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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF ROCKY MOUNTAIN POWER'S APPLICATION FOR APPROVAL OR REJECTION OF THE POWER PURCHASE AGREEMENT WITH CHESTER DIVERSION PROJECT	**CASE NO. PAC-E-21-06** **COMMENTS OF THE COMMISSION STAFF**

STAFF OF the Idaho Public Utilities Commission, by and through its Attorney of record, Dayn Hardie, Deputy Attorney General, submits the following comments.

BACKGROUND

On March 10, 2021, Rocky Mountain Power, a division of PacifiCorp ("Company") requested the Commission approve or reject a Power Purchase Agreement ("PPA") with Fall River Rural Electric Cooperative ("Seller") for the purchase and sale of energy from the Chester Diversion Hydro Project ("Facility").

The Facility is a run of river hydroelectric qualifying facility ("QF") under the Public Utility Regulatory Policies Act of 1978. The QF utilizes the Fremont – Madison Irrigation District's existing Chester Diversion dam on the Henry's Fork of the Snake River in Fremont County, Idaho.

The QF has three 1,200 kilowatt ("kW") generators. One operates as back-up when another generator is out of service. The available water gives the QF a maximum generating capacity of 2 MW. The Company states the rates, terms, and conditions are those previously approved by the Commission and effective June 1, 2020 for purchases from non-seasonal hydro QF projects.

Energy will be delivered from the QF to the Company's system at the Goshen substation by a transmission agreement with the Bonneville Power Administration.

STAFF ANALYSIS

Staff's review focused on the 90/110 firmness requirements, the long-range forecasts, the maximum delivery rate, the avoided cost rates, and the project ownership.

90/110 Firmness Requirements

Staff confirmed the PPA contains the 90/110 firmness requirements as required by Order No. 29632. It requires a Seller QF to provide utilities with a monthly estimate of the amount of energy the Seller QF expects the QF to produce. If the Seller delivers more than 110 percent of the estimated amount, then the utility must buy the excess energy for the lesser of 85 percent of the market price or the contract price. If the Seller delivers less than 90 percent of the estimated amount, then the utility must buy total energy delivered for the lesser of 85 percent of the market price or the contract price. *See* Order No. 29632 at 20.

1. <u>Monthly Estimates</u>

The Application states that the Facility's estimated annual net output over the term is 6,580 megawatt-hours. However, Section 4.9, Exhibit A, and Page 3 of the PPA indicate that the estimated annual net output is 5,481,400 kilowatt-hours ("kWh"). The Company explained in Response to Staff's Production Request No. 3 that the estimate for the month of June incorrectly includes a period instead of a comma. While the PPA states the forecasted energy for June is "1,100.000", it should read "1,100,000". This correction increases the estimated annual net output from 5,481,400 kWh to 6,580,300 kWh. Staff recommends the parties amend the PPA to correct the amounts.

Staff also notes that the output in January (10,000 kWh) is significantly lower than that in February (170,000kWh) or in December (175,200 kWh). The Company stated in Response to Staff's Production Request No. 2 that the monthly generation amounts were provided by the Seller, and the Company does not have an explanation for the monthly differentials, but typically changes in monthly production are the result of expected water flow variability at the Facility.

2. Advanced Notice

The PPA uses a 10-day advanced notice to revise future monthly estimates. Staff believes any timeframe between one month in advance and 5 days in advance is reasonable. The Commission allowed a month-ahead timeframe in Order No. 33103, which states:

> The intent of a QF providing generation estimates has always been to assist the utility in forecasting and operational planning so that the utility can provide the most reliable service possible to its customers. We find that a provision allowing for monthly generation estimate updates is consistent with that purpose.

Later, the Commission also allowed a 5-day timeframe in several cases, recognizing that monthly estimates provided closer to the time of delivery can improve the accuracy of input used for short-term operational planning. See Order Nos. 34263 and 34870 for example.

3. Market Prices

The Company uses Palo Verde Hub to establish market prices for the purpose of the 90/110 firmness requirements. Staff believes the Company's determination of market prices is fair and reasonable.

4. Firm Delivery

The QF is located outside the Company's service territory and will wheel its power through Bonneville Power Administration's ("BPA") transmission system. The Seller pays BPA for ancillary services to ensure that the energy delivered to the Point of Delivery in the Company's system is firm. The Seller provides the Company with a schedule of the next day's hourly scheduled Net Output at least 24 hours prior to the beginning of the day being scheduled, and the ancillary service is designed to correct a mismatch between energy scheduled by Seller and the actual real-time production of the QF. The Company agrees to accept and pay for the Supplemented Output from BPA, but the QF must offset the amount by delivering less than the amount generated before the month ends to ensure that the accumulated difference between the energy delivered at the Point of Delivery and the QF's Net Output is zero.[1] Effectively, only

[1] When the accumulated difference is greater than zero, the Company will accept the surplus delivery, but will not pay for it. When the accumulated difference is smaller than zero, the Company will reset the imbalance to zero at the end of the Settlement Period with no future chance of recovering the energy generated but not delivered. This understanding was confirmed by the Company through email on April 21, 2021.

energy generated by the QF receives payment. Table No. 1 illustrates how the offset works.

<u>Table No. 1: Zero Accumulated Difference</u>

	Energy Scheduled	QF Net Output	Ancillary Service	Energy Delivered
Hour X	5	3	2	5
Hour Y	7	9	-2	7
Sum		12		12

Although Staff believes the mechanism with BPA provides a way for the Seller to meet its 90/110 firmness requirements, it does not serve as a replacement. Maintaining 90/110 requirements provides the incentive and accountability necessary for the Seller to meet its 90/110 monthly estimates, while the BPA mechanism only firms production a day at a time.

Long-Range Forecasts

Seller agrees to provide an annual update to the 12 X 24 generation profile in Section 6.7.1. Although the Commission does not require 12 X 24 generation profiles for contracts that use published rates, Staff does not oppose to this provision agreed upon by the parties.

Maximum Delivery Rate

The "Maximum Delivery Rate" as listed in Exhibit A should state “2.0 MW” rather than "2.0 MWh", which is the nameplate capacity of the unit. See Response to Staff's Production Request No. 1. Staff recommends that the parties amend the PPA to correct this.

Avoided Cost Rates

Staff reviewed the non-seasonal hydro avoided cost rates contained in the PPA and believes the rates are incorrect. The Application states that the PPA was negotiated during 2020 and was subject to Commission Order No. 33917 that established the Company's first capacity deficiency of July 2028. The PPA was signed February 26, 2021, and the Commission approved a new first capacity deficiency of July 2029 in Order No. 34918 on February 9, 2021. Therefore, Staff believes that the parties should use new avoided cost rates that reflect the new first deficit date.

The difference between the old and new avoided cost rates occurs in year 2028. The annual rate for that year will change from \$67.85/MWh to \$37.65/MWh,[2] because the rate will not contain avoided cost of capacity due to the shift of the first deficit date by one year.

Project Ownership

The Application states that this project is a run-of-river hydroelectric project that utilizes the Fremont - Madison Irrigation District's existing Chester Diversion dam on the Henry's Fork of the Snake river in Fremont County, Idaho. Exhibit B states that this project is in Fremont County, Idaho, and utilizes Fremont-Madison Irrigation District's pre-existing Cross Cut Diversion Dam on the Henry's Fork of the Snake River. Exhibit E also lists real estate documents, which includes "Amended Lease Agreement between Fall River Rural Electric Cooperative and Fremont Madison Irrigation District dated October 28, 2013." However, an updated FERC Form No. 556 Form ("Form 556") for the project clarifies the ownership of the Facility by removing Fremont-Madison Irrigation District, which was listed as a direct owner on the previously filed Form 556. The updated Form 556 states that while Fremont-Madison Irrigation District has a right to become a direct owner with equity interest in the Facility upon occurrence of contingent events, Fremont-Madison Irrigation District is not currently a direct owner with an equity interest in the Facility. Therefore, Staff recommends that the parties should amend the PPA to reflect the correct ownership.

STAFF RECOMMENDATION

Staff recommends the parties file an amended PPA that includes the following updates:

1. The amounts of generation estimates in Section 4.9, Exhibit A, and Page 3 of the PPA;
2. The units for the Maximum Delivery Rate;
3. The avoided cost rates should be updated to reflect the new first deficit date of July 2029; and
4. The project ownership.

Staff recommends approval of an amended PPA with these updates and also recommends that, if the updates described above are made by the Company, the Commission declare that the

[2] The annual rate will be adjusted by monthly on-peak and off-peak multipliers.

avoided cost prices set forth in the Agreement are just and reasonable, in the public interest, and that the Company's incurrence of such costs are legitimate expenses.

Respectfully submitted this 4th day of May 2021.

Dayn Hardie
Deputy Attorney General

Technical Staff: Yao Yin

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 4th DAY OF MAY 2021, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-21-06, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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