actual GHG emissions, power costs, load forecasts uncertainties?[159]
- How the Company incorporates input from RBMs regarding commercial load forecasts and describe whether this increased load is reasonably expected within the Company's timeframe.[160]
- Load forecasts and peak load under aggressive electrification assumptions, including conducting a sensitivity of aggressive electrification scenarios in PLEXOS that includes

[156] *Id.* at 18-19.
[157] *Id.*
[158] *Id.*
[159] *Id.*
[160] *Id.* at 39.

the expected effects of building transportation and electrification on PacifiCorp's peak load.[161]

- The Company should (1) update the private generation forecast to include IRA tax credits for both solar and battery technologies, and apply that to the Company's load forecast and overall capacity need in the 2023 IRP preferred portfolio; and (2) by the next IRP, study the correlation between Private Generation solar installations and battery technology, and if applicable, use in the next battery technology IRP forecast.[162]

PacifiCorp thanks Staff for the thoughtful suggestions, and responds as follows:

To the first item, the IRP process, and the evolving CEP process as well, perform fundamental evaluations of changes in the status of technology, state and federal law, market conditions, and distinct analysis of key projects and decision points. PacifiCorp is committed to the continual improvement and evolution of these analysis as conditions change. Key studies in the 2023 filings include an examination of B2H, nuclear, offshore wind, small-scale renewables and other critical items. In addition, path analysis specifically addresses risks of significant portfolio change, as detailed in the Company's acquisition path analysis.[163]

Second, despite assumed risks to new technologies, some types of existing peaking resources can already use hydrogen, such as reciprocating engines, and technological advances indicate that burning hydrogen in large-scale frame combustion turbines, as assumed in the 2023 IRP, is likely to be possible. From a fuel supply perspective, existing combustion turbines are also capable of burning biodiesel today. While there is uncertainty in the cost of non-emitting generating capacity and non-emitting fuels, examples of both exist today. The Company anticipates that these types of resources will improve in performance and cost-effectiveness. As discussed in the 2023 IRP, advancement of non-emitting technologies will be critical to the

[161] *Id.* at 40.
[162] *Id.* at 45.
[163] 2023 IRP, Chapter 10 - Action Plan, pp. 363-385.

planned transition of our coal resources in a way that will minimize impacts to our employees and our communities.[164]

Additionally, in the 2023 IRP preferred portfolio, non-emitting peakers are forecast to reach an installed nameplate capacity of 1,240 MW by 2036, with no currently foreseen additions through the remaining 20-year planning horizon. This is less than 4 percent of all identified preferred portfolio additions (including DSM selections and storage capacity) by the end of the planning period. This limited presence, combined with the present-day existence of example resources, supports the Company's position that the risks are reasonable, and the long-term plan is appropriately forward-looking.

Achieving Oregon's 2030 GHG target is dependent upon emergent technologies to support the renewables presented in the preferred portfolio. Alternative acquisition path analysis is applicable to these technologies.

Third, key milestones for changes are to be indicated in the evolving outcomes examined primarily through the IRP, CEP and RFP processes. The IRP Update which occurs in even-numbered years, also plays a key role as a checkpoint in between the more expansive IRP filing, ensuring the preferred portfolio and action plan remain on track and responsive to change–

Fourth, in direct relation to the third item, immediately above, these processes include extensive stakeholder feedback, which is incorporated into planning, including public meetings, frequent meetings with regulators, workshops, additional stakeholder feedback via email, data requests and independent evaluators in the RFP process. This feedback informs assumptions, data development, modeling strategies and which cases are run for analysis at each step. Any of

[164] 2023 IRP, Volume I, Chapter 1 – Executive Summary.

these communications may result in a course change or addition to modeling strategy and planning approach.

Fifth, large customers provide information about their anticipated future operations to PacifiCorp's regional business managers (RBMs). Given the size of these individually forecasted customer's loads, and potential swings in load due to operational characteristics, the Company believes that projections for these large customers are better accounted for using an individual customer forecast rather than a regression approach.

This level of analysis is performed by RBMs for a select number of industrial and commercial customers. Individual commercial customer forecasts produced by RBMs are then added to the company's regression based commercial class forecast to generate the overall commercial class forecast. Historical loads for these customers are removed from the regression analysis to ensure that the forecast is not double counting projected loads for these customers.

The expected increase in Oregon commercial loads evident in the 2023 IRP are largely due new large data center projects. The reasonableness of this customer's load projections is based on RBM experience with similar projects, contract status and existing construction status. PacifiCorp reasonably expects the projected load for this customer to materialize within the timeframe put forth in the 2023 IRP.

Sixth, in addition to the base case load forecast, the 2023 IRP evaluates six additional load sensitivities under varying conditions – Low load growth, High load growth, High Private Generation, Low Private Generation, 1-in-20 extreme weather, and 20-year normal weather conditions. Each of these forecast sensitivities reflect the expected amount of building and transportation electrification part of the forecast. PacifiCorp will incorporate an additional load forecast sensitivity analysis within the 2025 IRP evaluating aggressive electrification assumptions.

Finally, the Company currently accounts for IRA tax credits for both solar and battery technologies as shown in Table 3-9 of the most recent Private Generation Long-Term Resource Assessment used for the 2023 IRP.[165] The results of this study are incorporated into the Company's load forecast and accounted for in determination of future capacity need. Additionally, the Company attempts to model the relationship between solar adoption and battery adoption in each state and will continue to do so in future modeling. Customer battery adoption forecast in the Private Generation study informs resource potential for utility control of batteries in the Conservation Potential Assessment.

2. Hydroelectric and Geothermal resources

CRIFTC comments that the Company should reduce over-reliance on federal hydro-electric resources and address the impacts from these resources to tribal treaty fisheries.[166] PacifiCorp's hydroelectric partnerships with federal entities provides a host of invaluable benefits to the communities it serves. In response, PacifiCorp notes that given the nature of this flexible base-load resource, the Company is able to provide clean, reliable and affordable power to its customers while maintaining our commitment to environmental stewardship with tribal nations across the six states we serve. As always, PacifiCorp appreciates stakeholders' continued participation in its long-term planning objectives and will continue to pursue meaningful solutions to modernize hydroelectric facilities to meet the needs of its diverse stakeholder interests

[165] Available here: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023-irp-support-studies/PacifiCorp_Private_Generation_Resource_Assessment.pdf.
[166] CRIFTC Round 1 Comments, at 9-10.

Fervo notes that the 2023 IRP "took an inadequate approach to modeling geothermal resources, and as a result fails to identify new geothermal capacity in any scenario,"[167] and provides various third-party studies and analyses that support its claims regarding the benefits of geothermal resources.

In PacifiCorp's IRP, there are many factors that make up the selection criteria for supply-side resources other than cost. It is a combination including, but not limited to, location, MW size, cost, risk, performance, net cost to the system and ability for load shift. Additionally, proxy resources not sited at existing interconnection locations require transmission investments to enable interconnection of new resources. In the 2023 IRP, transmission selections which enabled geothermal resources had their new resource interconnection limits filled with less expensive resources (and nuclear resources were not selected at those sites). The PLEXOS model considers all proxy resources in the LT model optimization decision taking into consideration the aforementioned criteria before making its selection.

During the preparation of the Company's response to a Fervo data request, the Company became aware of an error in the 2023 IRP supply-side tables related to geothermal costs. Specifically, the Company became aware of an error in the base capital dollars per kilowatt ($/kW) in the geothermal costs for the "Dual Flash Expansion of Blundell Plant" and the "Greenfield Binary Plant. The Company has corrected the error in the supply-side tables and has posted a corrected public / non-confidential work paper to the IRP section of its website.[168] Based on the relevant factors described above and the data correction, there was no indicator for a material change in the selection of geothermal in the 2023 IRP, particularly in the action plan

[167] Fervo Round 1 Comments, at 1.
[168] Public_SSR_Database_Summary_Tab.xlsx (live.com)

window. Geothermal will be fully re-assessed with updated inputs in the forthcoming 2023 IRP Update.

Also, the Company has the opportunity to acquire resources in the RFP process from all types of resources and actual project pricing would be used in the selection analysis. This means that all bids would be considered in the 2022 AS RFP (even though temporarily suspended). The Company notes that no geothermal bids were received.

3. Storage Resources

The Energy Advocates recommend PacifiCorp "look beyond storage co-location near generation sites and to identify substations and transmission lines that can use storage to flatten load peaks and avoid congestion and costly transmission and distribution upgrades."[169] PacifiCorp responds by first emphasizing that the PLEXOS model in its optimization accounted for proxy storage at the generator and load locations in the 2023 IRP. To further clarify, the storage locations added were not specifically tied to the generator. The specific substation and transmission would be identified in the request for proposal process after the 2023 IRP, where resource bids would be analyzed and contracts signed.

Regarding the Company's modeling of surplus interconnection, Sierra Club requests PacifiCorp allow storage to be paired with not only new renewable resources, but also existing fossil resources. This "hybridizing" of a thermal asset with a storage resource "would increase the flexibility of the asset and provide lower emission reliability services, such as spinning reserve" and likely "reduce operating costs as the storage asset could operate more responsively."[170]

[169] Energy Advocates Round 1 Comments, at 21.
[170] Sierra Club Round 1 Comments, at 57.

PacifiCorp believes it has met the aforementioned interest in its modeling of the 2023 IRP, where storage resource options were available to be selected modeled with potentially any technology or combination of technologies, allowing portfolio optimizations to recognize the best location, size and timing for storage concurrently with considerations of existing technology profiles, and also in tandem with thermal retirement options. Additionally, storage options that were not part of a cluster study were considered unconstrained by transmission requirements, such that any amount could be placed anywhere on the system.

4. EE/DER/DSM

CRIFTC comments that the Company should accelerate grid-interactive demand-side resources.[171] This includes demand-response resources that interact with the grid, like buildings, appliances and equipment, and on-site distributed energy resources.[172] This would provide "demand flexibility by adjusting power consumption based on grid conditions, energy prices, and occupant preferences," and limit the need for overbuild of solar, wind, and storage resources.[173] PacifiCorp continues to rapidly accelerate the deployment of demand response resources and will proactively evaluate the cost-effectiveness of these program designs and potential opportunities for grid interactive equipment in the future.

CUB comments that PacifiCorp should do more to implement the 2021 Energy Affordability Act. Specifically, CUB recommends PacifiCorp should expand its strategies to reduce energy burdens beyond the Low-Income Discount program; analyze the additive benefits from low-income energy efficiency programs when determining the cost-effectiveness of programs; increase energy efficiency programs across PacifiCorp's service territory; and work

[171] CRIFTC Round 1 Comments, at 10-12.
[172] *Id.* at 10.
[173] *Id.* at 11.

with the ETO to expand programs to target low-income customers.[174] As a result, PacifiCorp should analyze how it can expand energy efficiency and demand response services.[175]

The Energy Advocates recommend PacifiCorp take additional actions and conduct additional analyses to better implement HB 3141, better explain the decrease in demand response options, and explore additional energy efficiency and demand response options.[176]

In reply, the Company notes that it is currently working with ETO on expansion of low to moderate income programs, specifically finding ways to incorporate local, state, and federal funds to deliver efficiency to these customers. Furthermore, ETO's latest budget action plan highlights additional expansion of activities targeted at low to moderate income customers as well as future acceleration of energy efficiency. the Company will continue to explore additional actions and options for demand response and energy efficiency resources to support both system needs and implementation of HB 3141. The decrease in demand response options in the 2023 IRP was due to significant overlap of demand responses resources being modeled in the 2021 IRP. In the 2021 IRP, the Company relied on two distinct sources for demand response resource characterization—the 2021 CPA and bids solicited through the 2021 demand response RFP. The demand response resources in each source, while perhaps different in delivery structure, often relied on the same end-uses for capacity. As such, the volume of demand response is overstated in the 2021 IRP. This is the primary reason for the decrease in demand response options. The Company would note that since significant expansion of demand response programs has occurred since the 2021 IRP and the Company will continue to develop and implement a robust portfolio of demand response resources going forward.

[174] CUB Round 1 Comments, at 10-11.
[175] *Id.* at 2.
[176] Energy Advocates Round 1 Comments, at 21-23.

Staff recommends PacifiCorp: (1) optimize energy efficiency in the CEP to inform how increased adoption could help meet HB 2021 requirements in a least cost manner, as well as update the Company's CEP annual acquisition targets in light of the updated analysis;[177] and (2) provide details about HVAC and hot water end use assumptions, and how PacifiCorp is considering the efficiency of electrifying loads in relation to capacity constraints and increased demand.[178]

To these points, the Company first notes that on average the model selected 91% of energy efficiency potential between 2023-2030, and there is limited remaining potential identified to meet system needs. The Company models energy efficiency consistent with the Oregon rules and processes, with energy efficiency potential characterized by ETO. The Company evaluates energy efficiency based on the values and conditions that are consistent with Oregon's avoided cost docket for energy efficiency, UM 1893. Energy efficiency selections optimized for CEP requirements currently do not have a mechanism for demonstrating cost-effectiveness beyond what is shown in the preferred portfolio. The Company's energy efficiency selections are based on measures or programs could be shown to be cost-effective consistent with ORS 757.054. The Company's current selections for energy efficiency represent the level of resource that would be considered or shown to be cost-effective under current rules and practices used in docket UM 1893.

Second, PacifiCorp models HVAC and hot water end-uses based on technology saturations were developed using the PacifiCorp residential survey data and CBECS 2019 data for each state, segment, and baseline non-electric space and water heating technology. The Company assumes a modest ramp of electrification over time for these end-uses. The

[177] Staff Round 1 Comments, at 59.
[178] *Id.* at 62.

electrification model relies on the same market profile assumptions that were used in the CPA (Market Size, Segments, Saturation and Usage) to develop a baseline forecast. Total unit counts were then developed for each technology using the baseline saturation of these non-electric technologies and market size in each segment. These unit counts were translated to the technical stock turnover using the lifetime of each baseline technology for existing construction and the customer growth assumptions used in the CPA for new construction opportunities. All electrification measures were modeled as being available at the time of equipment failure (a lost opportunity). The additional load of each electrification measure was characterized using our calibrated consumption data from the CPA. The Company generally assumes that efficient electrified equipment is installed as much of the external funding identified in the Inflation Reduction Act of 2022 for electrification is tailored to efficiency as well.

5. Commercially Available Technology

The Energy Advocates recommend two changes to the Company's strategy for HB 2021 compliance. First, PacifiCorp should provide more weight to more commercially available, clean resources, like offshore wind, advanced geothermal, and iron-air batteries.[179] Second, if these resources do not achieve the required emissions reductions for PacifiCorp (as opposed to relying on nuclear or non-emitting peaking resources), the Company should consider additional resources besides small-scale renewables.[180]

Staff recommends PacifiCorp, in the IRP Update, provide a general estimate of transmission upgrade costs for the 1 GW of offshore wind modeled in P10 (and should be similar to proxy resource costs for confidential pumped-hydro storage projects).[181] Staff also

[179] Energy Advocates Round 1 Comments, at 27-28.
[180] *Id.* at 28.
[181] Staff Round 1 Comments, at 51.

recommends PacifiCorp identify other near-term actions and regional investments that would need to occur for PacifiCorp to consider adding 500 to 1,000 MWs of Oregon offshore wind by 2035 (either through RFPs or bilateral contracts).[182]

The Company responds that commercially available alternatives to future technologies were substantially evaluated, including offshore wind, geothermal and iron-air batteries. As noted above, this evaluation also included alternative acquisition path analysis specific to nuclear and non-emitting peaking resources in variant cases P05 and p06. Offshore wind was specifically evaluated in case P10. SSRs, which are not cost-effective compared to other alternatives, were ultimately selected only to achieve compliance with Oregon SSR requirements. All resource options were "weighted" with best estimates as to the relative cost and performance characteristics. The Company notes that at this time, offshore wind is hampered by transmission requirements, and was not selected even though it was assumed that any portion of the transmission and related resources could be selected, rather than assuming PacifiCorp was responsible for the entire project. Iron-air batteries are hampered by the fact that storage of a 1-to-5 hours duration is of highest value to the system because the overwhelming majority of shortfalls occur with a limited duration. In the 2023 IRP and CEP, this makes the economics of multiple 4-hour batteries superior to longer-term battery storage under all but the most exceptional conditions.

Additionally, the Company's modeling included the transmission upgrade cost required to enable the 1,000 MW of offshore wind, and also includes the general cost estimate for offshore wind. In the preferred portfolio, approximately one-third of the potential transmission enabling offshore wind was selected, however the model did not select offshore wind as the most

[182] *Id.*

effective use of that transmission. In the P10 counterfactual case, 935 MW of selected on-shore renewables were converted to offshore wind to assess performance and the magnitude of the economic impact. Analysis suggests that given the transmission project required to enable offshore wind, there are more cost-effective uses for this transmission. Given the timing of resource selections in Oregon through 2035, the Company is very interested in evaluating real offshore wind projects as data related to these projects becomes available to the Company through appropriate channels.

6. Coal-Fueled Generation Units and Gas Conversions.

CUB comments that there are implications for decommissioning and cost allocation with the Company's conversion of coal units to natural gas.[183] Specifically, because of diverging depreciation schedules, load growth, and decommissioning expenses between various states and for different resources, Oregon's share of converted gas assets (and cost-responsibility) could be increased compared to initial share and cost-responsibility of previous coal assets.[184] CUB notes that IRPs may not be the best place to resolve these questions, but would like the Company to address these concerns, even if ultimate resolution occurs within MSP or Oregon rate cases.[185]

The Company agrees the IRPs may not be the best place to address resource allocations and recognizes MSP is the forum for these discussions and resolution. CUB's comment shares two concerns. The increase in Oregon megawatt share of converted gas assets is dependent on the methodology on how these resources are allocated to the states which would be expected to be based on creating an MSP proposal. The increase in cost responsibilities for converted gas assets can be mitigated by recognizing Oregon depreciation schedule is different than other states

[183] CUB Round 1 Comments, at 6-7.
[184] *Id.* at 6
[185] *Id.* at 7.

and Oregon retaining its share of the costs. Both of these concerns should be raised in the MSP process.

The Energy Advocates comment that PacifiCorp's conversion of certain coal units has not been demonstrated as a least-cost path for Oregon under HB 2021: "Indeed, PacifiCorp has presented no economic analysis to show why it is beneficial for Oregon ratepayers to invest in gas conversions when their ability to utilize these plants would be short-lived."[186]

The Company provided analysis on the Jim Bridger 3 and 4 gas conversion in the 2023 IRP which reported a system benefit and Oregon would receive their allocated portion of the system benefits. Jim Bridger 1 and 2 gas conversion was analyzed in the 2021 IRP which addressed costly emission control equipment that would be required if not converted to gas. The study also reported a system benefit that Oregon would share. Naughton 1 and 2 gas conversion was not considered until the 2023 IRP and provides system reliability benefits that would be lost when the units no longer operate as coal. HB 2021 is addressing emission targets and by including coal converting to gas would be considered prudent to include in Oregon mix of resources as these units would operate at a lower capacity factor but would be able to meet peak load requirements as well as providing system reliability benefits.

Sierra Club recommends that PacifiCorp use the base tier coal pricing from the Company's 2023 Jim Bridger Long-Term Fuel Supply Plan for the Jim Bridger plant, as well as reevaluate the economic retirement dates of Jim Bridger, Hunter, Huntington, and Wyodak given Sierra Club's other concerns with PacifiCorp's modeling (high transmission network upgrade costs, reliability adjustments, SCNR installation, inflated granularity adjustments, and low coal prices for Jim Bridger).[187] Relatedly, Sierra Club recommends PacifiCorp provide a complete

[186] Energy Advocates Round 1 Comments, at 20-21.
[187] Sierra Club Round 1 Comments, at 42-45.

assessment of the availability and cost of firm interstate pipeline capacity that would be necessary to supply the Company's planned coal-to-gas conversions, and this should be completed prior to the IRP Update.[188]

PacifiCorp believes the best place to reevaluate the coal economic retirement is part of the 2023 IRP Update filing scheduled for April 1, 2024. This provides an opportunity to refresh the key thermal assumptions with the current data for the evaluation. Sierra Club comment did not consider the coal retirement were determined endogenously in the PLEXOS model, a new feature for the 2023 IRP. The Jim Bridger coal prices in PLEXOS are cash costs and do not include already incurred fixed costs in prior years, which is a better method to evaluate retirement. Lastly, the Company is not able to disclose metrics pertaining to firm interstate pipeline capacity for planned conversions as stipulated within the confidentiality agreements between PacifiCorp and third-party entities.

Staff recommends that PacifiCorp explain: why coal-to-gas conversions became prominent in this plan, but not in the 2021 IRP; how PacifiCorp evaluated risk of regret for coal-to-gas conversions; how it accounted for HB 2021's GHG targets in the gas conversion planning decisions; and under what circumstances would the Company expect to expand or pull back from these plans, or extend the lives of converted gas units?[189] Staff also requests PacifiCorp describe: (1) when it expects reconsideration of selective non-catalytic reduction (SNCR) investments to be concluded (if uncertain, describe point in time when costs from SNCRs outweighs the benefits);[190] in PacifiCorp's IRP Update, include a variant portfolio that optimizes system resource buildout under conditions of continuing Utah coal market disruption and elevated gas

[188] *Id.* at 53-55.
[189] Staff Round 1 Comments, at 47.
[190] *Id.* at 48.

prices through 2030 (and discuss implications for future conversions);[191] in reply comments, discuss whether existing minimum take agreements are modeled for PacifiCorp's coal plants (if not, explain why not);[192]

In PacifiCorp's 2019 IRP, a new simple-cycle combustion turbine was selected. This resource would have made use of the existing Naughton interconnection, and land at the site, but would have used little of the existing infrastructure. In contrast, the coal-to-gas conversions in the 2021 IRP and 2023 IRP rely almost entirely on the existing plants, requiring only natural gas piping capped by nozzles or burners within the existing boiler. As a result, the existing steam turbine, power generation, and all other assorted equipment in the existing facility continues to be used. A large part of the gas conversion costs contemplated in the 2023 IRP are associated with natural gas pipeline transport, such that there would be little impact on depreciation and decommissioning, to address CUB's concern. The Ozone Transport Rule was new to the 2023 IRP and also a factor for coal to gas conversions as the rule impacted the operation of the coal units in Utah and Wyoming.

Several stakeholders have identified concerns about future technology. PacifiCorp has also identified concerns about new natural gas-fired technology, as it may be subject to additional regulatory restrictions over a long technical life. The coal-to-gas conversions contemplated in the 2023 IRP represent a moderate, intermediate term bridge that will allow time for future technologies to be available, reliable, and cost-effective. With regard to The Energy Advocate's comments that the benefits of these facilities will be limited to Oregon customers, none of the units contemplated for gas conversion are projected to operate past 2037, which is ahead of the 2040 requirement under HB 2021, and gas conversion is lower cost, particularly in

[191] *Id.* at 49.
[192] *Id.* at 49.

combination with the other non-emitting options that make up the preferred portfolio. PacifiCorp's CEP does contemplate Oregon using MSP negotiations to secure a smaller allocation of emitting resources, such as the gas converted units, so as to minimize costs of meeting the interim targets under HB 2021.

With regard to Sierra Club's comments about coal fuel costs for Jim Bridger, PacifiCorp would highlight that the fixed and variable cost structure assumed in the 2023 IRP reasonably captures the cost of continuing or ceasing coal-fired operation at Jim Bridger 3 and 4. While there are opportunities to optimize coal supply for particular circumstances, they are ill-suited for modeling in the wide-range of cases and conditions contemplated in the IRP, and provide limited incremental benefit. Generally speaking, a more optimized fuel supply for Jim Bridger would identify additional benefits from ongoing operations, i.e., it would not result in retirement and result in changes in the action plan window. Note that in light of the significant impact of the Ozone Transport Rule, for the 2023 IRP PacifiCorp did not model take-or-pay coal supply requirements for any of its coal units. PacifiCorp did incorporate significant fixed costs for coal supply to Jim Bridger units 3 & 4. Those costs cease when Jim Bridger units 3 & 4 stop using coal or retire and did not have any minimum volume requirement.

With regard to Staff's questions about the increased prominence of coal-to-gas conversions in the 2023 IRP, several factors were involved. First, the benefits of gas conversions in the 2021 IRP led to a broader review of those options in the 2023 IRP, for which PacifiCorp worked to identify additional opportunities for gas conversions at each of its plants and made those options available for endogenous selection within the PLEXOS model. Second, the Ozone Transport Rule increased the benefits from gas conversions, as combustion of natural gas produces lower nitrous oxide emissions (a precursor to ozone) than coal. Third, the tax credits under the IRA significantly reduce the costs of clean resources, including wind, solar, and storage that are prominent in the preferred portfolio. Gas-converted units are well suited to filling in the gaps in these clean resources, as battery storage can respond quickly to changes in variable resources, and gas-converted units only need to be called upon in limited circumstances. Finally, the conversion of Naughton units 1 and 2 is more valuable as a result of the delay in the expected online date for NatriumTM demonstration project relative to the 2021 IRP, which results in at least additional two years of benefits from the conversion, as well as by the assumed extension of the technical life of those units, from 2029 to 2036.

With regard to Staff's questions about the decision to install SNCR, PacifiCorp's 2023 IRP reflects the Ozone Transport Rule as originally proposed, which included emissions allowance requirements starting in 2023 and major emissions reductions by 2027. The final rule released shortly before the 2023 IRP was finalized has emissions allowance requirements starting in 2027, with major emissions reductions in 2030. As a result, a decision concerning installation of SNCR for Ozone Transport Rule compliance could be delayed by four years, and the resulting modifications to the plants could be similarly delayed. PacifiCorp would also note that the final rule has been stayed pending litigation, so additional modifications to this timeline are likely. To the extent that any SNCR modifications occur in 2030 or later, such changes would likely be rendered moot as Oregon customers will have ceased taking service from coal-fired facilities prior to that date consistent with HB 1547.

7. Small Scale Renewables

The Energy Advocates urge PacifiCorp to "take a more proactive and supportive position regarding small-scale renewable projects, especially in selected areas of distribution system congestion in concert with substation battery storage systems so as to capture the grid benefits while also improving reliability and resilience."[193] The Energy Advocates also note that the Company's Oregon-Allocated SSR analysis appears to ignore grid benefits (like decreased GHG emissions) that small-scales could provide, and PacifiCorp's sensitivity studies are based on incorrect proxy resource assumptions that are too expensive and do not include site-specific grid benefits.[194]

The Company responds that the benefits of emissions reduction are directly evaluated for every resource in every model run as a core feature of PLEXOS modeling, and particularly with regard to the MM price-policy expected case assumption. The CEP also conservatively assumes no incremental transmission costs for small-scale renewable in recognition of the potential local benefit of avoiding utility scale transmission which may disrupt local communities. While additional benefits may accrue to SSRs in future analysis, the company's first CEP gave considerable favor to SSRs in its modeling, which would otherwise be less attractive compared to the cost savings inherent in utility projects which benefit from economy-of-scale. PacifiCorp stands by its assessment of SSR costs and benefits, and at the same time is committed to continual improvement of its evaluations.

Staff recommends that PacifiCorp: (1) identify the system-wide NPVRR impacts of meeting the SSR requirement, and 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);[195] (2) re-optimize the Preferred Portfolio and the best performing Preferred Portfolio Variants in Table 9.12 of the IRP (including P04 and P17, at a minimum) to incorporate the SSR requirement,[196] account for costs and performances of SSRs in the IRP to

[193] Energy Advocates Round 1 Comments, at 24.
[194] *Id.* at 25.
[195] Staff Round 1 Comments, at 17.
[196] *Id.* at 34.

reflect opportunities to meet a portion of this requirement with energy from QFs,[197] and then report out the resulting annual portfolio additions, retirements, and conversions, annual costs, PVRR, risk adjusted PVRR, ENS, and cumulative GHG emissions, and then use these portfolios for additional CEP analysis;[198] (3) identify barriers that SSR's face in the RPS certification process that could be relieved through changes in statute, rules, or through minimal additional informational resources;[199] and (4) detail how PacifiCorp could improve PURPA processes to facilitate rapid acquisition of new SSRs, in addition to the proposed SSR RFP.[200]

PacifiCorp is concerned that the current SSR statutes, regulations, and processes could frustrate SSR procurement. Each of these issues could be resolved by statutory solutions as well, however PacifiCorp provides the following regulatory recommendations:

- *The Commission should consider solutions to allow all non-emitting resources to qualify as SSRs by amending or waiving OAR 860-091-0030(1).* ODOE regulations require entities to register with WREGIS prior to seeking RPS certification,[201] and OPUC regulations require resources to be RPS-certified.[202] While Oregon statutes only require the owner or operator of SSR facilities to register their facility with the Western Renewable Energy Generation Information System (WREGIS) if they want to generate renewable energy certificates,[203] ODOE adopted additional regulations that apply this requirement to all entities that "wish to demonstrate compliance . . . with the Oregon RPS."[204] After certifying with WREGIS, facilities must apply to ODOE for RPS-certification.[205] This requires an ODOE decision regarding whether the facility satisfies the RPS statutes and ODOE regulations, and relevant here, an "explanation of the relationship between the applicant and the WREGIS account holder."[206] If the facility does not satisfy the RPS requirements, then ODOE will deny the application.[207] Once approved by the ODOE, a facility's RPS-certification does not expire,[208]

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197 *Id.* at 35.
198 *Id.*
199 *Id.* at 46.
200 *Id.*
201 OAR 330-160-0020(1)–(3), and OAR 330-160-0035(2).
202 OAR 860-091-0030(1).
203 ORS 469A.029.
204 OAR 330-160-0020(2).
205 OAR 330-160-0035.
206 OAR 330-160-0035(2).
207 OAR 330-160-0035(3)(b).
208 OAR 330-160-0038.

however facilities have an obligation to provide the ODOE of notice of material changes to the facility.[209]

Taken together, this requires SSR facility owners to register their resources with WREGIS and apply to ODOE for RPS-certification, prior to the Company having the ability to report the resource to the OPUC as qualifying for the SSR mandate. These conditions precedent limit the resources that can qualify as SSR resources. For example, PacifiCorp has several QF PPAs that could qualify as SSR, but limited authority to require these QFs to become certified as RPS-eligible facilities. These regulations also create transaction risk and require additional developer sophistication, as PacifiCorp believes SSR facility owners will have limited ability to finance their projects when facilities could be denied certification by the ODOE. The Commission should consider allowing all non-emitting resources to qualify as SSRs to count toward the SSR mandate.

- *The Commission should consider creating appropriate incentives for SSR adoption.* Currently, PacifiCorp's non-renewable rate for standard QFs is higher than the renewable rate. This incentivizes small QFs to elect to receive the higher non-renewable rate and reduces the likelihood they will take steps to qualify as SSR-eligible resources; PacifiCorp has signed three PPAs with QFs who have elected this route in the past six months. The Commission should consider options that eliminate this price arbitrage, either by capping the non-renewable rate at the renewable rate or combining the two price streams. Given the Company's upcoming SSR RFP, the Commission could consider these solutions in the near term.

- *The Commission should establish a for-profit SSR cost cap.* The Company anticipates that SSR resources will be much more expensive than utility-scale resources, even when generously considering benefits that these resources provide to system reliability or resiliency. Given the Company's considerable SSR mandate, the Commission should consider establishing an SSR cost-cap for for-profit SSRs, for example, by capping the price paid for SSRs to for-profit entities at the Company's relevant avoided cost rate. This would ensure developers of QFs are not incentivized to develop SSRs that will be more expensive than assets that result from a competitive solicitation, while at the same time allowing governments or non-profit entities to develop projects that could be more expensive than similarly situated QFs.

- *The Commission should consider opportunities to streamline SSR permitting given FERC's jurisdiction over certain SSRs.* The FERC has not addressed its jurisdiction over community choice aggregators,[210] however based on existing net metering (NEM) authorities, the FERC would have jurisdiction over certain SSRs that resemble community choice aggregators.

  The FERC has jurisdiction over the "sale of electric energy to any person for resale."[211] For NEM purposes, the FERC has interpreted this language to conclude that it does not have

[209] OAR 330-160-0070.
[210] *See In re NERA Decl. Pet.,* 172 FERC ¶ 61,042 (2020) (declining to issue declaratory ruling that could have impacted community choice aggregators).
[211] 16 U.S.C. § 824(d).

jurisdiction where "an individual homeowner or farmer (or similar entity such as a business) installs generation and accounts for its dealings with the utility through the practice of netting [net billing]."[212] However the FERC has jurisdiction when "there is a net sale to a utility, and the individual's generation is not a QF."[213] In these circumstances the generator would be subject to the Federal Power Act. This aligns with the FERC's interpretation of similar PURPA authorities.[214] The FERC has continuously adhered to this conclusion of law since 2001 and re-affirmed this position in 2003[215] and 2009.[216]

As a result, the Company expects that any SSR that is not a QF or otherwise resembles an NEM, will be required to receive authority from FERC prior to coming online. This would include SSRs that resemble community choice aggregators. The Company believes this additional step with FERC will create additional hurdles for SSRs. The Commission should consider issuing guidance or a declaratory ruling that confirms that state jurisdictional resources do not need to receive market sales authority from FERC.

- *The Commission should establish the SSR as a one-time compliance obligation.* The SSR mandate applies to utilities "by the year 2030."[217] The Commission, over utility protest, interpreted this to require an ongoing obligation, not only for year 2030.[218] As a result, PacifiCorp's approximate 490 MW SSR mandate in 2030 almost doubles to 802 MWs by 2037.[219] The Company suggests the Commission reconsider this policy given the Company's expectation that SSRs will be much more expensive than utility-scale resources.

212 *In re MidAmerican Decl. Pet.,* 94 FERC ¶ 61,340, ¶ 62,263 (2001).
213 *Id.*
214 *Id.* ("When there is a net sale to a utility, and the individual's generation is a QF, that net sale must be at an avoided cost rate consistent with PURPA and our regulations implementing PURPA.").
215 *In re SGIA and SGIP Rulemaking,* 106 FERC ¶ 61,220 ("under most circumstances the Commission does not exert jurisdiction over a net energy metering arrangement when the owner of the generator receives a credit against its retail power purchases from the selling utility. Only if the Generating Facility produces more energy than it needs and makes a net sale of energy to a utility over the applicable billing period would the Commission assert jurisdiction.") (emphasis added); *Id.* fn. 173 ("if there is a net sale of energy to a utility, and the generator is not a QF, the generator's owner must comply with the requirements of the FPA.").
216 *In re Sun Edison Decl. Pet.,* 129 FERC ¶ 61,116, 61,621 (2009) ("if the entity is either not a QF or is a QF that is not exempted from section 205 of the FPA by section 292.601 of our regulations, a filing under the FPA is necessary to permit the sale.") (emphases added); *Id.* ("We agree that, where the net metering participant (i.e., the end-use customer that is the purchaser of the solar-generated electric energy from SunEdison) does not, in turn, make a net sale to a utility, the sale of electric energy by SunEdison to the end-use customer is not a sale for resale, and our jurisdiction under the FPA is not implicated. That is, under the holding of MidAmerican, where there is no net sale over the applicable billing period to the local load-serving utility, there is no sale; accordingly, where there is no net sale over the applicable billing period to the local load-serving utility by the end-use customer that is the purchaser of SunEdison's solar-generated electric energy, SunEdison is likewise not making a sale "at wholesale," i.e., a "sale for resale." In these circumstances, SunEdison's sales of electric energy to end-use customers are not subject to the Commission's jurisdiction under Part II of the FPA.").
217 ORS 469A.210(2)(a).
218 AR 622, at 14; OAR 860-091-0040(1).
219 CEP Table 12.

PacifiCorp's CEP analysis filed May 31, 2023 identifies the cost of SSR compliance compared to the system-wide preferred portfolio.[220] This cost differential is key to assessing the cost of compliance with Oregon mandates. Regarding the suggestion to analyze cases P04-Huntington RET28 (Early retirement of Huntington 1 in 2028) and P17-Col3-4 RET25 (Colstrip units 3 and 4 retire end of 2025) with the small-scale resource additions for the CEP, the analysis could not reasonably lead to an actionable portfolio. This is because Oregon will no longer participate in these resources, and to the extent that small-scale resources can replace some of the generation from these facilities, Oregon cannot take a share of this emitting generation – or, if Oregon did take a share, then the small-scale resources would be supplying less energy to Oregon customers and therefore the amount of SSR selected would need to be commensurately larger and more expensive. Thae decision to analyze P04 and P17 as presented takes into account these considerations.

The Company looks forward to working with stakeholders and the Commission on how best to implement the SSR mandate.

8. CBRE Concerns

Overall, the Energy Advocates comment that PacifiCorp adopt more robust CBRE actions. These include: more details and a sense of urgency to the CBRE Project Pilot;[221] identify communities with current resiliency needs to prioritize the CBRE Project Pilot;[222] look beyond PacifiCorp's existing programs for CBRE inventories and analyses (including net-metering systems and a residential battery storage program);[223] broaden its analyses of CBREs beyond a

[220] CEP, Table 13 – System-wide PVRR(d) of 2023 IRP Relative to Small-Scale Renewables Portfolio
[221] Energy Advocates Round 1 Comments, at 8.
[222] *Id.* at 9.
[223] *Id.* at 15.

levelized electricity cost comparison;[224] adopt a ten percent adder for CBRE projects to appropriately reflect the full benefits of CBREs;[225] the CBRE sensitivity does not account for various CBRE benefits and likely inflates costs by not accounting for Infrastructure Investment and Jobs Act (IIJA) and IRA incentives;[226] and PacifiCorp's CEP would be stronger if PacifiCorp took a leading role, rather than relying on existing programs at status-quo levels of funding.[227]

The Company shares a sense of urgency as it relates to its CBRE Pilot and is working to develop a set of criteria by which resilience metrics will be used as a tool for prioritization. It should be noted that the initial Potential Study, found within the section on Community-Based Renewable Energy in the Clean Energy Plan, was in fact not limited to existing programs, that the Company signaled in the filing that a broader scope would be taken in the subsequent Potential Study as a better understanding of the CBRE landscape was developed over time, and that a 10% adder was in fact used in the initial filing (See excerpts from OPUC Staff Data Requests below). And while IIJA and IRA incentives were not taken into account in the initial analysis, it is inaccurate to state that this "inflates costs". The Company continues to refine its CBRE Pilot, has shared progress in its thinking across its multiple stakeholder engagement channels, and will continue to do so leading up to the filing for approval of the Pilot.

Regarding CBRE modeling in the CEP, PacifiCorp provided further details about how CBRE resources were modeled in the IRP Planning environment including the inclusion of a 10% cost reduction for CBRE resources to approximate the 10% "benefit adder" as suggested by Energy Advocates.

[224] *Id.* at 16.
[225] *Id.* at 17.
[226] *Id.* at 18.
[227] *Id.* at 18-20.

As noted by OPUC Staff in their current comments:

> 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.
>
> [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.

OPUC Data Request 160 and PacifiCorp's response dated August 31, 2023 are included below for reference:

OPUC Data Request 160

CBRE - PacifiCorp references an assumed price of $97/MWh for CBRE energy output. How is that value used in the modeling? Is the model required to purchase each MWh of CBRE energy output at that price?

Response to OPUC Data Request 160

As explained in the Company's response to OPUC Data Request 159, the community based renewable energy (CBRE) resources were forced on in the CBRE sensitivity portfolio, because it was not being selected as part of the least-cost least-risk solution. By "forcing on" the resources, it means they are included in the capacity expansion decision – the resources must be built (determined in the PLEXOS long-term (LT) model). The energy output of all resources, including the CBRE resources, are then determined in the short-term (ST) model where hourly load is met with least-cost dispatch given operational parameters and constraints. The model is not required to use available energy from the CBRE resources but given that there are no transmission constraints limiting production from small-scale renewable (SSR) resources, it is unlikely that the model curtails any energy from the CBRE resource. Generally, the CBRE resources will produce energy as determined by the shape of the resource and incur some cost per unit of energy.

The composite CBRE resource representing 80 megawatts (MW) capacity of solar, and solar with storage, was modeled with a variable price of $87.3 per megawatt-hour ($/MWh). Since compensation of $97/MWh under the Oregon Community Solar Program (CSP) has enabled some development of this type of resource, that value was used as the assumed costs for PacifiCorp's 2023 Integrated Resource Plan (IRP). The modeled value reflects a 10 percent credit to account for additional system benefits that resources at this scale might provide, consistent with the 10 percent credit applied to energy efficiency (EE) in Oregon based on the Northwest Power Act. The CBRE resource representing 20 MW capacity of a hydro unit was modeled with a variable price of $76.5/MWh, and also reflects the 10 percent credit.

Staff recommends that PacifiCorp consider whether additional CBRE capacity is advised, given observed demand for resiliency and growth of distribution-sited resources, and recommends PacifiCorp "study whether a CBRE program could leverage the existing demand and access new markets and opportunities with modest co-funding, such as the Inflation Reduction Act and Portland Clean Energy Fund."[228] Staff also recommends PacifiCorp describe the estimated cost and growth of planned local transmission and distribution system upgrades to accommodate load growth in Oregon load pockets, and address how these investments could be

[228] Staff Round 1 Comments, at 22-23.

a foundation to stack CBRE projects for only the marginal cost, rather than the entire cost of a new substation and/or feeder.[229]

The CBRE landscape in Oregon is very dynamic and full of both opportunity and varied expectations at this time. As such, PacifiCorp expects to learn a great deal from the continued focus on CBRE opportunities, especially the opportunities outlined in "Group B" of the potential study with a focus on an expanded CBRE Pilot. Since filing the CEP in May 2023, PacifiCorp has witnessed significant new activity advancing CBRE Projects. Examples include funding from ODOE C-REP grants, new legislation directing counties to develop resilience plans and significant external funding available to CBRE Projects. Of note, the second round of C-REP grants announced in August included approximately 20 new projects within PacifiCorp's Oregon service area. In response to this increased activity and funding, PacifiCorp has already shifted its focus for the proposed CBRE Pilot to leverage the demand resulting from C-REP, IRA, Portland Clean Energy Fund and other sources and focus its limited Pilot resources to support "in-flight projects", helping communities with technical assessments of CBRE opportunities and providing modest levels of grant matching funding. This refined approach recognizes the substantial shift in the environment around CBRE opportunities since the time of filing and will likely provide much greater CBRE potential than the 3.5 MW of Group B potential outlined in the Inaugural CEP. The Company has shared its revised approach to the CBRE Pilot with Stakeholders across its three Engagement Channels during September and October of this year, as well as in additional meetings with stakeholders and partners, and expects to have the CBRE Pilot proposal ready for external input in Q1 of 2024.

[229] *Id.* at 25.

9. Non-Emitting Peaking and Nuclear Resources

The Energy Advocates request a more comprehensive discussion of non-emitting peaking resources, and how PacifiCorp plans to incentivize development of this technology.[230] Staff recommends PacifiCorp discuss how it can identify key events and milestones around the costs and availability of non-emitting peakers to better understand the next IRP's preferred portfolio resource mix and associated Action Plan.[231]

In response, the Company staged the non-emitting peakers to be available in the PLEXOS model starting in 2030, outside of the action plan window and the current CEP compliance window, understanding there are technology and fueling risks.While there is uncertainty in the cost of non-emitting generating capacity and non-emitting fuels, examples of both exist today. The Company anticipates that these types of resources will improve in performance and cost-effectiveness. As discussed in the 2023 IRP, advancement of non-emitting technologies will be critical to the planned transition of our coal resources in a way that will minimize impacts to our employees and our communities. In the 2023 IRP preferred portfolio, non-emitting peakers are forecast to reach an installed nameplate capacity of 1,240 MW by 2036, with no currently foreseen additions through the remaining 20-year planning horizon. This is less than 4 percent of all identified preferred portfolio additions (including DSM selections and storage capacity) by the end of the planning period. This limited presence, combined with the present-day existence of example resources, supports the Company's position that the risks are reasonable, and the long-term plan is appropriately forward-looking.

[230] Energy Advocates Round 1 Comments, at 21.
[231] Staff Round 1 Comments, at 44.

Next, NewSun comments that PacifiCorp should remove nuclear resources from the model and allow existing capacity to serve Oregon's capacity needs in the near term.[232] This is because nuclear resources are "new and unproven," and unless PacifiCorp proves the economic and technical feasibility of these resources, PacifiCorp should be required to remove these resources from its portfolio, and instead select resources that are more commercially feasible.[233] Similarly, Sierra Club "urges PacifiCorp to evaluate future resource mixes that rely on proven and clean technologies," and not rely on nuclear resources for PacifiCorp's decarbonization strategies.[234] Similarly, Staff recommends PacifiCorp 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 the Natrium commercial online date (COD) as appropriate."[235]

In response, Oregon IRP Guideline 1(a) appears to support PacifiCorp considering NatriumTM demonstration project and other emerging clean energy technologies because the Commission indicated that utility consideration of resources should specifically "not be limited to those commercially viable or nearly commercially viable resources." IRP Guideline 1(b) also states that "risk and uncertainty must be considered" in developing an IRP and "utilities should identify in their plans any additional sources of risk and uncertainty." Similarly, IRP Guideline 1(c) provides in part that "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 utilities and its customers."[236] Consistent with this guidance, nuclear resources considered in the 2023 IRP

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232 NewSun Round 1 Comments, at 5-6.
233 *Id.* at 5-6.
234 Sierra Club Round 1 Comments, at 58-59.
235 Staff Round 1 Comments, at 44.
236 Order No. 07-002, Appendix A; Errata Order No. 07-047, Appendix A.

and CEP have been intentionally limited to years outside of the action plan and CEP planning windows with the understanding that while nuclear is an existing fuel technology and exciting resource, the NatriumTM demonstration project has a long lead time that requires continued evaluation of its potential (through, for example, nuclear variant studies and acquisition path analyses).

While PacifiCorp and TerraPower continue to work together to progress the Natrium facility toward commercial operations by the end of 2030, no commercial agreement has yet been reached. As a result, PacifiCorp cannot provide meaningful tracking and reporting on TerraPower's NRC Construction Permit Application. PacifiCorp remains open to providing annual updates once a commercial agreement has been executed and PacifiCorp begins seeking regulatory approvals relating to the Natrium facility.

E. The Company's procurement strategies are sound.

NewSun comments that PacifiCorp's obligation to comply with HB 2021's emissions reductions, and to make continual progress towards those targets, should not be excused by the suspension of the 2022 AS RFP.[237] As a result, NewSun requests the Commission require PacifiCorp to outline its path to compliance and how it plans to make continual progress to reduce emissions.[238]

Staff recommends PacifiCorp: (1) provide an update on the 2022 AS RFP suspension and current resource acquisition plans; (2) discuss impact of pausing the RFP on PacifiCorp's near-term resource targets (and also update Table 9.31 to reflect this shift in resources by type and year); (3) submit a revised Action Plan under Category No. 2 that reflects the 2022 AS RFP

[237] NewSun Round 1 Comments, at 4-5.
[238] *Id.* at 5.

suspension; (4) discuss the impacts and anticipated delay to other RFPs on market purchases, and executing upgrades and/or contracts from cluster study requests (and update load resource balance tables 6.11 and 6.12 along with Figure 6.4 through 6.7, and Figure 9.60); (5) discuss near term actions to issue the SSR RFP by QF 2023 (or RFI if helpful); and (6) discuss impact on annual system emissions (and provide updated Figure 1.12 that details PacifiCorp's CO2E emissions reduction trajectory.[239]

RNW comments that PacifiCorp's suspension of the 2022AS RFP "raises serious questions about the validity of the company's 2023 IRP and CEP," and recommends the Company either resume the RFP as soon as possible, or for the Commission to direct PacifiCorp to do so.[240]

In reply, the Company anticipates no delay in the process and issuance of the SSR RFP. Also, the 2023 IRP Update will address the RFP status change in its analysis with regard to potential impacts on the preferred portfolio. This will include an updated assessment of the 2023 IRP action plan, avoiding the duplicative nature of reworking the filed IRP at the same time.

Pertaining to the 2022 AS RFP, PacifiCorp has no revised plan or substantive updates available at this time and is actively working to incorporate a number of updated assumptions as part of portfolio development for its 2023 IRP Update, anticipated to be filed April 1, 2024. The result will be comprehensive changes to the portfolio, and not just specific line items that could be modified in a few figures in the filed 2023 IRP. In parallel with the modeling updates, the Company has engaged in a bilateral effort to procure commercially viable battery technology by June 1, 2026 to ensure that such near-term opportunities remain available. The completion of the

[239] Staff Round 1 Comments, at 64.
[240] RNW Round 1 Comments, at 5-6.

2023 IRP Update should provide clearer direction on any resource needs spanning the timeframe of the 2022AS RFP and indicate the appropriate next steps.

III. CONCLUSION

PacifiCorp appreciates the opportunity to respond to stakeholder comments and looks forward to continuing the discussion on these important issues.

Respectfully submitted this 1st day of December, 2023.

Matthew McVee
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PacifiCorp