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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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

REDACTED COMMENTS OF WESTERN RESOURCE ADVOCATES
March 4, 2022

Contents

Pursuant to the September 20, 2021, Scheduling Order and Notice of Technical Conference, Western Resource Advocates ("WRA") hereby submits these comments to the Public Service Commission of Utah ("PSC") regarding PacifiCorp's 2021 Integrated Resource Plan ("IRP").

WRA is a non-profit organization that addresses climate change to sustain the environment, economy, and people of the West. We work with decision-makers and other advocates to advance clean energy, protect air, water, and wildlife—and sustain the lives and livelihoods of the West. Our Clean Energy Program includes policy experts, economists, and attorneys and develops and implements evidence-based solutions to realize the benefits of a decarbonized electricity system that is reliable and economic for customers.

I. INTRODUCTION

The 2021 IRP public input process was conducted and the Preferred Portfolio developed during unprecedented times. The two-year IRP cycle that began in January of 2020 was colored by the covid pandemic and by the ever-growing recognition that averting the advancing climate crisis will require fundamental changes in all sectors of our economy. While the entire economy must evolve rapidly, the speed at which the electricity sector must transition is even greater, as a transformed electricity industry will be essential to support the transition in other sectors.

Further, reliable operation of a greenhouse gas ("GHG") emissions-free resource mix will require increased utility coordination across states and regions. In recognition of this rapid transition, multiple regional conversations are ongoing to address reliability and coordinated operations. Significantly, given PacifiCorp's size and geographic location, it is central to these discussions.

Transitions, particularly rapid transitions, are rarely smooth and often create social upheaval, while offering new opportunities. The rapid transition that is underway in the electricity sector has multiple causes and is uneven in its impacts. While the need to avert climate crisis is at its heart, fundamental economic drivers have shifted away from fossil-fuel generation. In addition, the potential for federal action and the policies of states representing the majority of the load in the Western Interconnection have increased the risk of siting any new fossil-based generation. As a result, local economies tied to fossil-fuel extraction and fossil-powered generation are already experiencing job and revenue losses with the accompanying political backlash and fear of further reductions.

The 2021 IRP was developed within this context of a rapidly evolving electricity industry, and it appears to achieve a political compromise between the interests of PacifiCorp's West-coast states, with their clean-energy mandates, and PacifiCorp's coal-operating states, with their legitimate employment, revenue, and community concerns. The Preferred Portfolio forecasts substantial GHG emissions reductions generally consistent with the requirements of the West-Coast states but leaves unchanged the operating lives of the longer-lived coal plants. This apparent dichotomy raises the question of whether the forecast emissions reductions are achievable, and, if they are, the implications for jobs and revenues in coal country.

This IRP like the times in which it was developed is also unprecedented. For the first time, PacifiCorp did not include new natural gas-fired generation as a supply-side resource option, although the Preferred Portfolio does include conversion to natural gas of two coal-fired units at Jim Bridger. As demonstrated by the Preferred Portfolio, PacifiCorp plans to meet its future needs with a combination of significant new transmission, energy efficiency and load control, solar, storage, wind, advanced nuclear, and non-emitting peakers, currently modeled as simple-cycle turbines fueled by hydrogen.

Others will likely address many of these key elements of the Preferred Portfolio. Our comments are more narrowly focused with our priority to explore the economics, customer benefits, public interest, and necessary conditions to achieve PacifiCorp's forecast emissions reductions and to provide the Commission with information of relevance to forthcoming dockets. In this context, we address and support PacifiCorp's decision to exclude new natural gas-fired resources from its modeling while converting Jim Bridger units 1 and 2 to natural gas. Second, we share with the Commission what we have learned of the changing expected system dispatch, along with cost and emissions implications: (1) we describe the long-lived coal plants as capacity resources; (2) we explain that Jim Bridger is a costly plant, describe how it's output was artificially supported through modeling assumptions, and recommend modeling changes of Jim Bridger going forward; (3) we explain why, despite significantly reduced generation across the coal fleet, no coal unit lives were shortened, (4) we identify the necessary conditions to achieve the emissions reductions projected by Preferred Portfolio resource optimization. Based on this analysis, we make specific recommendations for future Commission proceedings. Finally, we make recommendations for integrated resource planning in the context of a changing climate.

In these comments, we do not take a position regarding whether the Commission should acknowledge, or not, the 2021 IRP based on the IRP Standards and Guidelines. The purpose of these comments is to provide the Commission with key information from 2021 IRP modeling that is pertinent to future proceedings including any potential coal-resource Reassignment applications filed pursuant to the *2020 PacifiCorp Inter-Jurisdictional Allocation Protocol* (Docket No. 19-035-42). We appreciate the opportunity to provide this input.

II. CLIMATE CHANGE REQUIRES NEW APPROACHES TO RESOURCE PLANNING.

PacifiCorp's 2021 IRP was developed during the same time that the Intergovernmental Panel on Climate Change ("IPCC") released its *Sixth Assessment Report* on the latest climate science. The following three, high-level conclusions from the *Sixth Assessment Report* (Working Group 1) are helpful in placing PacifiCorp's IRP and Preferred Portfolio selection, as well as future planning, within the inescapable context of climate change.

- First, global heating has been "locked in" through mid-century due to human-caused GHG emissions. Compared to pre-industrial times, the planet is roughly 1.1 degrees Celsius hotter, and unprecedented weather events will continue to increase in frequency and severity.[1] However, if we can achieve economy-wide net-zero carbon emissions by mid-century, it may be possible to stabilize the climate at 1.5 degrees Celsius.[2]

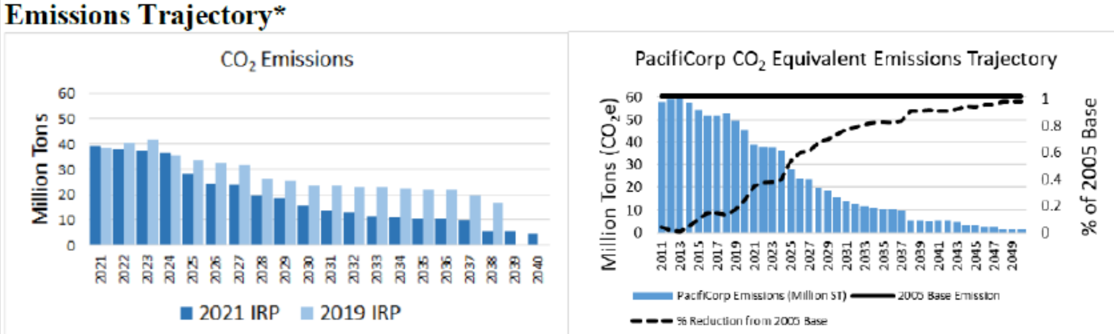
- Second, the trajectory of global heating (and resulting impacts) after mid-century is dependent on how quickly humans cut emissions. The amount and magnitude of climate disruption is directly related to the amount of GHG we emit; projected changes in future extremes are larger in frequency and intensity with every additional increment of global warming.[3] The faster we reduce emissions to net zero the less warming we will experience.[4]

- Third, *every ton of emissions reductions matters*. To reduce emissions at the scale necessary to mitigate the worst climate impacts is challenging. To adapt to climate change is both challenging and costly; however, if we don't take immediate steps to reduce emissions, it will become even more challenging and more costly,[5] assuming we don't cross a point of no-return.

[1] IPCC, 2021: Summary for Policymakers, at 17-19. In: *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [MassonDelmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press. In Press. [Hereinafter *Sixth Assessment Report WG1 Summary for Policymakers*.]
[2] *Sixth Assessment Report WG1 Summary for Policymakers, supra* note 1, at 37-40.
[3] *Sixth Assessment Report WG1 Summary for Policymakers, supra* note 1, at 23-24.
[4] *Sixth Assessment Report WG1 Summary for Policymakers, supra* note 1, at 37-40.
[5] Climate change adaptation is the process of adjusting to actual or expected climate change impacts. Climate change adaptation costs will be lower the more we can mitigate climate change by reducing GHG emissions.

PacifiCorp must achieve significant GHG emissions reductions in the near term. Fortunately, PacifiCorp's 2021 IRP Preferred Portfolio is *forecast* to produce meaningful progress. *To the extent the forecast reductions are achieved*, PacifiCorp's emissions reductions trajectory represents real progress. As can be seen in the figure below, relative to the 2019 IRP, optimization of the 2021 IRP Preferred Portfolio resources cuts emissions significantly,[6] and, as compared to a 2005 baseline, PacifiCorp projects GHG emissions reductions of 98 percent by 2050.[7]

Figure 1.13 – 2021 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory*



*Note: PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2020 from owned facilities, specified sources and unspecified sources. From 2021 through the end of the twenty-year planning period in 2040, emissions reflect those from the 2021 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.4708 short tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2040, emissions reflect the rolling average emissions of each resource from the 2021 IRP preferred portfolio through the life of the resource. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be incorporated following the 2023 integrated resource plan when PacifiCorp is required under the bill to file a Clean Energy Plan.

These emissions reductions result from a few important factors. Key among them are decisions that are unique to this IRP cycle. First, PacifiCorp excluded new natural gas resources

[6] *PacifiCorp 2021 Integrated Resource Plan, Volume 1*, 16 [hereinafter *Volume 1*]. As compared with its 2019 IRP Preferred Portfolio, PacifiCorp projects a relative emissions decline of 26 percent by 2026, 34 percent by 2030, 52 percent by 2035; and 88 percent by the end of the planning period.

[7] As compared to a 2005 emissions base line, PacifiCorp projects GHG emissions reductions of 74 percent by 2030; 83 percent by 2035, and 98 percent by 2050. *Volume 1*, *supra* note 7, at 16. 2005 is a frequently-used baseline when calculating emissions reductions.

from selection in portfolio development,[8] thereby limiting emissions from new fossil-fueled resources. However, to assure reliable operation without the addition of new natural gas generation, PacifiCorp introduced two emerging technologies as supply-side options: dispatchable nuclear resources and non-emitting peakers, modeled as simple-cycle turbines fueled by hydrogen.[9] The exclusion of new natural gas resources and the inclusion of these two additional technologies, in combination with increasingly cost-effective demand side management, solar, storage, and wind, resulted in the Preferred Portfolio. This portfolio adds significant amounts of transmission, wind, solar, storage, and demand response in the near term,[10] advanced nuclear and non-emitting peaking resources in the mid-term,[11] and reliance on coal resources over the longer term for *infrequent use* during periods of capacity constraints. As discussed in detail below, given the cost of new dispatchable resources, retaining coal generation to provide limited capacity in constrained circumstances was shown to be cost-effective.

PacifiCorp justified its decision to exclude new natural gas alternatives in the Preferred Portfolio by noting economic and practical matters: significant stranded-cost risks (depreciable lives may run to 2070), difficulty obtaining state siting and operating permits, and a general lack of development activity for natural gas resources.[12]

[8] *Volume 1*, *supra* note 7, at Table 8.9, footnote 3.
[9] "Advanced nuclear resources are characterized by continuous operation and substantial storage in the form of heat stored as molten salt. In contrast, non-emitting peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls." *Volume 1*, *supra* note 7, at 224.
[10] Almost 2,000 MW of solar and over 2,500 MW of wind by the end of 2026; 700 MW of battery storage by the end of 2024; and 400 percent more direct load control than in the 2019 IRP. *Volume 1*, *supra* note 7, at 10-13.
[11] 500 MW of advanced nuclear in 2028 (Natrium demonstration project), an additional 1,000 MW of advanced nuclear, and over 1,000 MW of non-emitting peaking resources by the end of the planning period. *Volume 1*, *supra* note 7, at 12.
[12] *Volume 1*, *supra* note 7, at 245; PacifiCorp response to DPU Data Request 5.2.

WRA agrees that these practical concerns are sound reasons to exclude new natural gas-fired resources, but, more fundamentally, we support excluding new natural gas resources as in the public interest given the ever-growing relevance of climate change to resource planning. That is, it would be *unreasonable not to* factor the reality of climate change and the climate-related risks and impacts of long-term fossil-fuel use, as well as stranded-cost risks, into resource planning.

With respect to the conversion of Jim Bridger Units 1 and 2 from coal to natural gas in 2023, this appears to be a cost-effective, near-term, resource option. Modeling results demonstrate that the converted units will run at low capacity factors[13] while adding value to PacifiCorp's system – providing long-duration, dispatchable capacity, and additional flexibility to integrate variable energy resources. Our interest is in reducing GHG emissions consistent with climate science. By focusing on emissions reductions over specific technologies, we believe PacifiCorp can more cost-effectively transition to a zero-carbon resource mix faster while maintaining system reliability.

III. THE ROLE OF COAL-FIRED GENERATION IS FADING AS THE ENERGY TRANSITION ACCELERATES.

Within the context of achieving a rapid transition to a zero-carbon resource mix, WRA scrutinized PacifiCorp's forecast emissions reductions, particularly those associated with coal plant operations, to evaluate whether the forecast emissions reductions are realistic and achievable. Our evaluation of the modeling results led us to conclude that coal can provide valuable system capacity, but that it is not in the economic interest of ratepayers, or in the public

[13] Capacity factor refers to the amount of energy generation from a unit over the course of a year relative to the full generation capacity of that unit over that same period (i.e., the ratio of actual energy output to the maximum possible energy output, expressed as a percentage).

interest when considering GHG emissions, to operate coal as it has been in the past. Going forward, coal-fired power should be dispatched only infrequently.

The following sections rely heavily upon seven confidential exhibits, one with multiple pages, created from PacifiCorp's confidential workpapers and from confidential responses to data requests. Having these exhibits available to review side-by-side with this document will be helpful to the reader. WRA has provided a PDF compiling all these exhibits to make this easier.

A. Coal-fired Generation is Transitioning from an Energy Resource to a Capacity Resource.

For decades, coal-fired power has provided around-the-clock energy. However, as the grid transitions to non-emitting alternatives, coal-fired power is becoming relatively costly. Abundant, cost-effective demand-side management, cheap renewable energy, and relatively low natural gas prices are displacing coal-fired generation as an energy resource. As a result, instead of providing energy across all seasons, an optimized coal fleet, if not supported with take-or-pay fuel contracts,[14] operates less like an energy resource and more like a capacity resource, operating seasonally and during hours of high system need. With the planned new resources in PacifiCorp's Preferred Portfolio, the transformation of PacifiCorp's coal fleet is projected to accelerate significantly over the coming decade from the provision of round-the-clock energy to seasonal dispatch with limited annual hours of operation.

Confidential Exhibit 1 displays the annual capacity factors for PacifiCorp's existing coal generation and planned nuclear units, assuming the addition and optimized dispatch of the

[14] As discussed in greater detail below, a "take-or-pay" or minimum-take contract is a fuel supply agreement in which PacifiCorp agrees to pay for a minimum tonnage of fuel at a specific price. It is a sunk cost regardless of actual fuel use.

Preferred Portfolio resources.[15] The upper portion of Confidential Exhibit 1 shows the capacity factors of all PacifiCorp's owned and partially-owned coal units. The units are listed in the order of their assumed retirement dates which are shown to the right of the planning period along with PacifiCorp's capacity share. The lower portion reproduces the same information as the upper portion for the coal plants whose lives extend past the end of 2029 ("long-lived").[16] Since Oregon customers must have coal costs out of rates by the end of 2029, PacifiCorp will likely seek to Reassign[17] the costs (and benefits) of these remaining coal units to Rocky Mountain Power states.[18] This warrants review of the economics and projected dispatch of these plants.

As can be seen in the exhibit, more than 2,200 MW of PacifiCorp coal-fired capacity is retired or converted to natural gas by the end of 2028, leaving slightly more than 3,000 MW of coal-fired generation operating past 2029. These long-lived coal resources are eligible for Reassignment. However, beyond 2030, after all the current take-or-pay coal supply agreements expire, the number of hours the fleet is projected to dispatch drops off, other than for Jim Bridger. As we discuss in greater detail further below, the dispatch of Jim Bridger Units 3 and 4 is artificially supported throughout the 20-year planning period. The modeling results demonstrate that operating coal less frequently is in the economic interest of customers while benefitting the public through reduced emissions.

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[15] These results are from the Short Term ("ST") Model that assures sufficient resources have been added to meet reliability requirements.
[16] The ordering has been slightly rearranged; the Wyoming plants are listed first, followed by the Utah plants.
[17] Pursuant to the *2020 PacifiCorp Inter-Jurisdictional Allocation Protocol* (Utah Docket No. 19-035-42), after any state Commission issues an "Exit Order" to stop paying for a coal resource after a specific date, PacifiCorp will evaluate whether it is reasonable to continue operating the resource on behalf of states without Exit Orders. Based on such analysis, PacifiCorp may propose to "Reassign" a greater share of the coal resource to each state without an Exit Order. In other words, PacifiCorp may ask non-exiting states to assume the share of resource costs previously born by the exiting state. Sections 4.1 and 4.2.
[18] This assumes no further changes are made to the planned operating lives through future IRPs.

Key Assumptions in Modeling Coal-fired Generation

In developing the Preferred Portfolio, no coal-fired unit was modeled as "must-run," and, other than for the Jim Bridger plant, once existing "take-or-pay" contracts expired no new contracts were assumed. This contrasts with modeling assumptions used when setting base net power costs ("NPC") in a rate case, where coal units are modeled as "must-run" with "take-or-pay" contract terms in place for the duration of the test year. This matters, because with different modeled assumptions, one would expect different results, and in the case of the IRP, we would expect to see lower capacity factors than seen when setting base NPC.

Under current conditions, with cheaper energy available to displace coal-fired power, the absence of a "must-run" assumption necessarily leads to lower capacity factors in modeling results because the plant is allowed to turn off. The effect of a take-or-pay contract in modeling coal dispatch depends on the contract terms and duration. If a contract is not economically competitive under current conditions, the contract's expiration will lower the associated plant's capacity factor. In other words, when no longer constrained by a minimum-take obligation, the model will select to run the plant less because fuel costs are avoidable.

Modeling Coal-Fired Generation: No "Must-Run" Operating Assumption

When a coal-fired generating unit is modeled as "must-run," as it is in setting base NPC, it is modeled as "committed" in all hours, no matter how its operating costs compare with alternatives. When cheaper resources are available to the model, the relatively more expensive coal units back down to their operating minimums but continue to operate 24 hours per day. However, in the absence of a must-run assumption, when cheaper alternatives are available, units can be shut down for extended periods and restarted only when the market price is great enough to compensate for the startup costs or the unit is needed to reliably meet system needs.

An examination of Preferred Portfolio "startup" data provides insight into how an optimized coal fleet would operate if coal-fired generation was decommitted when cheaper alternatives are available, and it reinforces the concept that the value of coal-fired generation is rapidly shifting to the provision of flexible seasonal capacity as opposed to round-the-clock energy. Confidential Exhibit 2 displays the number of starts per year for each long-lived coal-fired unit following an economic shutdown, assuming the addition and optimized dispatch of the Preferred Portfolio resources.[19] As can be seen in the exhibit, the optimization model decommits these units multiple times over the course of a year, apparently [redacted], overcoming startup costs to dispatch only in the hours needed.[20] These results demonstrate that *limiting coal-fired operation to actual need is in the economic interest of ratepayers* (it also reduces emissions). Keeping coal units "committed" and operating when cheaper alternatives are available is costly and exacerbates emissions.

Modeling Coal-fired Generation: Take-or-Pay Contracts

Modeling "take-or-pay" coal supply agreements that are not cost competitive with other resource options will also result in higher capacity factors than modeling a fuel contract without a "minimum-take" component. A take-or-pay coal contract is structured such that the buyer commits to purchase a given volume of coal at a fixed price.[21] From a sellers' perspective, the

[19] In constructing Exhibit 2, WRA used Confidential Attachment WRA 4.4 which provides the number of shutdowns and starts in each year of the planning period for each unit assuming the dispatch of the Preferred Portfolio resources. In actual operations, shutdowns are of four types: forced outage; maintenance outage; planned outage; and reserve shutdown in which the unit is available but not dispatched for economic reasons. However, given that forced outages (and maintenance outages) are modeled in PLEXOS as a derate, the values in Confidential Attachment WRA 4.4 reflect economic shutdowns and planned maintenance. WRA used the planned outage data found in the confidential workpapers to remove planned outages, leaving economic shutdowns.
[20] The inclusion of startup costs is part of portfolio optimization logic; these costs are available in the confidential workpapers and are not inconsequential.
[21] Under some contracts, but not all, additional quantities of coal are made available at declining prices.

purpose of a minimum-take requirement is to assure recovery of the mine's fixed costs by assuring a sufficient volume of coal is sold. From a purchasers' perspective, the effect of a take-or-pay contract is to convert the minimum-take quantity multiplied by its price into a sunk cost that must be paid whether or not the plant dispatches in actual operations. Therefore, assuring sufficient fuel burn (hours of dispatch) at each plant to meet the minimum-take provisions of each take-or-pay contracts is part of an optimizing algorithm.[22] However, if any of the contracts' minimum-take provisions are too large for current system conditions, uneconomic over-generation and higher capacity factors will result.

The role of take-or-pay contracts in supporting generation in excess of what would otherwise be cost-effective is identifiable in Confidential Exhibit 1 for the units at Naughton, Hunter, and Huntington. Take-or-pay contract modeling of the Jim Bridger plant is also apparent in the exhibit; however, because PacifiCorp's treatment of Jim Bridger is unique, we discuss its economics in its own section below.

As shown in Confidential Exhibit 3,[23] the take-or-pay contracts with the mine that serves the Naughton plant terminate in [redacted], and the resulting precipitous decline in Naughton's capacity factors between [redacted] and [redacted] is quite dramatic. As shown in Confidential Exhibit 1, in [redacted], Naughton Unit 1 is modeled with a capacity factor of [redacted] percent and in [redacted] it falls to [redacted] percent. In [redacted], Naughton Unit 2 has a capacity factor of [redacted] percent, and in [redacted] it falls to [redacted] percent. While not as dramatic, contract expirations at Hunter and Huntington are also obvious in the exhibit. Contracts at Hunter end in [redacted] and

[22] This is the case in setting base NPC using GRID and in IRP modeling using PLEXOS.
[23] Confidential Exhibit 3 provides a summary of PacifiCorp's current take-or-pay contracts for the plants it operates. The exhibit shows contract termination dates, minimum-take quantities, and the pricing of the minimum quantities.

[redacted]. Between [redacted] and [redacted], the capacity factor for Hunter Unit 1 falls from [redacted] percent to [redacted] percent; for Hunter Unit 2, it falls from [redacted] percent to [redacted] percent; and for Hunter Unit 3, it falls from [redacted] percent to [redacted] percent. Renewable additions in 2024 and 2025 contribute to lower capacity factors at Hunter and Huntington; however, the magnitude of the decline at Hunter is noticeably larger than at Huntington due to the expiration of the take-or-pay contract. The contracts for Huntington don't terminate until [redacted]. As can be seen, between [redacted] and [redacted], the capacity factor for Unit 1 falls from [redacted] percent to [redacted] percent and for Unit 2 from [redacted] percent to [redacted] percent.

These optimized results demonstrate that take-or-pay contracts can artificially support coal-fired generation, resulting in excess costs for customers and excess emissions. Therefore, understanding the terms of any new contract on system dispatch will be essential going forward. We recommend that the terms of new contracts be scrutinized as part the next rate case and subsequent rate cases, using then current IRP modeling assumptions. Customers should not have to bear the entire cost of contracts with uneconomic "minimum-take" provisions that that don't represent optimized coal dispatch.

Monthly Data: An In-Depth View of Coal Resource Transformation

A review of the monthly dispatch data from the Short-Term Model achieves two ends. First, it provides an even clearer picture of the transformation of coal-fired generation from the provision of energy to the provision of capacity than does the annual data. Second, it underscores the significance of take-or-pay contracts in supporting uneconomic dispatch. Confidential Exhibit 4 is comprised of six pages, and displays monthly capacity factors for PacifiCorp's long-lived coal plants: Jim Bridger, Wyodak, Hunter, and Huntington.[24] A review of the exhibit makes clear that once take-or-pay contracts expire, the units at Hunter and Huntington operate only seasonally, and beginning in 2032, Wyodak operates only a few hours per year until its retirement at the end of 2039.[25] Further, despite Jim Bridger's dispatch being artificially supported by take-or-pay contract modeling, seasonal dispatch shows up as early as [redacted] for Unit 3 and [redacted] for Unit 4.

B. Jim Bridger is A Costly Plant Whose Dispatch is Artificially Supported with Take-or-Pay Contract Modeling, Resulting in Uneconomic Dispatch and Excess Emissions

Absent PacifiCorp reconsidering its decision to fuel the Jim Bridger plant with coal through 2037, PacifiCorp will likely seek to Reassign some portion of the plant to Utah customers, pursuant to the *2020 Inter-Jurisdictional Allocation Protocol*. If the Commission were to approve a Reassignment of Jim Bridger's costs to Utah on a proportionate basis with Idaho and Wyoming, Utah's customers would pay for almost 70 percent of PacifiCorp's share of Jim Bridger' costs. Therefore, understanding the actual economics of the Bridger plant, as opposed to what has been modeled as part of this IRP, will become important. We recognize that consideration of any Reassignment proposal will happen in a formal proceeding under then current system conditions and will include other essential information.[26] Our intent here is to provide foundational information for understanding the economics of Reassignment and to recommend that the Commission provide guidance to the Company regarding its modeling

[24] This exhibit was derived from ST modeling results.
[25] PacifiCorp response to OPUC Data Request 071, as found in DPU data request 1.1 4th Supplemental.
[26] Additional information that will be needed to assess whether Reassignment of existing coal resources would be beneficial to Utah customers includes the effect on NPC to be calculated using the Nodal Pricing Model (locational marginal pricing tool), and how a proposed Reassignment affects Utah's allocation of new resources.

assumptions ahead of any Reassignment filing and ahead of the next IRP, whose public input process has already begun.[27]

Jim Bridger is a four-unit coal-fired plant with a combined capacity of approximately 2,300 MW located near Rock Springs, Wyoming. PacifiCorp operates the plant, which it co-owns with Idaho Power. PacifiCorp's two-thirds share approximates 1,400 MW of summer capacity. Units 3 and 4 were retrofitted with Selective Catalytic Reduction ("SCR") pollution control equipment in 2016 and 2015, respectively, while Units 1 and 2 face near-term Regional Haze ("Clean Air Act") compliance deadlines. As discussed above, the 2021 IRP Preferred Portfolio identifies natural gas conversion in 2023 as a least-cost resource choice. Of the four units, Units 3 and 4 are the least efficient to operate because the SCR controls act as parasitic load lowering the output per unit of heat input. All four units are scheduled to retire at the end of 2037. The primary source of fuel for the Bridger plant is the Bridger Coal Company ("BCC"), which operates the Bridger mine, a PacifiCorp rate-based asset. The underground mine closed last year, and the surface mine will close in 2028.[28] In addition to BCC coal, PacifiCorp fuels the plant through a take-or-pay contract.[29] Following closure of the mine, PacifiCorp expects to fuel the plant with coal from Black Butte Coal Company and from the Powder River Basin.[30]

The Jim Bridger plant is one of PacifiCorp's costliest, if not *the* costliest plant, and operating it with high capacity factors when cheaper alternatives are available is harmful to customers and results in excess emissions. Jim Bridger's relatively high capacity factors – previously reviewed in Exhibits 1 and 4 – do not reflect a cheap resource with beneficial

[27] The first public input meeting was held February 25, 2022.
[28] PacifiCorp Response to WRA Data Request 2.5.
[29] See Confidential Exhibit 3 for a summary of the terms of the contract.
[30] PacifiCorp Response to WRA Data Request 2.5.

economics for customers; rather, the high capacity factors reflect PacifiCorp's decision to support the modeled dispatch by modeling take-or-pay contracts throughout the entire 20-year planning period, including in the nine years following the closure of the mine. Jim Bridger is the only plant whose dispatch PacifiCorp artificially supported with a *projected* take-or-pay contract assumption.[31] Without the "minimum-take" component of the projected contract, it appears that the optimizing model would dispatch the remaining two coal-fired generating units very little, if at all, following mine closure. Further, it appears that the high volume of BCC coal that drives generation at Jim Bridger from 2021 until the mine's closure in 2028 is not in the economic interest of customers, but may reflect shareholders' interests.

The Bridger mine is a Company-owned, rate-based asset. While the Company earns a return on the mine, the mine's fixed operations and maintenance costs are recovered through fuel expense, a component of NPC, and not through base rates. To assure recovery of BCC's fixed costs, PacifiCorp modeled these costs in a manner similar to a take-or-pay contract,[32] setting a minimum-take amount that must be met and is effectively priced at zero in the dispatch algorithm.[33] The minimum-take assumptions are essential to the modeled capacity factors because the size of the minimum-take determines the number of hours the plant will dispatch at a zero price. Until the full volume of coal determined by the minimum-take requirement is modeled as having been burned, the model will continue to see a zero dispatch price and will continue to dispatch the units with priority over other resources. Notably, once the terms of the

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[31] PacifiCorp Response to WRA Data Request 4.28.
[32] PacifiCorp Response to OPUC Data Request 021, as found in PacifiCorp Response to DPU 1.1 4th Supplemental.
[33] Video recording: Special Public Meeting LC 77 PAC 2021 IRP Commission Workshop 1, 53:48-55:20 (January 13, 2021) (Daniel McNeil speaking on behalf of PacifiCorp) (available on the Oregon Public Utility Commission website at: https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=883).

take-or-pay contracts at the other plants expire, the Jim Bridger coal-fired units are first in the dispatch stack, ahead of other coal units, and ahead of relatively cheap natural gas units, and they remain first in the stack throughout their operating lives.[34] Clearly this is not in customers' economic interests and the excess emissions are not in the public interest.

The effect of take-or-pay modeling of BCC costs, as well as the high cost of operating Units 3 and 4, is clearly apparent in Confidential Exhibit 1. Throughout the life of the Bridger mine, the Bridger plant operates with consistently high capacity factors, although the bulk of generation shifts from Units 1 and 2 to Units 3 and 4 following conversion of Units 1 and 2 to gas peakers. The fact that Units 1 and 2 carry the bulk of generation ahead of conversion demonstrates that Units 3 and 4 cost more to operate. However, despite their higher operating costs, their conversion to natural gas was not considered. PacifiCorp considered only the conversion of Units 1 and 2,[35] which suggests that the decision to consider conversion of these units was driven by their Regional Haze compliance obligations rather than the most economic solutions for customers.[36]

As can further be seen in Confidential Exhibit 1, the capacity factors at Units 3 and 4 drop notably following the mine's closure; however, sustained by the projected take-or-pay contracts' minimum-take requirements, generation remains fairly constant over the remaining

[34] Video recording: Special Public Meeting LC 77 PAC 2021 IRP Commission Workshop 1, 53:48-55:20 (January 13, 2021) (Daniel McNeil speaking on behalf of PacifiCorp) (available on the Oregon Public Utility Commission website at: https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=883).
[35] PacifiCorp Response to WRA Data Request 2.2; *see also* PacifiCorp Response to WRA Data Request 7.1.
[36] In conversing with the Oregon Commission on behalf of PacifiCorp, Daniel McNeil acknowledged that dispatch at Jim Bridger is uneconomic and indirectly alluded to the possibility of converting Units 3 and 4 to natural gas at a future point. Video recording: Special Public Meeting LC 77 PAC 2021 IRP Commission Workshop 1, 46:32, 42:50-44:59 (January 13, 2021) (available on the Oregon Public Utility Commission website at: https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=883).

nine years the plant is assumed to operate, even as the capacity factors at the other long-lived plants *with lower fuel costs* drop off.

Confidential Exhibit 5 provides comparative fuel prices by plant in $/ton and supports the notion that Jim Bridger would not dispatch past 2030 without a minimum-take requirement. As can be seen, projected fuel costs at Jim Bridger increase by an average [redacted] percent following mine closure and, beginning in 2030, exceed projected fuel costs at any other plant. A comparison of projected Bridger fuel prices with Wyodak's and Huntington's fuel prices appears particularly instructive given the limited hours these plants operate over this same period.

Operating an uneconomic plant with high capacity factors is not in customers' interests, since customers will pay the actual price paid for each ton of coal that is burned in their rates; nor is it in the public interest, given that each ton burned adds to climate-heating emissions. These results raise the question of why PacifiCorp would artificially support modeled dispatch from such a costly plant over so many years, particularly following the closure of the mine.

One explanation may be that PacifiCorp is trying to manage its cost-recovery risk. Without sufficient modeled generation at Jim Bridger after 2030, the economics of early retirement improve. PacifiCorp could be concerned that if Bridger were to close early, it would not fully recover the investments it made in the plant and mine, thereby, putting shareholders' returns at risk. As noted above, PacifiCorp installed very expensive controls on Units 3 and 4 in 2015 and 2016 to reduce haze-causing emissions and comply with Wyoming's EPA-approved Regional Haze State Implementation Plan. During the proceeding to consider PacifiCorp's voluntary request for preapproval of the SCR costs,[37] PacifiCorp used a 2037 plant life to

[37] Utah PSC Docket No. 12-035-92.

demonstrate the benefit of installing SCRs over simply retiring the units. With a shorter economic life to spread the SCR costs over, retirement would have been the better option. Therefore, if Bridger were to cease coal-fired operation early, PacifiCorp could fear disallowance of some portion of the SCR investments. Further, the need to seek Reassignment could amplify the risk of early closure. If, in an optimized dispatch, the units did not dispatch past 2030, the economics of Reassignment would degrade. Along with increased decommissioning cost risk associated with Reassignment, this lack of economic dispatch might persuade Utah to reject Reassignment of additional coal costs.[38] This would further pressure PacifiCorp to retire the plant early, increasing the risk of a partial disallowance.

Similarly, PacifiCorp made substantial past investments in the mine. Since recovery of the mine's fixed costs depends on the volume of fuel that is burned, PacifiCorp has an incentive to assure that the amount of fuel burned recovers its full past investment within the remaining life of the mine. With reduced dispatch, cost recovery would not be assured, and PacifiCorp might need to seek special regulatory treatment of the remaining unrecovered investments. However, this approach could appear riskier from a shareholders' perspective than simply operating Jim Bridger at high capacity factors over the life of the mine. And so it may be that PacifiCorp is putting shareholders' interests ahead of the economic interests of its customers.

Regardless of PacifiCorp's motivation, the outcome – over-generation from Jim Bridger's coal-fired units – is not in customers' economic interest, and the excess emissions are not in the public interest. Further, the modeling approach not only results in over-generation at Jim Bridger, but it also distorts all optimized results. If Jim Bridger were not placed first in the

[38] See the *2020 PacifiCorp Inter-Jurisdictional Allocation Protocol* (filed in Docket 19-035-42) at section 4.3 for a discussion of decommissioning costs.

dispatch stack throughout its operating life, not only would the modeled dispatch of Jim Bridger decline, *but the dispatch of every other modeled resource would also change*.

WRA recommends that the Commission direct the Company to incorporate two modifications as part of the next IRP and ahead of any Reassignment filing. First, the Company should *develop an alternative mine plan* with lower "minimum-takes" that reflects the economics of the fuel supply and plant consistent with customers' interests. Second, *projected take-or-pay contracts should not be assumed*. An optimized portfolio with these two changes will provide the Commission and the stakeholder community a better understanding of the actual economics of PacifiCorp's remaining coal fleet, including the Jim Bridger plant, ahead of any Reassignment proceedings.

C. PacifiCorp's Endogenous Coal Retirement Modeling Demonstrates that the Value of Coal-Fired Generation is its Ability to Provide Limited Capacity.

In this IRP cycle, PacifiCorp used a new modeling tool that provided a system view of coal-retirement decisions. The PLEXOS model can determine whether investing significant capital as part of a regular planned maintenance cycle is cost-effective or whether the capital expenditure should be avoided through early retirement. The ability of the model to make this coal retirement determination internally is referred to as "endogenous."

Despite the few hours per year that some of the remaining units operate, the PLEXOS model did not select a single unit for early retirement. This result initially seems surprising given the results of past coal-retirement studies that suggested early retirement of many units was economically beneficial; however, when the modeling assumptions of this IRP cycle are considered, the results make sense. In past IRP cycles, natural gas resources were available to replace retired coal-fired generation and to meet system reliability needs, but, as discussed above, in this IRP cycle, new natural gas resources have been excluded. The dispatchable resources available to PLEXOS include batteries, dispatchable nuclear, and non-emitting peakers, and have a combination of higher capital costs, significantly higher operating costs,[39] or greater operating limitations than a new natural gas resource.[40] When compared to the costs of these newer technologies, the costs to maintain the aging coal units, even though substantial, are apparently cost effective in comparison.

The situation at Wyodak provides an illustration. After 2032, Wyodak operates in only a few hours per year. In fact, as seen in Confidential Exhibit 7, in the optimized solution, Wyodak operates [redacted] – an unlikely outcome in actual operations. However, from the point of view of the optimization model, this may be a lower-cost solution to a needle-peak need than adding an additional non-emitting peaking unit. PacifiCorp explains it this way: "because a non-emitting peaker is more expensive in both fixed and variable costs, it is more cost-effective to keep Wyodak's capacity available as long as possible," and, unlike storage resources, Wyodak would be "able to respond for an extended duration in response to variation in load and unit outages that are not reflected in the 'ST' model study."[41]

Given the cost of new capacity, maintaining existing coal-fired resources to provide very limited generation during times of system need appears to be in customers' economic interests,

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[39] In conversations with the Oregon Commission on behalf of PacifiCorp, Daniel MacNeil referred to the operating costs of the non-emitting peakers as "massively" more expensive on an energy basis than operating natural gas. It is for this reason that their use is limited to reliably serving in times of system constraint. Video recording: Special Public Meeting LC 77 PAC 2021 IRP Commission Workshop 1, 47:12-48:06 (January 13, 2021) (available on the Oregon Public Utility Commission website at: https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=883).

[40] For the 2019 IRP, the difference in cost between the Preferred Portfolio and the "Retire all Coal by 2030" scenario portfolio was roughly $500 million. In the 2021 IRP, the difference is roughly $2 billion.

[41] PacifiCorp Response to OPUC 071, as found in PacifiCorp Response to DPU Data Request 1.1 4th Supplemental.

assuming that PacifiCorp operates its remaining coal fleet consistent with least-cost optimization and does not operate in hours when cheaper alternatives are available.

III. Can PacifiCorp Achieve the Benefits of Lower Costs and Reduced GHG Emissions?

Two themes have arisen throughout these comments: first, averting climate crisis will require a rapid reduction in emissions from across the economy, including from PacifiCorp, and second, while coal-fired generation can provide valuable system capacity, it is *no longer an economic energy resource*. Operating coal in more hours than is absolutely necessary to maintain reliability is not in the economic interest of ratepayers nor is it in the public interest when considering the adverse effect of GHG emissions on our climate. This means that in actual operations, coal-fired generation must no longer be operated as "must-run," but must be optimized and decommitted for extended periods as driven by economics and system need. Further, any take-or-pay contracts that PacifiCorp signs must be of short duration and reflect the limited hours of operations established using optimization tools.

Unfortunately, as of 2020, PacifiCorp was not operating its coal fleet as flexibly as it must if costs are to be contained and emissions limited. Confidential Exhibit 6 provides historical start data for 2015 through 2020. The bottom chart shows the total number of starts for each long-lived, coal-fired unit following a closure for any of four reasons these units shut down, including "forced outages," "maintenance outages," "planned outages," and "reserve shutdowns," defined as economic shutdowns.[42] The top chart shows the number of starts following an *economic* shutdown. As can be seen in the exhibit, in each of the six years, other

[42] Reserve Shutdown: Unit is available to the system but not synchronized for economy reasons. *See* Law Insider, https://www.lawinsider.com/dictionary/reserve-shutdown-hours.

than in 2016 when there were [redacted] economic shutdowns, there were at most [redacted] shutdowns per year across the entire fleet. In 2020 there was but [redacted]. Over the course of those six years, a total of [redacted] starts followed an economic shutdown.

This historical information can be compared with the optimized IRP results. Confidential Exhibit 2, introduced above, identifies [redacted] starts in 2021 and [redacted] in 2022 as being least-cost. Significantly, *this is with the current resource mix and current take-or-pay contracts' terms still in place*.

Clearly there is a disconnect between modeled optimization and actual operations. Unless PacifiCorp begins to operate its fleet in the least-cost manner assumed in its IRP modeling, customers will pay more in NPC than they should, and emissions will be far in excess of the reductions projected as part of this IRP.

Alternatively, if the coal fleet cannot be operated in the manner in which it was modeled in the 2021 IRP, then assumptions should be included in the next IRP to better approximate actual operating limitations while providing as much flexibility as possible. Including operating limitations would likely result in a modified resource mix, but most significantly it would change the modeled dispatch of the remaining coal fleet. The extent of the operating limitations will determine how great the increase in the coal dispatch is and the associated increases in operating costs and emissions are. Significantly higher dispatch, with associated higher operating costs, in addition to planned maintenance costs, could result in the model selecting additional units for early retirement.

It appears to us that PacifiCorp must decide whether it will embrace least-cost operations or retire some of its remaining coal-fired generation early.[43] If it does neither, customers will continue to pay too much in NPC, and the projected emissions reductions touted by PacifiCorp as part of this IRP will be a mirage.

IV. RECOMMENDATIONS BASED ON THE FOREGOING ANALYSIS OF PACIFICORP'S IRP

Consistent with the foregoing analysis, WRA recommends the following:

- Any take-or-pay contracts that PacifiCorp signs should be of short duration and reflect the limited hours of operations established using optimization tools.
- Parties and the Commission should scrutinize the terms of all new coal supply agreements as part the next rate case, and subsequent rate cases, using then current IRP assumptions.
- The Commission should provide guidance to the Company regarding its modeling of the Jim Bridger plant ahead of any Reassignment filing and ahead of the next IRP. Specifically, it should direct the Company *to develop an alternative mine plan* with lower "minimum-takes" that reflects the economics of the fuel supply and plant consistent with customers' interests. Second, *projected* take-or-pay contracts should not be assumed. An optimized portfolio with these two changes will provide the Commission and the stakeholder community a better understanding of the actual economics of PacifiCorp's remaining coal fleet, including the Jim Bridger plant, ahead of any Reassignment proceedings.

V. RECOMMENDATIONS FOR FUTURE INTEGRATED RESOURCE PLANNING

WRA recommends that the Commission direct PacifiCorp to include additional information and/or opportunities for meaningful stakeholder input in future filed plans or planning processes. These recommendations are based on the following interests:

- Understanding system planning within the context of state-specific considerations will be even more important following the expiration of the 2020 cost allocation agreement, after which PacifiCorp plans to assign new resources (or portions of resources) to individual states, rather than assigning a proportionate share of system resources to states based on their load.

[43] Our analysis suggests that Jim Bridger units 3 and 4 and Wyodak are likely candidates for early retirement.

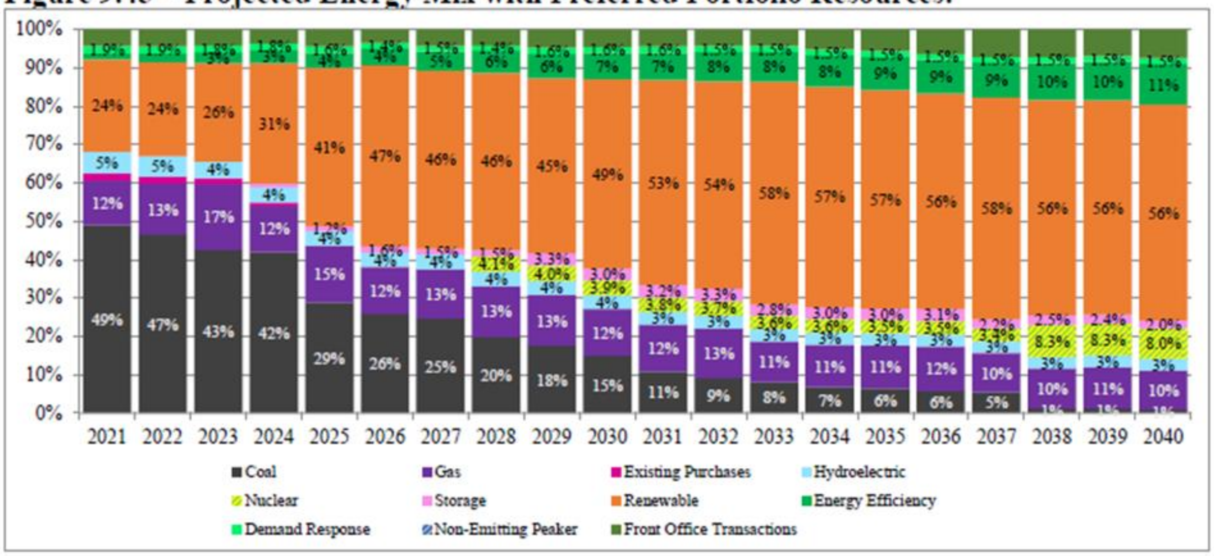
- As climate impacts mount, and as states and the federal government take additional actions in response, it will be necessary to accurately evaluate the emissions implications of system planning, state resource assignment, and policies designed to address GHG emissions.

A. More Accurate Representation of Preferred Portfolio Energy Mix Over Time

WRA requests that the Commission require PacifiCorp to provide additional information about the distinction between renewable energy and "null power" (defined below) in future resource plans.

In the 2021 IRP, PacifiCorp illustrated how the system energy mix will change over time assuming the addition of Preferred Portfolio resources:[44]

Figure 9.45 – Projected Energy Mix with Preferred Portfolio Resources.



This is a generally useful illustration; however, going forward, WRA recommends that the Commission require additional information about renewable energy and "null power" to make this illustration accurate and more transparent. Specifically, WRA recommends that

[44] *Volume 1*, *supra* note 7, at 305, Figure 9.45. PacifiCorp provides this information on a capacity basis as well (Figure 9.46).

PacifiCorp explicitly describe and visually indicate the portion of forecast "renewable" energy for which state Commissions have directed the utility to sell the renewable energy attributes.

Energy generation from eligible "renewable" resources *without renewable attributes* cannot be claimed to be renewable and should be referred to as null power. Null power is the underlying power remaining when renewable attributes (in the form of renewable energy credits or "RECs") are sold. Null power is the "unspecified and undifferentiated power that *has the attributes of the overall system mix or the residual mix* where specified power purchases have been removed."[45]

Regarding PacifiCorp's Figure 9.45, PacifiCorp explained that the renewable energy information (in orange) is based on "categorization by technology type and *not disposition of renewable energy attributes*."[46] In a footnote, PacifiCorp further explained,

> The projected PacifiCorp 2021 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) *sold to third parties in the form of renewable energy credits or other environmental commodities*; or (c) *excluded from energy purchased*. PacifiCorp's 2021 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.[47]

In other words, the energy labeled as "renewable" in the Figure may not actually represent renewable energy; rather, it may represent null power.

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[45] https://www.green-e.org/glossary (emphasis added).
[46] *Volume 1*, *supra* note 7, at 304 (emphasis added).
[47] *Volume 1*, *supra* note 7, at 304 (emphasis added).

Accuracy in this type of energy mix reporting is important for states, communities, and customers who have an interest in the renewable make-up of PacifiCorp's resource mix.[48] For example, Utah communities participating in the Community Renewable Energy Program ("HB 411," Utah Code 54-17-901 *et seq.*) need an accurate calculation of the amount of renewable energy serving PacifiCorp's system to calculate how much additional renewable energy will allow them to be 100 percent net renewable by 2030 and going forward.

The renewable energy attributes, in the form of RECs, that PacifiCorp generates from its own resources are allocated across its six states based on an agreed-upon protocol.[49] RECs represent the legal right to claim the renewable and environmental attributes associated with eligible energy generation.[50] On behalf of California, Oregon, and Washington, PacifiCorp retains RECs to use for compliance with those states' respective renewable portfolio standards.[51] In Idaho, Utah, and Wyoming, PacifiCorp has been directed to sell those states' allocated RECs and return the revenue back to customers.[52] In other words, in Idaho, Utah, and Wyoming, customers get REC revenue in exchange for renewable attributes. As a result of these states'

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[48] The Federal Trade Commission has weighed in on renewable energy claims, stating, "It is deceptive to misrepresent, directly or by implication, that a product or package is made with renewable energy or that a service uses renewable energy. …Unless marketers have *substantiation for all their express and reasonably implied claims, they should clearly and prominently qualify their renewable energy claims*." Federal Trade Commission, *Guide for the Use of Environmental Marketing Claims ("Green Guides")*, 32 (emphasis added). Further, "If a marketer generates renewable electricity but sells renewable energy certificates for all of that electricity, *it would be deceptive for the marketer to represent, directly or by implication, that it uses renewable energy*." *Id.* at 33 (emphasis added). The FTC Green Guides "set forth the Federal Trade Commission's current views about environmental claims. The guides help marketers avoid making environmental marketing claims that are unfair or deceptive under Section 5 of the FTC Act, 15 U.S.C. § 45." *Id.* at 1. The FTC Green Guides are available at https://www.ftc.gov/sites/default/files/attachments/press-releases/ftc-issues-revised-green-guides/greenguides.pdf.
[49] PacifiCorp Response to WRA Data Request 2.12.
[50] Renewable and environmental attributes are "[a]ny and all credits, benefits, emissions reductions, offsets, and allowances—however titled—attributable to the generation from the Generating Unit, and its avoided emission of pollutants." *WREGIS Operating Rules*, 13 (January 4, 2021) (available at https://www.wecc.org/Administrative/WREGIS%20Operating%20Rules%202021-Final.pdf).
[51] PacifiCorp Response to WRA Data Request 2.12.
[52] *Id.*

policies, PacifiCorp cannot claim that it generates or will generate renewable energy for customers in Idaho, Utah, and Wyoming.[53]

PacifiCorp can quantify an amount of forecast energy generation (that is, Idaho, Utah, and Wyoming's allocated shares of eligible generation) for which they *cannot* claim renewable attributes. This amount should not be labeled as renewable in any figures representing PacifiCorp's projected energy mix (unless and until PacifiCorp is directed to retain the renewable attributes associated with that energy). This energy should be designated as null power in any representation of PacifiCorp's energy mix. Without this clarification, PacifiCorp is misleading the public, and it is impossible to accurately understand the energy mix projected to serve PacifiCorp customers over time.

B. Discussion of Emissions Accounting

WRA recommends that, as part of future public input processes, PacifiCorp discuss with stakeholders and receive feedback on system-wide emissions accounting and state-specific emissions allocations.

Transparent emissions reporting and accounting will be necessary in resource planning going forward because 1) some of PacifiCorp's states have GHG emissions-based climate mitigation policies, 2) PacifiCorp may be transitioning from share-of-system resource allocation to state-specific allocation, and 3) it is important to have accurate visibility into the GHG emissions implications of PacifiCorp's planning in order to evaluate climate impacts and mitigation opportunities. Additionally, as PacifiCorp becomes more transparent about the quantity of null power serving customers (consistent with WRA's foregoing recommendation),

[53] In these comments, WRA does not address whether the direction to sell the renewable attributes associated with eligible generation allocated to Idaho, Utah, and Wyoming is in the public interest.

PacifiCorp should also endeavor to be accurate about the emissions profile associated with null power.

In the 2021 IRP, PacifiCorp reported its forecast Preferred Portfolio GHG emissions using emissions from specified sources reported in CO2 equivalent and assuming a default emission factor for market purchases.[54] An emission factor is intended to represent the GHG emissions intensity of a specific resource or a mix of resources serving a particular geographic area, and is represented in tons/MWh (either short tons or metric tons).[55] In its GHG reporting, PacifiCorp uses emission factors published by the US Environmental Protection Agency ("EPA") for thermal resources (owned and specified purchases) and uses a default emission factor of 0.428 metric tons of CO2 equivalent per MWh for market purchases.[56] PacifiCorp also calculates its own system emission factor annually by dividing annual system emissions by annual system generation.[57] In 2020, PacifiCorp's system emission factor was 0.633 metric tons of CO2 equivalent per MWh.[58] This emission factor is consistent with the emission intensity of the WECC region's fossil fuel plants (0.631 metric tons/MWh).[59]

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[54] *Volume 1*, *supra* note 7, at 16 (emissions associated with sales are not removed in the forecast).
[55] For more information on the calculation of emission factors, see the EPA's *Basic Information of Air Emissions Factors and Quantification*, available at: https://www.epa.gov/air-emissions-factors-and-quantification/basic-information-air-emissions-factors-and-quantification#:~:text=An%20emissions%20factor%20is%20a,the%20release%20of%20that%20pollutant.&text=Such%20factors%20facilitate%20estimation%20of%20emissions%20from%20various%20sources%20of%20air%20pollution.
[56] This default emission factor for unspecified purchases is consistent with GHG reporting requirements in Washington, Oregon, and California. This value was adopted from the Western Climate Initiative Partners *Default Emissions Study*. PacifiCorp Responses to WRA Data Requests 3.8 and 3.9.
[57] PacifiCorp calculates this for purposes of GHG reporting in California and Oregon. PacifiCorp Response to WRA Data Request 3.9.
[58] PacifiCorp Response to WRA Data Request 3.9.
[59] https://www.epa.gov/egrid/data-explorer query for output emission rates (lb./MWh) for CO2 equivalent for all fossil fuels at the NERC regional level for 2020. Metric tons/MWh calculated by dividing lbs./MWh by 2204.62 lbs.

PacifiCorp's GHG accounting assumes that direct emissions associated with renewable energy generation is zero. However, when PacifiCorp sells RECs, it loses the right to claim these zero emissions attributes (someone else has purchased the exclusive right to claim them). This practice leads to emissions double-counting because it allows both PacifiCorp and off-system REC purchasers to claim the zero-emissions attributes of generation from PacifiCorp's renewable resources. This may be remedied by assigning an emission factor to null power, which would increase the overall emissions intensity of PacifiCorp's resource mix.

Currently, it is easy to calculate tons of emissions associated with any of PacifiCorp's state loads by multiplying the emission factor (tons/MWh) by load (MWh). Following the conclusion of the 2020 cost allocation protocol, it will be more complicated to calculate state-allocated emissions. From the perspective of PacifiCorp doing its part to reduce GHG emissions, total system emissions matter; however, individual states have their own policies and accounting requirements, so disaggregating system emissions at the state level will be necessary. States without GHG policies have an interest in GHG accounting because GHG emissions represent a source of risk and potential internalized costs for customers. In sum, PacifiCorp should work with stakeholders to develop a transparent method to account for emissions associated with null power and attribute emissions to each state.

C. Discussion of Planning for Climate Impacts.

WRA recommends that, going forward, PacifiCorp discuss with stakeholders and receive feedback on appropriate ways PacifiCorp can account for climate change impacts in resource planning.

In its 2021 IRP, PacifiCorp discussed consequences of climate change that affect resource planning, including climate-related load changes, weather-related impacts on variable generation, wildfire impacts, and extreme weather events.[60] PacifiCorp indicated that additional (i.e. future) research will assist the utility in factoring such impacts into the resource planning process.[61]

The Washington Commission has directed PacifiCorp to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change."[62] In complying with this direction, PacifiCorp relied on projected temperatures in the Bureau of Reclamation's *West-Wide Climate Risk Assessments: Hydroclimate Projections* (2016) to project load in its "climate change scenario."[63]

WRA is aware that other utilities are working to incorporate climate science into resource planning. For example, in its 2021 IRP filing, NV Energy transitioned its load forecasting to incorporate trended normal degree-days rather than using a 20-year historical average because "assuming constant normal degree days will likely underestimate cooling loads and overestimate heating loads."[64] ConEdison developed a *Climate Change Vulnerability Study* to evaluate climate

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[60] *See, e.g., Volume 1, supra* note 7, at 105 (reliability and resilience); 115-16 (load changes); and 119-23 (weather-related impacts on generation resources, wildfires, extreme weather).
[61] *See, e.g., Volume 1, supra* note 7, at 120 ("There is limited research on site-specific impacts from extreme weather events and thus how to plan to improve the resiliency of intermittent generation resources. Resiliency will be enhanced as planning to ensure site access occurs in response to observed changes in extreme weather events and as more research is available to locally forecast impacts of climate change and extreme weather so those impacts can be factored into the resource planning process.").
[62] *Volume 1, supra* note 7, at 249.
[63] PacifiCorp Response to WRA Data Request 3.4; *see also Volume 1, supra* note 7, at 116 ("As illustrated in Table 5.10, relative to the 2021 IRP forecast, the climate change scenario results in summer peaks being higher by approximately 50 MW (<1% higher) over the 2021-2025 timeframe. By 2040, summer peaks are projected to be 318 MW (2.7%) higher than the 2021 IRP Base. As illustrated in Table 5.11, increasing winter temperatures results in less heating load, which drive lower winter peaks. By 2040, winter peaks are projected to be 259 MW (2.3%) lower than the 2021 IRP Base. As illustrated in Table 5.12, increasing temperatures are driving a slightly lower energy forecast. This is driven by lower heating loads for Oregon, which is largely offset by increased loads in Utah.").
[64] Direct Testimony of Eric Fox for NV Energy before the NV PUC in the matter of the Application of NEVADA POWER COMPANY d/b/a NV Energy and SIERRA PACIFIC POWER COMPANY d/b/a NV Energy, seeking approval to add 600 MW of renewable energy and 480 MW of energy storage capacity, among other items, as part of their joint 2022-2041 integrated resource plan, for the three-year Action Plan period 2022-2024, and the Energy

impacts specific to their service area (followed by a *Climate Change Implementation Plan*).[65] WRA recommends that PacifiCorp look into what other utilities are doing to account for climate change in resource planning to inform their own planning.

WRA also recommends that PacifiCorp utilize climate science made available through the IPCC's reports. Specifically, the First and Second Working Group reports associated with the *Sixth Assessment Report* have been released (on August 9, 2021, and February 28, 2022, respectively). The First Working Group Report focused on the physical science basis of climate change while the Second Working Group Report focused on climate impacts, adaptation, and vulnerability.[66] The Third Working Group Report, to be released this spring, will focus on mitigation of climate change.

VIII. CONCLUSION

WRA appreciates the opportunity to provide these comments. Integrated Resource Planning during a rapidly changing climate is complex and consequential. PacifiCorp's forecast GHG emissions trajectory represents important progress mitigating climate change to the extent the utility can achieve significant emissions reductions through actual operations, including negotiating coal supply agreements. In support of customers and the public interest, WRA requests that the Commission direct PacifiCorp to implement the recommendations made in these comments.

Supply Plan period 2022-2024. Volume 2, fox-DIRECT, page 9. Docket No. 21-06-001. Available at: https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/recent-regulatory-filings/nve/irp/2021-irp-filings/NVE-21-06-IRP-VOL2.pdf

[65] https://www.coned.com/en/our-energy-future/our-energy-vision/storm-hardening-enhancement-plan.

[66] The First Working Group Report and associated resources are available at https://www.ipcc.ch/report/ar6/wg1/, and the Second Working Group Report and associated resources are available at https://www.ipcc.ch/report/ar6/wg2/.

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Respectfully submitted,

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