Office of the Secretary
Service Date
September 14, 2020

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF ROCKY MOUNTAIN POWER'S 2019 ELECTRIC INTEGRATED RESOURCE PLAN	))))	**CASE NO. PAC-E-19-16** **ORDER NO. 34780**

On October 25, 2019, PacifiCorp dba Rocky Mountain Power ("Company") filed its 2019 Electric Integrated Resource Plan ("2019 IRP" or "IRP") pursuant to Commission Order No. 22299.

On December 3, 2019, the Commission issued a Notice of Filing and Notice of Intervention Deadline. *See* Order No. 34494. No one petitioned to intervene.

On April 30, 2020, the Commission issued a Notice of Modified Procedure setting deadlines for public comments and the Company's reply. The Commission received comments from Staff, Idaho Sierra Club, and six members of the public. The Company filed reply comments in response to Staff and Sierra Club.

The Commission now issues this Order acknowledging the Company's 2019 IRP.

BACKGROUND

An IRP is a status report on the utility's ongoing, changing plans to serve its customers adequately and reliably at the lowest system cost and least risk over the next 20 years. The IRP informs the Commission and the public about the utility's plans, and is like an accounting balance sheet, i.e., it is a snapshot of the utility's resource planning process. *See* Order No. 22299. The IRP is meant to demonstrate the utility has prepared for, and considered, many scenarios through a reasonable planning process. The Commission thus expects a utility to have vigorously tested the IRP's assumptions and methodologies to ensure the IRP accurately reflects changing markets and customer demand.

The Company must update its IRP every two years and allow the public to participate in developing the IRP. *See id.*; Order No. 25260. The final IRP must address the areas required by the Commission's prior Orders, including Order Nos. 22299 and 25260. In summary, the final IRP should explain the Company's present load/resource position, expected responses to possible future events, and the role of conservation in those responses. It also should discuss "any flexibilities and analyses considered during comprehensive resource planning, such as: (1)

examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand- and supply-side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold." *See* Order No. 22299. The 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. If the Commission finds the IRP discusses these required subjects, then it will enter an order acknowledging the Company's IRP. By acknowledging the IRP, the Commission is acknowledging the Company's ongoing planning process, but not the conclusions or results reached through that process. By acknowledging the IRP, the Commission is not offering any prudency determinations for resources or investments included in the IRP.

ROCKY MOUNTAIN'S 2019 IRP

The Company developed its 2019 IRP through comprehensive analysis and public input. The 2019 IRP preferred portfolio includes accelerated coal retirements and investment in transmission infrastructure that will facilitate the addition of nearly 11,000 Megawatts ("MW") of new renewable resources—plus the deployment of new technologies—during the 20-year planning period.

The primary objective of the Company's 2019 IRP is to identify the best mix of resources to serve customers going forward. The best mix of resources is identified through analysis that measures both cost and risk. The least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risk, while considering customer demand for clean energy and ensuring compliance with state and federal regulatory objectives.

The Company's Filing states, "the 2019 IRP sets forth a clear path to provide reliable and reasonably priced service to [its] customers." The analysis supporting the IRP helps the Company, customers, and regulators understand the effects of both near-term and long-term resource decisions on customer bills, the reliability of electric service the Company's customers receive, and changes to greenhouse gas emissions from the electricity generation assets used to serve customers. In its 2019 IRP, the Company presents a preferred portfolio that "builds on its vision to deliver energy affordably, reliably, and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity over the longer-term planning horizon while maintaining substantial investment in energy efficiency."

The Company's 2019 IRP includes investment in new resource technologies including—renewables, battery storage, and modern grid technology. It also outlines new transmission investments across the Company's territory needed to remove existing transmission constraints and improve grid resilience so the lowest-cost renewable resources can be delivered to customers.

The Company's Filing states comprehensive data analysis and an extensive stakeholder input process supported its 2019 IRP preferred portfolio. The Company's 2019 IRP preferred portfolio continues investments in new wind, transmission, and demand side management ("DSM"), while adding significant solar and battery storage resources. By 2025, the preferred portfolio includes nearly 3,000 MW of new solar resources, 3,500 MW of new wind resources, nearly 600 MW of battery storage capacity[1], 860 MW of incremental energy efficiency resources and new direct load control capacity.

Over the 20-year planning horizon, the IRP preferred portfolio includes more than 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, more than 2,800 MW of battery storage[2], and more than 1,890 MW of incremental energy efficiency resources and new direct load control capacity.

For delivery of new renewable power to customers, the Company's 2019 IRP preferred portfolio also includes the construction of a 400-mile transmission line, Gateway South, connecting southeast Wyoming with northern Utah.

[1] All storage will be combined with new solar resources.
[2] More than 1,400 MW of storage capacity consists of stand-alone storage resources being developed beginning in 2028.

The Company's 2019 IRP Action Plan highlights the Company's planned actions over the next two to four years to deliver its preferred portfolio. Action items are based on the type and timing of resources in the preferred portfolio and include:

1. **Existing Resource Actions**
   - Finish conversion of Naughton Unit 3 from coal to natural gas during 2020.

   - Begin retiring Cholla Unit 4 during Q1 2020 and complete the process by January 2023, including all regulatory notices and filings.

   - Begin retiring Jim Bridger Unit 1 in Q2 2020 and complete the process by the end of 2023, including all regulatory notices and filings.

   - Begin retiring Naughton Units 1-2 by the end of 2023, including all regulatory notices and filings.

   - Request the operator of Craig Unit 1 administer termination or amendment for existing agreements to prepare for closure by the end of 2025.

2. **New Resources Actions**
   - Work with Utah customers to develop customer-resource preferences for: 1) one 15-year power purchase agreement ("PPA") for 80 megawatts ("MW") of solar for six schedule 34[3] customers, and 2) two 20-year PPAs for approximately 80 MW of solar for one large schedule 34 customer.

   - Issue an all-source request for proposal ("RFP") for resources that can achieve commercial operation by December 2023. By the end of 2019, file an interconnection queue with the Federal Energy Regulatory Commission. By Q1 2020, file the draft RFP with Oregon, Washington, and Utah regulators. Execute PPAs with winning bids by Q2 2022.

3. **Transmission Action Items**
   - *Energy Gateway South*: By Q2 2021, the Company will receive its final Certificate of Public Convenience and Necessity from Wyoming Public Service Commission and Public Service Commission of Utah to construct a 400-mile, 500-kilovolt ("kV") transmission line from Medicine Bow, WY to Mona, UT. By Q4 2023, construction will be complete, and the new transmission line will be in service.

[3] Schedule 34 in Utah is for Renewable Energy Purchases for Qualified Customer—5,000 kilowatts and over.

- *Utah Valley Reinforcements*: To facilitate interconnection of customer-preference resources (*See* New Resource Actions, above), the Company will reinforce its system in the Utah Valley, as necessary.

- *Northern Utah Reinforcements*: Rebuild two-miles of the Morton Court—Fifth West 138 kV line. Loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond.

- *Utah South Reinforcements*: Develop a service plan to support the 2019 IRP Preferred Portfolio for resource additions in southern Utah. Finish rebuilding the Mona to Clover #1 and #2 345 kV transmission lines. Identify a route and terminals for a 70-mile 345 kV transmission line in south/central Utah.

- *Yakima Washington Reinforcements*: By Q2 2020, complete the Vantage to Pomona 230 kV line, and establish the type and location of new resources.

- *Boardman to Hemmingway ("B2H")*: Continue supporting the project under the conditions of the B2H Joint Permit Funding Agreement.

- *Energy Gateway West*: Continue permitting for the Energy Gateway West transmission plan, with near-term targets. Continue building Segment D.2 with target in-service date of 12/31/2020. For Segments D.3 and E, continue funding of required federal agency permitting and continue public outreach.

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.[4]

   - Target 29 MW of cost-effective, Class 1—demand response ("DR")—Direct Load Control in Utah between 2020 and 2023.

5. **<u>Front Office Transactions</u>**
   - Acquire short-term market purchases for on-peak delivery from 2019-2021.

   - Balance month, day, and hour-ahead transactions through an intercontinental exchange with competitive pricing.

[4] In 2020, the Company estimates it will have 132 MWhs of Annual Incremental Capacity and 536 gigawatt-hours of Annual Incremental Energy from Class 2 DSM activities.

6. **Renewable Portfolio Standards**

- Issue unbundled Renewable Energy Credit ("REC") RFPs to meet state Renewable Portfolio Standard ("RPS") requirements.

- Issue RFPs seeking current-year vintage unbundled RECs that will qualify to meet California's RPS through 2020, and current-year, forward-year RECs that will meet Washington State's RPS targets.

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

STAFF COMMENTS

Staff filed comments and recommended the Commission acknowledge the Company's IRP. Staff's recommendation is supported by its review of the IRP filing, the Company's response to production requests, and the Company's efforts to solicit comments from stakeholders through the public input process. Staff noted the Company's 2019 IRP was the most comprehensive IRP analysis to date and "substantially improved upon methodologies for evaluating the costs, benefits, and timing of integrating new generation and transmission resources into the system."

Staff noted the 2019 IRP preferred portfolio "reflects accelerated coal retirements and expanded investment in new wind and solar resources, battery storage, and [DSM]." The Company's preferred portfolio includes investments in transmission throughout the Company's territory to remove existing transmission constraints and improve grid resilience to deliver low-cost renewables according to Staff. This includes construction of Gateway South—a 400-mile transmission line connecting southeast Wyoming and northern Utah—among others.

Staff recognized enhanced modeling efforts employed in the 2019 IRP to address the choice of coal plant retirement dates. In its 2017 comments, Staff stated the Company "relied on predetermined retirement dates tied to environmental compliance rather than evaluating the economic viability of coal units over a range of potential retirement dates." Staff continued "[p]redetermining retirement dates in the 2017 IRP prevented the optimization model from selecting coal plant retirement dates based on economics." Staff also expressed concerns in its 2017 IRP comments that the Company was including benefits beyond the 20-year planning horizon, thereby distorting comparisons between portfolios. Staff noted the Company fully addressed these concerns in the 2019 IRP. Staff acknowledged that the Company improved its ability to robustly analyze its resources and refined its understanding of system reliability with increased renewable penetration.

Staff noted that the Company's preferred portfolio, for the first time, included battery storage to enhance "reliability of a system increasingly supported by renewable resources and variable generation." Staff indicated tax incentives were important in supporting the economics of battery storage.

Staff recognized the 2019 IRP relied less on front office transactions ("FOT") than past IRPs. Staff noted the Company treated FOT's as proxy resources assumed to be firm. Staff observed that the Company's FOT limits in the 2019 IRP were built upon its "active participation in wholesale power markets, physical delivery constraints, market liquidity and market depth, and regional resource supply." Staff believed the reduced reliance on FOT was prudent given supply uncertainties for later dates in the forecast model.

Staff identified five areas where it believed additional review or focus was warranted:

1. Capacity Deficiency Date in the Load and Existing Resource Balance

Staff noted, based on load and resource balance, the Company's system will become capacity deficient during the summer peak of 2028. Because the timing and amount of deficiency identified in the load and resource balance will be used to determine when new Public Utility Regulatory Policies Act of 1978 ("PURPA") contracts are eligible for capacity payments, Staff was concerned that inclusion of the Company's coal plant retirements might affect the deficit date. Staff stated:

> The load and existing resource balance identifies resource deficiencies in the Company's system acting as a starting point for developing and evaluating future resource portfolios. A decision to close a plant early must be evaluated against other alternatives that maintain system reliability and should be made as part of the portfolio development and evaluation phase of the IRP. Regardless of whether the closure decision is driven by economics or by environmental compliance, one should choose the least cost alternative that maintains system reliability, which likely requires additional replacement resource(s). The early retirement and the replacement resources should be considered as a combined resource decision and should only be included together so an accurate deficit date can be determined. However, the Company has reflected coal plant retirements from the preferred portfolio in the load and resource balance contained in Tables 5.12 and 5.13 (2019 IRP), which Staff believes is improper for purposes of establishing a first deficiency date for PURPA.

2. Coal Unit Decommissioning Costs

On January 17, 2020, and March 16, 2020, the Company filed supplemental confidential decommissioning studies for each of the Company's remaining coal units.[5] The studies provided an in-depth, third-party analysis for the requirements and costs associated with closing each of the remaining coal units, according to Staff. Decommissioning costs are important in determining a plant's economic viability and substantiate future timing of the coal unit closures. Staff suggested the Company use the updated studies in the forecasting model for the 2021 IRP.

3. Forecasted Natural Gas Prices

Staff noted that the Company used a high natural gas price forecast in its 2019 IRP, which Staff stated, "is a striking change from its 2017 IRP, where the Company used a relatively low natural gas price forecast." According to Staff:

> From 2022 through the end of the planning period in 2039, the Company's long-term forecasted natural gas prices in the 2019 IRP significantly exceed the forecast prices in the U.S. Energy Information Administration's (EIA) "Reference" case and "High Oil and Gas Supply" case. The Company's forecasted prices exceed EIA's Reference case prices by more than 30% in ten of the eighteen years of the 2022-2039 period. The Company's prices exceed EIA's High Oil and Gas Supply case prices by more than 40% in seventeen of the eighteen years of the 2022-2039 period. The Company's forecast more closely tracks EIA's higher priced "Low Oil and Gas Supply" case.

Staff observed that the Company's forecast for natural gas prices exceeded similar forecasts from industry consultants and other Commission regulated utilities' forecasts.

In its 2017 IRP comments, Staff was concerned the Company was using too low of a natural gas forecast, offering that the forecast would cause the resource optimization model to select higher than optimal levels of gas plants and transmission resources. In the 2019 IRP, Staff held the opposite concern. Staff noted that using a high natural gas forecast might disadvantage gas plants and transmission in favor of renewables. Staff noted the Company's 2019 IRP includes a large share of renewable resources compared to past IRPs. Staff Stated:

> State law in Oregon and Washington mandate the removal of coal generation from their rates and impose carbon limits or cap and trade. Oregon and Washington also have ambitious renewable portfolio standards. Idaho does not impose the same mandates nor share the same timetable for renewable portfolio standards. By over-estimating long-run natural gas prices, a portfolio excessively rich in renewable

[5] The supplemental confidential decommissioning cost studies will be dealt with in Phase II of the Company's depreciation docket, PAC-E-18-08.

> resources may be erroneously identified as least cost. Under this scenario, Idaho customers potentially pay higher prices for electricity and subsidize Oregon's and Washington's regulatory priorities.

4. Transmission Planning

Staff mentioned that the Company is currently providing funding for B2H but noticed the Company's preferred portfolio excludes B2H. Staff noted "the Company appears to have plans to move forward with B2H even though its own modeling does not identify this as a least cost resource." Staff added that it is not appropriate for customers to fund construction of system resources without "defined quantifiable benefit and revenue streams." Staff reasoned that "defined quantifiable benefits and revenue streams" need to be present before it will be prudent for Idaho customers to fund B2H as a system resource.

5. DSM and Time-of-Use

Staff noted the Company has a large DR capability—about 200 MW of operating reserve capacity it can dispatch. Staff also noted the Company had recently began work to expand its DR program by creating a grid-scale solution that turns DR resources into frequency-responsive operating reserves. Staff encouraged the Company to continue to expand its cost-effective DR programs.

Staff offered that time-of-use rates can promote peak load reductions and load shifting to off-peak times. If successful, shifting demand to off-peak hours could lower power costs and help reduce or defer capital expenditures. Offering time-of-use pricing also provides customers an opportunity to reduce their bills in response to market signals according to Staff.

Staff suggested the Company should continue to evaluate expected costs and benefits of potential time-of-use programs and DR programs for Idaho customers. Staff continued that time-of-use should be mandatory for commercial, industrial, and irrigation customers. In evaluating potential time-of-use programs for Idaho, Staff opined that "rate designs incorporating customers' preferences can improve satisfaction and may boost subscription to time-of-use programs." Staff analyzed two proposed time-of-use programs—one for Oregon and one for Washington—and agreed that the Company's "varied criteria for time-of-use rate design is appropriate for a system with diverse climate regions and end-uses."

SIERRA CLUB'S COMMENTS

Idaho Sierra Club submitted comments describing its concerns with the Company's IRP and recommendations. First, Sierra Club was concerned the Company is subsidizing the continuation of uneconomic coal units. Sierra Club cited disparities between Idaho Power's IRP and the Company's IRP for closure of all four units at Jim Bridger. Sierra Club asked that the Company be required to re-evaluate the economics of each coal unit in all future IRPs and for the Commission to ensure the Company does not impede other utilities serving Idaho customers from exiting coal to best serve their Idaho customers.

Second, Sierra Club asked the Commission to investigate the potential for securitization to further reduce ratepayer expenses when non-economic coal plants retire. The Company cited recently enacted legislation in New Mexico and Colorado that allows utilities to refinance existing coal plant balances at retirement. Sierra Club indicated Utah may pass similar legislation, which would improve the rate payer basis for retiring non-economic coal plants while minimizing impacts to the Company's bottom line. The Company, according to Sierra Club, elected to assume it is entitled to full recovery of and on remaining plant balance, even for non-economic coal plants.

Third, Sierra Club asked the Commission to not acknowledge any expenditures on transmission assets listed in the Company's action plan "unless they are contingent on the Company's all-source RFP process identifying those as part of a least-cost resource plan." Sierra Club cited the lack of specifics in the Company's generation plan and much more specific transmission plan, including the Gateway South transmission line. Sierra Club argued the transmission lines are "tied to notional generation resources that the Company is not committed to developing and for which the Company has not established a tangible need."

Last, Sierra Club asked, "that the Company be more diligent in removing coal-favored biases from its analyses and to be resourceful and perseverant in pursuing options to accelerate its exit of coal." Sierra Club noted the Company's complex analyses contain "overly optimistic assumptions on future coal prices or under-stated assessments of risk factors" when investigated.

PUBLIC COMMENTS

The Commission received six public comments (from five commenters) offering their support for clean energy generation to help reduce climate change. The commenters encouraged several means of renewable and alternative energy generation to promote clean energy. Two commenters suggested dams should be removed to allow for salmon and steelhead recovery in Idaho.

THE COMPANY'S REPLY

The Company filed reply comments, responding to Staff and Sierra Club.

A. Reply to Staff

1. Capacity Deficiency Date in the Load and Existing Resource Balance

The Company noted the 2028 deficiency date in its IRP is largely the outcome of the preferred portfolio selection process rather than an input to that process. Therefore, the Company argued Staff's concerns about a deficiency date would not have affected the Company's analysis of the 2019 IRP and eventual selection of a preferred portfolio. The Company continued that within its 2019 IRP modeling process, planning reserve requirements, portfolio optimization, and reliability assessments were combined to find the least-cost, least-risk portfolio of resources across time instead of resources to meet a specific capacity deficit in any particular year. The Company stated Staff's concerns about deficiency period timing for PURPA contracts would be better addressed in the capacity deficiency filing after the Commission acknowledges the 2019 IRP.

2. Integrating Updated Coal Unit Decommissioning Cost Studies into Planning Process

The Company stated its IRP utilized information available when its analysis was performed. The decommissioning studies were not finalized until January and March of 2020, after assumptions for the 2019 IRP were established. The Company will incorporate the latest coal unit decommissioning cost information into the 2021 IRP, which will allow intervening parties to review the studies before they are included in the IRP.

3. Long Range Gas Assumptions

The Company suggested a discrepancy between gas forecasting graphs included in the Company's 2019 IRP filing and Staff's comments originated from the years of the selected forecast data. The Company's forecast was established before the 2019 IRP was filed. Staff's data referenced in its comments was from 2020. The Company included a graph from Staff's comments with forecast data from 2019 substituted for the 2020 forecast data used by Staff. Both data sets originated from the same source. The Company suggested the graph using 2019 data more closely aligned with the timing when it established its natural gas forecast and offered the forecast using the timelier data was reasonable.

4. Transmission Planning

The Company acknowledged Staff's B2H comments and agreed to focus more on B2H in the 2021 IRP. The Company will include quantification of the benefits, as necessary. The Company noted it has not committed to construction of B2H and has not entered into a construction agreement with Idaho Power or Bonneville Power Administration—the other parties considering the transmission line.

5. Continuation of DSM and Time-of-Use

The Company stated it plans to continue to support, evaluate, and grow its DR and time-of-use offers to maintain cost effectiveness.

B. Reply to Sierra Club

In response to Sierra Club's comments the Company stated: (1) it uses its IRP to evaluate the most cost-effective options to serve its customers system-wide and that it plans to re-evaluate the economics of its coal units in the 2021 IRP analysis; (2) it uses its IRP process to evaluate cost-effective alternatives which includes continuing to respond to legislation and regulatory guidance in its operating territories; (3) that specific resource determinations and economics will be tied to its RFP process and the 2021 IRP, and past IRPs, continues to model proxy resources and an aggregated transmission topology; and (4) the Company disagreed with Sierra Club's assertion that the IRP analysis was biased. The Company stated its goal "has always been and continues to be to produce an unbiased IRP."

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 Case No. PAC-E-19-16, including the Company's 2019 IRP and its appendices and comments from members of the public, Staff, Sierra Club, and the Company's reply comments, the Commission finds that the Company 2019 IRP is presented in the appropriate format and contains the information outlined in Order No. 22299. Accordingly, the Commission accepts and acknowledges the Company's 2019 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 that incorporates 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 Sierra Club. The Commission expresses its appreciation for 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 and a key factor in developing an effective resource planning document.

The Commission appreciates the Company addressing concerns brought up in the 2017 IRP comments in its 2019 IRP. As the Commission has stated, the IRP is an ongoing process that continually evolves through each iteration. The Commission continues to encourage interested parties to be part of the development of each successive IRP. When parties see that their comments and concerns have been addressed, it shows the Company is paying attention. The Commission believes robust participation helps the Company develop the best planning document. The Commission expects the Company to actively 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 2021 IRP.

The Commission notes the 2019 IRP's endorsement of increased amounts of wind, solar, and battery storage. The Commission understands transmission investments will be necessary to move the energy generated by new investments to customers. The Commission encourages the Company to fully study the costs and benefits of additional transmission resources in its 2021 IRP. Although the Commission offers no current prudency determination, we look forward to the Company developing resources from its least-cost resource portfolio to help meet demand in a safe and reliable manner. Additionally, the Commission is encouraged by the Company's development of DSM resources and continues to encourage the study, development, and implementation of economical DSM programs. The Commission looks forward to observing and working with the Company as it continues to develop time-of-use pricing policies to help shift peak demand in its service territory.

Finally, the Commission expects the Company to continue refining and enhancing its forecasting methodologies by analyzing a broad and diverse range of measures to avoid disadvantageous or unfair forecasting treatment of certain resources over others.

ORDER

IT IS HEREBY ORDERED that the Company's 2019 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 14th day of September 2020.

Paul Kjellander
PAUL KJELLANDER, PRESIDENT

Kristine Raper
KRISTINE RAPER, COMMISSIONER

Eric Anderson
ERIC ANDERSON, COMMISSIONER

ATTEST:

Jan Noriyuki
Jan Noriyuki
Commission Secretary

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