UTAH DEPARTMENT OF COMMERCE
Division of Public Utilities

MARGARET W. BUSSE
Executive Director

CHRIS PARKER
Division Director

SPENCER J. COX
Governor

DEIDRE M. HENDERSON
Lieutenant Governor

Memorandum

To: Rocky Mountain Power

From: Utah Division of Public Utilities

Chris Parker, Director
Brenda Salter, Assistant Director
Doug Wheelwright, Utility Technical Consultant Supervisor
David Williams, Utility Technical Consultant

Date: October 10, 2023

Re: **Docket No. 23-035-10,** 2023 IRP

Technical Conference Topics

The following is a list of topics and questions the Division of Public Utilities would like to address at the technical conference on October 24, 2023 in Docket No. 23-035-10.

1. The Division would like to discuss possible effects of the suspension of the 2022 AS RFP on the 2023 IRP. The Division expects to ask follow-ups to the Company's answers to Division DRs 4.1 through 4.3. Depending on the Company's answers to these DRs, some aspects of the discussion may be confidential.

2. Does the Company expect that the transmission projects in the 2023 Action Plan will be delayed as a result of the suspension of the 2022 AS RFP? The Company's "Second Notice of Update to Schedule in 2022 All Source RFP" in Docket 21-035-52 states that one reason for the suspension of the 2022AS RFP is: "Wildfire risk and associated liability across our six-state service area and throughout the West." Will this associated liability affect the timing or costs of the transmission projects that were selected in the 2023 IRP as part of the Preferred Portfolio? Has the Company performed any modeling runs using an increased cost of debt/cost of capital?

3. Page 306 of Volume I of the IRP states:

> In consideration of current policies in motion and unmodeled risks for which ongoing trends recommend the adoption and development of tax-supported renewable projects, P-MM is determined as the preferred portfolio.

   Please elaborate on this statement. Was this determination done by comparing the effect of "current policies in motion and unmodeled risks" on the cases and rankings listed in Tables 9.14 through 9.17, or on some other lists? Please list the policies and unmodeled risks that were considered.

4. Please provide expanded versions of Tables 9.15, 9.16, and 9.17 to include as many of the Table 9.14 variant cases as possible.

5. Using the definition of "implementation time" the Company provides in response to confidential Division DR 3.1, what are the implementation times (actual or projected) for each resource selected as a result of the 2020AS RFP?

6. If different than the answer to the previous question, please list the time, for each resource selected for the 2020AS RFP, from the announcement of the final shortlist to the actual or projected "online" dates.

7. Do the costs for the small modular nuclear reactor on p. 182 of the IRP (base capital costs of $5,706/kW, etc.) reflect the total projected costs of the project, or the total costs that PacifiCorp and/or the ratepayers would be expected to bear? If the latter, please explain how these costs were calculated.

   If the former, please discuss in general terms why the Natrium base capital costs are lower than some other common estimates of nuclear base capital costs. For example, Lazard's Levelized Cost of Energy Analysis—Version 16.0 gives a range of capital costs for new nuclear as $8,475 to $13,925/kW.[1] The EIA in its "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023" lists total overnight capital costs of a new "Nuclear—small modular reactor" as $8,880/kW in the BASN region.[2]

   Similarly, the Company's projected fixed O&M costs of $68.77/kW-year are much lower than some other estimates (Lazard has a range of $131.50-152.75/kW-year

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[1] See https://www.lazard.com/research-insights/levelized-cost-of-energyplus/ (Lazard) at p. 11. The Division realizes that these Lazard costs are based on conventional PWR/BWR nuclear plants, and that the Natrium plant is a new technology. However, being the first utility-scale reactor of a new technology would tend to drive costs even higher than those of conventional nuclear plants.

[2] See https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf Table 2, p. 5 (costs in 2022 dollars).

for conventional nuclear, and the EIA has an estimate of $106.92/kW-year for small modular reactors).[3]

Please discuss in general terms how these cost estimates were made, and why they appear to be lower than some commonly used reference estimates.

8. Although variant P20-JB3-4 CCUS performed well in the modeling (see Table 9.14, p. 268 of the IRP), the Company did not select it as the preferred portfolio, due to several reasons, including:

    a. "The CCUS assumptions included in the updated variant are not based on bids or proposals from CCUS technology companies, but are proxy assumptions for project-specific costs and operational characteristics." (p. 296)

    b. "The scale of the proposed CCUS technology in P20-JB3-4 CCUS (699 MW) has never been demonstrated on a coal plant commercially anywhere in the world." (p. 297)

    c. "While the Company has carried out and received feasibility studies for amine-based carbon capture at Jim Bridger Units 3 and 4, it does not currently have evaluation or equivalent cost data to that of a front-end engineering and design (FEED) study." (p. 297)

    d. "The updated fueling strategy to source coal for Jim Bridger exclusively from the Powder River Basin has not been previously attempted by PacifiCorp. …. The risks and benefits of this strategy to supply coal for a full-scale CCUS-retrofitted coal unit need to be fully evaluated." (p. 297)

    In the Division's view, most of these factors also apply to the hydrogen peaker plants and/or the Natrium plant. The costs for hydrogen and nuclear resources: (a) are not based on currently available bids or proposals; (b) have not yet been demonstrated in commercial utility use (especially the 100% hydrogen option and Natrium technologies); (c) do not have FEED studies, to the Division's knowledge; and (d) have unknown fuel supply strategies (especially the hydrogen production and transportation).

    These three technologies (CCUS, non-emitting hydrogen peakers, Natrium) appear to not be treated in a similar manner. Please discuss.

9. The Division's understanding is that dispatch of resources on an hourly (fifteen-minute) basis is generally governed by the WEIM.

[3] Lazard at p. 39; EIA 2023 at p. 2. Again, the Division realizes that some of these estimates are based on conventional nuclear plants, with technologies different than the Natrium plant.

a. How in general terms does the IRP modeling forecast WEIM dispatch? How does the IRP ST model decide on coal and natural gas dispatch, if using modeling different than the WEIM uses?

b. What assumptions are made in the IRP modeling about transmission and other dispatch limitations when performing hourly dispatch? Can the model differentiate or isolate limitations that are a result of the physical system (e.g. transmission constraints) and limitations that are partially driven by policy considerations (e.g. GHG adders from state policies)?