Natrium

Party	Question
DPU	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.
DPU	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.
DPU	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?
OCS	1. Regarding the proposed Natrium nuclear power plant. The OCS is concerned that if PacifiCorp decides to proceed with construction of this type of plant, ratepayers could bear the burden of large cost overruns. For example, the Vogtle nuclear plant in Georgia has seen costs increase from $13 billion to $27 billion while the costs for the V.C. Summer nuclear plant in South Carolina increased from $11.5 billion to $25.7 billion. Please discuss how PacifiCorp would deal with cost overruns if Natrium nuclear plants are constructed for the PacifiCorp system.
OCS	2. Regarding the proposed Natrium nuclear plant. Please discuss how PacifiCorp will mitigate the risk that this new technology will not perform as planned once constructed, considering that PacifiCorp may be the first utility to own such a plant.
IEA	1. In reference to the proposed Natrium unit in Kemmerer, Wyoming: a. Please describe the milestones for the Natrium project between now and the projected in service date. b. What milestone dates are integral to RMP to determine whether it can continue the project? c. What are the backup plans if the project is delayed? d. If the project is determined to not be feasible for any reason, when will transmission rights be released?
UAE	The IRP indicates that the Natrium nuclear plant will be placed in service by the summer of 2028. Natrium will be located at or near the site of the existing Naughton plant. Natrium is proposed to be a 345 MW baseload unit that, when combined with its storage capability, has a maximum output of 500 MW for a period of 5.5 hours. Naughton 1 & 2 are scheduled to be retired by the end of 2025. Naughton 3 (gas conversion) is scheduled to be retired by the end of 2029. Naughton 1 and 2 have a combined nameplate capacity of 357 MW (Naughton 1 = 156 MW; Naughton 2 = 201 MW). Naughton 3 has a nameplate capacity of 247 MW. In Table 1.1 on page 10 of the IRP, PacifiCorp asserts that it will use “reclaimed transmission upon retirement of Naughton 1 & 2” for the 500 MW Natrium project. As of summer of 2028 when Natrium is intended to come online, however, the reclaimed transmission rights for Naughton 1 & 2 will not be sufficient to deploy the 500 MW maximum output for Natrium. Will there be sufficient transmission rights to interconnect Natrium as a 500 MW project as of the summer of 2028, or will it require provisional interconnection service until Naughton 3 is retired in 2029?
OCS	4. Page 164 of the IRP states “PacifiCorp ultimately did not allow new gas-fired resources in its portfolio selection process”. On page 244 of the IRP, PacifiCorp provides one paragraph justifying

	its decision to not allow new gas-fired resources. Please provide additional detail and discussion of the factors listed in that paragraph on page 244 for not pursuing new gas resources. Also, please discuss why these factors would or would not also apply to the proposed Natrium nuclear power plant.

Reliability Methodology and Assessment

Party	Question
UCE	2. Appendix E states that "PacifiCorp has identified specific areas for research that include technologies such as dynamic line rating, phasor measurement units, distribution automation, advanced metering infrastructure (AMI), automated demand response and other advanced technologies" that are intended to "continually improve system efficiency, reliability and safety, while providing a cost-effective service to our customers." Please explain the process PacifiCorp went through to identify the areas of research referenced, and how the Plexos model identifies reliability and resiliency benefits from these technologies, specifically from energy efficiency and distributed energy resources?
Sierra Club	1. PacifiCorp has explained that it was required to make certain pre- and post-modeling adjustments to account for reliability shortfalls identified between the LT and ST model runs. a. Please explain what reliability analyses were conducted for the P-02 variant cases, including P-02h (early Jim Bridger retirement), and the reliability shortfalls that were identified—including the size, duration, and time of year—that required prior post-modeling adjustments; b. Please provide a detailed explanation of which specific resources were considered to meet the reliability gaps and why, including whether any resources were initially considered but ultimately not included for possible selection; c. Of the four resource types that PacifiCorp used as portfolio refinements (solar + storage; storage; nuclear; non-emitting peaker), please identify the specific resources that were added in any of the P02 and P03 variant portfolios, by year, MW, and type; d. Please provide a detailed explanation for why PacifiCorp did not re-optimize its model runs after making reliability adjustments.
Sierra Club	2. PacifiCorp has noted that the 13 percent reserve margin it applied for individual load areas is consistent with Western Electricity Coordinating Council (WECC) and Northwest Power Pool reserve margins. Please explain why it is appropriate to apply a 13 percent reserve margin to PacifiCorp's individual load areas, which are much smaller geographic areas than those considered by WECC or the Northwest Power Pool. Page 2 of 2 a. Please explain how many individual load areas are in each control area.

Removal of New Gas from Modeling

Party	Question
DPU	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.

DPU	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.
DPU	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.
DPU	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.
DPU	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.
DPU	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.
OCS	4. Page 164 of the IRP states "PacifiCorp ultimately did not allow new gas-fired resources in its portfolio selection process". On page 244 of the IRP, PacifiCorp provides one paragraph justifying its decision to not allow new gas-fired resources. Please provide additional detail and discussion of the factors listed in that paragraph on page 244 for not pursuing new gas resources. Also, please discuss why these factors would or would not also apply to the proposed Natrium nuclear power plant.

Proxy Resources/ Storage/ Hydrogen

Party	Question
DPU	4. In Figure 9.22, why does a non-emitting peaker resource replace some of the solar plus storage in 2037?
IEA	2. Regarding modeling of battery energy storage: a. Why were battery installations only modeled at 4 hour sizes? b. Can the model pick 2 hour or 8 hour (for example) battery storage?
IEA	3. Please give an update on the permitting and approval status for your pumped storage projects.

OCS	3. Regarding the unspecified non-emitting peaking resources. Please discuss in detail what kinds of resources this term refers to and what potential products PacifiCorp sees falling under this category. Please also discuss what PacifiCorp's plan is if none of these potential resources materialize or are not economically viable.
UAE	Page 11 of the IRP states: "Through 2040, the 2021 IRP includes 4,781 MW of storage co-located with solar resources, 1,400 MW of standalone battery, and 500 MW of pumped hydro." For transmission modeling purposes, are storage resources modeled like other generation resources? For instance, when a new generation resource proposes to interconnect to the PacifiCorp system, PacifiCorp models that generation resource as though it will produce at nameplate capacity at the same time that all other existing resources (and prior queued resources) are also producing at nameplate capacity. Storage resources are valuable in large part because they can store excess energy produced from intermittent resources at times when load does not require that energy, and then to deploy that stored energy when the intermittent resources are not generating. For transmission modeling purposes, however, does PacifiCorp assume—or is PacifiCorp required to assume—that the storage resources will deploy stored energy at their nameplate capacity at the same time as other intermittent generating resources? If that is the case, does this modeling requirement constrain the deployment of storage resources that might otherwise make more efficient use of transmission resources? What, if anything, can be done to change how resources are modeled to allow for greater deployment of storage resources in a way that does not—for modeling purposes—create additional transmission constraints but, rather, makes more efficient use of those transmission resources?

Coal Retirements

Party	Question
UCE	4. We support and reiterate Sierra Club's 4th question: "Please explain how Idaho Power's exit from the Jim Bridger plant could impact the viability of assumed continued operations of the plant in the Company's preferred portfolio."
Sierra Club	3. Please explain why minimum take assumptions were necessary for the Jim Bridger coal plant through the anticipated life of the plant if the modeling also included an assumption that when the plant retired, it no longer incurred any take or pay costs
Sierra Club	4. PacifiCorp has indicated that it is not making any assumptions regarding Idaho Power's continued participation in the Jim Bridger power plant. Idaho Power's 2021 IRP indicates that it will exit Unit 3 by 2025, Unit 4 by 2028, and the gas-converted Units 1 and 2 by 2034. Please explain how Idaho Power's exit from the Jim Bridger plant could impact the viability of assumed continued operations of the plant in the Company's preferred portfolio.

Misc IRP Modeling and Assumptions

Party	Question
DPU	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?
UCE	1.The variability of solar and wind integration costs from year-to-year in the 2021 IRP is significantly greater than the year-to-year variability in integration costs from the 2019 IRP, and integration charges are significantly higher from 2023 to 2028 (see Figure F.11 in Volume II of the 2021 IRP, page 145). Please discuss the differences between the integration charge study in the 2019 and 2021 IRPs—how are you calculating the integration charge, and how does the projected integration charge match up to historical actual charges?
UCE	3. Have PacifiCorp's hedging policies changed from the 2019 IRP? Please explain how the Plexos model evaluates and models PacifiCorp's current hedging costs in the portfolios.
DPU	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.

CETA/Allocation of Costs

Party	Question
DPU	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.
Sierra Club	5. Please explain whether the Company has evaluated whether the P02h variant case is inherently CETA compliant. If not, please explain why not.

RFP Process

Party	Question
IEA	4. In 2022 RFP under the Action Plan, the target commercial operation date is end of December, 2026, or earlier. Please confirm that you will still accept resources with an earlier commercial operation date.
IEA	5. Will Rocky Mountain Power accept long lead-time development resources with later CODs?
IEA	6. A bidder's conference is scheduled before the RFP will be filed for approval. Will there be another bidder's conference after issuance of the RFP?
IEA	7. What will be the bid response deadline and how does that correlate to the cluster study timelines if any bidders are relying upon approval in the short list for cluster study milestone compliance, or if they require cluster study reports to estimate transmission costs?
IEA	8. Will completed interconnection studies be required for eligibility to bid?

Geothermal

Party	Question
Fervo	1. Fervo and other geothermal stakeholders and researchers have noted that in some cases, selection of geothermal resources in IRP modeling is highly sensitive to assumed geothermal costs.3 What is the derivation of the assumed geothermal costs in the supply resource tables (see summary Table 1 from pgs 169-184 IRP)? Have these costs been updated to reflect recent research cost estimates and data on public contracts?
Fervo	2. Does the PacifiCorp IRP modeling assume cost declines in geothermal technologies over the planning period, and if not, how does this assumption compare to assumed cost declines in geothermal technology studies and cost declines assumed for other technologies? Can PacifiCorp examine how geothermal cost reductions might affect geothermal selection in the IRP modeling?
Fervo	3. What is PacifiCorp's assumed geothermal resource potential in the region? How does PacifiCorp's assumed geothermal resource potential in the region compare to other regional estimates(see Table 2 below)?
Fervo	4. Can the process for the Plexos LT modeling be described further to explain whether geothermal was screened out prior to the modeling or included in the modeling but not selected by the tool?
Fervo	5. This question addresses sensitivity analysis on the resource scenarios analyzed in the 2021 IRP: (a) Can PacifiCorp conduct sensitivity analysis on assumed geothermal costs to establish the costs at which the Plexos LT model selects geothermal? For example, these sensitivity cases could include \$60/MWh, \$65/MWh and \$70/MWh to help capture the potential range of selected geothermal if geothermal costs were to be reduced due to technical innovation. CPUC Proceeding R.16-02-007, Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements, Inputs & Assumptions (Exhibit B to ALJ Ruling issued September 19, 2017). Utah FORGE is a dedicated underground field laboratory sponsored by the DOE with a stated purpose of accelerating breakthroughs in Enhanced Geothermal Systems. (b) Further, can PacifiCorp conduct sensitivity analysis on assumed geothermal regional potential to determine how much geothermal is selected at different cost assumptions? We recommend evaluating no constraint on geothermal resource potential (or the potential for equivalent zero-carbon firm resources) at the stated costs. The selection of scenarios to model in this fashion should include the preferred portfolio scenarios as well as selected other portfolios.
Fervo	6. Why does the IRP modeling select small modular nuclear reactors at a higher cost and slightly lower capacity factor than geothermal, when the two resources otherwise have similar operating and emissions characteristics (See Table 3)?
Fervo	7. Can PacifiCorp provide additional details on the potential cost and resource development impact of displacing wind, solar and storage with flexible but firm resources such as geothermal (or other firm or dispatchable non-emitting resources)? These benefits can include lower capital costs, landuse needs and transmission requirements.
Fervo	8. Has PacifiCorp considered geothermal projects that provide operational flexibility? Could PacifiCorp clarify what opportunities may exist for new geothermal projects to provide operational services?