UAE Exhibit 2

Rocky Mountain Power Responses to Data Requests Referenced in UAE Comments

25-035-22 / Rocky Mountain Power
September 12, 2025
DPU Data Request 1.6

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> The Division's understanding is that no particular cost was assigned to the Natrium resource. For example, see the Company's response to the 2/7/2025 Stakeholder Feedback Form (p. 446 of the pdf of Vol. II of the IRP): "Natrium was endogenously selected by the model as part of the least-cost, least-risk portfolio. At the January public input meeting, PacifiCorp explained that no costs associated with Natrium were included in the modeling process given that the Company has not yet reached an agreement with Terra Power". Does this mean that the Natrium project was assigned a cost of zero in the modeling, and that is why it was endogenously selected by the model? Please explain.

Response to DPU Data Request 1.6

> The Division of Public Utilities (DPU) is correct in its understanding that the Natrium project (also known as Kemmerer Unit 1) was assigned no costs in PacifiCorp's 2025 Integrated Resource Plan (IRP) PLEXOS modeling and that the model was able to endogenously select the resource. While the zero cost nature of the Natrium project was certainly a primary reason for the model to see the resource as valuable, assigning zero costs to the Natrium project is not necessarily the **only** reason the model endogenously selected Natrium. Natrium was not assigned any Western Resource Adequacy Program (WRAP) contribution (i.e. capacity contribution) in the model but was assigned an energy value which the model saw as valuable.
>
> This modeling approach is consistent with a power purchase agreement that PacifiCorp recently signed with US SFR Owner, LLC, a subsidiary of TerraPower. In October, PacifiCorp anticipates filing an application with the Utah Public Service Commission seeking approval of its significant energy resource decision and waiver of requirements to solicit bids.

WRA Data Request 2.6

Supply Side Resources.

(a) Confirm that the "ATB CAPEX Number" used by PacifiCorp in its **Cost Forecasts** tab of the Public_SSR_Database_Summary_Tab_2025 for Solar - 200 MW, Class 1- 10 in *2024*—in cell F22—is 1312.744864 (accounting format removed).

(b) Confirm that the number reported by NREL in the **Summary_CAPEX** tab of the 2024 Electricity Annual Technology Baseline workbook for Utility PV - Class 5 - R&D - Moderate in *2028*—in cell N66—is the same number (rounded): 1312.7449.

(c) Confirm that the capex costs used by PacifiCorp for Solar - 200 MW, Class 1- 10 in the years *2024-2029* (cells F22, G22, H22, and I22 in the **Cost Forecasts** tab mentioned in **2-6.a**) match the capex costs reported in the NREL ATB (cells N66, O66, P66, Q66 in the **Summary_CAPEX** tab mentioned **2-6.b**) for utility scale solar for the years *2028-2032*.

Response to WRA Data Request 2.6

(a) Confirmed.

(b) Confirmed.

(c) Confirmed.

PacifiCorp is aware of the difference between the National Renewable Energy Laboratory (NREL) capital expenditure (CAPEX) costs reported in tab "Summary_CAPEX" of NREL's 2024 Electricity Annual Technology Baseline workbook and the CAPEX costs presented on tab "Cost Forecasts" of PacifiCorp's "Public_SSR_Database_Summary_Tab_2025" workbook. CAPEX costs in PacifiCorp's 2025 Integrated Resource Plan (IRP) supply-side resource table were presented in real 2024 dollars (2024$) based on the technology costs in the first year available, as listed in the supply-side table, while NREL's CAPEX costs are presented in commercial operation year.

Modeling in the 2025 IRP incorrectly applied factors based on 2024 commercial operation date (COD) technology costs. In the 2025 IRP supply-side resource table, escalation rates for each proxy resource option did not align with the earliest commercial operation year, but instead, all escalation rates began in 2025, rather than in the first year available, as intended. PacifiCorp identified and corrected this error following the completion of the 2025 IRP modeling and has presented this correction in multiple public forums, an example of which is on slides 15 and 16 of the public 2025 Oregon

Clean Energy Plan (CEP) presentation: OR_CEP_Meeting_2025-05_May_Slides.pdf. The impact of this correction on the total resource cost (TRC) for any given proxy resource option is minimal as the CAPEX costs are only a portion of the TRC and the correction had less than a 10 percent impact on CAPEX costs for any given proxy resource option.

WRA Data Request 3.1

End Effects. In the 2023 IRP, the Company did not present comparative metrics for end effects (i.e. a portfolio valuation and risk assessment that projects costs of the selected portfolio beyond the planning horizon). However, in the 2025 IRP, the Company presented end effects in Table 9.34.

(a) Define end effects.

(b) In the selection of the preferred portfolio, is the consideration of end effects required by any state jurisdictional IRP standards, guidelines, or statutes?

(c) In detail, explain the method used to calculate end effects in the 2025 IRP. Include a description of all relevant qualitative and quantitative assumptions made by the Company in the calculation of end effects. Explain whether end effects are modeled based on static assumptions from the final year of the planning horizon or from dynamic assumptions and cost escalations after the planning horizon.

(d) Explain how the calculation of end effects was factored into the Company's ranking of integrated portfolios as shown in Table 9.34.

(e) Please provide the workpapers showing calculations of end effects for each integrated portfolio variant shown in Tables 9.34, 9.35, 9.36, and 9.37 of the 2025 IRP. If already provided, please explain where to find this information in the Company's work papers.

(f) Did the Company calculate and/or consider end effects in the 2023 IRP?

(g) If so, please explain whether and how the end effect calculation methodology changed between the 2023 IRP and the 2025 IRP.

Response to WRA Data Request 3.1

(a) "End effects" evaluates performance of a portfolio beyond the study horizon.

(b) No. Consideration of end effects is not specifically required in the selection of the preferred portfolio. However, Oregon standards require that "The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource". A list of all state-specific standards and guidelines is included in Appendix B of PacifiCorp's 2025 Integrated Resource Plan (IRP).

(c) In the 2025 IRP, end effects are based on a static continuation of the costs in the final year of the study horizon, which is the same way end effects is considered in PLEXOS long-term (LT) planning when used. Rather than take a perpetuity approach, as PLEXOS would, PacifiCorp calculated the net present value (NPV) of the final year's revenue requirement as if they continued at a static level for an additional five years.

(d) Calculation of end effects allowed PacifiCorp to evaluate if a portfolio performed particularly well or poorly in early years of the horizon. If a portfolio was more expensive in early years of the horizon, but much less expensive later this would be important information to consider when evaluating the risk to customers. A portfolio which was less expensive early due to tax credits could become very expensive when tax credits expire, posing a risk to customers.

(e) The calculation of end effects is contained in cell C79 of all integrated variant short-term (ST) cost summaries evaluated under the "MN" price curve. These files include 2409MN after either .EP., .HH., .SC., .MR. or .LN. in their names.

(f) No.

(g) Not applicable.