Office of the Secretary
Service Date
August 30, 2022

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF ROCKY MOUNTAIN POWER'S FOR ACKNOWLEDGMENT OF ITS 2021 ELECTRIC INTEGRATED RESOURCE PLAN	)))))	**CASE NO. PAC-E-21-19** **ORDER NO. 35514**

On September 1, 2021, Rocky Mountain Power ("Company"), a division of PacifiCorp, filed its 2021 Electric Integrated Resource Plan pursuant to Commission Order No. 22299.

On September 15, 2021, the Company filed an updated IRP ("2021 IRP" or "IRP") for the purpose of clarifying some changes in the IRP filed on September 1, 2021. The Company assured that the updated IRP did not "affect the analysis or outcomes of the 2021 IRP." Updated IRP Vol. I Cover Letter at 1.

On October 28, 2021, the Commission issued a Notice of Application, and Notice of Intervention Deadline. Order No. 35209.

On December 1, 2021, the Idaho Conservation League ("ICL") and Sierra Club (collectively, "Intervenors") intervened. Order No. 35238.

On December 27, 2021, the Commission issued a Notice of Modified Procedure and established deadlines for public comments and for the Company's reply. Order No. 35271.

On March 15, 2022, Commission Staff ("Staff") submitted comments and the Intervenors submitted joint comments. One hundred sixteen public comments were received.

On April 4, 2022, the Company submitted the "2021 IRP update"[1] and filed comments replying to Staff, the Intervenors, and REC.

The Commission now issues this Order acknowledging the Company's 2021 IRP.

BACKGROUND

In 1989, the Commission ordered electrical utility companies operating in Idaho to submit a "Resource Management Report" ("RMR"). *See* Case No. U-1500-165, Order No. 22299. The RMR detailed the status of an electric utility's resource planning, including how it planned to meet future resource needs. The Commission ordered electric utilities to develop and complete

[1]The Company stated that the 2021 IRP update provided "a number of updates including a description of resource planning, procurement activities, an updated load and resource balance, an updated resource portfolio reflecting updates to load forecast and other model inputs, and a status update on action plan items from the 2021 IRP." 2021 IRP Update Cover Letter at 1.

RMRs biennially to publicly document the utility's forecasted resource plan to meet demand over the upcoming 20-year period. In developing the RMR, the Commission directed utilities to "emphasize clarity, understandability, resource capabilities, and planning flexibility." *Id.* at 12.

The Commission considered "ongoing comprehensive planning essential to good utility management." *Id.* at 6. The Commission also recognized that resource planning was the sole domain of utility executives and that only prudence reviews of a utility's plans are necessary. Th RMR evolved into what is now referred to as the "IRP".

Pursuant to Commission orders, the Company must file an IRP biennially with the Commission that allows for public participation and examines and discusses the following four areas: (1) load forecast uncertainties; (2) the effects of known or potential changes to existing resources; (3) considerations of demand and supply side resource options; and (4) contingencies for upgrading, optioning, and acquiring resources at optimum times (considering such factors as cost, availability, lead time, reliability, and risk) as future events unfold. Order No. 34780 at 1 (citing Order No. 22299).

In acknowledging the Company's 2019 IRP the Commission stated an IRP should separately address:

- "Existing resource stack," by identifying all existing power supply resources.
- "Load forecast," by discussing expected 20-year load growth scenarios for retail markets and for the federal wholesale market including ""requirements" customers, firm sales, and economy (spot) sales. This section should be a short synopsis of the utility's present load condition, expectations, and level of confidence.
- "Additional resource menu," by describing the utility's plan for meeting all potential jurisdictional load over the 20-year planning period, with references to expected costs, reliability, and risks inherent in the range of credible future scenarios.

Id. at 2. If the Commission finds the IRP discusses these required subjects, then it will enter an order acknowledging the Company's IRP. Commission acknowledgement of a filed IRP is an affirmation of the Company's completion of the requirements of the IRP planning process, but not of the conclusions or prudency of the resources contained in the plan. *Id.* at 12-13.

ROCKY MOUNTAIN'S 2021 IRP

The Company stated its 2021 IRP was developed through comprehensive analysis with extensive public input. Rocky Mountain updated 2021 IRP at 1. The Company's primary objective of the 2021 IRP was to identify the best mix of resources to continue to serve customers by considering both cost and risk. *Id*. at 7. The Company stated that the least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—was the portfolio that could be delivered through specific action items at a reasonable cost and with manageable risks, while considering customer demand for clean energy and ensuring compliance with federal and state regulatory objectives. *Id*. The Company stated that the 2021 IRP preferred portfolio included accelerated coal retirements, no new fossil-fueled resources, continued growth in energy efficiency programs, and a greater reduction in greenhouse gas emissions relative to the 2019 IRP. *Id*. at 1.

The Company stated that the preferred portfolio included investments in renewables, facilitated by incremental transmission investments, demand-side management resources, storage resources, and advanced nuclear. *Id*. at 5-6. Specifically, the Company stated that, by the end of 2024, the preferred portfolio included the 2020 All-Source Request for Proposal final shortlist proposals of 1,792 Megawatts ("MW") of wind resources, 1,302 MW of solar additions, and 697 MW of battery storage capacity,[2] as well as the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. *Id.* at 8. The Company further stated that, over the 20-year planning horizon, the IRP preferred portfolio included 3,628 MW of new wind resources, and 5,628 MW of new solar resources co-located with storage. *Id.*

To facilitate the delivery of energy to customers, the Company's 2021 IRP preferred portfolio also included constructing a 416-mile transmission line—Gateway South—which will connect southeastern Wyoming with northern Utah. *Id*. at 31.

The Company's 2021 IRP Action Plan highlighted the Company's planned actions over the next two to four years to deliver its preferred portfolio. Action items were based on the type and timing of resources in the preferred portfolio and included:

1. **<u>Existing Resource Actions</u>**:
    - Seek to exit Colstrip Units 3 and 4 by December 31, 2025.
    - Seek to exit Craig Unit 1 by December 31, 2025.
    - Begin retiring Naughton Units 1-2 by December 31, 2025.
    - End coal-fueled operations at Bridger Units 1 and 2 and seek permitting for natural-gas conversion by 2024.

[2] Of this total storage capacity, 497 MW will be paired with solar and a 200 MW as a standalone battery.

- Continue to comply with regional haze standards.

2. **<u>New Resource Actions</u>**:

- Work with Utah customers to develop a program to achieve goal of net 100 percent renewables by 2030.
- Pursue necessary regulatory approvals to authorize the acquisition and repowering of Rock River I and Foote Creek II-IV wind facilities.

  Complete regulatory steps and finalize agreements to begin training operators by 2025 for the Natrium Demonstration project.

3. **<u>Transmission Action Items</u>**:

- Complete construction and place in service by Q3 2024, Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line).
- Complete construction and place in service by Q3 2024, Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line).
- Continue supporting construction of Boardman to Hemingway 500 kV transmission line.

4. **<u>DSM Activities</u>**:

- Acquire cost-effective Class 2 DSM—energy efficiency—resources by targeting annual system energy and capacity selections from the preferred portfolio.
- Pursue cost-effective, Class 1—demand response—resources targeting annual system capacity selections from the preferred portfolio.

5. **<u>Market Purchase Items</u>**:

- Acquire short-term market purchases for on-peak delivery from 2021-2023 and balance month, day, and hour-ahead transactions through an intercontinental exchange with competitive pricing.

6. **<u>Renewable Energy Actions</u>**:

- Pursue unbundled Renewable Energy Credit ("REC") requests for proposals ("RFPs") to meet state Renewable Portfolio Standard ("RPS") requirements.
- Issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify to meet California's RPS through 2024.

- Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

STAFF COMMENTS

Staff filed comments recommending the Commission acknowledge the Company's IRP. Staff's recommendation was supported by its review of the IRP filing, the Company's responses to production requests, and the Company's efforts to solicit comments from stakeholders through the public input process.

Staff noted the Company addressed the areas required to be addressed in an IRP by the Commission and therefore recommended the Commission acknowledge the 2021 IRP. However, Staff expressed concern with certain portions of the 2021 IRP and provided recommendations to the Company for its next IRP.

1. 2021 IRP OVERVIEW

Staff noted the Company took the following planning steps in developing its IRP: (1) develop key inputs and assumptions; (2) model a range of resource portfolios; (3) analyze variants to the top performing resource portfolios; (4) select a preferred portfolio; and (5) identify next steps within the action plan. *Id.* at 8.

Staff further noted that the 2021 IRP preferred portfolio identified the following changes, relative to the 2019 IRP: (1) accelerated coal-unit retirements; (2) no new fossil-fueled resources; (3) continued growth in energy-efficiency ("EE") programs; (4) incremental new renewable resources; (5) greater reduction in greenhouse gas emissions; (6) increased investment in transmission infrastructure; (7) conversion of two coal units to natural gas peaking units; (8) growth in demand response ("DR") capacity; (9) new advanced nuclear resources; (10) increased reliance on energy storage resources; and (11) non-emitting peaking resources using technology requiring further technology development.

a. <u>Preferred portfolio</u>

Staff noted the Company selected its preferred portfolio, which, on a risk-adjusted present-value revenue requirement ("PVRR") basis, was $164 million higher than the top performing, least-cost least-risk portfolio due to the requirement to meet Washington's Clean Energy Transformation Act ("CETA") requirements.[3] *Id*. at 4-5. Staff noted the significant

[3] The 2021 IRP Update indicates that the "CETA portfolio in the 2021 IRP Update is $42 million less costly than in the 2021 IRP on a risk-adjusted PVRR(d) basis." 2021 IRP Update at 85.

cumulative incremental cost of the preferred portfolio over the least-cost least-risk portfolio over the 20-year planning horizon. *Id.* at 5. Staff noted that the cost difference between the two portfolios indicated the magnitude of additional cost the State of Washington should be allocated in the Multi-State-Protocol ("MSP") to ensure that Washington legislation does not increase costs to customers in other jurisdictions.

b. <u>Issues Addressed from the 2019 IRP Staff Comments</u>

Staff believed the Company addressed—with varying levels of success—concerns that were raised in the 2019 IRP in the 2021 IRP. *Id.* at 6-7. Specifically, Staff believed the Company responded to the concern that it failed to include updated coal unit decommissioning costs in the 2019 IRP by including in the 2021 IRP the base estimate demolition costs from a 2019 study. *Id.* at 6. Staff further noted the Company, by not including any new natural gas resources for selection by the model in the 2021 IRP, failed to address Staff's concern expressed in the 2019 IRP that the high natural gas price forecast disadvantaged natural gas plants and transmission resources compared to new renewable resources. *Id.* at 7.

c. <u>Improved Modeling Capabilities</u>

Staff believed the 2021 IRP improved upon the quality of the IRP results. Staff stated the Company began using Plexos software in 2021. As a result of using the new software, the volume of individual portfolios needed to evaluate the impacts of varying resource decisions was greatly reduced and the Company became able to evaluate the timing of plant retirements, gas conversions of coal plants, carbon capture and sequestration, retrofits to coal units, battery optimization, and alternative transmission topologies. *Id.* at 7.

2. RELIABILITY ASSESSMENT

Staff was concerned with some of the methods the Company used to ensure reliability of its portfolios.

a. <u>Use of Minimum of 13 percent PRM</u>

Staff noted the 13 percent planning reserve margin ("PRM") used in the 2021 IRP was a number determined in the 2019 IRP that did not account for the inputs, parameters, and assumptions specific to the 2021 IRP. Staff believed the Company needed to justify why the old planning margin of 13 percent was still appropriate.

b. <u>Verification of Loss of Load Hour ("LOLH") Reliability Target</u>

Relatedly, Staff noted the 13 percent PRM was selected "to meet a [LOLH] reliability target of 2.4 hours per year, which equates to one day in ten years, a common reliability target in the industry." *Id.* at 10. However, the PRM is not a reliability target in and of itself serving as an interim adjustment factor used to increase load in development of the portfolios. Without verification back to the original reliability target, it is unclear that the portfolios met the one day in ten-year level of reliability.

3. EVALUATION OF IRP RESOURCES

a. <u>Natural Gas Resources, Coal Generation, Renewables, and Energy Storage</u>

Staff noted the Company did not include any new natural gas proxy resources in its portfolios for a variety of reasons. Staff believed the Company could have used an approach that would allow Plexos to select new natural gas resources while simultaneously considering the cost of these facilities becoming potential stranded assets. *Id.* at 11.

Staff noted state and federal regulations were driving the early retirement of much of the Company's coal fleet and that coal plant capacity retained beyond 2025 and 2030 would be reassigned to the Company's other jurisdictions through the MSP due to Washington's and Oregon's coal plant restrictions. *Id.* at 12.

Staff noted that, due to the declining cost of renewables and battery storage, the preferred portfolio continued to add new renewables. Staff noted the Company's continued investment in transmission and energy storage resources in the 2021 IRP, along with the selection of the advanced nuclear Natrium project. *Id.* at 13.

b. <u>Market Purchases and Front Office Transaction ("FOT") Availability</u>

Staff noted FOTs play a specific role in the IRP for fulfilling capacity requirements throughout the 20-year planning horizon. Staff noted the IRP's assumption that FOT availability limits of 500 MW for summer and 1,000 MW for winter was a significant reduction from the 2019 IRP projections. Staff believed the Company should be more transparent by describing the steps and the assumptions it uses in its method to determine FOT availability limits in the next IRP. *Id.* at 14. Staff recommended the Company clarify in the first deficit year filing and the next IRP whether FOTs in the Load and Existing Resource Balance ("L&R") above the availability limit are properly reflected and can be counted on to provide the stated amount of capacity.

Staff noted that the L&R in the 2021 IRP—unlike in the 2019 IRP—did not include the three percent increases in the FOT Availability Limit. Staff stated the Company's explanation that "the [three] percent adder is for contingency reserves that firm energy sellers are required to hold" does not explain whether the additional amount of contingency is available to the Company to meet its load. *Id.* at 14. Staff recommended the Company provide more clarity on this issue in the upcoming first deficit year filing and in the next IRP.

c. <u>Private Generation, DSM, Advanced Nuclear Projects, and Non-emitting Peaker Resources</u>

Staff stated the IRP's reference to the "first ten years (2021-2030) of the planning horizon" in the sentence, "the hourly system load is reduced by hourly private generation projections to determine the net system coincident peak load for each of the first ten years (2021-2030) of the planning horizon," was incorrect and should, according to the Company's response to Staff's Production Request, refer to the first "20 years of the IRP planning horizon (2021 through 2040)." *Id.* at 15.

Staff further noted the Company effectively deployed a mature portfolio of EE and DR programs to reduce and reshape loads and that these programs are cost-effective, and "reduce the cost the Company incurs to serve customers." *Id.*

However, Staff was concerned that while the TerraPower advanced nuclear Natrium demonstration project in the preferred portfolio could be beneficial, it came with significant risks. Staff identified the federal licensing process, undeveloped technological issues, the lack of a practical fuel source, and issues endemic to spent fuel disposal and plant decommissioning as factors that could add significant cost and delay to the project. *Id.* at 16.

Staff stated the Company added 1,224 MW of hydrogen fueled non-emitting peaker resources to its preferred portfolio starting in year 2033. Staff acknowledged the technology for hydrogen was immature and therefore it was acceptable to include these resources in portfolios only during the second half of the 20-year planning horizon. Staff noted that the status and feasibility of the technology could be updated in future IRPs as the addition of these types of resources approach construction lead times.

Based on the above analysis, Staff recommended the Commission acknowledge the Company's 2021 IRP, but further recommended:

1. The Company clarify whether a LOLH reliability target of 2.4 hours per year was achieved by the Company's portfolios;
2. The Company clarify the development of FOT availability limits in future IRPs; clarify whether the inclusion of three percent contingency amounts for firm purchases were appropriate to include to meet Company load; and clarify the issue of exceedance of FOT limits in the early years of the planning horizon as it pertains to the first deficit date for purposes of PURPA avoided cost rates;
3. The Company explore an approach allowing for the selection of natural gas resources in a portfolio while also providing an adjustment to the cost based on the expected cost risk of becoming a stranded asset; and
4. The Company better assess the risks of technology viability and potential delays inherent with the Natrium nuclear plant implementation and plan for contingencies.

COMPANY'S REPLY COMMENTS TO STAFF

1. Clarify whether the LOLH reliability target of 2.4 hours per year was achieved.

The Company contended that a 13 percent PRM was still applicable in the 2021 IRP. Company Reply Comments at 6. In support of this conclusion, the Company pointed to numerous studies in Chapter 5 of the 2021 IRP that considered PRM of 15 percent and the PRM study in the 2019 IRP that directed the Company to hold 10.5 percent to 11.5 percent. *Id.*

In response to 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 pointed to the stochastic studies in Chapter 5 of the IRP that recognized that this is an issue to be considered and stated its intent to further evaluate the relationship between the Company's reliability analysis, load, hydro conditions, and thermal availability in its 2023 IRP. *Id.* at 7.

2. Improve clarity on the development of the availability limits of FOTs

Staff recommended the Company: (1) provide more transparency on the methods used for determining FOT availability limits in the next IRP; (2) clarify whether the inclusion of 3% contingency amounts for firm purchases are appropriate to include to meet Company load; and (3) clarify the exceedance of FOT limits in the early years of the planning horizon as it pertained to the first deficit date for purposes of PURPA avoided cost rates. In response, the Company stated that it discussed the above issues in Chapter 5 of the IRP and would continue to "address the topic of FOTs in its upcoming avoided cost filing and . . . continue to evaluate market purchase limits in future IRPs." *Id.* at 8-9.

3. Select Natural Gas resources.

In response to Staff's suggestion to include natural gas resources in its portfolios, the Company replied that it was not feasible to assume new natural gas resources can obtain the permits needed to site and operate such facilities in parts of the Company's service territory due to current state and federal policies, and that "there is very limited development activity for new natural gas facilities." *Id.* at 9. However, the Company stated it would "consider alternative modeling scenarios and/or sensitivities in the development of the 2023 IRP as appropriate" to allow for the selection of natural gas resources in a portfolio. *Id.*

4. Assess the risks of the selection of the Natrium nuclear plant.

In response to Staff's concerns with Natrium, the Company replied that it had not currently signed a contract with TerraPower regarding the Natrium project, that there were other alternatives to Natrium to meet demand in 2028, and that it would continue to evaluate this project in future IRPs. *Id.* at 10-11.

5. Washington's CETA's impact on the Company's preferred portfolio.

The Company pointed out that the issue of CETA compliance increasing the preferred portfolio by $164 million was "more appropriately addressed in the [MSP] discussions and is not a requirement that can be altered in the IRP process." *Id.* at 11.

INTERVENOR COMMENTS AND COMPANY REPLY

The Intervenors stated the Company did not demonstrate that the plans and objectives of the IRP were in the public interest. Intervenor Comments at 1. The Intervenors averred that, due to the Company's undue favoritism towards its coal fleet, and by omitting critical information, the IRP "process and selection errors result in a resource plan that will cost customers more money and expose them to more risk [sic] inevitable carbon regulations." *Id.* at 2.

The Intervenors were specifically concerned with five areas in the IRP: (1) the Company's methodological choices related to reliability; (2) the analysis of coal unit economics and plant retirements; (3) risks related to the Natrium plant; (4) risks related to the Jim Bridger gas conversion; and (5) barriers to clean energy development. *Id.* at 5.

1. Concerns over methodological choices related to reliability.

The Intervenors stated that due to inconsistencies in the contribution study and the preferred portfolio with respect to the capacity value of solar plus storage may be leading to overbuild of coal replacement resources. *Id.* at 5 and 11. The Intervenors pointed out that the Company's "application of a 13 percent hourly reserve margin to individual load areas was not fully justified and may be overly conservative." *Id.* at 5 and 14. The Intervenors mentioned that the Company's "portfolio development process included a non-transparent post-modeling 'reliability adjustment' [that] lacked adequate supporting data or analysis." *Id.* at 5 and 17.

The Intervenors recommended that the Commission direct the Company to provide in all future IRPs more detail on solar plus storage and the decline in capacity after 2030. *Id.* at 7. The Intervenors further recommended the Company "define a specific reliability metric for evaluating its resource portfolios along with a specific performance target as well as clearly identifying transmission constraints impacting load area's ability to meet planning reserve margins." *Id.* at 7-8. The Intervenors further recommended the Commission direct the "Company to provide the hourly results of its reliability analysis, prior to making any reliability-related cost adjustments or other portfolio refinements . . . [and] to 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." *Id.* at 8.

***Company Reply*:** The Company replied that it discussed and/or clarified the issues related to solar plus storage and the decline in capacity after 2030 in the 2021 IRP. *See* Company Reply Comments at 14-16.

The Company disagreed with the Intervenor's recommendation that it be required to provide more detail on its assumptions for capacity contributions in the resource selection process, arguing that it did not assume any inherent decline in the capacity contribution of resources over time, so this recommendation was off point. *Id.* at 16.

The Company further replied that its reliability adjustment was supported and sufficiently transparent. *Id.* at 17. The Company explained the extensive process it undertook in developing its reliability adjustments during the IRP process. *Id.* at 17-19. This process, the Company explained, allowed it to discover the shortcomings in its modeling and reevaluate its models.

2. Coal unit economics and plant retirements.

The Intervenors alleged that, by failing "to include a unit-by-unit coal analysis" the Company overlooked an essential step in analyzing the reasonableness of retirements in its portfolio-wide analysis. Intervenor Comments at 5 and 21. The Intervenors further alleged that the Company, by "inappropriately assum[ing] a significant share of its future coal fuel expenditures were 'sunk costs' in the form of future take-or-pay contracts" significantly hampered "any coal retirement analysis since these costs would never materialize if the plants retired early." *Id.* at 5-6 and 25. The Intervenors further argued that the Company did not clearly explain coal fuel pricing costs, the preferred portfolio was not the least cost option, and the IRP didn't adequately address the risks of Idaho Power Company's ("Idaho Power") early exit from the Jim Bridger plant or a scenario in which selective catalytic reduction ("SCR") installations are required in Utah and Wyoming. *See Id.* at 6 and 30-45. The Intervenors also contended that the PO3 "Early Coal Retirement Case" was misleading as to increased costs relative to the preferred portfolio. *Id.* at 6 and 47.

The Intervenors recommended the Commission direct the Company to conduct a unit-by-unit coal retirement analysis in the current 2021 IRP and in all future IRPs. *Id.* at 8. The Intervenors also recommended the Company consider more wind resources and be precluded from investing in new coal production prior to a "thorough prudency review of an updated long-term fuel supply for Jim Bridger." *Id.* at 8-9.

The Intervenors recommended the Commission "require that the dispatch of coal resources modeled in future IRPs is based upon the total or 'average' fuel costs over a period of one or more years (rather than some lower incremental value within each year)." *Id.* at 9.

Finally, the Intervenors recommended the Commission direct the Company to consider a variety of different portfolios which would contemplate different scenarios related to the Company's and Idaho Power's withdrawal from Jim Bridger and the installation of SCRs in Utah and Wyoming. *Id.*

Company Reply**:** The Company replied that a "unit-by-unit" coal analysis was not required by the IRP but noted that it did discuss coal unit retirement in numerous public-input meetings, and used Plexos modeling to evaluate "260,000 retirement and coal alternatives[,]" and looked forward to continuing to use Plexos to model coal plant retirements in the coming years. Company Reply Comments at 21-22.

The Company further replied that "coal supply strategy is multi-faceted" and the Intervenors' assumption that "take or pay assumptions" regarding coal plants that extend beyond five years is treated purely as a sunk cost was incorrect. *Id.* at 22. The Company argued that it should not be required to model an additional 1,000 MW of new wind resources to replace Jim Bridger units 3 and 4 under a model posed by the intervenors that does not include a minimum "take or pay" provisions.. *Id.* at 23. Essentially, the Company replied that the Plexos model considered alternative retirement scenarios, take-or-pay scenarios and, "for reasons of economics," selected the preferred portfolio. *Id*. at 24.

The Company replied that its IRP "modeling is intended to reasonably represent the constraints and operating parameters faced by each resource" and reasonably reflected the total fuel supply cost for each of its coal units." *Id.* The Company summarized that, "[b]y allowing for dispatch based on incremental costs, the Company's results automatically capture changes in average fuel costs as a function of coal demand." *Id.*

The Company further replied that it accurately and appropriately accounted for its joint-ownership interests in Jim Bridger with Idaho Power considering all the inherent complexities and uncertainties. *Id.* 28-29

Finally, the Company replied that it did not model the installation of SCRs in Utah and Wyoming because of disparate state and federal requirements, current litigation at some of the plants in the respective states, and the high cost of SCRs to customers. *Id.* 29-30.

3. Natrium Nuclear Plant.

The Intervenors suggested that the Company's expectation that it could rely on the Natrium reactor for power by 2028 was unrealistic. Intervenor comments at 6 and 49. The Intervenors recommended the Commission require the Company "to provide a detailed risk assessment for Natrium to be completed on time and within budget[,]" and not "acknowledge the Natrium plant as part of this IRP until such an assessment is available and evaluated." *Id.* at 10.

***Company Reply*:** The Company replied that, due to Department of Energy ("DOE") grants and other factors, the inclusion of Natrium was cost-effective and properly included in the preferred portfolio. Company Reply Comments at 31. The Company further replied that because the Company had not signed any contracts with TerraPower and was not responsible for the development of the project, and there was significant federal funding secured from the DOE, the risks with Natrium were mitigated. *Id.* at 31-32.

4. Jim Bridger Gas Conversion.

The Intervenors stated the Company's proposed gas conversion of the Jim Bridger plant came with significant risks which should be borne by shareholders and not customers. Intervenor Comments at 6 and 58. The Intervenors further stated that the IRP contained unresolved questions about the coal-to-gas conversion analysis and noted that the Company and Idaho Power did not appear aligned on the gas conversion proposal. *Id.* at 6 and 61.

The Intervenors recommended the Commission require the Company better assess the risk of gas fuel based on recent price trends and "reconcile the allocation of costs and liabilities arising from different exit date plans" from Jim Bridger with co-owner Idaho Power. *Id.* at 10.

Company Reply**:** The Company replied that it properly assessed the risks around natural gas prices in the MT model using stochastics in the 2021 IRP. Company Reply Comments at 32. The Company further replied that converting an existing asset like Jim Bridger was less expensive than acquiring a new asset. *Id.*

5. Barriers to Clean Energy Development.

The Intervenors summarized that the Company's long-term resource cost assumptions were not fully informed by the recent all-source request for proposal ("RFP") results and therefore recommended that the Commission require the Company "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." *Id.* at 10.

Company Reply**:** The Company replied that it "understands [the Intervenors'] reference to the '2019 all-source RFP' to be to the 2020 All-Source RFP." Company Reply Comments at 33. The Company further replied that:

> As early as October 2020, the 2020 [All-Source 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.

Id.

PUBLIC COMMENTS AND COMPANY REPLY

All the public comments specifically recommended the Commission reject the Company's IRP as it was not the least cost and least risk energy plan for Idahoans due to its reliance on coal, volatile natural gas prices, and unproven nuclear technology.

The Renewable Energy Coalition ("REC") filed public comments contending that the Company's assumption in the IRP that no Qualifying Facilities ("QFs") would renew or enter new contracts with the Company at the end of their current contracts was inconsistent with prudent and reasonable planning and departed from the practice of Idaho Power and the Oregon Public Utility Commission. REC further contended that the Company did not produce a sensitivity analysis or provide an adequate explanation of the impact of renewing QF contracts on its load resource balance

***Company Reply*:** The Company stated it understood REC's argument that it could include some level of QF capacity in the IRP because some QFs do renew their contracts. Company Reply Comments at 12. However, the Company further explained that to do so would be problematic from a planning and reliability perspective because some QFs choose not to renew their contracts and the Company cannot require them to do so. *Id.*

The Company further stated that "trying to develop an assumption around potential additional QF capacity based on historical trends related to renewal could lead to unreasonable or misleading results." *Id.* The Company also stated that making assumptions about QFs has PURPA implications because QFs are compensated based on the avoided costs of the resources that a utility would otherwise require at the time a contract is signed; if it is assumed in the IRP that a QF contract is extended in the preferred portfolio, however, the Company contended it would not be possible "to discern the replacement resources." *Id.* at 13.

In response to REC's last contention, the Company replied that the IRP process is not the appropriate venue to conduct a sensitivity analysis to explore the compensation and contracting practices of QFs. *Id.*

COMMISSION DISCUSSION AND FINDINGS

The Company is an electrical corporation and public utility as defined in *Idaho Code* §§ 61-119 and -129, and the Commission has jurisdiction over it and the issues in this case under Title 61 of the Idaho Code, including *Idaho Code* § 61-501.

Having reviewed all the filings in this case, including the Company's 2021 IRP and its appendices and comments from members of the public, Staff, the Intervenors, and the Company's reply comments, the Commission finds that the Company's 2021 IRP is presented in the appropriate format and contains the required information as outlined in Order No. 22299. Accordingly, the Commission accepts and acknowledges the Company's 2021 IRP filing.

In doing so, the Commission reiterates that a standard IRP is merely a plan, not a blueprint. An IRP is a utility planning document incorporating many assumptions and projections at a specific point in time. It is the ongoing planning process we acknowledge, not the conclusions or results. The Commission offers no opinion or ruling regarding the prudency of the Company's election of its preferred resource portfolio.

The Commission acknowledges the comments and criticisms of interested parties, including Staff and the Intervenors. The Commission appreciates the Company's willingness to furnish an IRP process which fosters meaningful opportunities for input and participation from interested parties. The Commission believes that such participation by multiple interested parties is necessary to develop an effective resource planning document. We encourage the Company to continue to evaluate its involvement in Jim Bridger, coal unit economics, plant retirements, and other alternatives.

The Commission appreciates the Company addressing concerns brought up in the 2019 IRP comments in its 2021 IRP. As this Commission has stated numerous times, the IRP is an ongoing process that continually evolves through each iteration. The Commission continues to encourage interested parties to engage in the development of each successive IRP. When parties see that their comments and concerns have been recognized whether the Company agrees with them or not, it shows the Company is paying attention. The Commission believes robust participation helps the Company develop the best planning document. The Commission believes the Company should consider the concerns raised in comments submitted in this case as it plans, and to continue evaluating all resource options and the best interests of customers when developing the 2023 IRP.

The Commission notes the Company's parent PacifiCorp's service area is vast, including areas in Idaho, Washington, Oregon, California, Wyoming, and Utah. The impact of these different states' policies and objectives on the development of the Company's 2021 IRP is complex. In assessing the IRP, the Commission's primary concern is and always will be the potential impact of the Company's plan on Idaho ratepayers. We understand that the MSP process is designed to ensure that the costs of service to the customers in different states is properly allocated. We will be closely watching the allocation process and MSP proposals. However, with this Order we reiterate our continued commitment to ensuring that Idaho ratepayers do not pay additional costs for service attributed solely to customers in other states.

We direct the Company, in its next IRP, to clarify whether a LOLH reliability target of 2.4 hours per year was achieved by the Company's portfolios and explain the development of FOT availability limits. We further direct the Company to clarify the issue of exceedance of FOT limits in the early years of the planning horizon as it pertains to the first deficit date for purposes of PURPA avoided cost rates and whether the inclusion of three percent contingency amounts for firm purchases were appropriate to include to meet Company load.

While we understand the market realities of natural gas, we encourage the Company to continue exploring an approach in its IRP process that allows for a reasonable and accurate selection of cost-effective natural gas resources in a portfolio. Finally, we acknowledge the inherent complexities with the Natrium project and direct the Company to continue to assess the risks of technology viability and potential delays with Natrium and plan accordingly.

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ORDER

IT IS HEREBY ORDERED that the Company's 2021 IRP is acknowledged.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order regarding any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 30th day of August 2022.

ERIC ANDERSON, PRESIDENT

JOHN CHATBURN, COMMISSIONER

JOHN R. HAMMOND, JR., COMMISSIONER

ATTEST:

Jan Noriyuki
Commission Secretary

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