WRA Exhibit 8 – Data Request Responses from PacifiCorp (dba Rocky Mountain Power in Utah) referenced in WRA comments

- Response to DPU Data Request 5.2 (UPSC Docket No. 21-035-09)
- Response to OPUC Data Request 021 (OPUC Docket No. LC 77, via DPU Data Request 1.1)
- Response to OPUC Data Request 071 (redacted version) (OPUC Docket No. LC 77, via DPU Data Request 1.1)
- Response to WRA Data Request 2.2 (UPSC Docket No. 21-035-09)
- Response to WRA Data Request 2.5 (redacted version) (UPSC Docket No. 21-035-09)
- Response to WRA Data Request 2.12 (UPSC Docket No. 21-035-09)
- Response to WRA Data Request 3.4 (UPSC Docket No. 21-035-09)
- Response to WRA Data Request 3.8 (UPSC Docket No. 21-035-09)
- Response to WRA Data Request 3.9 (UPSC Docket No. 21-035-09)
- Response to WRA Data Request 4.28 (UPSC Docket No. 21-035-09)
- Response to WRA Data Request 7.1 (UPSC Docket No. 21-035-09)

DPU Data Request 5.2

Please identify each specific state IRP requirements or Commission guidelines (including Washington's CETA) that informed the Company's "no gas" decision.

Response to DPU Data Request 5.2

The decision not to model new proxy gas resources in PacifiCorp's 2021 Integrated Resource Plan (IRP) is the summation of the following considerations:

As discussed at the 2021 IRP public input meetings held on June 25, 2021 and July 30, 2021, considering the potential for future greenhouse gas (GHG) policies, PacifiCorp noted there are considerable stranded-cost risks associated with planning a system that is reliant on new natural gas resources with depreciable lives ranging between 30 to 40 years (i.e., a new natural gas-fired resource placed in service in 2030 would be depreciated as late as 2070). Further,
when considering current state policies, it is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such a facility in parts of PacifiCorp's service territory. Washington and Oregon legislation currently include provisions to meet all retail customer load requirements with non-emitting energy in the future, which explicitly limits the useful life and potential of new natural gas resources to significantly less than 30 years. In addition, it is not envisioned that new natural gas resources could be economically permitted in northern Utah due to state implementation plans (SIP) for the counties of Salt Lake, Davis and Box Elder regarding particulate matter (PM) of 2.5 microns or less. There would also be challenges complying with the state SIPs regulating ozone (O) and nitrogen oxides (NOx). Finally, PacifiCorp has observed that there is very limited development activity for new natural gas facilities. This was most recently evident in the Company's 2020 All Source Request for Proposals (2020AS RFP) which did not result in a single bid for new natural gas resources. Nonetheless, PacifiCorp produced a sensitivity in the 2021 IRP that allowed new natural gas proxy resources.

OPUC Data Request 021

Coal modeling - Please explain why a minimum take assumption is included for Jim Bridger units 3 and 4 in the near term, given that PacifiCorp and Idaho Power are in control of the mine plan and could shut down the mine without needing to pay for additional coal after mine closure.

Response to OPUC Data Request 021

The Jim Bridger plant receives coal from the Bridger Coal Company (BCC) and from a third party mine.

The coal modeling includes minimum take provisions for the third party coal supply agreement (CSA), which is a standard practice for CSAs.

BCC represents a significant long-term investment with fixed costs that cannot be avoided in the short-term. These fixed costs are treated in a manner similar to minimum take obligations in order for the models to properly reflect the impacts of these costs.

OPUC Data Request 071

CONFIDENTIAL REQUEST - PLEXOS Work Papers

[redacted]

[redacted]

[redacted]

Response to OPUC Data Request 071

Wyodak generation is very small for 2032 through 2039 (except in 2034 when it did not generate at all). The combination of proxy solar renewables resources plus storage with zero operating cost added in 2031 at Utah North 820 megawatts (MW), 2033 at Utah South 1,100 MW, and 2037 at Hunter 909 MW displaced and lowered the generation at Wyodak. Because Wyodak fuel prices and emissions cost escalate through time, in this timeframe it is among the highest variable cost dispatchable resources in the Company's portfolio. As a result, it is only dispatched in a few hours per year to meet peak requirements. Unlike storage resources, Wyodak is also able to respond for an extended duration in response to variations in load and unit outages that are not reflected in the "ST" model study. Because a non-emitting peaking unit is more expensive in both fixed and variable costs, it is more cost-effective to keep Wyodak's capacity available as long as possible.

WRA Data Request 2.2

Gas Conversion at the Jim Bridger Plant - During the August 6, 2021, PIM, when asked whether gas conversion of Bridger Units 3 and 4 was made available to PLEXOS, a PacifiCorp representative answered, "no."

(a) Please confirm that gas conversion of Jim Bridger Units 3 and 4 was not considered in the IRP modeling.

(b) If gas conversion of units 3 and 4 was not made available to the model, please explain why not.

Response to WRA Data Request 2.2

(a) Confirmed natural gas conversion of Jim Bridger Unit 3 and Jim Bridger Unit 4 was not considered in the 2021 Integrated Resource Plan (IRP) modeling.

(b) Jim Bridger Unit 3 and Jim Bridger Unit 4 had selective catalytic reduction (SCR) installed in 2015-2016 to meet state and federal environmental requirements. This represented a significant investment and resulted in the resources having operating lives longer than those of Jim Bridger Unit 1 or Jim Bridger Unit 2. Because these investments were already made and the units do not require anything additional to maintain compliance with environmental regulations, they were not deemed as potential candidates for natural gas conversion.

WRA Data Request 2.5

Jim Bridger Fuel Cost - From what mine and coal company does PacifiCorp expect to purchase coal fuel to serve the Bridger plant after the Bridger mine closes? Please provide the forecast fuel cost in $/ton associated with this source by year.

Confidential Response to WRA Data Request 2.5

In the 2021 Integrated Resource Plan (IRP), closure of the Bridger coal mine is assumed at the end of 2028. A combination of coal supply from the Black Butte Coal Company and Powder River Basin (PRB) coal supply are assumed for the continued operation of Jim Bridger Unit 3 and Jim Bridger Unit 4 through the end of life of the units in 2037.

For 2029 through 2037, the coal costs by year, expressed in dollars per ton ($/ton), are forecast as follows:

[redacted]

[redacted]

[redacted]

Confidential information is provided subject to R746-1-601–606 of the Utah Public Service Commission Rules.

WRA Data Request 2.12

August 27 Public Input Meeting presentation - On page 24, PacifiCorp states that it will purchase unbundled RECs to meet is states' requirements and that it will maximize the sale of RECs that are not required to meet state RPS compliance obligations.

(a) Please explain why PacifiCorp is both a buyer and a seller of unbundled RECs.

(b) Does PacifiCorp "transfer" RECs and revenues between states such that states that need additional renewable MWh provide revenues to other states without renewable mandates for their allocated share of renewable generation?

Response to WRA Data Request 2.12

(a) The renewable energy credits (REC) that PacifiCorp generates from its own eligible generating resources are allocated across the six states based on an agreed-upon allocation protocol.

The states located in the PacifiCorp West (PACW) balancing authority area (BAA), namely California, Oregon, and Washington, retain their shares of RECs to meet their state's renewable portfolio standards (RPS) compliance requirements. If a given state's allocation of RECs is not sufficient to meet its RPS requirement for a given compliance period, PacifiCorp may purchase RECs in the market to address the shortfall.

The states in the PacifiCorp East (PACE) BAA, namely Idaho, Utah, and Wyoming, have directed the Company to sell RECs from its allocated pool of RECs and return the revenue from those sales back to customers of those states.

(b) Yes, in limited circumstances PacifiCorp transfers RECs and revenues between states such that states that need additional renewable megawatt-hours (MWh) for compliance provide revenues to other states in exchange for a portion of their allocated share of RECs.

WRA Data Request 3.4

Please provide all of the information and studies PacifiCorp used to model Washington's requirement to utilize the "best available climate science." If the information is publicly available, please provide web-links.

Response to WRA Data Request 3.4

PacifiCorp's 2021 Integrated Resource Plan (IRP) climate change scenario relies on projected temperatures as determined by the United States (U.S.) Department of the Interior (DOI), Bureau of Reclamation, in the West-Wide Climate Risk Assessments: Hydroclimate Projections study (Technical Memorandum No. 86-68210-2016-01) published March 2016. Please refer to the link provided below:

https://www.usbr.gov/climate/secure/docs/2016secure/wwcra-hydroclimateprojections.pdf

This study was identified based on consultation with the Northwest Power and Conservation Council (NW Council) regarding their efforts to incorporate climate change within their load forecast.

WRA Data Request 3.8

Please explain the derivation of the 0.4708 tons CO2e/MWh emissions rate applied to market purchases (see e.g. IRP Volume I, page 16). Is this a default emissions rate in one or more of PacifiCorp's states? How often is the data this rate is based upon updated and verified?

Response to WRA Data Request 3.8

A default emission rate of 0.4708 short tons carbon dioxide equivalent per megawatt-hour (CO_2e/MWh) is a standard emission rate applied to unspecified market purchases in greenhouse gas (GHG) reporting for Washington, Oregon, and California. This value was adopted from the Western Climate Initiative Partners (WCI) Default Emission study. As recently as January 2021, the Washington Utilities and Transportation Commission (WUTC) reviewed and adopted this emission rate for use in calculating unspecified market purchases emissions for the Washington Clean Energy Transformation Act (CETA) implementation. There is no set schedule for updating the default rate.

WRA Data Request 3.9

Has PacifiCorp calculated a default emissions rate that is specific to PacifiCorp's system? If so, please provide it and explain its derivation.

Response to WRA Data Request 3.9

PacifiCorp interprets "default emission rate" to be a reference PacifiCorp total system emission factor. Based on the foregoing interpretation, the Company responds as follows:

PacifiCorp's total system emission factor is calculated annually during mandatory greenhouse gas (GHG) reporting submittal to California Air Resource Board (CARB) and Oregon Department of Environmental Quality (DEQ). PacifiCorp's system emission factor for 2020 generation is 0.633 metric tons of carbon dioxide equivalent per megawatt-hour (CO_2e/MW). This factor is calculated by dividing annual system emissions by annual system generation. Annual system emissions include those from owned resources, specified power purchases and unspecified market purchases net of specified wholesale sales. Owned and specified power purchase emissions are based on individual resource emission rates reported to the United States (U.S.) Environmental Protection Agency (EPA). Unspecified market purchases use a standard default rate of 0.428 metric tons of CO_2e/MWh.

WRA Data Request 4.28

In undertaking endogenous coal retirement, was the model allowed to avoid projected take-or-pay coal supply agreements (CSA) by retiring the unit, or were projected CSAs considered a sunk cost?

Response to WRA Data Request 4.28

The PLEXOS model avoided the projected take-or-pay fuel costs when the Jim Bridger plant retired early. In the PLEXOS model, only Jim Bridger was set-up with projected take-or-pay fuel costs.

WRA Data Request 7.1

In response to WRA data request 2.2, PacifiCorp stated that the installation of SCRs on Bridger Units 3 and 4 resulted in Units 3 and 4 having longer operating lives than Units 1 and 2. In addition to adding SCRs, what life-extending investments were made in Bridger Units 3 and 4 that were not made in Bridger Units 1 and 2?

Response to WRA Data Request 7.1

During the upgrade of the selective catalytic reduction (SCR) units, the economizers were also replaced on Jim Bridger Unit 3 and Jim Bridger Unit 4. The economizer replacement / upgrade was critical to the SCR project to control the economizer outlet flue gas temperature prior to the flue gas entering the SCR and possibly sintering the catalyst due to excessive temperatures. Additionally, the economizer was designed to also reduce maintenance. Typical fly ash and sootblower erosion protection measures were incorporated in the new design.