State of Utah

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Division of Public Utilities

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Comments

To: Public Service Commission of Utah

From: Utah Division of Public Utilities
Chris Parker, Director
Artie Powell, Manager
Joni S. Zenger, Utility Technical Consultant
David Williams, Utility Technical Consultant

Date: January 5, 2022

Re: **Docket No. 21-035-09,** PacifiCorp's 2021 Integrated Resource Plan.

Following are some questions the Division of Public Utilities (DPU or Division) would like addressed at the technical conference.

1. Please describe how cost overruns with the Natrium plant will be handled. Are there circumstances under which ratepayers could be responsible for cost overruns? If yes, is there a maximum on the amount cost overruns that ratepayers will be responsible for? Please explain.
2. Please describe the back-up plans if for some reason the Natrium plant is not built (for example, if permits cannot be obtained). Our understanding is that Table 10.3 and Figure 9.22 (describing the P02e-No Nuc scenario) indicates that in the absence of the Natrium plant, the capacity deficit would be made up by solar co-located with storage? Please confirm and explain.

3. Does Figure 9.22 also indicate how the Natrium capacity would be replaced if the project were simply (for example) delayed for one or two years, rather than not built at all? In other words, if there is such a delay, would the deficit still be made up by solar plus storage?
4. In Figure 9.22, why does a non-emitting peaker resource replace some of the solar plus storage in 2037?
5. The Company has chosen not to model new natural gas resources (see, e.g., IRP Chapter 8, p. 245). The Company states that "it is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such a facility in many parts of PacifiCorp's service territory." Is this referring to federal, state or both federal and state permitting assumptions? Please list and describe all federal policy or federal permitting issues that the Company considered in its "no gas" decision.
6. With respect to state permitting, did the Company intend to state that it is not feasible to obtain permitting in just the states of Washington, Oregon, and California, or does the Company also assume it is not feasible to obtain permitting in the states of Utah, Wyoming, and Idaho as well? Does the Company have reason to believe permits for a new natural gas plant would not be forthcoming in (for example) Utah in counties other than the ones mentioned on p. 167 of the IRP? Please list and discuss each state regulation or policy that the Company considered in its "no gas" decision. In addition, please identify all state PSC IRP requirements or guidelines resulting in the "no gas" decision.
7. If there are any national industry publications or data that informed the Company's "no gas" decision, please discuss and provide the source for this information.
8. Please discuss the Company's assumptions in the sensitivity case that enables new gas-fired proxy resources (Chapter 7, p. 164). In the New Proxy Gas Sensitivity (S04), new gas peaking resources replace non-emitting peaking, and new CCCTs replaced advanced nuclear resources. Does S04 also include end of life for existing gas resources? Please explain. Please discuss and provide a copy of the S04 results for the Technical

Conference. Please provide the name and location of the file/s that contain the results from the "no gas" sensitivity.

9. Did the Company perform a sensitivity based on the BAU1 and BAU 2 case definitions, which, when initially developed with stakeholders, both included existing gas resources through the end of life? Did the Company run a sensitivity that enabled BAU1 and BAU2 portfolio definitions (including end of life dates for gas plants), or was the sensitivity based on the already-decided P02 portfolio? If yes, please discuss the sensitivity results and provide a copy of the sensitivity for the 20-year planning period. If no, please explain what the purpose of the Business as Usual Case discussions and development was; in particular, why the Company changed the BAU1 and BAU2 portfolio definitions from what was developed by stakeholders at the time it turned on the model optimization? The stakeholders were unaware at the time of the BAU discussions that the Company intended to exclude new gas-fueled additions as proxy resource selections.
10. Please speak to the prudency of not modeling a proven technology for new peaker plants (natural gas) with costs that are fairly well-known, while at the same time including non-emitting peaker plants (presumably hydrogen) in the modeling for technologies that are still in infancy, with costs that are unknown.
11. Please explain how Washington will pay for costs for its CEIP, both in the near-term and in the 20-year term. Please discuss how resource decisions from the implementation of the CEIP can be situs assigned to Washington for resources that may not be constructed for 10-20 years and may have a 30 or 40-year life. Please explain specifically how Utah ratepayers will not be harmed by such decisions in the mid- and long term. Similarly, explain how Utah ratepayers will be protected from policy decisions or IRP constraints that are solely in place to meet Oregon policy or IRP requirements.
12. Please discuss the factors that led to the reduction of the EE targets in the Action Plan from 2019 to 2021. For example, in Action Item 4a follow-up on p. 336 of the 2021 IRP (describing the 2019 IRP), the annual incremental energy target for 2022 is 571 GWh and the annual incremental capacity is 243 MW. In the 2021 IRP on p. 326, Action Item 4a has a target of 492 GWh for 2022, and 138 MW.

13. Regarding the Company's March 2, 2020 Reply Comments in the 2019 IRP docket, page 24: "However, to partially accommodate the DPU's request, as part of future filings, the Company will incorporate Figures similar to Division's Figures 1 and 3 in future filings." Has the Company reproduced the referenced Division Figure 1 and Figure 3 with updated IRP forecast vs. actual data?

If time does not permit the Company to answer any or all of the DPU's questions, the DPU requests that the Company provide specific responses to each question in writing. The Division appreciates and looks forward to the Company's responses.

Cc: Jana Saba, Rocky Mountain Power

Michele Beck, OCS