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July 31, 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 Reply Comments

PacifiCorp d/b/a Pacific Power submits to the Public Utility Commission of Oregon for filing its Reply 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'S REPLY 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 written comments on the 2023 IRP and 2023 CEP from Commission Staff (Staff), Renewable Northwest (RNW), the Cascade Policy Institute (CPI), the Citizens' Utility Board of Oregon (CUB), Sierra Club (SC), the Oregon Solar + Storage Industry Association (OSSIA), and Swan Lake North Hydro, LLC (Swan Lake).

PacifiCorp looks forward to continuing to work with stakeholders in their review of the 2023 IRP and CEP. The Company also appreciates the feedback received through the IRP and CEP development process, and Round 0 stakeholder comments regarding the Company's current modeling methods that incorporates sophisticated capabilities and updates the approach to flexibility and reliability.[1] In response to Staff and Stakeholder Round 0 Comments, the Company reply comments:

- Summarizes the Commission's standards for acknowledgment of the IRP and CEP, and explains how the 2023 IRP and CEP, and their associated action plans, satisfies these standards;
- Clarifies the relationship between the IRP and CEP;
- Confirms that the CEP portfolio is the optimal portfolio for Oregon;
- Supports the ongoing evaluation of the Natrium demonstration project, and addresses risk mitigations present in the 2023 IRP and CEP portfolios;
- Confirms that the 2023 IRP contains all cost-effective demand-side management (DSM) resources; and
- Responds to questions regarding transmission action items identified in the 2023 IRP and how these transmission action items facilitate the interconnection of new renewable resources to PacifiCorp's system.

[1] Pursuant to the procedural schedule in this proceeding, comments due on June 30, 2023 were "Round 0 comments."

II. OVERVIEW OF THE 2023 IRP AND CEP

A. The 2023 IRP and CEP Satisfy the Commission's Standards for Acknowledgement.

The Commission will acknowledge a utility's IRP if the plan meets the substantive and procedural requirements for least-cost planning and is "reasonable at the time that acknowledgement is given."[2] In an IRP, the Commission "looks at the reasonableness of individual actions in the context of the entire plan,"[3] and "generally does not address the need for specific resources, but rather determines whether the utility has proposed a portfolio of resources to meet its energy demand that presents the best combination of cost and risk."[4]

The Commission's IRP guidelines require that the IRP: Evaluate all resources on a consistent and comparable basis; Consider risk and uncertainty; Select a portfolio of resources with the best combination of expected costs and associated risks and uncertainty for the utility and its customers; and be consistent with the long-run public interest as expressed in Oregon and federal energy policies.[5]

PacifiCorp's 2023 IRP and action plan complies with the Commission's requirements for resource planning and ensures that PacifiCorp will provide adequate and reliable electricity supply at a reasonable cost "consistent with the long-run public interest."[6] The 2023 IRP preferred portfolio includes accelerated coal retirements, coal-to-gas fueling conversions, and investment in transmission infrastructure that will facilitate the addition of over 6,000 megawatts (MWs) of new renewable resources and 3,900 MWs of battery storage capacity by the end of

[2] *In the Matter of Public Utility Commission of Oregon Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at 2 (Jan. 8, 2007) (corrected by Order No. 07-047).
[3] *Id.* at 25.
[4] *In the Matter of Idaho Power Company 2009 Integrated Resource Plan*, Docket No. LC 50, Order No. 10-392 at 2 (Oct. 11, 2010).
[5] Order No. 07-002 Appendix A at 1-2 (corrected by Order No. 07-047).
[6] *Id.* at 7.

2025, with nearly 17,000 MWs of new renewable resources over the 20-year planning period through 2042.[7]

To facilitate the delivery of new renewable resources, the preferred portfolio also includes a 416-mile transmission line known as Energy Gateway South that will connect southeastern Wyoming and northern Utah; a 200-mile transmission line known as Energy Gateway West Segment D3 that will connect substations in Wyoming to Idaho; a 150-mile transmission line known as Energy Gateway West Sub-Segment D2.2 that will connect a substation in Wyoming to Southeastern Wyoming; a 59-mile transmission line known as Energy Gateway West Subsegment D.1 that will connect substations in Wyoming; a 290-mile transmission line known as Boardman-to-Hemingway that will connect substations in Oregon and Utah; and additional local transmission upgrades to enable renewable resource requests to connect to transmission in southeast Idaho, central Utah, central Oregon, the Willamette Valley in Oregon, and in Yakima and Walla Walla, Washington.[8] These renewable resources will expand and further diversify the Company's portfolio while also meeting changing customer needs, including significant projected load growth.

The economic drivers behind this plan lead to a portfolio that is consistent with Oregon law establishing renewable energy targets and elimination of coal-fueled resources from electricity rates; PacifiCorp's preferred portfolio sets a course to meet the laws' requirements while ensuring that customers are served reliably and at least cost.

PacifiCorp's selection of the 2023 IRP preferred portfolio is supported by detailed data analysis using five fundamental steps: (1) developing key inputs and assumptions to inform the modeling and portfolio-development process; (2) developing a wide-range of resource portfolios;

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[7] 2023 IRP Volume I at 2.
[8] *Id.* at 9.

(3) targeted reliability analysis of the portfolios to ensure sufficient flexible capacity resources to meet reliability requirements; (4) analysis of the resource portfolios to measure comparative costs, risks, reliability and emission levels that inform selection of a preferred portfolio; and (5) development of the near-term resource action plan required to deliver resources in the preferred portfolio.[9] Each of these steps in the 2023 IRP development process are presented in greater detail in the Company's filing, including the supporting work papers that present the underlying data for each of the portfolios that PacifiCorp analyzed.

These IRP-specific guidelines generally complement the Commission's recent CEP guidelines, which require that the CEP: Reduce greenhouse gas emissions associated with electricity sold to Oregon consumers by 100 percent by 2040, with interim emissions reduction milestones of 90 percent by 2035 and 80 percent by 2030;[10] Increase Oregon's small-scale renewables capacity to at least 10 percent of its resource portfolio by 2030;[11] and Address equity in planning and program implementation.

The 2023 IRP and 2023 CEP feature expanded reporting, including the highly confidential category to the existing public and confidential data disks. This additional category provides increased transparency and visibility to stakeholders,[12] and results in more than a three-fold increase in the number of public data disk files provided.

Although the 2023 IRP uses a 20-year planning horizon, the Commission has historically focused on the action plan, which identifies the specific resource actions PacifiCorp intends to

[9] *Id.* at 11.
[10] ORS § 469A.410.
[11] ORS § 469A.210(2).
[12] The previous 2021 IRP public data disk featured approximately 75 files including initial and updated filings. The 2023 IRP includes nearly 270 public files.

undertake in the next two to four years.[13] The key resource actions in the 2023 IRP action plan include, but are not limited to, the following items:

- **Action Items 1a, 1b, 1c, and 1d**: PacifiCorp is pursuing a beneficial change in ownership agreements that will enable the Company to exit the Colstrip Generating Facility in Montana by 2030. PacifiCorp will continue to work closely with co-owners of Craig Unit 1 to seek the most cost-effective path forward toward the 2023 IRP preferred portfolio target exit date of December 31, 2025. PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, with natural gas operations anticipated to commence spring of 2026. PacifiCorp has initiated the process of ending coal-fueled operations at Jim Bridger Units 1 and 2 by the end of 2023, with natural gas operations anticipated to commence spring of 2024.[14]
- **Actions Item 2a, 2b, 2c, and 2d**: PacifiCorp is currently evaluating proposals in its 2022 All-Source (AS) Request for Proposal (RFP) and expects to conduct an RFP for additional resources in 2024. Resource options will be evaluated with respect to both system needs, state compliance requirements, and voluntary customer programs.[15]
- **Action Items 3a, 3b and 3c**: PacifiCorp will continue to develop new transmission capacity through the Energy Gateway South, Energy Gateway West, and Boardman to Hemingway projects. These projects will allow the Company to facilitate the interconnection of new resources.
- **Action Item 4a:** PacifiCorp will acquire cost-effective energy efficiency resources with state specific targets. Acquiring additional energy efficiency throughout the Company's service territory will provide benefits to all customers.

Key actions in the 2023 CEP action plan include, but are not limited to, the following:

- Community Engagement. Monitor and evaluate the Company's six interim CBIs and 14 metrics, while continuing to refine CBIs and seek additional stakeholder engagement and input.
- Capacity Additions. Conclude the 2022 AS RFP; issue a new 2023-2024 AS RFP for resources to come on-line through the end of 2028; evaluate and issue a small-scale renewables RFP; and continue investigating feasible community-based renewable energy projects.

The combination of the 2023 IRP and CEP action plan items will allow the Company to move into the future with a reliable and diverse portfolio that minimizes risk and costs to

[13] *Id.* at 8, 22.
[14] *Id.* at 27.
[15] Id. at 24. See also, In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of 2022 All Source Request for Proposals, Docket No. UM 2193.

PacifiCorp's retail customers and meets the letter and spirit of HB 2021 and principled resource planning. PacifiCorp is committed to obtaining the best outcomes for all of its customers under these obligations, while at the same time pursuing broader system decarbonization based on least-cost least-risk principles.

As discussed in the IRP Public Input Meeting Series,[16] CEP Engagement Series,[17] and Community Benefits and Impacts Advisory Group meeting series,[18] PacifiCorp's CEP modeling strategy assumes the 2023 IRP preferred portfolio as its starting point. This approach establishes a consistent baseline preferred portfolio, and a filing cadence, that allows the Company to reasonably incorporate new and sometimes competing legislative and regulatory requirements from the six states that it serves, while still allowing all committed and acquired resources to be reflected in future IRP and CEP portfolio optimizations—while also allowing Oregon customers to continue to benefit from this systemwide multistate planning process. This approach most accurately incorporates the necessarily cyclical nature of multiple state and federal directives that influence the Company's procurement strategies.

Taken together, the Company believes that its IRP and CEP exceed the Commission's respective guidelines for acknowledgment.

B. 2023 IRP and CEP Filing and Stakeholder Process.

Stakeholders have been involved in the development of the 2023 IRP and CEP from the beginning and informed the Company's interim customer benefit indicators for this initial CEP.

The 2023 IRP public-input meetings were initiated in January 2022, and have been the cornerstone of the Company's public-input process for the IRP, and also included CEP

[16] IRP Public Input Meeting Series, September 1-2, 2022; October 13, 2022; December 1, 2022. Exploration of the modeling plan continued in CEP Engagement Series and the CBIAG Advisory Group meetings, see below.
[17] CEP Engagement Series, February 24, 2023; April 28, 2023; June 23, 2023.
[18] CBIAG Advisory Group, March 16, 2023.

considerations. There have been 11 public-input meetings held as part of the 2023 IRP development cycle, 10 prior to the May 31 Addendum filing and one post-filing. All meetings have been held via phone conference, with no in-person participation, to allow for greater participation. In addition to these six-state public meetings, the IRP public-input process also included state-specific stakeholder sessions in the summer of 2022, with the goal of capturing key areas of concern to each state (including the CEP for Oregon) and discuss how to tackle these issues from a system planning perspective.

In addition to the IRP public input meetings, PacifiCorp continues to hold other engagement meetings that cover multiple topics, several focused on its CEP. This suite of engagement meetings and forums include the Community Benefits and Impacts Advisory Group (CBIAG), Clean Energy Series for Tribal Nations, and the Clean Energy Plan Engagement Series meetings. These more focused meetings attempt to, among other things, increase understanding of IRP planning principles, improve interaction and collaboration with stakeholders in the planning cycle, and provide a forum to directly address stakeholder concerns regarding equitable representation of state interests during public-input meetings.

For example, consistent with the Company's CEP Engagement Strategy filed with the Commission on August 4, 2022, PacifiCorp formed its CBIAG, and has held monthly meetings that began in November of 2022. Prior to the filing the CEP, the Company was able to hold seven CBIAG meetings, and the Company continues to discuss CEP-related issues to refine and improve its plan and planning processes. The Company's CBIAG provides insights and understanding of their respective communities, and the Company will continue to explore and increase the exchange of information from the CBIAG, to the utility, and back to the CBIAG.

The Company continues to actively seek input from its engagement participants on how to distribute information and grow participation. The Company also is seeking to increase the number of CBIAG members and is identifying potential members through consultation with the CBIAG members and Regional Business Managers. PacifiCorp recognizes capacity challenges do exist for many participants therefor the Company offers participation on the Organization level as to allow flexibility by the members to include proxies, and/or mentees to participate. Finally, all presentation content and materials are posted publicly for distribution and access in English and Spanish on the PacifiCorp website.

PacifiCorp also launched a five-part Oregon Clean Energy Plan Engagement Series on February 24, 2023. The series aims to complement existing stakeholder engagement such as the CBIAG, Tribal Nations Engagement, Distribution System Planning, Integrated Resource Planning, Transportation Electric Planning, Community Based Renewable Energy, and more. The sessions highlight engagement and feedback processes. The series also strives to demystify the intersectionality of crucial planning and program processes and provides an excellent perspective into how the CEP fits into the IRP.

PacifiCorp also launched a Clean Energy Plan Tribal Nations Engagement series on March 24, 2023. This series mirrors the content and cadence of the Clean Energy Plan Engagement Series and includes accessibility considerations and adaptions in response to participation capacity challenges described by several Tribal leaders. The Tribal Nations series provides opportunities for consultation by participants on programs and planning, including but not limited to Clean Energy Plans and Transportation Electrification. The initial meetings have been focused on relationship building and determining best engagement design, including meeting frequency, modality, and format, through co-development between PacifiCorp and

Tribal Nations representatives. PacifiCorp understands that participants may not speak for all Tribes or represent the view of an entire Tribe. Accordingly, PacifiCorp also offers presentations to the state-level Economic Development and Community Cluster Group, which includes representation from the state's Nine Federally Recognized Tribes. The Company continues to support and grow its relationships between the Regional Business Managers and their Tribal liaison in the community and participates in a significant number of conferences and events held by Tribal Nations.

PacifiCorp also recognizes the value of creating additional engagement opportunities that focus specifically on the CEP, and to that end PacifiCorp scheduled a public engagement series. This Clean Energy Plan Engagement Series meets every other month. These meetings are recorded and posted to the Company's webpage. The Company held two of these meetings prior to filing the CEP and has planned five meetings in total for 2023. These meetings allow the utility and its customers to share information and explore options for future CEPs and CEP planning processes.

These information-sharing spaces inform the Company's approach to health, environmental, and community benefits, and related strategies to achieve each. For example, PacifiCorp discussed its community benefit indicators (CBI) creation process and the Interim CBIs and metrics with its CBIAG at its monthly meetings in November 2022, December 2022, January 2023, February 2023, and March 2023. Health and community well-being CBIs and related metrics were the focus of the February 2023 CBIAG meeting, while Interim CBI progress (including health and community well-being) were provided to stakeholders as part of the February and April 2023 CEP Engagement Series.

As a result of these meetings, and after additional internal subject matter expert considerations, PacifiCorp established the Interim CBI to Decrease the Number of Residential Disconnections to improve community health and well-being. PacifiCorp has not explicitly evaluated or associated health benefits for other CEP topic areas; however, there could be health benefits associated with many if not all of PacifiCorp's CBIs, as reduced carbon emissions generally improve health outcomes for our customers. This is why the Company's CBIs are tailored to emissions reduction strategies, although the Company is willing to consider additional CBIs that address environmental benefits beyond emissions reductions.

The Company's Interim CBIs drew extensively from our prior experiences in Washington with our 2021 Clean Energy Implementation Plan (CEIP). Washington similarly requires robust community engagement, establishing benefit indicators, and creating relevant metrics to track performance, and the Company's CEP CBIs relied heavily on these lessons learned. PacifiCorp believes this approach was reasonable, as it moves toward more consistent CBIs across the Company's service territories and allows for more data to inform future improvements where our Oregon and Washington stakeholders and communities share similar vulnerabilities. Yet it bears repeating that these CEP CBIs are interim indicators, and the Company continues to engage with and discuss how to tailor each CBI (or adopt or create new CBIs as necessary) to respond to our Oregon-specific needs.

III. REPLY TO PARTY OPENING COMMENTS

In reply to the Round 0 stakeholder comments, the Company responds that our IRPs and CEPs, either together or individually: expand and enhance the processes from the 2021 IRP; have reasonable supply and demand-side resource needs; include market assumptions that are consistent with long-term planning objectives; include reasonable procurement strategies, portfolio modeling strategies, and CBIs; clearly discusses the relationship between our transmission capabilities and resources enabled by expanded transmission; include Action Plans that provide appropriate planning and risk mitigation to address dependencies and barriers; reasonably modelled our thermal generation units; appropriately consider impacts from federal legislation; appropriately consider Natrium; and responds to several additional important issues.

A. The 2023 IRP Expands and Enhances 2021 IRP Processes.

PacifiCorp is committed to transparency and improving processes for developing both the IRP and CEP. In addition to expanded reporting and workpaper availability, the filed 2023 IRP and CEP documents contain a large volume of public information, and as discussed below, the outcomes for both compare favorably to the 2021 IRP, and the Company has greatly expanded its core modeling capabilities.

1. The Company's 2023 IRP and CEP Outcomes Compare Favorably to the 2021 IRP.

The 2021 IRP did not include analysis related to HB 2021 or any state-specific capacity or energy actions beyond demand-side management resource selections that are state-specific. However, the 2023 IRP shows that the Company continues on its path to decarbonize the systemwide portfolio, which benefits Oregon customers and the Company's ability to meet objectives as established under HB 2021.

For example, on a systemwide basis, PacifiCorp's 2023 IRP compares favorably to the 2021 IRP in terms of proposed energy and capacity actions. PacifiCorp's 2023 IRP includes over 5,000 MW more new wind resources, 2,000 MW more new solar resources, and almost 2,000 MW of more storage resources, including batteries co-located with solar, over the 20-year planning horizon as compared to the resources selected in the 2021 IRP, all of which contribute to the Company's projected decreases in system greenhouse gas emissions. The 2023 IRP preferred portfolio is projected to result in lower systemwide carbon dioxide equivalent emissions, relative to emissions projections in the 2021 IRP, for 2029 and onwards. Forecasted loads in the 2023 IRP are higher than loads in the 2021 IRP, and in some years, this results in higher projected annual carbon dioxide equivalent (CO_2e) emissions; however, further analysis for these years indicates that total emissions rates in the 2023 IRP are lower relative to the 2021 IRP.

The 2023 IRP also results in roughly 370 MW more of energy efficiency resources in Oregon from 2023 onwards, though there is about 165 MW less demand-response resource capacity selected in the same years, relative to the 2021 IRP. Demand response selections are lower relative to the 2021 IRP primarily because resources from the 2021 demand response RFP and conservation potential assessment (CPA) were modeled together in the 2021 IRP, assessing the upper limit for demand response opportunities. This is the result of evaluating varying program designs from the RFP and CPA, acknowledging that some overlap likely existed between programs, overstating the total resource volume. The 2021 IRP Update attempts to improve the accounting of demand response resources within the 2021 demand response RFP and the CPA. Additionally, the Company has procured and launched significant demand response resources in 2022 and 2023 with programs across all sectors, resulting in less incremental resources available for model selection as existing demand response resources have expanded within the model. Relative to the 2021 IRP update, the 2023 IRP selects 42 MW more of demand response in Oregon over the 2023-2042 planning horizon.

Since there was no analysis specific to HB 2021 in the prior IRP, and this is the Company's first CEP, assumptions related to the Company's multi-state interjurisdictional allocation methodology were not explicitly needed in the 2021 IRP regarding Oregon-allocated resources. As such, while a proposed future allocation methodology is under development, prior assumptions are not relevant as a comparison to the 2023 IRP or CEP. Assumptions made regarding future interjurisdictional allocations for the purpose of analysis in this CEP at this time represent the status quo (2020 Protocol) in lieu of any future allocation methodology.

2. The Company Greatly Expanded the Number of Alternative Portfolios that Were Considered.

CUB requested more information on whether PacifiCorp modeled alternatives that do not result in higher emissions, as opposed to the Company's recommended two paths for compliance.

These alternatives were comprehensively considered and are an inherent part of optimizing the Company's 2023 IRP Preferred Portfolio but were not considered when determining emissions compliance pathways. For example, the September 1-2, 2023, IRP Public Input Meeting discussed the sea-change in the extent of thermal unit options considered in its PLEXOS portfolio optimizations. In the 2019 IRP, 78 combinations of competitive coal retirement options were considered, the 2021 IRP considered more than 260 thousand combinations, and the 2023 IRP evaluated more than 5 trillion combinations using PLEXOS. These step changes are the result of expanding the types of coal options (including carbon capture usage and storage and gas conversions), the addition of gas unit retirement options, leveraging increasingly sophisticated modeling approaches at a technical level to maintain achievable technical performance and expanding our IRP experts to meet expanding regulatory requirements to benefit our customers. Yet it is important to note that this highlights only one area of portfolio optimization (thermal units specifically), and the Company has significantly expanded its modeling capabilities in other areas as well (battery and storage options, and transmission options modeling, to name a few).

Together, every portfolio that PLEXOS produces considers *every option it does not select* as a core function of the modeling tool. These improved performances and techniques allow PacifiCorp to absorb additional complexities in the IRP and CEP and perform more staff and stakeholder sensitivities.

It would be inconsistent with traditional least-cost least-risk planning to assume that reducing emissions takes priority and should supersede other typical IRP considerations. Rather the emissions levels achieved in the IRP (and associated CEP compliance pathways) are the optimal result in light of all modeled requirements, constraints and inputs. Subsequently, the compliance pathways are intended to present two, illustrative and non-mutually exclusive options under which PacifiCorp can comply with HB 2021, while leveraging the portfolio evaluation processes already incorporated in least-cost least-risk planning that resulted in the Preferred Portfolio.

In addition, Staff requested the Company update CEP table 16 to reflect the present value revenue requirement (PVRR) of each compliance pathway. Given the nature of each compliance pathway alternative, a forecasted PVRR would be highly speculative. PacifiCorp, however, is providing a supplemental workpaper, as described below in subpart E(4), but believes it will be of limited value given the ongoing nature of the discussions on a future allocation methodology. Similarly, Cascade challenges the cost premium of pathways 1 and 2 above HB 2021. PacifiCorp believes this is a misunderstanding. HB 2021's small-scale renewable capacity and emissions compliance requirements cannot be achieved without employing compliance strategies underpinning Pathway 1, Pathway 2, or an as-yet unidentified alternative or combination of strategies that are incremental to the compliance results of the Preferred Portfolio.

B. The 2023 IRP and CEP Resource Needs Are Reasonably Considered.

As discussed below, the Company's IRP and CEP: demonstrated resource needs that provide adequately specific targets for HB 2021 purposes, appropriately developed and modeled energy efficiency and demand response, included appropriately diverse and properly represented supply-side resource options, and private generation is appropriately implemented.

1. The Company's Demonstrated Resource Needs Provide Adequate Specific Targets.

CUB refers to HB 2021's requirement to include annual goals to meet targets. While stakeholders can generally infer targets and directionality from IRP and CEP planning outcomes (in either the documents themselves or in related workpapers), the Company wants to make clear that these planning outcomes represent proxy resources and strategies, and that they do not represent specific targets regarding the location, type, size, and costs of resources. Rather, specific resources are a result of downstream processes (particularly RFPs or other procurement efforts).

To highlight two examples, the role of the Company's IRP and CEP is to provide a signal to the market regarding the Company's supply-side need for small-scale renewables, while it is the market's role to respond and the Company's role to select the best available resources from actual offers based on this response. Similarly, with respect to energy efficiency and demand response, the CPA provides an overview of what resources were modeled and how they were characterized in the IRP and CEP. As with supply side resources, the acquisition of these resources is not limited to what the IRP and CEP targets, but rather a floor for the Company to achieve. If additional cost-effective and achievable resources are identified, they will be evaluated separately for procurement determinations.

Given these realities, the Company believes that the resource needs identified in the IRP and CEP adequately represent reasonably discrete annual goals to meet HB 2021's requirements.

2. The Company Appropriately Developed and Modeled Energy Efficiency and Demand Response.

Regarding energy efficiency and demand response, PacifiCorp provided the model with a robust set of prospective energy efficiency and demand response resources for selection as detailed in the Company's CPA. The identification of these resources as cost-effective in the model is based in part on emissions attributes associated with those resources. It is worth noting that the model selected quantities of energy efficiency and demand response that represent a relatively aggressive near-term acquisition of resources that may prove challenging to achieve. While the IRP and CEP outcomes inform targets that the Company seeks to procure, the Company will neither accept or reject actual resources or demand-side programs solely upon the basis of its inclusion in an IRP and CEP portfolio. The consideration of actual projects and programs, including opportunities, will generally require a fresh evaluation that, while originally signaled by the IRP and CEP, can vary substantially in terms of what is ultimately offered and obtained.

3. Supply-side Resources are Appropriately Diverse and Properly Represented.

Cascade notes that the Commission should endeavor to protect ratepayers by allowing PacifiCorp to do whatever is necessary to maintain reliability, even if certain HB 2021 standards are temporarily violated. PacifiCorp understands Cascade's concern, and notes that the Commission has the power to consider reliability exceptions to HB 2021 if the facts and circumstances are warranted.

Cascade also suggests that no amount of electricity should be forecasted from technologies that do not currently exist. The Company notes that while some technologies will benefit from expanded research and development, each of the resource options represented in the 2023 IRP supply side resource table can be commercialized, and any remaining uncertainty is centered primarily around cost and performance considerations (as opposed to theoretical or operational concerns). Moreover, the supply-side resource table is intended to represent not just a single generator design, but a proxy for other technologies that can provide comparable cost and performance. For example, in the case of non-emitting peaking resources, the Company included a proxy dispatchable resource with a relatively low fixed cost and a relatively high variable cost. There are many options for both generation and fuel that currently exist today that would satisfy these conditions, and these technology options are projected to expand in the future. It is not the Company's position that a specific technology will win out, but rather that given the current state of development of certain resources (in this case, peaking resources), it is reasonable to assume that these options exist and may continue to expand. Moreover, Commission guidance has been clear regarding the need to consider alternative technologies, and in part prompted the expanded discussion of alternative fuels at the June 9-10, 2022, IRP public input meeting.[19]

4. Private Generation is Appropriately Implemented.

The IRP and CEP modeled Private Generation in a manner consistent with how private generation resources are adopted in Oregon. The study was first completed for the IRP in July 2022, however, to ensure our modeling accounted for recent federal legislation, the study was

[19] *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").

updated in September 2022 to ensure the impact of updated tax credits from the Inflation Reduction Act (IRA) was incorporated into the forecast. The study developed a low, base, and high case of adoption for consideration. More information on the results and methodologies can be found in the Private Generation Report.[20]

C. The Market Assumptions are Consistent with Long-term Planning Objectives.

The Company's market assumptions reflect long-standing long-term planning obligations, specifically regarding long-term contracts, front office transactions and market risk, and participation in the California Independent System Operator's (CAISO) energy imbalance market (EIM) and extended day ahead market (EDAM).

1. Long-term Contracts, Front Office Transactions and Market Risk are Appropriately Considered.

Staff seeks clarification of the relationship between front office transactions and the consideration of long-term contracts and short-term market depth and asks if front office transactions include the potential for longer-term bilateral capacity contracts.

The Company's 2023 IRP and CEP modeling represent markets according to long-term planning objectives, and with the intent of mitigating market risk over time. This strategy reduces market reliance consistent with the availability of cost-effective resources, with the potential to reduce risk exposure while enhancing reliability.

For example, in the 2023 IRP and CEP modeling, front office transactions compete with all resource alternatives to provide capacity and energy. As a result, future resources, including long-term contracts, will reduce the need for resources to cover capacity and energy and can potentially reduce front office transactions. The 2023 IRP and CEP do not model specific market

[20] 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.

products or short-term supply options, which are pursued in venues that are distinct from the IRP. Cost-effective contracts are pursued as appropriate, and their contributions are included in the IRP and CEP as part of the process of gathering input assumptions prior to operating the PLEXOS optimization model. In this sense, front office transactions represent the Company's open position, and stand-in for activities which occur outside of the IRP and CEP. The Company evaluates longer-term bilateral capacity contracts when offers are available but does not have pricing and quantity information such that those opportunities can be represented in the IRP supply-side resource table. Pricing and quantity uncertainty is also an aspect of the front office transactions allowed in the IRP, and the Company would take advantage of longer-term contract opportunities instead of the typical short-term front office transactions if doing so was cost-effective.

Similarly, long-term contracts such as power purchase agreements are represented in the IRP and CEP by proxy resource selections. As the IRP and CEP precede and inform downstream RFP processes, no ownership structure is generally assumed. A proxy Oregon solar resource selected in the IRP, for example, may eventually manifest as a solar PPA bid, a self-built PacifiCorp project or a combination of projects, potentially of different technology types and at differing locations. As a long-term planning tool, the IRP and CEP focus on the role of signaling to the market the optimally determined needs of the system. PacifiCorp then leverages an RFP process to poll the market and then uses IRP modeling tools to select the best options from among actual projects. These actual projects are then represented by specific project characteristics such as technology, size, timing, location, performance, and price.

Similarly, the Company evaluates market risk. For example, the CEP included a sensitivity analysis that tested the resilience of the CEP portfolio from year 2040 onward if no market purchases are assumed. These analyses, among others, attempt to capture and quantify the operational and cost risks that could result from too much, or too little, reliance on market transactions to serve customer load.

2. EIM and EDAM Participation.

Staff also recommends the Company include additional information regarding the extent to which the EIM and EDAM reduce the amount of capacity available for short-term bi-lateral market transactions to support capacity needs through market purchases.

In actual operations PacifiCorp evaluates all available market and bilateral products and opportunities, including a range of durations and contract structures. The front office transaction concept in the IRP is a placeholder for that whole range of transactions. While front office transactions are described as "short-term," PacifiCorp also evaluates all longer-term opportunities that become available through its RFP process with bilateral discussions, and with auctions and other offerings conducted by other generation owners. Ultimately, all such transactions are backed by generation resources and EIM and EDAM will not directly impact the physical capability of the electric grid.

Taking that further, participation in EIM does not reduce the amount of capacity available for short-term bilateral market transactions. EIM allows for economic dispatch of resources with a very low hurdle rate, because it does not require incremental wheeling costs. This means the unsold capacity can create real-time benefits in EIM where in the past it would have remained unused. As a result, there is less need for sellers with excess generation to transact their resources and balance their open position ahead of time, resulting in fewer market transactions and reduced liquidity. Capacity that would otherwise be offered into EIM is still available for bilateral transactions, but higher prices may be necessary to incentivize sellers to forgo the expected benefits in EIM.

Because the EDAM is not yet operational, it is unclear how it will impact power markets. That said, PacifiCorp expects the WRAP will likely have larger implications, as WRAP requires capacity to be procured several months in advance of each summer and winter season, whereas today a portion of the procurement is done on a day-ahead basis. This will necessitate changes in capacity procurement, including both how and when capacity is transacted. However, given the ongoing and projected evolution of the western grid, PacifiCorp expects regional demand and physical generation supply to be the bigger factor in the available market opportunities, rather than evolving market structures.

D. The AS RFPs and Resource Acquisition Strategies are Necessary and Reasonable.

The Company's planned RFPs and resource acquisition strategies—including for the planned 2024 AS RFP, small-scale renewables RFP, and community based renewable energy (CBRE) investigation and pilots—are reasonable.

1. The Company's 2024 AS RFP and Small-scale RFPs are Necessary and Reasonable.

PacifiCorp's 2023 IRP Action Plan includes a 2024 AS RFP for resources online by the end of 2028. The draft RFP would be filed with the OPUC in Q3 2024. A small-scale RFP is also planned, with resources operational by 2028.

Regarding the 2024 AS RFP, Staff and Swan Lake request that the Company confirm whether long lead-time resources such as pumped hydro storage, with in-service dates after 2028, will be supported in the upcoming RFP. In the prior RFP, the Company allowed for two additional years beyond the proposed RFP deadline identified in the 2022 AS RFP. The 2021 IRP action plan asked for resources which could come online by the end of 2026, and PacifiCorp allowed for long-lead time resources which could come online by the end of 2028. In its upcoming RFP, the IRP has identified resource need by the end of 2028, and the Company will allow for long lead-time resources which can come online by the end of 2030.

Additionally, Staff requests the Company comment on the potential to extend the in-service date of the upcoming AS RFP from 2028 to 2029, to allow for increased efficiency of procurement and potentially reduce the number of RFPs needed to meet acquisition needs. PacifiCorp notes that it will propose the 2024 AS RFP allow for resources which can come online through 2028 consistent with the need identified in the 2023 IRP and the 2023 IRP Action Plan. However, extending the allowable development and construction timelines can result in immature developments and premature bids, and other additional risk to customers related to cost curve changes. If, for example, an immature development with a later COD is chosen, and the resource is ultimately unable to obtain required permits, customers will not benefit from that resource being chosen over a more developed, closer term resource with lower risk. These issues and similar uncertainties will need to be balanced in the upcoming 2024AS RFP proceeding.

2. The Company's Small-scale Renewable Strategy Considers Resource Competition and Anticipates Possible Procurement Challenges.

Staff requests more details regarding how the small-scale and AS RFPs will interact with each other, and with the IRP/CEP. For example: Are there any drawbacks or synergies to running two concurrent RFPs for differently sized resources?

The Company responds that it is considering ways to simplify the requirements and RFP process for small-scale resources, and opportunities to encourage more diverse bidders to meet its small-scale resource need. PacifiCorp is considering educational opportunities with local/state interests to assist in the development of small renewable generation projects, targeting municipalities and smaller local interested parties. Simultaneously, PacifiCorp will solicit small-scale renewables as part of the anticipated 2024 AS RFP in order to create awareness for the small-scale resource need with larger, more traditional developers who may have distributed generation groups. In as much as the two solicitations will require competing workstreams and resources, to completely fold the small-scale solicitation into the larger 2024AS RFP may confuse or discourage small-scale bids.

Staff also notes that PacifiCorp's CEP shows that the Company appreciates the urgency and difficulty of procuring enough small renewables in a limited time and at the best price possible. However, Staff requests more clarity on the additional steps the Company will take to procure these resources at a reasonable cost, including steps to increase the competitiveness of the small-scale renewables RFP and the availability of CBRE resources for procurement. The Company believes that a separate solicitation may generate more interest. This forum may provide bidders more comfort that they are not competing with utility scale generation assets, and improve the likelihood of success. If possible, the Company will also encourage developers to utilize and leverage other available resources such as state agencies (e.g., Energy Trust of Oregon) or larger, national developers who might partner with or assist local interests in such small-scale resource development. The Company will also participate in the development of small-scale reviewable generation resources to assure ample new generation resources are developed in the timeline prescribed by Oregon HB 2021. The Company might offer benchmarks to assure compliance if inadequate market participation does not occur on a timely manner through the processes discussed above.

Staff also requests discussion regarding the potential range of small-scale renewables that could be acquired by 2030, given various policy interpretations around the treatment of existing, non-RPS eligible renewables in Oregon. The Company understands the issue, and notes that other policy related dockets like UM 2273 are currently exploring Oregon's various clean energy and decarbonization policies and could provide an appropriate forum to investigate this issue.

3. The IRP includes detailed small-scale renewable assumptions.

Staff would like to see a supply side resource table that lists the cost assumptions small-scale renewables, and requests the Company provide this information either in an Addendum to the CEP or in workpapers provided in Docket No. LC 82. Similarly, CUB suggests a discussion of the IRP preferred portfolio in the CEP allowing for all stakeholders to have all of the information in one place.

As an initial matter, the Company notes that it has no relevant or recent market data specific to the cost of small-scale renewables (e.g., less than 20 MW) other than interest generated from Oregon's current Community Solar Program at pricing specified by tariff. PacifiCorp's two previous RFPs (2020 AS RFP and 2022 AS RFP) had no offers for small-scale renewable generation resources, and as a result has no cost information for these resources.

Because of the lack of actual resources, the Company determined that it needs to conduct a separate small-scale RFP as discussed above, and only included proxy cost information for small-scale resources in the 2023 IRP Supply-Side Resource Table (resources with a new capacity of 20 MW).[21] Additionally, while PacifiCorp can provide duplicative information separately in the 2023 CEP, the Company cautions against repeating information in both documents when it is acknowledged that the two are aligned and are best understood in relation to each other. As the IRP is where these inputs are developed, this seems the appropriate place to provide this and similar information. However, PacifiCorp supports expanding references in

[21] Refer to the 2023 IRP, Volume I, Chapter 7, Resource Options, Table 7.1.

future CEPs to point directly to information provided in the IRP document as an aid to stakeholders.

PacifiCorp also supports including a hyperlinked table of contents that allows the reader to click on an item and be taken to the appropriate page and continue to improve the readability and accessibility of its documents.

4. The small-scale renewable and CBRE strategies are coordinated.

Staff asked what actions the Company could take to identify key barriers to SSR and CBRE development (for example, interconnection and deliverability costs and timelines and the ability of community-driven projects to participate in competitive solicitations?), and to enable projects that drive community benefits and help control costs.

The Company responds that the small-scale renewable and CBRE provisions in HB 2021 are separate requirements and distinctly different workstreams: The small-scale renewable mandate is a capacity requirement akin to a portfolio standard, while the CBRE provisions suggest a community and customer engagement strategy that may—cost depending—result in unique resource opportunities and in a timeline outside of the small-scale renewable RFP.

Yet although these are different requirements, resources procured under either will be subject to the Company's interconnection processes which are largely a function of Federal Energy Regulatory Commission policy and oversight. While PacifiCorp can assist small developers and communities by identifying resources and partnerships that might facilitate a more robust response, it will require effort from parties to successfully interconnect with PacifiCorp. The Company anticipates that its small-scale renewable RFP can help mitigate some of these concerns (by allowing ample time and opportunity for interested parties to review the Company's Open Access Transmission Tariff, and subsequently request and receive interconnection study(ies) from PacifiCorp Transmission)).

5. The Company's CBRE evaluation is reasonable and progressing.

Staff asked how quickly does the Company anticipate the CBRE Action Plan result in procuring CBRE resources, and how will the Company engage communities and other partners to identify CBRE actions that drive community benefits in manner that also controls costs?

The Company responds that there is no CBRE procurement requirement, and the Company has not proposed one. Instead, the Company intends to continue to operate the programs and encourage participation of potential CBRE projects via the "Group 1" channels included in the CBRE Potential Study, namely the Oregon Community Solar Program and Blue Sky Renewable Programs, and existing channels for various QF resources. These "Group 1" programs and channels represented approximately 92 MW of the 95 MW of initial CBRE potential, and these programs have established mechanisms for evaluation and acceptance of resource costs.

PacifiCorp is also proceeding with its plans for community engagement followed by the development of a program to actively support the advancement of CBRE projects. With stakeholder and community feedback informing this programming, the Company will strive to strike a balance between the associated costs and benefits of specific CBRE projects. The Company expects the discussion of CBRE costs and benefits and socialization of potential excess costs to continue to be a topic of conversation as all parties gain a clearer sense of the implications for meeting the requirements of HB 2021. One the critical topics for discussion with Stakeholders will be how to address the higher cost of CBRE projects as compared to utility scale renewables. As outlined in the Oregon Department of Energy (ODOE) Study on Small-Scale and Community-Based Renewable Energy Projects, the study concluded that "policymakers will need to consider the difference between economic and other societal and local benefits versus utility system benefits" when evaluating the overall value of small-scale renewable and CBRE projects in meeting the goals of HB 2021.[22] It should be noted that one of the learning objectives from the Company's CBRE development work will be to provide technical and feasibility assessment to potential community resilience projects and better understand the potential costs and benefits of actual CBRE opportunities. PacifiCorp will endeavor to connect interested parties with third parties such as state agencies (e.g., Energy Trust of Oregon) or other independent renewable developers who might partner or otherwise assist local interests in their development goals.

E. The 2023 IRP and CEP Portfolio Modeling Strategies are Complementary.

The Company's IRP and CEP strategies complement each other. For example, using the 2023 IRP preferred portfolio as the basis for the CEP Portfolio is appropriate; the Company appropriately evaluated market sales consistent with Department of Environmental Quality (DEQ) guidance; energy efficiency and demand response are appropriately optimized on each portfolio; and the PVRRs are correctly calculated and represented in various portfolios.

1. It is necessary and appropriate to use the 2023 IRP Preferred Portfolio as the basis for the CEP Portfolio.

Staff specifically requests information regarding why the 2023 IRP preferred portfolio is used as the starting point for determining its small-scale renewable resources. CUB also questions the appropriateness of "layering" CEP compliance obligations upon the systemwide preferred portfolio.

The Company disagrees that using the 2023 IRP for the starting point for CEP portfolio development may not be least cost, least risk. The Company's stepwise approach, which establishes the systemwide portfolio as the floor for the CEP portfolio, optimizes not just final

[22] ODOE Study on Small-Scale and Community-Based Renewable Energy Projects (Sept. 2022) Page 43 (available https://www.oregon.gov/energy/Data-and-Reports/Documents/2022-Small-Scale-Community-Renewable-Projects-Study.pdf).

cost and portfolio risk, but also regulatory risk and the risk of under-acquiring renewable and non-emitting resources on behalf of Oregon customers. This approach recognizes that "least-cost, least-risk" remain bedrock objectives for IRPs/CEPs, and that PacifiCorp actions must adhere to all legal and practical requirements of each jurisdiction where it operates. PacifiCorp's methodology accomplishes these objectives for the benefit of all customers and does so without denying Oregon customers the benefits of systemwide planning.

In particular, it would create several complex and ultimately unnecessary challenges if the Company did not use the 2023 IRP as the base portfolio, and instead evaluated small-scale renewable compliance as a base IRP assumption. Namely:

- Without the 2023 IRP preferred portfolio as the starting point, there is no timely basis to determine the small-scale renewable need. A prior IRP or other portfolio could be used as a starting point, but for reasons to follow, the 2023 IRP preferred portfolio is the logical choice.
- Fewer renewable resources will be selected since, per core model functionality, small-scale renewables will displace utility-scale renewables if selected in the baseline systemwide optimal portfolio.
- The replaced utility-scale resources would have been allocated among all states, while small-scale resources are Oregon-allocated resources (assuming they were selected to meet a small-scale capacity requirement). This would result in an allocation imbalance in meeting all state's needs.
- The Oregon requirement will have explicitly reduced allocatable capacity for other states and will have explicitly changed the systemwide portfolio, which may conflict with PacifiCorp's obligations to serve the other states with whom Oregon shares resources.
- Assuming an initial small-scale requirement position, additional iteration of the model will be required to restore systemwide resource selection and to modify the amount of small-scale renewables on each pass.
- Concerns regarding overbuilding either utility-scale or small-scale renewables are unwarranted at this time given the projected increase in capacity throughout the 2023 IRP study horizon. Risk regarding timing, availability and interest in the market as experienced in the 2022 AS RFP indicate that the compliance risk of under-acquisition is currently much greater than the risk of over-acquisition, which given the cadence of future IRPs and CEPs is expected to be self-correcting within a reasonable timeframe. Cascade also calls out this risk in comments.
- The stacking of the 2023 IRP preferred portfolio and the indicated amount of small-scale renewables for compliance do not quite yield a portfolio that is compliant with HB 2021 emissions targets. As explained in the CEP, this means that additional

> renewables and allocation considerations are required. Given that all portfolio proxy additions in the 2023 IRP and CEP are non-emitting, PacifiCorp's approach has not overstated the amount of renewable resources in the final CEP portfolio.

Given PacifiCorp's current resource position and procurement trajectory, the risk of under-acquiring appears a far greater risk than the risk of over-acquiring resources. PacifiCorp's position is therefore that the approach as recommend in this CEP is currently superior to other alternatives. With these considerations, the Company remains open to conducting the requested sensitivity and reporting on outcomes.

2. Market Sales are appropriately evaluated consistent with DEQ guidance.

Staff inquired about treatment of wholesale sales in the CEP and how emissions from market sales are assumed to be allocated to Oregon in the CEP. To answer this question, it is worth revisiting DEQ's methodology for calculating Oregon's forecasted emissions in a given year. First, the preferred portfolio is developed, and each resource's generation is multiplied by an Oregon allocation factor consistent with its cost allocation, resulting in an Oregon-allocated generation megawatt-hour number for each resource. Second, those Oregon-allocated megawatt-hours for each resource are multiplied by DEQ-issued emissions factors for those resources, resulting in total Oregon-allocated emissions.[23] Third, total Oregon-allocated emissions are divided by the total Oregon-allocated generation, which results in a PacifiCorp Oregon emissions factor. Fourth, that Oregon emissions factor is multiplied by Oregon retail sales in a given year, to arrive at total Oregon emissions in a given year.[24]

When resources in the preferred portfolio are allocated to Oregon consistent with their cost allocation (the first step above), the Oregon-allocated generation may be higher than forecasted Oregon retail sales from the IRP's load forecast in a given year. To the extent the forecasted Oregon-allocated generation is greater than forecasted Oregon sales in a given year, that difference is treated as a "sale of the utility's overall resource mix," consistent with DEQ's guidance: "Non-retail sales of a utility's power without specification of any particular portion of the utility's portfolio are removed by proportionately subtracting it across the utility's overall resource mix for that year."[25] This "proportional subtracting" effect is achieved in the course of allocating PacifiCorp's total system generation resources to Oregon (resulting in an Oregon-allocated emissions factor); and the subsequent application of that emissions factor to Oregon forecasted retail sales.

3. Energy efficiency and demand response are appropriately modeled, optimized, and consistent with known strategies.

Energy efficiency and demand response resources were characterized in the Company's CPA in a manner that permits the model to compare demand side resources with supply-side resources on a least-cost and least risk basis. Energy efficiency resources were provided by Energy Trust of Oregon for inclusion in the model and consistent with the assumptions used in delivery of energy efficiency in Oregon and includes potential associated with low-income customers as a separate segment. The identification of demand response and energy efficiency resources as cost-effective in the model is based in part on emissions attributes associated with those resources, which is a key consideration for HB 2021 requirements and compliance. It's worth noting that the model selected quantities of energy efficiency and demand response that represent a relatively aggressive near-term acquisition of resources that will be challenging to achieve. As such, the Company welcomes additional discussion with stakeholders, staff, and the Energy Trust of Oregon to determine whether additional opportunities exist to support the acquisition and planning of energy efficiency and demand response resources.

4. The Company's present value revenue requirement (PVRR) is correctly calculated and represented in workpapers.

The PVRR is calculated and reported for all systemwide IRP portfolios in both the 2023 IRP document and supporting workpapers. For the purposes of the CEP, both systemwide PVRR and estimated Oregon-allocated PVRR values were reported. Given that the IRP is not a rate-making exercise and does not include all costs in customer rate base, PVRR is a present value estimate of costs to be incurred as a result of long-term resource planning decisions on a systemwide basis.

To calculate an estimate of Oregon customer share of systemwide PVRR, allocation assumptions were made. The base assumptions assumed that the current muti-state interjurisdictional cost allocation methodology, the 2020 Protocol, would continue in perpetuity. Resource-specific assumptions were made based on best available knowledge to determine resources that would be included in Oregon customers' portfolio, given requirements under HB 2021, specifics around voluntary and qualifying facilities, demand-side management resources and system-shared new proxy non-emitting resources. Annual resource-specific allocation factors were assigned to every resource and associated costs in the systemwide portfolio for Oregon customers. Additionally, annual system generation factors were applied to most systemwide cost outcomes included in the portfolio cost summary, like market purchases and sales and unserved energy costs. As described in PacifiCorp's CEP, under these base allocation assumptions and systemwide portfolio operations, Oregon-allocated emissions were estimated to be in excess of compliance targets. Under the base allocation assumptions (2020 Protocol), PacifiCorp's CEP portfolio results in an estimated PVRR of $11,810 in millions of dollars for Oregon customers, when no additional actions are taken to bring Oregon emissions into compliance.

Compliance pathways 1 and 2 described two potential pathways whereby the Company could reduce Oregon usage of thermal emitting resources, resulting in lower emissions. One pathway requires a shift in other non-emitting and storage resource capacity to Oregon customers to backfill the capacity no longer assumed to be served by gas-fueled resources, while the second manages emissions and provides a reliability backstop to ensure reliable service to customers. Compliance pathway 1 resulted in an estimated PVRR of $12,204 in millions of dollars and pathway 2 in an estimated PVRR of $12,340 in millions of dollars. The increase in PVRR for Oregon customers, under either path, is a result of removing Oregon customers from some amount of gas-fueled capacity and replacing it with some combination of new proxy non-emitting solar, solar plus storage, stand-alone battery, and non-emitting peaker technology. While lower allocations of gas-fueled resources also results in a reduction in fuel costs, the addition of greater proxy capital investments costs increases total allocated costs to Oregon customers. It is important to recognize that embedded costs, or sunk costs, of existing resources, like thermal units, are not included in the IRP. There are other additional costs in Oregon customer rate base that might be impacted by actions taken to comply with HB 2021 that are not reflected here.

Three sets of Oregon-allocated PVRR estimates are reported for each portfolio in the CEP in the publicly available workpapers in the data template provided to Staff.

F. PacifiCorp's Community Benefit Indicators are Incremental and Reasonable.

The Company represents that its CBIs and metrics represent an incremental and reasonable approach to the inaugural CEP.

1. The Company drew from its Washington CBIs experience to develop Oregon's Interim CBIs.

For its first CEP, PacifiCorp relied largely on its prior Washington experience in completing the 2021 CEIP. Given timeline considerations, and that the CBIs for the CEP must address resilience, health and community well-being, environmental impacts, energy equity and economic impacts, PacifiCorp prioritized those CBIs/metrics that demonstrated a relationship with these same topic areas within the Washington CEIP.

In some instances, not all of stakeholder's proposed CBIs/metrics were selected for inclusion within PacifiCorp's inaugural CEP. For example, many CBIs/metrics proposed by the Joint Advocates were affiliated with topics that require thoughtful discussion with broader group of stakeholders. These include Joint Advocate proposed CBIs/metrics associated with Tribal specific recommendations. PacifiCorp believes that CBIs/metrics specific to Tribes should be discussed with Tribal representatives prior to incorporation within the CEP. Additionally, several of the Joint Advocates proposed CBIs/metrics are associated with energy efficiency and bill assistance programs. In consideration of stakeholder time and competing meeting priorities, PacifiCorp was unable to review the topic of energy efficiency with the CBIAG prior to CEP filing.

Over the coming months, PacifiCorp will be undertaking a thoughtful approach to better consider, understand and socialize the Joint Advocate proposed CBIs and metrics.

2. The Role of CBIs will expand with downstream processes, and will evolve with subsequent IRPs, CEPs, and RFPs.

The role of CBIs will have implications not only on the IRP's planning process, but also downstream processes. For its inaugural CEP, PacifiCorp relied on the metrics for its portfolio CBI of Increasing Energy from Non-emitting Resources and Reducing carbon dioxide (CO2) Emissions to meet HB 2021 Targets to score IRP portfolios and sensitivities within the CEP. Specifically, please see Table 15 of PacifiCorp's CEP, which highlights CO2 emissions for various portfolios and sensitivities. Of the portfolios and sensitivities analyzed, the Small-scale Renewable 2028 sensitivity had the lowest CO2 emissions, indicating that it scored best with regard to the portfolio CBI of Increasing Energy from Non-emitting Resources and Reducing CO2 Emissions to meet HB 2021 Targets.

Downstream of the IRP planning process, PacifiCorp anticipates issuing a small-scale RFP. As part of the RFP process, PacifiCorp is requesting bidders to provide equity specific project details. This requested information will include information such as local hire and diversity spending projections for project development. The bidder responses to these equity-related question will have implications on their non-price score. Over the coming months, PacifiCorp will also be working with stakeholders to develop and formalize its CBIs and discuss their evolving relationship with planning and procurement efforts.

G. The Relationship Between Transmission and Transmission-Enabled Resources is Increasingly Transparent and Fully Represented in the 2023 IRP.

OSSIA requests additional clarity regarding the connection between the resources identified in the preferred portfolio and the transmission investments needed to support those resources. Similarly, Cascade questions the cost effectiveness of resources that require significant and expensive transmission projects.

The Company responds that the cost of transmission is accounted for in the optimization modeling as a component of core functionality. The PLEXOS model evaluates the costs of all resource options, including dependencies upon transmission capabilities and costs, and determines which transmission projects produce a least-cost, least-risk solution. The timing of transmission projects and resources are also simultaneously considered.

This transparency and functionality has only improved. New to the 2023 IRP, the endogenous modeling of transmission was enhanced to leverage cluster study results to inform the amount, types and location of proxy resource options so as to better align with probable near term projects and their transmission dependencies. As a result, many of transmission upgrades and resource additions in the first five years of the IRP preferred portfolio reflect cluster study requests submitted in the last two years, with completed studies posted on PacifiCorp's transmission website.[23] Additional transmission expansion projects beyond those identified as part of recent cluster studies provide additional opportunities for locations that have not had significant cluster requests or near-term upgrade options.

H. The 2023 IRP and CEP Action Plans Provide Adequately Detailed Planning and Risk Mitigation to Address Dependencies and Barriers.

The Company's Action Plans appropriately detail the Company's twenty-year plans and respond to, or consider, relevant dependencies and barriers to meeting our various objectives, and we will need Commission and stakeholder assistance to meet HB 2021's ambitious requirements.

1. The potential for initially higher-than-minimum renewables compliance is a low-regret strategy.

PacifiCorp, as well as state and federal policy, have been on a trajectory of increased renewables coupled with decarbonization for the past many IRP cycles. In each cycle, policy driving decarbonization and encouraging renewables has escalated, and the Company has anticipated and incorporated this trend in its modeling and long-term planning. And as the IRA and recent Environmental Protection Agency's Ozone Transport Rule (OTR) confirm, the Company anticipates these long-standing trends to continue. This reality, combined with the potential for demonstrated load growth, indicates that any risk of significant reliance on renewables in its IRP or CEP is a low-regret outcome.

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[23] PacifiCorp's Open Access Same-Time Information System: http://www.oatioasis.com/ppw/. Select Generation Interconnection…Cluster Queues in the sidebar.

2. The 2023 IRP analyzes alternative acquisition paths to mitigate risk.

The 2023 IRP's Action Plan includes relevant examples of alternate acquisition path analysis and risk mitigation.[24] For example, the Action Plan identifies actionable technology and policy avenues over the next two-to-four years to deliver resources to the preferred portfolio. Notable examples to reach these long-term strategic objectives include action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs). Additionally, PacifiCorp has applied cost reduction credits to energy efficiency, reflecting risk mitigation benefits, transmission and distribution investment deferral benefits, and a ten percent market price credit for the State of Oregon pursuant to the provisions of the Northwest Power Act.

In the 2023 IRP acquisition path analysis, sensitivities and variants are leveraged to explore insight on how changes in the planning environment might influence risks inherent in the action plan and future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and carbon dioxide (CO2) emission polices.

3. The 2023 CEP analyzes additional risk mitigation scenarios by including multiple compliance pathways.

In addition to IRP risk mitigation and alternate path analyses, the CEP's illustrative compliance pathways show multiple outcomes that achieve HB 2021 compliance. The purpose of including multiple illustrative pathways, which are not mutually exclusive and preserve the benefits of system planning, is to demonstrate there are several paths to comply with HB 2021, including pathways not explicitly outlined in the CEP. Preserving options that are flexible in how

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[24] 2023 IRP, Vol I at 368.

they could be achieved offers additional risk mitigation and an opportunity for guidance from Staff and stakeholders as the Company develops subsequent CEPs. Given the amount of resources that need to be procured in a short period of time, it is imperative that we continue to remain partners and work with our stakeholders, Staff, and the Commission on these identified strategies. None is without risk: either from increased load, procurement challenges, coordination problems between and among various states, additional regulatory requirements, or looking at the small-scale requirement specifically, sheer limited time to accomplish.

I. The Company's Modeling of its Coal-fueled Generation Units and Gas Conversions is Reasonable.

The resource portfolios produced for the 2023 IRP were created considering a wide range of potential coal retirement dates, options to convert to gas or to retrofit for carbon capture utilization and sequestration for certain coal units and other planning uncertainties.[25] The preferred portfolio and the CEP portfolio demonstrate the Company's progress in aligning planning priorities with decarbonization goals, noting the plan to cease coal-fired operations at 15 coal plants by 2030. The retirement of these coal plants is driven in part by ongoing cost pressures on existing coal-fueled facilities and dropping costs for new resource alternatives. Of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes cessation of coal burning at the aforementioned 15 units by 2030 and the remaining seven units by the end of the planning period in 2042.[26]

[25] 2023 IRP Volume I at 8.
[26] 2021 IRP Volume I at 15.

1. **The Company has already committed to convert Jim Bridger Units 1 and 2 to operate on natural gas, and are appropriately modeled.**

CUB challenges whether gas conversions have been sufficiently analyzed and whether it is better for Oregon to exit these units entirely, and also asks how cost allocations will be determined.

PacifiCorp has sufficiently analyzed gas conversions. The Jim Bridger 1 and 2 conversions were derived from the 2021 IRP, where the PLEXOS model was used to endogenously optimize their conversion, and considered many options, including: whether to continue to operate as coal, retire early, convert Jim Bridger 1 to carbon capture, utilization and sequestration and whether to convert to gas. In the end, Jim Bridger 1 and 2 gas conversion was determined to be the most cost-effective option for customers in the 2021 IRP, the 2021 IRP Action Plan listed out the requirements and timeline to gas convert Jim Bridger 1 and 2, and the 2023 IRP Action Plan noted the Jim Bridger 1 and 2 gas conversion project is on schedule for completion in 2024. The 2023 IRP continues to identify large near-term system capacity needs, and in the absence of Jim Bridger 1 and 2, would be more reliant upon market transactions that may or may not be available to maintain reliable service to customers. This does not eliminate the opportunity to procure alternative resources that could replace Jim Bridger 1 and 2 in the future, however such alternatives are not available for 2024.

Allocation of costs are based on Commission-approved allocation methodologies. PacifiCorp is currently discussing changes to its current allocation methodology with signatories to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol, including CUB. Issues regarding a future allocation method are better addressed through PacifiCorp's Multi-State Process (MSP) and Oregon's leadership in that process. Neither the IRP nor CEP are ratemaking exercises, nor do they address the multitude of issues related to allocations.

Accordingly, the CEP presents multiple compliance pathways for consideration including possible future allocations. The judgements included in the CEP of course have a quantitative basis, but they are ultimately qualitative and will depend on discussions in the MSP negotiations and Commission approval of a future allocation methodology.

2. Installing cost-effective emissions control equipment is reasonable even as coal plants prepare to retire.

CUB and Cascade express concerns with potential upgrades to coal units shortly before they are to close or cease coal operations. However, the emissions control technology, selective non-catalytic reduction, is inexpensive enough to warrant the upgrade even if the operation of the facilities continues for a relatively short duration.

3. Gas conversion costs are properly modeled.

CUB and OSSIA question whether the conversion of coal-fired resources to natural gas is appropriately being reflected in decommissioning cost estimates. The Company's modeling of coal-fired resources ensures that ongoing fixed costs, including all capital additions and retirement costs, are fully captured within a unit's operating life as selected endogenously within the PLEXOS model. In PacifiCorp's 2019 IRP preferred portfolio, the Naughton 1 and 2 units were to retire at the end of 2025 and be replaced by new simple cycle combustion turbines. This would result in significant incremental decommissioning costs, with only modest savings relative to a simple cycle combustion turbine being constructed in a greenfield location where existing facilities at Naughton, like roads and interconnection equipment, could continue to be used. In contrast, the gas conversions at Jim Bridger and Naughton in the 2021 IRP and the 2023 IRP continue to use most of the existing plants, except for coal handling equipment, and will require the addition of only gas pipeline laterals and burners, with a relatively small footprint and cost that will not impact decommissioning costs significantly. The decommissioning costs for gas conversion are reflected in the 2023 IRP studies at a level that is comparable to a coal retirement.

J. The 2023 IRP and CEP Appropriately Evaluates the Benefits of Federal Legislation.

CUB asks how the presented plans maximize benefits for customers from federal funding. In an important sense, PacifiCorp's IRP and CEP are designed to optimize rather than maximize any particular benefit. However, so long as we define maximize to be constrained by the need to meet all system requirements and to balance costs and risks, we represent that both the IRP and CEP maximize benefits from federal legislation: for both supply-side and DSM resources. This is important because the 2023 IRP includes a specific sensitivity, for example, to represent maximum DSM which disregards some of those necessary boundaries to provide a bookend for the maximum potential of certain benefits.

For example, the 2023 IRP and CEP both incorporated the most current federal legislation related to both tax law and the OTR at the time the models were being run and evaluated. The IRA extension, and expansion, of tax credits (both by type of credit, production or investment, and resource eligibility) were applied to all eligible resources with selection dates prior to 2038. Additionally, compliance with the OTR was evaluated on all portfolios based on the best available understanding of the law as of January 1, 2023. Federal updates to these rules or any clarifications regarding legislation which occurred after that date could not be included in the IRP modeling process but will be incorporated as appropriate into the IRP update.

Similarly, the Private Generation Resource Assessment captures updates to the Federal investment tax schedules in the IRA. Please refer to the 2023 IRP, Volume II, Appendix L (Private Generation Study) for additional details. The CPA assumes accelerated adoption of specific measures and or specific customer types that were targeted the IRA. Please refer to

Volume I and Volume II of PacifiCorp's Demand-Side Management (DSM) Potential Report for additional details on how components of the IRA were accounted for in the study.[27]

K. Natrium is Properly Considered in the 2023 IRP and CEP.

OSSIA questions whether the Company should include Natrium in the IRP and CEP, given the potential challenges and risks from the new technology.

However, Oregon IRP Guideline 1(a) appears to support PacifiCorp considering Natrium 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."[28] 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."[29]

Consistent with this guidance, nuclear resources considered in the 2023 IRP 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 Natrium project has a long lead time that requires continued evaluation of its potential (through, for example nuclear variant studies and acquisition path analyses).

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[27] Available here: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integratedresource-plan/2023-irp/2023-irp-support-studies/cpa/PacifiCorp_DSM_Potential_Report_Vol_1.pdf; https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integratedresource-plan/2023-irp/2023-irp-support-studies/cpa/PacifiCorp_DSM_Potential_Report_Vol_2.pdf.
[28] Order No. 07-002, Appendix A; Errata Order No. 07-047, Appendix A.
[29] Id.

L. Additional Questions and Concerns.

Finally, the Company responds to several additional concerns regarding the Company's IRP and CEP.

First, in its comments, CUB indicates that it is interested in the Company's investment strategy to meet HB 2475 goals. At this time the Company does not have a particular long-term strategy for reducing energy-burden beyond learning from the current Low Income Discount (LID) and considering reasonable opportunities to improve the program. As learnings are gleaned from this program and other utility efforts, the Company looks forward to discussions with stakeholders and incremental progress on energy burden reduction, as the Company believes that achieving HB 2475 goals will be an evolving and iterative process that will take shape through listening to, and collaborating with, community members.

Second, Staff, CUB, OSSIA, and Cascade Resilience requested additional information regarding PacifiCorp engagement with communities and environmental justice organizations. PacifiCorp continues to engage with its CBIAG for input and feedback into the development of its resilience analysis. In addition to the CBIAG, PacifiCorp also has held recurring meetings for CEP Engagement Series to solicit feedback from interested parties and resilience stakeholders. To date, limited feedback on resilience has been received. PacifiCorp, for example, received feedback that census tract level data does not sufficiently account for variations of socioeconomic data within communities. PacifiCorp is currently evaluating how to decompose census tract level to be more granular to account for this variation in its next data set.

Third, Staff, CUB, OSSIA, and Cascade Resilience requested additional information on how PacifiCorp developed definitions of resilience and reliability. PacifiCorp includes utility and community resilience data in its utility-community resilience scoring methodology. The utility component of this composite score includes utility resilience data based on system performance and reliability metrics including major event days. Community resilience data is sourced from the Federal Emergency Management Agency (FEMA) National Risk Index (NRI) which includes 78 variables in two data sets. PacifiCorp selected the NRI based on input from resilience stakeholders to include community and population characteristics in its development of a community resilience score. The NRI is a publicly available data set with detailed technical documentation available to interested parties through FEMA.

Fourth, Staff, CUB, OSSIA, and Cascade Resilience requested additional information regarding how PacifiCorp applied recommendations from the UM 2225 docket to its resilience analysis. PacifiCorp continues to review recommendations from this docket and additional resilience stakeholder engagements to develop and refine its resilience analysis. To date, the initial framework developed by PacifiCorp relies on existing utility databases and publicly available community resilience data. Once PacifiCorp completes this initial analysis and the planned stakeholder feedback process, PacifiCorp will evaluate the recommendations from the UM 2225 docket to include in a future iteration of its resilience analysis.

Finally, Staff, CUB, OSSIA, and Cascade Resilience requested additional information regarding the inclusion of extreme weather and wildfire risk in PacifiCorp resilience analysis. Extreme weather impacts are directly included in the utility-community resilience scores through the use of outage and reliability data to calculate the utility component of those scores. By including major event days, which are typically excluded from traditional reliability metrics and reporting, PacifiCorp accounts for the impact of, for example, large winter storms. Similarly, the community resilience component of the utility-community composite risk scores includes the potential probability and impact of wildfires through FEMA NRI data, which includes FEMA assessments of vulnerability to various environmental hazards including, for example, wildfires, flooding, or earthquakes.

IV. CONCLUSION

PacifiCorp appreciates the opportunity to provide these reply comments for the Commission's consideration and looks forward to continuing the important IRP and CEP discussions with the Commission and interested stakeholders.

Respectfully submitted this 31st day of July, 2023.

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PacifiCorp