ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

RECEIVED
2022 APR -4 PM 4:49
IDAHO PUBLIC UTILITIES COMMISSION

April 4, 2022

VIA ELECTRONIC FILING

Jan Noriyuki
Commission Secretary
Idaho Public Utilities Commission
11331 W Chinden Blvd
Building 8 Suite 201A
Boise, Idaho, 83714

RE: CASE NO. PAC-E-21-19 - PACIFICORP'S APPLICATION FOR ACKNOWLEDGEMENT OF THE 2021 INTEGRATED RESOURCE PLAN

Dear Ms. Noriyuki:

Pursuant to Commission Order No. 35271 - Notice of Modified Procedure, issued December 27, 2021, in the above referenced matter, PacifiCorp submits reply comments to written comments filed on March 15, 2022, by Commission Staff, the Idaho Conservation League, Sierra Club and Renewable Energy Coalition.

Informal inquiries may be directed to Ted Weston, Idaho Regulatory Affairs Manager, at (801) 220-2963.

Sincerely,

Joelle Steward
Senior Vice President, Regulation

Emily Wegener (ISB# 11614)
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
Telephone No. (801) 220-4526
Mobile No. (385) 227-2476
Email: emily.wegener@pacificorp.com

Attorney for Rocky Mountain Power

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFICORP'S APPLICATION FOR ACKNOWLEDGEMENT OF THE 2021 INTEGRATED RESOURCE PLAN	CASE NO. PAC-E-21-19
PACIFICORP'S REPLY COMMENTS	

In accordance with Rule 202.01(d) of the Rules of Procedure of the Idaho Public Utilities Commission ("Commission") and the Commission's December 27, 2021 Order No. 35271 – Notice of Modified Procedure, PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company"), by and through its counsel, provides these Reply Comments to the comments received by the Commission from the Commission's Staff ("Staff"), Sierra Club and Idaho Conservation League ("Sierra Club"), and the Renewable Energy Coalition ("REC") on March 15, 2022.

PROCEDURAL BACKGROUND

On September 1, 2021, PacifiCorp filed its 2021 Integrated Resource Plan ("2021 IRP") with the Commission pursuant to the Commission's Order No. 22299, Case No. U-1500-165, dated January 1989 ("Order No. 22299") that requires utilities to file bi-annual Integrated Resource Plans ("IRPs").

On October 28, 2021, the Commission issued Order No. 35209 - Notice of Filing and Notice of Intervention. Interested parties were given 21 days to intervene in the case.

On December 6, 2021, the Commission issued a Notice of Parties listing the Company, Staff, and Sierra Club as parties to the case.

On December 27, 2021, the Commission issued Order No. 35271 - Notice of Modified Procedure, which informed the parties that the case would be processed under the Rules of Procedure 201 through 204 and established a procedural schedule for interested parties to file comments by March 15, 2022, with the Company's reply comments due on April 4, 2022.

On March 15, 2022, Staff and Sierra Club filed comments on the Company's 2021 IRP. While REC did not formally intervene in the case, they did submit public comments.

In addition, there were several public comments submitted from February 28 – March 14, 2022, most of which were sent by KnowWho, as a service provider on behalf of the Sierra Club by individuals who are not PacifiCorp customers, focusing on a transition to renewable energy generation sources.

COMMISSION IRP STANDARDS

The IRP is a 20-year long-term resource plan intended to identify the least-cost, least risk portfolio of generation and transmission resources needed to meet the Company's obligation to serve. In Order No. 22299, the Commission required each electric utility party to submit a report of the status of its resource planning and established the standard for IRPs. The reporting requirements the Commission established are:

(1) Discuss any flexibilities and analyses considered during comprehensive resource planning, such as:

a. Examination of load forecast uncertainties;

b. Effects of known or potential changes to existing resources;

c. Consideration of demand and supply side resource options; and

d. Contingencies for upgrading, optioning, and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.

(2) Address Existing Resource Stack, Load Forecast, and Additional Resource Menu.[1]

In addition to complying with Order No. 22299, PacifiCorp must also comply with the 2019 IRP Order No. 34780, Case No. PAC-E-19-16, dated September 14, 2020 ("2019 IRP Order"). Those requirements are:

- Actively consider the concerns raised in comments submitted in this case as it plans;
- Continue evaluating all resource options and the best interests of customers when developing the 2021 IRP;
- Fully study the costs and benefits of additional transmission resources in its 2021 IRP; and
- Continue to: (1) study, develop, and implement economical DSM programs; (2) develop time-of-use pricing policies to help shift peak demand in its service territory; and (3) refine and enhance its forecasting methodologies by analyzing a broad and diverse range of measures to avoid disadvantageous or unfair forecasting treatment of certain resources over others.[2]

The Company has met these standards and requirements. Further, Appendix B of the 2021 IRP lists the requirements included in the 2019 IRP Order and provides a reference to where those requirements were met.[3]

---

[1] *Id.* at 7.

[2] *In the Matter of Rocky Mountain Power's 2019 Electric Integrated Resource Plan,* Case No. PAC-E-19-16, Order No. 34780 at 13 (September 14, 2020).

[3] 2021 IRP, Appendix B – IRP Regulatory Compliance at 35.

To be acknowledged, the 2021 IRP must address the areas required by Order No. 22299 and the 2019 IRP Order. Because the Company's 2021 IRP meets the requirements of those orders, the Commission should acknowledge the Company's 2021 IRP.

INTRODUCTION

The 2021 IRP was developed after substantial stakeholder input. The stakeholder process for the 2021 IRP began in January 2020 with a series of technical workshops focused on energy efficiency modeling assumptions. PacifiCorp also held a series of four technical workshops in January, February, April, and August of 2020. PacifiCorp began a series of broader-topic general public-input meetings starting in June 2020, which addressed a range of topics describing PacifiCorp's modeling methodology, inputs, and assumptions for the 2021 IRP. Agenda topics included, but were not limited to, resource cost-and-performance assumptions, model function and overview, load forecast, price-policy assumptions, market price assumptions, and transmission options. In all, PacifiCorp held 18 public-input meetings. Public-input meeting materials, supporting studies, and stakeholder feedback forms can be found on PacifiCorp's IRP webpage.[4]

The resulting 2021 IRP and action plan[5] ensures that PacifiCorp will provide adequate and reliable electricity supply to its customers at a reasonable cost. PacifiCorp's selection of the 2021 IRP preferred portfolio is supported by detailed data analysis using five fundamental steps: (1) development of key inputs and assumptions to inform the modeling and portfolio-development process; (2) development of a wide-range of resource portfolios; (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

[4] *See* https://www.pacificorp.com/energy/integrated-resource-plan.html; See also the 2021 IRP Volume II, Appendix C – Public-Input Process for more detail.
[5] 2021 IRP, Chapter 1 – Executive Summary, Table 1.2 at 23. The 2021 IRP action plan identifies specific resource actions PacifiCorp will take over the next two-to-four years to deliver resources included in the preferred portfolio.

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.[6] Each of these steps in the 2021 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 analyzed by PacifiCorp.

In these Reply Comments, PacifiCorp describes how the 2021 IRP and the associated action plan comply with all Commission requirements and responds to comments made by Staff, Sierra Club, and REC. Because the 2021 IRP meets all Commission guidelines, the Company respectfully requests that the Commission acknowledge the 2021 IRP.

REPLY TO PARTIES' COMMENTS

I. STAFF'S COMMENTS.

Staff recommends the Commission acknowledge the Company's 2021 IRP based on their review of the 2021 IRP, data responses, and participation in stakeholder meetings. Staff recognizes that the 2021 IRP met the requirements in Order No. 22299 and the 2019 IRP Order by (1) developing a load forecast with load growth over a 20-year time horizon, (2) considering changes to existing resources, (3) evaluating both demand and supply side resources, and, finally, (4) considering a wide range of resource alternatives and resource contingencies in its determination of a least-cost, least-risk preferred portfolio. Furthermore, Staff found that with the 2021 IRP, the Company addressed many issues that Staff raised in its comments to the 2019 IRP. Staff specifically recognized the improvements in the quality of the 2021 IRP results following the Company's use of PLEXOS, which solved issues raised by the Company's previous modeling software.

[6] 2021 IRP, Chapter 1 – Executive Summary at 7-8.

Although Staff recommends that the Commission acknowledge the 2021 IRP, Staff also identifies areas for future analysis and/or improvement. Specifically, Staff suggests the Company (1) clarify whether the loss of load hour reliability target of 2.4 hours per year was achieved by the Company's portfolios; (2) improve clarity on the development of the availability limits of Front Office Transactions ("FOTs") in future IRPs; (3) explore an approach in the modeling that allows for the selection of new natural gas resources but that also provides an adjustment to the cost based on the risk of the resource becoming a stranded asset; and (4) assess the risks of the selection of the Natrium nuclear plant due to technology viability questions and potential delays. Staff also notes that the impact of Washington's Clean Energy Transformation Act ("CETA")[7] on the Company's preferred portfolio was $164 million higher than the top performing P02-MM portfolio on a risk-adjusted present-value revenue requirement (PVRR) basis.

A. <u>Loss-of-Load Hour Reliability Target of 2.4 Hours Per Year</u>

Staff questions whether the use of a historical fixed 13 percent planning reserve margin ("PRM") supports the loss-of-load hour reliability target of 2.4 hours per year. Staff raises concerns that the 13 percent PRM was developed in conjunction with the 2019 IRP, and Staff asserts that a floor of 11.5 percent was appropriate. Staff also suggest that, in the future, the Company should be able to demonstrate whether the analyzed portfolios met the reliability target measured in Loss of Load Hours ("LOLH") since portfolios with greater amounts of variable resources will require higher PRMs compared to portfolios with high concentrations of dispatchable resources.

PacifiCorp's 2021 IRP discusses planning reserve margins in Chapter 5: Reliability and Resiliency. As noted in Chapter 5, both the Western Electricity Coordinating Council ("WECC") and the Northwest Power Pool ("NWPP") consider planning reserve margins of 15 percent. The

[7] Washington Clean Energy Transformation Act, SB 5116 (effective May 7, 2019).

Company's 13 percent PRM was determined in the PRM Study in the 2019 IRP and provides that the Company must hold approximately 10.5 percent to 11.5 percent of its resources in reserve to meet contingency reserve requirements and as regulating margin, depending on system conditions at the time of peak load, and this is before longer-term uncertainties such as extended outages (transmission or generation) and customer load growth are considered. In the 2021 IRP, taking these studies into account, the Company concluded that the 13 percent PRM was still applicable.

Regarding Staff's concern that future IRPs provide greater clarity relative to whether the Company can verify if resulting portfolios are able to meet the established LOLH reliability target, the Company recognizes that this an issue to be considered. As discussed in Chapter 5, stochastic analysis is a key aspect of determining reliability risks and identifying an appropriate PRM. In PacifiCorp's reliability analysis load, hydro conditions, and thermal availability all vary stochastically. PacifiCorp's PRM is intended to cover not only spinning and non-spinning reserve requirements, but also higher than expected load, lower than expected hydro availability, and lower than expected thermal availability. If load is high in a dry hydro year when multiple thermal resources are experiencing forced outages, more resources will be necessary to ensure reliability. To the extent renewable resource shortfalls are correlated with high load or dry hydro conditions, a larger planning reserve requirement might be necessary. Increasing volatility as a result of climate change may also increase planning reserve requirements. PacifiCorp intends to further evaluate these relationships in its 2023 IRP.

In capturing portfolio reliability, the Company considers a PRM in the long-term (LT) model, stochastic risk in running the medium-term (MT) model, and hourly shortfalls in the short-term (ST) model. All three models contribute to the determination of least-cost least-risk portfolio to meet system needs, and all three models apply operating reserve requirements in their optimization. Reliability is achieved in the PLEXOS portfolios through a combination of meeting the 13 percent PRM, applying the stochastic risk-adjustment and addressing hourly shortfalls.

B. FOT Availability Limits

Staff recommends the Company provide more transparency on the methods used for determining FOT availability limits in the next IRP. Staff also questions whether there are occurrences of the limits being exceeded and whether the contingency adder required for market sellers is capacity available for the Company to meet load. They also highlight that FOTs were significantly greater during the summers of 2021 through 2023, and they assert that this has implications for the first capacity deficit date used for setting rates under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Staff recommends that that the Company provide greater clarity on this issue in the upcoming first deficit year filing and in the next IRP.

FOTs represent market purchases that the Company could potentially make to meet its capacity requirements and ensure sufficient resources to reliably serve load. Load and resources must be balanced from moment to moment, so market purchases are ultimately sourced from physical resources and the Company provided significant discussion of regional resource adequacy in Chapter 5 of the IRP as a backdrop for the FOT availability limits it identified. The most significant change from the prior IRP was that market locations connected to California were assumed to have zero availability during California's peak season, which is summer, driven in part by concerns about scarcity conditions that occurred in California in August 2020. This is the first IRP in which these reduced FOT availability limits were used, and the Company expects to rely on FOTs at levels above the new targets until resources procured as part of its 2020 All-Source Request For Proposals reach commercial operation. The Company will address the topic of FOTs in its upcoming avoided cost filing and will continue to evaluate market purchase limits in future IRPs.

C. **Selection of Natural Gas Resources**

Although Staff acknowledges the reasons the Company did not include any new natural gas proxy resources in any of the Company's portfolios, Staff recommends the Company explore an option that allows PLEXOS to select new natural gas resources but also considers the cost of these facilities potentially becoming stranded assets. They state the value of this approach would allow the benefits of a fully dispatchable resource that is not time limited, as is the case with battery storage, to be considered.

The challenge with Staff's suggestion is that when considering current state and federal policies, it is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such facilities in parts of PacifiCorp's service territory. Additionally, as Staff noted, PacifiCorp has observed that there is very limited development activity for new natural gas facilities. This was most recently evident in the Company's 2020 all-source request for proposals ("2020AS RFP"), which did not result in a single bid for new natural gas resources. Nonetheless, PacifiCorp produced a sensitivity in the 2021 IRP that allowed new natural gas proxy resources for transparency, and with the understanding that the inclusion of new natural gas could not be considered the least-risk resource.[8] Additionally, the Company will consider alternative modeling scenarios and/or sensitivities in the development of the 2023 IRP as appropriate.

D. Assessment of Risks Associated with Natrium Nuclear Plant

The Natrium demonstration project is a 500 MW advanced nuclear resource expected to come online in 2028. This non-emitting thermal resource is a molten sodium-cooled nuclear

[8] 2021 IRP, Chapter 9 – Modeling and Portfolio Selection Results at 317; and supplemental filing "Sensitivity – Modeling Results" at 5.

reactor paired with a molten salt thermal energy sodium tank.[9] The reactor and storage generate power through a single turbine.[10] Operating characteristics include: 345 MW of baseload energy production at a 92 percent capacity factor; maximum output of 500 MW and minimum output of 100 MW; a ramp rate of approximately 40 MW per minute from minimum to maximum; molten salt storage supports maximum output of 500 MW for a 5.5-hour duration;[11] and maximum storage efficiency of 99 percent.[12]

While Staff acknowledges the potential benefits from the advanced nuclear Natrium project, they also identified the following concerns and risks: (1) the licensing process by the U.S. Nuclear Regulatory Commission ("NRC") has historically been a source of large delays; (2) there are several technology issues that still require development, and if not resolved, could result in substantial delays; (3) the fuel source for this type of plant has yet to be developed; and (4) there are issues related to spent fuel disposal and plant decommissioning, which could add substantial cost, and should be included in the lifecycle cost of the plant. Because of these risks, Staff recommends that the Company assess contingencies in future IRPs in case the plant is determined to no longer be viable, or if significant delays are likely.

While Natrium is included as a resource in the preferred portfolio, currently PacifiCorp has not signed any contractual agreements with TerraPower regarding the Natrium project. Future contracts will ensure risk and costs are minimized for PacifiCorp customers. Furthermore, TerraPower has many years of nuclear experience that will help in both construction and commissioning. While the project design has not received certification approval from NRC and

---

[9] *Id.* at 204.
[10] *Id.*
[11] Maximum output then drops to 345 MW until output is reduced and more heat can be stored.
[12] 2021 IRP Volume I at 204.

the project has not been submitted for a construction permit and operating license, there are ongoing pre-application meetings with the NRC.

Staff's concerns regarding NRC approval, technological development, fuel availability, center around the risk of the project being substantially delayed. However, the Company notes that the risk is mitigated because alternatives to Natrium require much shorter lead-times than nuclear projects, and there will be opportunities to meet demands in 2028 and beyond prior to a firm commitment from TerraPower. The Company also notes that while there are excellent reasons to continue to pursue the Natrium demonstration project in the near-term, the potential realization of the project does not fall within the action plan window.

The Company's decision to include the Natrium demonstration project was based in part on the unique opportunities that the project offers, including substantial grants from the U.S. Department of Energy and development by TerraPower. Based on these unique attributes, the Company anticipated customer benefits from including the project in the preferred portfolio. Given that the project will not be acquired if it cannot demonstrate benefits to PacifiCorp's customers, the Company will continue to evaluate this project in future IRPs, as recommended by Staff.

E. Effect of CETA

As a final matter, we note that Staff expresses concern that to meet the requirements of Washington's CETA, the Company's preferred portfolio was $164 million higher than the top performing P02-MM portfolio on a risk-adjusted PVRR basis. However, because the Company is obligated to comply with Washington law, and because Washington bears the cost of CETA-driven compliance requirements, this issue is more appropriately addressed in the Multi-State Protocol discussions and is not a requirement that can be altered in the IRP process.

II. REC COMMENTS

REC suggests that the Commission should not acknowledge PacifiCorp's 2021 IRP assumptions because it claims the 2021 IRP assumed that no qualifying facilities ("QF") contracts are renewed. REC also states that PacifiCorp did not produce a sensitivity analysis or provide an adequate explanation of the impact of renewing QF contracts on its load resource balance, or if it did it is not clearly articulated.

PacifiCorp's modeling of QFs in its preferred portfolio assumes that QFs will not renew their contracts at the conclusion of the existing QF contract term, similar to how they were modeled in PacifiCorp's 2017 and 2019 IRP. In its comments, REC recommends that the Commission direct PacifiCorp to assume a reasonable amount of QFs renew their PPAs.[13]

While the Company understands REC's argument that it could be appropriate to include some level of QF capacity because some amount of QFs do renew or negotiate a new contract at the conclusion of their existing contracts, PacifiCorp cannot require a QF to renew (or execute a new agreement) which would make reliance on their inclusion problematic from a planning perspective and a reliability perspective should those projects ultimately not renew.

In addition, it is important to note that the IRP is prepared on a two-year cycle and includes all QF PPAs that have been executed, even if the projects are not yet on-line if the projects are expected to reach commercial operation within the IRP planning period (based on information from the QF developer), including those that renew an existing contract or negotiate a new contract. Trying to develop an assumption around potential additional QF capacity based on historical trends related to renewal could lead to unreasonable or misleading results. For example, during the period 2013 to 2019, PacifiCorp executed new or renewed PPAs ranging between a low of 84 MWs in 2019 and a high of 209 MWs in 2014. These are the projects that are either currently

[13] REC Opening Comments at 6-8.

operational or under construction. However, during this same time period PacifiCorp terminated over 400 MWs of new QF PPAs because the facilities were never built. A forecast based on historical trends could erroneously overestimate the number of QF PPAs in the IRP. Further, historical trends are almost certainly not a reasonable predictor of future QF development activities, which are influenced by a broad range of complex factors. Instead, the Company continues to assert that using the best available data based on actual contracts is the most appropriate incorporation of QF capacity when developing an IRP, especially where new capacity resources represented by proxy resources can be QFs.

Assumptions about the extensions of QFs also have PURPA implications. PURPA is designed to compensate QFs based on the avoided costs of the resources that a utility would otherwise acquire. This compensation determination is made at the time that a QF contract is signed; the resource a QF is allowing a utility to avoid changes over time. As a result, if all QF contracts were assumed extended in the preferred portfolio it would not be possible to discern the replacement resources.

REC suggests that PacifiCorp complete a sensitivity analysis requiring the Company to continue paying QFs the capacity payment at the beginning of their renewed PPA (*i.e.*, eliminate the sufficiency period at the beginning of a new or renewed QF contract).[14] While IRP models may be a tool to help determine the appropriate capacity value of QF contracts, the IRP process is not the appropriate venue for exploring the compensation and contracting practices of QFs.

III. SIERRA CLUB COMMENTS.

Sierra Club claims that PacifiCorp did not fulfil its responsibility to demonstrate that its plans and actions are in the public interest by balancing costs and risks to customers. To support

[14] REC Opening Comments at 9.

this claim, Sierra Club identifies five areas of concern: (1) the Company's methodological choices related to reliability; (2) coal unit economics and retirement assumptions; (3) inclusion of the Natrium nuclear power plant; (4) converting Jim Bridger units 1 and 2 from burning coal to natural gas; and (5) purported barriers to clean energy deployment. Also, Sierra Club provides fourteen recommendations related to the 2021 IRP and future IRPs.

A. Methodological choices related to reliability

Sierra Club expresses concerns regarding reliability modeling, specifically inconsistencies between PacifiCorp's capacity contribution study and the 2021 IRP preferred portfolio with respect to the capacity value of solar with storage. As a result, Sierra Club recommends that the Commission direct PacifiCorp to (1) provide more detail on the capacity value of solar with storage assumed in each year its model and justify the decline in capacity value after 2030;[15] (2) define a specific reliability metric for evaluating its resource portfolios along with a specific performance target along with clearly identifying transmission constraints impacting load area's ability to meet planning reserve margins; and (3) provide the hourly results of its reliability analysis before making any reliability-related cost adjustments or other portfolio refinements.

1. Capacity value of solar plus storage

PacifiCorp discussed capacity contribution in Volume II, Appendix K of the 2021 IRP and highlighted the fact that a resource's capacity value (or contribution to ensuring reliable system operation) is dependent on both its characteristics and the composition of the overall portfolio. PacifiCorp's portfolio composition changes dramatically over time, as a result of retirements and expiring contracts. PacifiCorp's portfolio also changes dramatically over time as a result of resource additions identified in the 2021 IRP preferred portfolio, and with the resource additions

[15] Sierra Club Comments at 7.

specific to each other portfolio. As shown in Figure 1.1 in PacifiCorp's 2021 IRP, solar capacity increases significantly above an already high level in 2030 and beyond. As solar capacity increases, each incremental addition has a lower capacity contribution than the prior increment, as any remaining shortfalls will be less and less likely to occur during hours when the sun is shining. To help temper this effect, PacifiCorp's 2021 IRP assumed all proxy solar resources were combined with four-hour storage equal to the solar nameplate capacity, as storage can allow solar output to be spread across additional hours. However, storage is also subject to diminishing capacity value, as the shortest duration events are eliminated and periods in which surplus energy is available to allow storage to recharge shrink.

PacifiCorp discussed the details of its reporting of the load and resource capacity balance in Chapter 6 of its 2021 IRP, and noted in that discussion that the load and resource results would not match the marginal or "last-in" capacity contribution estimates provided in Appendix K. The load and resource balances reported in Chapter 9, Tables 9.18 and 9.19 also reflect a portfolio capacity contribution (the cumulative contribution for each resource type) in the same manner as that described in Chapter 6 rather than marginal capacity contribution values as identified in Appendix K.

With regard to the annual changes in solar capacity contribution in the load and resource results, PacifiCorp notes that the timing of solar output and peak load changes from year to year, as the solar output reflects a static hourly profile (8,760 hours), while the peak load day rotates with the calendar (so the peak load day never falls on a weekend). While the alignment from year to year varies as a result, the average alignment between renewable output and load setup reflects the actual alignments observed in recent history, as discussed in Appendix K.[16]

[16] 2021 IRP Volume II at 221-223.

i. Results of study for solar with storage

PacifiCorp's capacity contribution analysis was based on a 2030 portfolio composition. After 2030, PacifiCorp's 2021 IRP preferred portfolio contains an additional 820 MW of solar with storage in 2031 and 1,100 MW in 2033. These subsequent incremental solar with storage resource additions amount to roughly 20 percent of PacifiCorp's annual peak load on top of the Company's existing resources, 2020 AS RFP selections, and proxy resource additions through 2030, so significant changes are anticipated relative to the 2030 values shown in Appendix K. While the preferred portfolio also includes significant solar resource additions in 2037, this coincides with the expiration of a significant quantity of QF solar contracts, resulting in a relatively small net change in solar resources. Furthermore, the Company's load and resource balance for the preferred portfolio includes FOTs in the winter starting in 2038. Because solar output is relatively low in the winter, solar combined with storage does not provide sufficient total energy to both serve load during the day and enable charging for even higher loads in the evening and the following morning.

PacifiCorp identified that further additions of solar with storage resources were inadequate to address reliability issues in the 2038 timeframe as part of its reliability assessment.

ii. Assumptions for capacity contributions

With respect to Sierra Club's recommendation that the Commission require PacifiCorp to provide much more detail on its assumptions for capacity contribution in the resource selection process, PacifiCorp disagrees. This additional detail is not relevant as PacifiCorp did not assume any inherent decline in the capacity contribution of any resources over time. PacifiCorp's reliability analysis indicated that, once solar with storage reached a relatively high penetration level, incremental solar with storage no longer provided sufficient incremental capability during the remaining shortfall periods, which became increasingly prevalent in the winter. Given limitations on the available interconnection capacity, it was not feasible to add more solar with storage to compensate, and it was necessary to add resources with higher capacity contributions during the winter, relative to their interconnection capacity.

iii. Transparency of the reliability adjustment

The Company's reliability adjustment is supported and sufficiently transparent. Sierra Club claims that the Company's portfolio development process included a non-transparent pre-modeling reliability adjustment that lacked adequate support. To aid in transparency, Sierra Club recommends that PacifiCorp be directed to (1) provide the hourly results of its reliability analysis, prior to making any reliability-related cost adjustments or other portfolio refinement; and (2) identify which resources in each portfolio were added manually as part of the "portfolio refinement" step and provide a detailed justification for why that specific resource type was selected and what alternatives were considered.[17]

Early in the IRP process, the Company identified shortcomings in the LT model portfolio selection, in terms of both economics and reliability and the Company discussed this topic in Chapter 8 of its 2021 IRP. The PLEXOS model reports the value or revenue for every resource based on its hourly generation profile and locational marginal price. Using that data, the Company identified that the resource value estimates coming from the LT model diverged for some resource types from the values identified by the more granular ST model. PacifiCorp calculated the difference in resource value between the two models and fed that difference back into the LT model as an adjustment to fixed costs for use in portfolio selection. Resources that provided more value in the ST model than the LT model were assigned credits, resources that provided less value

[17]Sierra Club Comments at 8.

in the ST model than the LT model were assigned costs. While this improved portfolio selections, it did not result in fully reliable portfolios, as the Company continued to see unserved load and unmet reserve requirements in some hours in ST model results. The Company presented LT Portfolio 3112 at the June 25, 2021 IRP public-input meeting.[18] This "indicative portfolio" was the initial production portfolio vetted for reliability in the 2021 IRP.

In this indicative portfolio, the largest shortages tended to occur in summer shoulder and evening/night hours when solar radiance was falling off. Due to the duration and timing of the shortages, short duration and solar/wind resources were not sufficient to cover all hours of shortfall. To address the identified shortfalls, PacifiCorp increased the capacity requirements in the PLEXOS model, requiring it to add additional resources. Depending on the timing and year of the reliability needs, resources eligible for consideration for the reliability additions included:

A. Solar with storage
B. Standalone battery
C. Non-emitting peaker
D. Nuclear

As part of this process, the Company identified that system interconnection constraints were limiting the ability of solar combined with 50 percent storage capability to address reliability needs. In response, the storage component of proxy solar with storage resources in the portfolio was increased from 50 percent of the PV resource capacity to 100 percent of the PV resource capacity. The storage duration was held at four hours, so the effective storage capability was doubled.

[18] See https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorps_2021_IRP_PIM_June_25_2021.pdf Slides 18-32 of the presentation discuss the indicative portfolio. Slides 39-41 in the PIM deck describe the reliability assessment process, while slide 42 presents details on the reliability requirements.

A number of resource additions were required over the 2021 IRP study horizon to address reliability needs, and by 2038, interconnection constraints and the declining capacity contribution from further additions of solar with storage meant that it was no longer sufficient to meet reliability requirements, which were increasingly in the winter. As a result, the addition of nuclear and non-emitting peaking resources became the most cost-effective options to address reliability needs. The Company did not make any further changes to modeled costs as part of the reliability adjustment, beyond that already incorporated as part of the granularity adjustment. Because the granularity adjustment represents the difference in value between the LT model and the ST model, it does not impact dispatch in the ST model and is not reported as part of the ST model results.

After the reliability assessment was completed, a portfolio optimized under the MM price-policy scenario, the Company incorporated portfolio refinements to adjust to portfolios under other price-policy conditions. The relative value of available resource options varies by price-policy conditions, but the reliability of the portfolio does not, as resources will be dispatched to ensure reliability regardless of their economics. For each price-policy scenario and at each location with potential proxy resource options, the most economic resource option was selected, while attempting to maintain the overall level of reliability resources through time. The most economic resource option was calculated based on the net cost per kW-year, calculated by subtracting a resource's reported revenue in the ST model from its fixed and variable costs. Where shortfalls were able to be covered by solar with storage, that resource was generally the most cost-effective. In instances where that was not the case and longer duration energy was needed, non-emitting peaking and nuclear resources were typically selected, depending upon the need and cost per kW-year of each option. For each price-policy scenario, this optimized LT portfolio for P02-MM was run through the ST model. Any residual shortfalls were evaluated and the most economic resources available were selected to resolve shortfalls.

After the reliability adjustments described above, the Company also re-optimized energy efficiency and demand response selections to ensure all cost-effective demand-side resources were included, based on the net cost per kW-year metric. Because demand-side measures do not require interconnection capacity, they do not compete with utility-scale resources for limited interconnection capacity. The changes to energy efficiency and demand response were generally minor and would not have materially impacted the reliability assessment.

B. Coal unit economics and retirement assumptions

Sierra Club highlighted eight concerns with the 2021 IRP modeling of the Company's coal resources. They claimed PacifiCorp: (1) failed to include a unit-by-unit coal analysis as was done in the 2019 IRP; (2) inappropriately assumed a significant share of coal fuel expenditures are "sunk costs"; (3) coal fuel pricing tier assumptions lack any clear explanation or justification; (4) P02h variant is lower in cost than the Preferred Portfolio; (5) 2021 IRP did not fully assess the risks associated with Idaho Power's early exit from the Jim Bridger plant; (6) did not adequately assess the risk of a scenario in which selective catalytic reduction ("SCR") installations; (7) P03 Early Coal Retirement Case paints a misleading picture of increased costs; and (8) 2021 IRP failed to evaluate a feasible scenario in which the EPA Requires SCR Installations to comply with the Clean Air Act. As result Sierra Club makes six recommendations to the Commission: (1) Require PacifiCorp to conduct a unit-by-unit coal retirement analysis, which it claims was not performed in the 2021 IRP; (2) Adopt the "No Minimum Scenario" where contractually required minimum take requirements at Jim Bridger are removed from the model and related solicit bids for replacement energy through the 2022AS RFP and limit future investments in Black Butte and

Bridger Coal Company mines; (4) Require that the dispatch of coal resources modeled in future IRPs is based upon the total or "average" fuel costs over a period of 1 or more years (rather than some lower incremental value within each year); (5) Direct the Company to evaluate whether the P02h variant portfolio should replace the preferred portfolio if the Company does not use the "No Minimum Scenario"; and (6) Direct the Company to model the preferred portfolio with SCRs installed on all relevant facilities before 2030.

i. Unit-by-unit coal study

Sierra Club incorrectly asserts that PacifiCorp failed to perform a unit-by-unit coal analysis as it has done in the 2019 IRP.[19] There was no requirement to produce such an analysis, but more importantly, the analysis performed in the 2021 IRP is substantially improved over the earlier approach. PacifiCorp held an initial discussion of coal retirement analysis options as part of the December 3, 2020 IRP public-input meeting. PacifiCorp's modeling system provided multiple retirement options for each relevant coal-fueled generator, modified for the case requirements of each portfolio. Specific retirement dates were optimized as part of the short-term deterministic analysis.

As discussed at the July 30, 2020, and December 3, 2020, public-input meetings, instead of producing a narrow set of unit-by-unit coal studies examining a single unit in a single year for each, the 2021 IRP endogenously considered an estimated 260,000 retirement and coal alternatives before selecting the best initial capacity expansion plan. This was achieved in PLEXOS allowing for multiple options per coal unit to compete within the same optimization analysis. While the Company did not endogenously model every possible coal and transmission option, such as every possible retirement year, due to data availability and performance constraints, this still represents

[19] Sierra Club Comments at 5.

a sea-change, expanding analytical options considered by more than 2300 percent. The Company looks forward to building on its experience with PLEXOS to improve this further, with an aim to incorporating additional years and options where it is possible and likely to lead to valuable insights.

ii. Minimum take or take or pay assumptions.

Sierra Club recommends that the Commission should consider a "No Minimum Scenario" for its preferred portfolio, using a model run that does not include any minimum take or "take or pay" provisions.[20] To support its recommendation, Sierra Club relies on assertions regarding the influence these provisions have on the decision of when to retire a plant; the appropriateness of the Company's assumptions, and the environmental clause in the Huntington coal supply agreement.[21]

The Company's coal fuel inputs for the 2021 IRP incorporate existing contracts through the end of their terms as well as expected costs for any additional volumes or future periods not covered by existing contracts. Coal supply strategy is multi-faceted, especially at the Company's larger plants, so specific details of future coal procurement are beyond the scope of the IRP. The inputs are intended to be representative of the expected operations and restrictions that would likely exist in the future but there is flexibility in how coal supply could be procured over time, and this would be expected to evolve over time.

In the 2021 IRP, the key plants where this is an issue are Huntington and Jim Bridger, both of which included take or pay assumptions that extended beyond the next five years. However, Sierra Club is incorrect that this is treated as a purely sunk cost. The Company's 2021 IRP results

---

[20] Sierra Club Comments at 8, 31-42.
[21] *Id.* at 39-41.

reflected the assumption that when a plant is retired it no longer incurs any take or pay costs from that point forward. The primary effect of take or pay obligations in the 2021 IRP is to constrain future coal-fired operations. Without this constraint, future coal-fired operation would have more flexibility, which would manifest as lower costs across a range of conditions. This flexibility would have little impact in early-retirement scenarios, as they already reflect zero coal-related costs in those future periods. As a result, the Company anticipates that model runs removing future take or pay commitments would provide greater benefits to the preferred portfolio than to early-retirement scenarios. The benefits to the preferred portfolio would be particularly high under scenarios with high greenhouse gas costs, as economic coal-fired dispatch would be expected to be low under those conditions.

Finally, with respect to the environmental regulation provision of the Huntington coal supply agreement, conditions do not exist at this time to invoke this clause. Therefore, it would not be an efficient use of resources to run models under the hypothetical scenario that the Company is not subject to the terms of this contractual provision.

The Company should not be required to model 1,000 MW of new wind as replacement energy for Jim Bridger units 3 and 4 under the No Minimum Scenario.[22] Similarly, the Commission should not constrain the Company from considering coal resources or evaluate changes to operating timelines for the Bridger mine as part of the IRP process. To the extent that the model did not select early retirement for Jim Bridger in the No Minimum scenario, and replace the retiring units with wind, it was because it was not economic to do so. In a PLEXOS model run, all proxy resources are considered in response to any resource being removed from the system for any reason, including retirement. It is core functionality of the PLEXOS model to determine the

[22] Sierra Club Comments at 9, 38-39.

optimal response to the exclusion of a resource, such as upon retirement, and it is a mistake to believe that the model did not have this option. The model may also select alternative resources with different timing, technology, capacity and location if it is economic to do so. The model may also split such a replacement across differing technologies. In the case of alternative retirement scenarios and take-or-pay scenarios, the model has elected, for reason of economics, to retain Jim Bridger 3 and 4 through end of life whether take-or-pay was included or not.

iii. Modeling of the dispatch of coal resources should be based on incremental costs in future IRPs.

Sierra Club continues to argue that in future IRPs, the dispatch of coal resources should be modeled based on average fuel costs over a period of one year or more.[23] The Company's IRP modeling is intended to reasonably represent the constraints and operating parameters faced by each resource. The Company's 2021 IRP results reasonably reflect the total fuel supply costs for each of its coal units. While some of these coal resources are dispatched based on take or pay contracts, with an incremental cost that is lower than the average, this structure is consistent with many of the Company's existing obligations and comparable structures are likely in future coal supply procurement. While each coal supply procurement is likely to extend only a few years into the future, the capital requirements and balance of fixed and variable costs associated with coal production make the take or pay contract design preferable or necessary to coal suppliers each time a new contract is under consideration. The Company notes that total coal costs are reflected in the Company's reported results, so each portfolio incorporates what is effectively an average fuel cost in that regard. By allowing for dispatch based on incremental costs, the Company's results automatically capture changes in average fuel costs as a function of coal demand.

iv. The Company's modeling of the P02 variants and P03 studies are appropriate.

[23] Sierra Club Comments at 9, 30-31.

a. <u>The P02h variant retiring Jim Bridger units 3 and 4 early is not an appropriate replacement for the preferred portfolio.</u>

Sierra Club claims that the P02h variant, which retires Jim Bridger units 3 and 4 before 2030, is lower in cost than the 2021 IRP preferred portfolio despite some "questionable assumptions that needlessly inflate cost".[24] Sierra Club asserts that the P02h variant is lower cost than the Clean Energy Transformation Act case (CETA)[25], and could be CETA compliant already, making it the lowest cost portfolio.[26] Sierra Club recommends that the Commission direct PacifiCorp to evaluate the P02h variant portfolio for Washington's CETA compliance and assess whether it should be considered as a potential replacement for the preferred portfolio.[27]

Sierra Club's claims make incorrect assumptions regarding the P02h variant. As a P02-MM variant case that is not least-cost, it is inappropriate to include CETA compliance costs, particularly as the early retirements, that are the specific subject of the study, are not Washington-allocated, and occur outside of the action plan window, in a timeframe that will be restudied on an ongoing basis as long-term resource plans evolve. The system-wide optimization in the P02 variants is based on the optimal portfolio for all states, whereas costs inherent to CETA's increased requirements and constraints are to be borne by Washington customers as provided by the incremental cost of CETA calculation.

Regardless of the relative cost of a P02h case adjusted for CETA compliance, adopting P02h as the preferred portfolio would inherently and needlessly increase costs to other states, as P02h's present value revenue requirement differential (PVRR(d)) clearly demonstrates when compared to P02-MM.

[24] Sierra Club Comments at 41.
[25] Washington Clean Energy Transformation Act, SB 5116 (effective May 7, 2019)
[26] Sierra Club Comments at 41-42.
[27] *Id.*

The correct comparison for P02h is therefore not the preferred portfolio (which includes the reconfigured Washington Situs resource and other costs that will only impact Washington customers), but rather P02-MM as presented in the 2021 IRP Chapter 9 in Table 9.14.[28] The result of P02h study was that retiring Jim Bridger units 3 and 4 early was $95 million more expensive ($60 million more expensive adjusted for risk) under medium gas and medium CO_2 (MM).

The Company further notes that the preferred portfolio's costs relative to P02-MM are impacted by approximately $65 million of increased energy efficiency investment for Washington, a CETA-driven cost that would be similarly incurred in P02h regardless of other resource selections made for CETA compliance. Other resource additions are allocated based on each state's load and resource balance and Washington receives a significantly smaller portion of the total. As a result, the total quantity of renewable resources in each portfolio is not a good gauge of CETA compliance.

Furthermore, with respect to the addition of a nuclear resource in 2030, Sierra Club fails to recognize that Jim Bridger units 3 and 4 are dispatchable resources and available all hours. Removing two dispatchable resources, per the study request, accelerated the need for additional long duration resources that could run around the clock. The best fit was nuclear located at the Jim Bridger site. The Jim Bridger nuclear addition was accelerated from 2038 when Jim Bridger units 3 and 4 were assumed to retire in the P02-MM portfolio, and also removed a non-emitting peaker. The short term (ST) study was run to verify reliability before finalizing the portfolio.

The assertion that the Company should have re-optimized the portfolio is irrelevant, as the purpose of the long term (LT), medium term (MT), and ST analyses is to determine the optimal

[28] 2021 IRP Volume I at 289.

portfolio considering all requirements. At the conclusion of the analysis, which includes the full optimized dispatch of the final portfolio in the ST model, there is nothing left to optimize.

Similarly, Sierra Club's claim that the nuclear resources were not economic selections because they were selected for reasons of reliability is irrelevant, because all resource selections are optimized as least-cost to meet system requirements. The nuclear resources in question were determined as the least-cost option to meet system reliability requirements.

As such, Sierra Club's recommendation that the Commission direct PacifiCorp to evaluate the P02h variant portfolio for Washington's CETA compliance and assess whether it should be considered as a potential replacement for the preferred portfolio[29] should be rejected.

b. The P03 early retirement case does not reflect deficiencies and subjective choices in the Company's modeling methodology.

Sierra Club claims that the Company's P03 Early Retirement Case does not set forth an accurate picture of costs as compared to the preferred portfolio in part due to deficiencies and subjective choices in the Company's modeling methodology.[30] Sierra Club asserts that nuclear and non-emitting peaker additions are included in the variant and are the main cost drivers between the variants in the base case; however, Sierra Club claims that it is difficult to know what reliability constraints the Company is trying to resolve with these resources as no hourly data for its reliability analysis was provided.[31]

The duration and timing of shortfalls identified by control area in a given year is what led to specific resource selections. Where shortfalls were limited to hours where solar radiance is forecast to be high, solar with storage was the resource selected due to the flexibility to cover

[29] Sierra Club Comments at 41-42.
[30] Sierra Club Comments at 47-49.
[31] *Id.*

shortfalls during the day and up to four more hours during periods with low or no solar generation. In instances where the shortfall durations were short, but in hours when solar resources cannot satisfy reliability, standalone battery was selected. Where shortfalls were of a duration more than four hours, the need for long duration energy led to either nuclear or non-emitting peaker units being selected. Ultimately, the size of the shortfalls and relative system energy value of these options determined which would be selected for reliability. The non-emitting peaker is available in smaller increments but has a very high variable cost. In contrast, each unit of nuclear is large but has a high capacity factor, continuous availability and low variable costs.

v. The Company has accurately and appropriately accounted for ownership of its coal units.

Sierra Club recommends that the Commission direct PacifiCorp to model a variant of its preferred portfolio that includes PacifiCorp absorbing Idaho Power Company's share of Jim Bridger plant costs from 2028-2037 and compare this variant to retiring the plant by 2028.[32] Sierra Club also recommends that the Commission should require PacifiCorp to reconcile the allocation of costs and liabilities arising from the different exit date plans.

Idaho Power's most recent IRP shows an exit from Jim Bridger Units 3 and 4 in 2025 and 2028.[33] At the time of the 2021 IRP Idaho Power had not yet issued its IRP with early exit dates. PacifiCorp therefore made no assumptions regarding whether or how Idaho Power will handle its property, because to do so would be speculative and outside of PacifiCorp's control. A key purpose of PacifiCorp's IRP is to determine the portfolio that best meets the needs of PacifiCorp's customers. The Company uses its IRP to inform strategy as it negotiates agreements with Idaho

[32] Sierra Club Comments at 9, 17-19.
[33] Sierra Club Comments at 61-62.

Power concerning these issues. Moreover, as more information becomes available and as stakeholder questions arise, they can be addressed through the stakeholder input process in the 2023 IRP. There is no need for the Commission to order the Company to account for Idaho Power's plan outside of the already existing processes.

Idaho Power's potential early exit from the Jim Bridger plant is a complex issue requiring a legal agreement around the transfer of its 33 percent ownership, funding its share of the reclamation, transferring water rights, and its portion of the coal agreements. Until a settlement is reached and there is certainty on the outcome, the IRP appropriately models PacifiCorp's ownership share. The Company has appropriately modeled the minimum take provisions of its coal supply agreements.

vi. The Company has accurately and appropriately modeled environmental compliance for, and ownership of, its coal units.

In its comments, Sierra Club asserts that the Company did not adequately assess the risk of a scenario in which selective catalytic reduction ("SCR") installations are required for coal units in Utah and Wyoming.[34] Sierra Club recommends that the Commission direct PacifiCorp to model a variant of the preferred portfolio with SCRs installed on all relevant facilities in Utah and Wyoming, which should be compared to early retirement at these facilities before 2030.[35]

PacifiCorp serves Oregon, Washington, and California, each of which has time-certain laws requiring the utility to remove coal generation from the respective states' retail load. SCR system installation scenario for each of the respective coal units in Utah and Wyoming is seen as an extremely high-risk recovery scenario to undertake when SCRs are capital intensive and three out of the six states that PacifiCorp serves have legislation in place to prevent further investment

[34] Sierra Club Comments at 45-47.
[35] *Id.* at 9.

in coal generation. In addition, PacifiCorp evaluated scenarios with SCRs on the Utah and Wyoming units in its 2017 and 2019 IRPs respectively during the analysis phase that showed installation of SCRs would not be economic for customers, and thus was not selected for the preferred portfolios in the respective IRPs. Thus, there was no appetite to consider high risk SCR installation scenarios further in the 2021 IRP.

Furthermore, there are no state or federal SCR requirements for PacifiCorp's Utah coal plants. There are also no SCR requirements at Naughton or Dave Johnston. The SCR requirements at Jim Bridger units 1 and 2 have been removed from state law, and revision processes for the federal requirements were underway during 2020-2021; this is currently subject to litigation. The SCR requirement at Wyodak is stayed and is subject to litigation. PacifiCorp did not model SCR on all of its coal units in Utah and Wyoming because there are no broad SCR requirements on all of the coal units in Utah and Wyoming. It is speculative and simply inaccurate to state that "SCR requirements will at some point be required under the Clean Air Act." Regional haze requirements vary by source, by pollutant, and by state.

C. Natrium nuclear power plant

Sierra Club questions the reasonableness of the 2021 IRP assumption that power from the Natrium nuclear technology would be available by 2028, and it asserts that the project introduces substantial cost and execution risks that are not adequately addressed in the IRP.[36] Sierra Club asserts the Commission should require PacifiCorp to provide a detailed risk assessment for Natrium to be completed on time and within budget, and it argues the Commission should not acknowledge the Natrium plant as part of this IRP until such an assessment is available and evaluated. With respect to Sierra Club's concerns regarding potential delays associated with the

[36] Sierra Club Comments at 49.

Natrium demonstration project, the Company notes that it addressed these issues in response to recommendations of Staff in section I.C. *supra.*

i. Selection of the Natrium demonstration project for the 2021 IRP preferred portfolio

Sierra Club expresses concerns related to the economic selection of the Natrium demonstration project and asked for additional variant analysis.[37] It seeks a detailed explanation of how the Natrium demonstration project can be both non-economic (requiring hardwiring into PLEXOS) and economic (removing the project from the model increasing costs to the system).[38]

While the Natrium demonstration project was assumed in the preferred portfolio, it is incorrect to characterize its inclusion as uneconomic. The Company modeled reasonably anticipated costs based on currently available information and took the additional step of ensuring that the Natrium demonstration project is indeed cost effective as modeled by conducting a variant study, P02e. The results demonstrated $158 million of risk-adjusted customer benefits which will nonetheless continue to be evaluated with a clear focus on customer protection and realizing customer benefits. As noted previously, the Company's unique attributes of the Natrium project, such as substantial grants from the DOE and the development of the project by TerraPower, support the Company's expectation of significant customer benefits from including the project in the preferred portfolio, as demonstrated by the modeled economic benefits over P02e.

ii. Execution Risks of the Natrium demonstration project

Sierra Club suggests that there are substantial execution risks associated with the Natrium demonstration project that have not been adequately addressed in the 2021 IRP. As noted previously, PacifiCorp has not signed any contracts with TerraPower regarding the project, and it

[37] Sierra Club Comments at 6, 53.
[38] *Id.* at 31.

will ensure that risks and costs are minimized for customers in doing so. Risks of this project are also mitigated by the fact that TerraPower is responsible for the development of the Natrium project. The Company would not acquire a nuclear resource that did not come on-line under a build own transfer.

Regarding the financing, government funding, and cost sharing concerns, again, PacifiCorp will minimize risks and costs through future contractual agreements with TerraPower regarding the Natrium demonstration project. Further, with recent passing of the Infrastructure Investment and Jobs Act, significant federal funding has been secured from the United States Department of Energy.

D. Jim Bridger Units 1 and 2 natural gas conversion

Sierra Club claims that the Company's planned natural gas conversion of Jim Bridger units 1 and 2 by 2024 carries significant fuel costs risks.[39] As such, Sierra Club recommends that the Company provide an updated risk assessment of gas and fuel that reflects recent price trends. The 2021 IRP looked at the risk around natural gas prices in the MT model using stochastics. The Company also looked at several price-policy scenarios for natural gas and greenhouse gas costs. The dispatch of Jim Bridger units 1 and 2 when converted to natural gas peaking units is generally very low. For example, the annual capacity factor averages under 5 percent under medium gas / medium CO_2 price-policy conditions, so significant changes in gas prices would have a relatively small impact on annual operating costs. The ability to respond to changing conditions adds to the value of this type of resource on the system. The Company's 2021 IRP further increases the amount of renewable resources and storage on the system such that further out in time, solar with storage provides a lesser degree of incremental capacity value. The Jim Bridger units 1 and 2 gas

[39] Sierra Club Comments at 6, 10, 54-58.

conversions delay the need for alternative long duration dispatchable assets, and because they reuse primarily existing infrastructure, the conversion provides capacity at a significantly lower cost than a new asset.

E. **Barriers to Clean Energy**

Sierra Club claims that the 2021 IRP's long-term resource cost assumptions are not fully informed by the recent all-source RFP results. Sierra Club recommends that the Commission require PacifiCorp to revise its long-term resource cost assumptions, particularly for battery storage (standalone or paired with other resources), to better reflect the results of its "2019 all-source RFP."[40] PacifiCorp understands Sierra Club's reference to the "2019 all-source RFP" to be to the 2020 All-Source RFP. Further, Sierra Club claims that PacifiCorp's long-term resource cost assumptions are not fully informed by the 2020AS RFP.[41]

Sierra Club indicated long-term resource cost assumptions are not fully informed by the recent all-source RFP results. As early as October 2020, the 2020AS RFP initial shortlist was developed from bids received in the RFP process. The final shortlist RFP was completed July 2021. The Supply Side Table (SST) in the 2021 IRP was finalized March 2021. During this time, the RFP bid costs for 2023 to 2024 were compared to the SST in the same years. That comparison found that the wind and solar capital investment costs were reasonably aligned but the standalone Li storage in the SST was higher cost than the RFP. In light of this, battery costs were assumed to de-escalate faster between 2021 and 2024 to be more in line with the RFP.

CONCLUSION

PacifiCorp's 2021 IRP complies with the Commission standards and requirements. The 2021 IRP includes robust and extensive portfolio modeling under a wide-range of price-policy

[40] Sierra Club Comments at 10.
[41] Sierra Club Comments at 62-65.

scenarios and other prudent planning assumptions discussed with, and reflective of, stakeholder input that ultimately results in the selection of a least-cost, least-risk preferred portfolio. The 2021 IRP also includes an action plan that is consistent with the long-term public interest. PacifiCorp appreciates the comments received from an active and engaged stakeholder group and continues to support stakeholder participation throughout the IRP development process to foster constructive dialogue and inform its long-term resource planning efforts. Therefore, PacifiCorp requests that the Commission accept for filing the 2021 IRP and the 2021 IRP action plan.

Respectfully submitted this 4th day of April, 2022.

Emily Wegener

Emily Wegener
Attorney for Rocky Mountain Power