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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**
	COMMENTS OF THE COMMISSION STAFF

STAFF OF the Idaho Public Utilities Commission, by and through its Attorney of record, Dayn Hardie, Deputy Attorney General, submits the following comments.

BACKGROUND

On October 25, 2019, PacifiCorp dba Rocky Mountain Power ("Company") filed its 2019 Electric Integrated Resource Plan ("2019 IRP") pursuant to the Commission's rules and in compliance with the biennial IRP filing requirements mandated in Order No.22299. The Company's Application requested acknowledgement of the 2019 IRP.

The Company's IRP filing consists of the following items: 1) 2019 Integrated Resource Plan - Volume I; 2) 2019 Integrated Resource Plan - Volume II, Appendices A-L; 3) 2019 Integrated Resource Plan - Volume II, Appendices M-R; 4) Supplemental Data Discs; and 5) Supplemental Corrections (October 25, 2019 and November 8, 2019).

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

STAFF REVIEW

Staff believes the Company has met the requirements for an Integrated Resource Plan set forth in Commission Order No. 22299 and recommends the Commission acknowledge the Company's 2019 IRP filing. Order No. 22299 requires that the Company provides:

1. An examination of load forecast uncertainties;
2. An identification of effects of known or potential changes to existing resources;
3. Consideration of demand and supply side resource options; and
4. Recognition of contingencies for upgrading, optioning, and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.

Staff's recommendation is supported by its review of the IRP filing, the Company's responses to production requests, and the Company's effort to solicit comments from stakeholders through the public input process. Staff directly participated in all IRP stakeholder meetings.

The 2019 IRP is the product of the Company's most comprehensive IRP analysis to date. Staff believes that the Company has substantially improved its methodology for evaluating the costs, benefits, and timing of integrating new generation and transmission resources into its system. The Company has also extensively examined the reliability implications of its resource options.

Staff has identified areas where it believes additional review or focus is warranted. These include:

- Capacity Deficiency Date in the Load and Existing Resource Balance;
- Integrating updated coal unit decommissioning cost studies into the planning process;
- Long-run gas cost assumptions. The Company's 2019 IRP gas cost forecast is significantly higher than the Company's 2017 forecast;
- Transmission Planning; and
- Continuation of Demand Side Management (DSM) and time-of-use efforts.

2019 IRP Overview

The primary objective of the Company's 2019 IRP is to identify the best mix of resources to serve customers' energy requirements in future years. 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 a 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 2019 IRP preferred portfolio reflects accelerated coal retirements and expanded investment in new wind and solar resources, battery storage, and demand side management. By 2025, the preferred portfolio includes nearly 3,500 MW of new wind resources, 3,000 MW of new solar resources, nearly 600 MW of battery storage capacity, 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, and more than 1,890 MW of incremental energy efficiency resources and new direct load control capacity.

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

The Company enhanced its 2019 IRP modeling to address the choice of coal plant retirement dates. In 2017 IRP 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. Predetermining retirement dates in the 2017 IRP prevented the optimization model from selecting coal plant retirement dates based on economics. In the 2017 IRP, Staff was also concerned that including benefits beyond the 20-year planning horizon distorted comparisons between portfolios. The Company, in its 2019 IRP, has fully addressed these issues. The Company has also improved its ability to conduct a robust analysis of its resources - including its coal unit retirements - and refined its understanding of system reliability associated with increased amounts of renewable resources. The methodology used in the coal studies informed the preferred resource portfolio reflected in the Company's IRP.

Table No. 1 below shows accelerated coal plant retirement dates in the 2019 IRP compared to the retirement dates in the 2017 IRP. As Table No. 1 shows, coal plant retirements in the 2019 IRP are four to nineteen years earlier than previously planned. The multi-state process ("MSP") is also engaged in coal plant retirement analyses.

Table No. 1 – 2017 and 2019 IRP Planned Coal Unit Retirement Dates

Coal Unit	Retirement Date 2019 IRP	Retirement Date 2017 IRP	Difference in Years
Jim Bridger Unit 1	2023	2028	5
Jim Bridger Unit 2	2028	2032	6
Naughton Unit 1	2025	2029	4
Naughton Unit 2	2025	2029	4
Craig Unit 2	2026	2034	8
Colstrip Unit 3	2027	2046	19
Colstrip Unit 4	2027	2046	19

The 2019 IRP includes new battery storage for the first time as part of the least-cost, least risk preferred portfolio. Battery storage is used to support reliability of a system increasingly supported by renewable resources and variable generation. Tax incentives are important in supporting the economic viability of battery storage.

The use of front office transactions ("FOT") in the resource mix is reduced in the 2019 IRP compared to prior IRPs. In this IRP, the Company has treated FOTs as proxy resources, assumed to be firm, representing on-going procurement activity to help cover short positions, with FOTs being made on a balance of month, day-ahead, hour-ahead, or intra hour basis. The Company states that FOT limits are based upon its active participation in wholesale power markets, physical delivery constraints, market liquidity and market depth, and regional resource supply. Staff believes that reduced reliance on FOTs is prudent given supply uncertainties for later dates in the forecast model. Increased renewable generation and battery storage are drivers in the FOT reduction.

The 2019 IRP includes the conversion of the Naughton 3 coal unit to natural gas. Staff supports this conversion because it is a cost-effective transition from coal and retains a firm dispatchable resource.

Capacity Deficiency Date in the Load and Existing Resource Balance

The load and resource balance presented in Chapter 5 of the IRP identifies the Company's capacity and energy deficiencies before identifying the resources that will be used to economically meet future load and reliability needs. The capacity deficiency information is also used in a biennial capacity deficiency filing, which occurs after the acknowledgement of the IRP, to determine avoided cost rates under PURPA. Based on the load and resource balance, PacifiCorp's system first becomes capacity deficient during the 2028 summer peak. (*See* Table No. 5.12 of the Company's IRP).

The capacity deficiency in the load and resource balance, both the timing and the amount of the deficiency, will be used to determine when new PURPA contracts are eligible to receive capacity payments. However, Staff is concerned that the inclusion of the Company's coal plant retirements in the load and existing resource balance may affect the deficit date.

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 decision to close a plant early is driven by economics or by environmental compliance, the Company 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 its load and resource balance contained in Tables 5.12 and 5.13 of the 2019 IRP, which Staff believes is improper for purposes of establishing a first deficiency date for PURPA.

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. The studies provided an in-depth third-party analysis for the requirements and costs associated with closing each of the remaining coal units. Decommissioning costs are important in determining a plant's economic viability and substantiate future timing of the coal unit closures. These updated studies, completed after the 2019 IRP filing, should be used in the forecast model supporting the 2021 IRP.

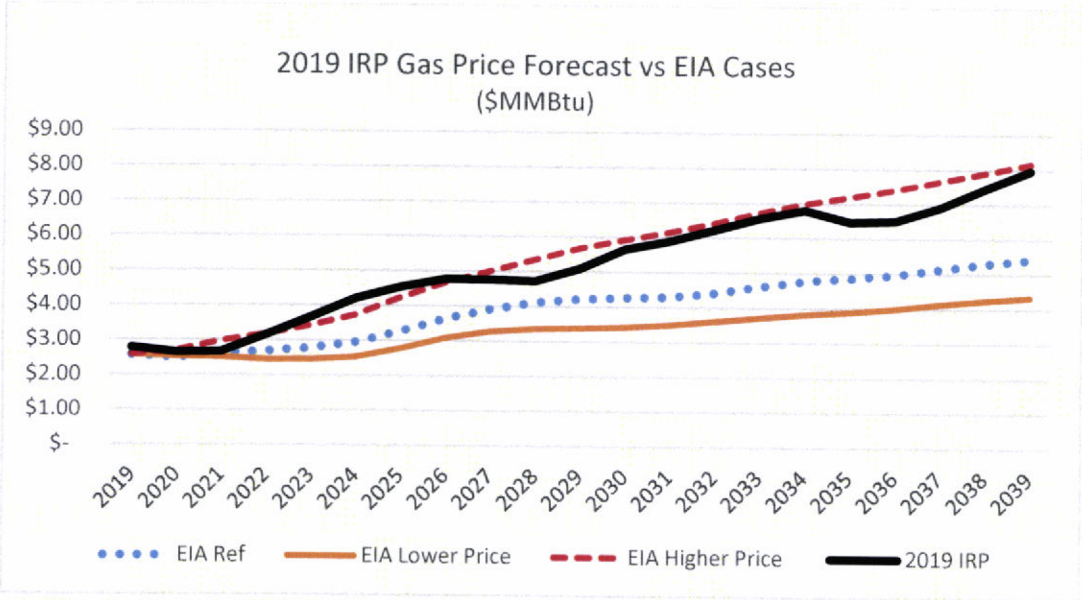
Forecasted Natural Gas Prices

The Company used a relatively high natural gas price forecast in its 2019 IRP. This is a significant change from its 2017 IRP, where the Company used a relatively low natural gas price forecast.

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" (lower price) case.[1] The Company's forecasted prices exceed EIA's Reference case prices by more than 30% in ten of the 18 years in the 2022-2039 period. The Company's prices exceed EIA's High Oil and Gas Supply case prices by more than 40% in 17 of the 18 years of the 2022-2039 period. As shown in the figure below, the Company's forecast more closely tracks EIA's higher priced "Low Oil and Gas Supply" (higher price) case.

[1] Source of EIA natural gas forecast data: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2020&region=0-0&cases=ref2020&start=2019&end=2050&f=Q&sid=ref2020-d112119a.60-13-AEO2020~ref2020-d112119a.40-13-AEO2020~ref2020-d112119a.39-13-AEO2020&sourcekey=0

Table No. 2 – 2019 IRP Gas Price Forecasts



Note: Lower Price case is EIA's "High Gas and Oil Supply"
Higher Price case is EIA's "Low Gas and Oil Supply"

The Company's gas price forecast also exceeds the forecasts of selected natural gas industry consultants and of other utilities regulated by the Commission. Staff reviewed long-term gas cost forecasts from consultancies Deloite, McKinsey, and Knoema. All of these forecasts are lower than the Company's 2019 forecast. Deloite's forecast closely tracks the most recent EIA Reference case forecast.

In Staff's comments on the Company's 2017 IRP natural gas price forecast, Staff expressed concern that the relatively low gas price estimates would cause the resource optimization model to select more than the optimal level of natural gas plants and transmission resources (because market electricity prices are strongly correlated with natural gas prices).

In the 2019 IRP the opposite has occurred. The Company is using a relatively high natural gas price forecast, so natural gas plants and transmission resources are disadvantaged as compared to renewable resources. If gas price forecasts are too high, it can create an incentive to increase investment in renewable resources beyond the economically efficient or optimal level.

The Company's 2019 preferred portfolio includes a large share of renewable resources compared to past IRPs. State laws in Oregon and Washington mandate the removal of coal generation from their rates and impose either carbon limits or cap and trade. Oregon and Washington also have ambitious renewable portfolio standards ("RPS"). Idaho does not impose the same mandates or share the same timetable for RPS. By over-estimating long-run natural gas prices, a portfolio excessively rich in renewable resources may be erroneously identified as least cost. Under this scenario, Idaho customers could potentially pay higher prices for electricity and could be supporting Oregon's and Washington's regulatory priorities.

Transmission Planning

One notable aspect of the Company's transmission planning within the IRP is that the Boardman to Hemingway ("B2H") transmission project is not shown as part of the Company's preferred portfolio. The Company currently provides funding to B2H within a partnership agreement, along with Idaho Power and the Bonneville Power Administration.

The Company indicates that although B2H and Gateway West are beyond the scope of its 2019 IRP, that both transmission projects are expected to bring future benefits to the region. In response to Staff's discovery requests, the Company stated that it continues to evaluate B2H, and that it expects to further address this project in its 2021 IRP. The Company also stated that it continues to invest in planning and permitting for the project and that it is well-positioned to advance the project at the appropriate time.

Staff is concerned that the Company appears to have plans to move forward with B2H even though its own modeling has not identified it as a least cost resource. This project may provide certain benefits, but defined quantifiable benefits and revenue streams must be included before it is prudent for Idaho customers to fund construction as a system resource.

Demand Side Management and Time-of-Use

The Company has a mature portfolio of energy efficiency and demand response programs it effectively deploys to reduce and reshape loads. Because these programs are cost-effective, they reduce the costs the Company incurs to serve customers.

The Company's demand response is quite large – it currently has 92,000 customers and provides 200 MW of operating reserve capacity that can be dispatched within seconds. The Company has recently begun work to expand the capability of its demand response program by creating a grid-scale solution that turns demand response resources into frequency-responsive operating reserves. The Company's efforts to economically expand its cost-effective demand response programs are encouraged.

Time-of-use rates can promote peak load reductions and load shifting to off-peak times. These changes may lower power costs and help reduce or defer capital expenditure and incremental operation and maintenance expenses. Additionally, time-of-use customers may reduce their monthly bills by adjusting when they consume electricity.

The Company currently offers several optional time-of-use programs to Idaho customers: Schedule 35 for general service customers, Schedule 35A for irrigation customers, and Schedule 36 for residential customers. Irrigation customers also have an option to participate in a third-party operated Irrigation Load Control Program. Customers are offered a financial incentive to participate, which gives the Company the right to interrupt service during peak periods. The Company should continue to evaluate the expected costs and benefits of potential time-of-use and demand response programs in Idaho, including mandatory time-of-use for larger commercial, industrial, and irrigation customers.

The Company also has existing and proposed time-of-use rates in other states. Efforts to maintain and expand cost-effective time-of-use across the Company's system may provide improvements in system load characteristics that potentially benefit all customers. The Company has a noteworthy residential electric vehicle rate in Utah with time periods based on the Company's system and distribution system peaks[2], and price differentials between periods based on stakeholder workshop feedback. Rate designs incorporating customers' preferences can improve satisfaction and may boost subscription to time-of-use programs.

The Company has proposed new time-of-use programs in Washington and Oregon. Washington's proposed time-of-use periods are based on Mid-Columbia wholesale price projections and Oregon's are based on historic energy imbalance market prices. Price differentials between time-of-use periods for Washington programs are based on wholesale price differentials. Oregon's price differential is consistent with price differentials in Idaho's Rate Schedule 36. PacifiCorp's varied criteria for time-of-use rate design is appropriate for a system with diverse climate regions and end-uses.

[2] An emphasis on system peak is focused on upstream generation and bulk transmission needs (coincident peak) and an emphasis on distribution peaks is focused on more localized needs (non-coincident peaks).

STAFF RECOMMENDATIONS

The Company's 2019 IRP satisfies all the requirements in Order No. 22299; therefore, Staff recommends the Commission acknowledge PacifiCorp's 2019 IRP filing. Additionally, Staff recommends continued attention to the areas discussed above:

- Capacity Deficiency Date in the Load and Existing Resource Balance;
- Integrating updated coal unit decommissioning cost studies into the planning process;
- Long-run gas cost assumptions. The Company's 2019 IRP gas cost forecast is significantly higher than the Company's 2017 forecast;
- Transmission Planning; and
- Continuation of DSM
- and time-of-use efforts.

Respectfully submitted this 5th day of August 2020.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 5th DAY OF AUGUST 2020, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-19-16, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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