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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF ROCKY MOUNTAIN POWER'S APPLICATION FOR APPROVAL OR REJECTION OF A POWER PURCHASE AGREEMENT BETWEEN PACIFICORP AND FALL RIVER ELECTRIC COOPERATIVE, INC.	**CASE NO. PAC-E-20-10** **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 June 9, 2020, Rocky Mountain Power ("Company" or "PacifiCorp"), a division of PacifiCorp, applied for an order approving or rejecting a Power Purchase Agreement ("Agreement") with Fall River Electric Cooperative, Inc. ("Fall River") for energy generated by the Felt Hydro Facility[1] ("Facility"), a small hydro facility in Teton County, Idaho. The Facility is a qualifying facility ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA").

[1] The Facility was previously known as CDM Hydro.

The Facility has been delivering energy to the Company in accordance with a PURPA contract dated December 4, 1984. The existing PURPA contract will expire at midnight on March 31, 2021.

The Facility has a nameplate capacity of 7.45 megawatts. The Agreement contains non-seasonal hydro avoided cost rates based on the surrogate avoided resource cost methodology for a 20-year term. The Agreement also contains capacity payments for the entire term with no sufficiency period.

On July 2, 2020, the Commission issued a Notice of Application and Notice of Modified Procedure establishing an August 17, 2020 comment deadline and August 24, 2020 reply deadline.

On July 31, 2020, Staff sent its Second Production Request to the Company. Staff received Responses to Staff's Production Request Nos. 8-11 on August 10, 2020 and Staff's Production Request Nos. 12-14 on August 11, 2020.

STAFF REVIEW

Staff reviewed the Application and the Agreement. Staff's analysis focuses on three issues it believes should be addressed. These issues are:

1. The appropriate mechanism that will allow capacity payments for generation from Powerhouse #2, while not providing capacity payments to Powerhouse #1 when the amount of generation for both powerhouses—the total Facility—is currently only measured through a single meter;
2. The use of incorrect non-firm market rates for generation outside of the 90/110 performance band; and
3. How to determine the payments when monthly generation falls outside of the 90/110 band, given that Fall River could be paid two separate rates during the month.

Capacity Payments

Under the proposed PPA, the Company will receive generation from the Facility which has a total nameplate capacity of 7,450 kW. The facility is made up of two powerhouses: Powerhouse #1 has two turbines and two generators with a total capacity rating of 5,500 kW; and Powerhouse #2 also has two turbines and two generators with a total capacity rating of 1,950 kW.

The proposed rate structure includes immediate capacity payments for the entire generation of both powerhouses over a 20-year term.

A QF should only receive compensation for capacity when the utility is capacity deficient, unless it is a renewal/extension project that was paid for capacity at the end of the original contract (*see* Order No. 32697), or has contributed to meeting the utility's capacity needs during the original contract term when the utility became capacity deficient (*see e.g.,* Case Nos. IPC-E-19-04, IPC-E-19-30, and IPC-E-19-35). In the current contract, Staff is uncertain if the rate design reflects a *capacity deficit* or an *energy deficit*; thus Staff is uncertain if the Facility is paid for capacity at the end of the original contract term. However, the Company has added resources to meet its capacity deficiencies since 1984, when the original contract was executed between Bonneville Pacific Corporation. For example, Lake Side 2 was brought online in 2014 to meet the Company's capacity deficiency identified in its Integrated Resource Plan ("IRP"). (*See* Page 9 of Volume I of PacifiCorp's 2011 IRP, Case No. PAC-E-11-10). Staff is confident that the Facility has contributed to meeting the Company's need for capacity and should receive capacity payments throughout the Agreement.

However, Staff discovered, by reviewing Federal Energy Regulatory Commission ("FERC") Form 556, that Powerhouse #1 has not been in operation since 2006. Fall River indicates there are plans for Powerhouse #1 to be operational at or before the start of the new contract.[2] Because Powerhouse #1 has not been contributing capacity for about 14 years, Staff believes it should be treated as a new project without capacity payments in the proposed PPA until the Company's first deficit year in 2028. (*See* Order No. 33917).

Staff learned on August 11, 2020, that the Facility has no way to separate the generation output from Powerhouse #1 from the generation output from Powerhouse #2 because the point of metering is the same for both powerhouses. (*See* Company's Response to Staff's Production Request No. 12). Because of the inability to meter the generation from each powerhouse separately, an alternative solution needs to be determined that will ensure two objectives. First, that Fall River does not receive capacity payments for generation from Powerhouse #1. Second,

[2] Fall River stated through Response to Staff's Production Request No. 1 that both powerhouses were operational from commencement of sales in 1986 until 2006 when flooding damaged Powerhouse #1, precluding safe operation of Powerhouse #1. From that point in 2006 until the present time, only Powerhouse #2 has remained in regular operation. Work to return Powerhouse #1 to service is ongoing at this time, and the QF expects that Powerhouse #1 will be returned to service before April 1, 2021, the commencement date of sales under the proposed PPA.

that Fall River will continue to receive capacity payments for generation from Powerhouse #2 equivalent to payments it has historically received and for capacity costs which the Company should have already avoided.

Because of the lack of two meters, Staff requests that the Commission allow additional time for discovery and analysis, and to initiate conversations with the parties, so that a solution can be developed that address the two objectives stated above. If granted, Staff proposes to file supplemental comments on October 1, 2020.

Staff believes there are several reasons to allow an extension in the schedule to file supplemental comments. First, to identify a reasonable method, Staff needs to understand the capabilities of the Company's meter and accounts payable processes, gather historical actual generation data, determine how the Facility is operated under different water flow conditions, and review information about the configuration of the Facility. Second, Staff wishes to initiate conversations with Fall River and the Company to explore potential solutions. Third, there is ample time before a new Agreement becomes effective. Finally, there are about seven years before the deficit date that would be impacted by a relatively large difference between a rate with and without capacity payments depending on the Commission's decision for determining the proper rate.

Whatever method is developed to functionally separate generation from the two powerhouses and to apply different rates, the development and calculation of avoided cost rates and capacity payments are important pieces of the analysis. The method for paying QFs for avoided cost of capacity in published rates is strictly based on the amount of actual generation on a $/kWh basis, and not the nameplate capacity of a QF. The $/kWh rate structure is designed to reward QFs for the avoided cost of capacity because of energy delivered, not its nameplate capacity. The Surrogate Avoided Cost ("SAR") model that calculates these rates is based on this method and has been reviewed and the rates authorized in a filing that has occurred every year since at least 2013. (*See* Order Nos. 32817, 33041, 33305, 33538, 33773, 34062, 34350, 34683).

The SAR method accomplishes two objectives. First, it provides a publishable standard rate schedule that can apply to any QF of a certain type (wind, solar, seasonal hydro, non-seasonal hydro, etc.), regardless of the nameplate capacity of the QF as long as it qualifies for published rates under the respective eligibility cap. In this case, Fall River is compensated using the published rate schedules for Non-Seasonal Hydro shown in Exhibit K of the Agreement.

These rates will be no different than any other Non-Seasonal Hydro QF that has a fully executed contract while these rates are in effect. Second, it holds the QF accountable, requiring it to generate energy to earn the capacity value for the cost of capacity that it avoids for the utility.

90/110 Rule

Staff has reviewed the contract provisions related to the 90/110 rule and believes the firm market price needs to be converted to a non-firm market price, using an 82.4% discount. Staff also recommends that the term "Mid-C-85" in Exhibit K be changed to "PV-85" to reflect the use of the Palo Verde Hub. Finally, Staff may propose additional changes to how the parties implement the 90/110 rule, depending on the information and the data Staff will examine through additional discovery to accommodate two sets of rates needed for the Facility.

<u>Monthly Estimates</u>

The Application states Fall River has demonstrated to the Company's reasonable satisfaction "the likelihood the facility, under average design conditions, will generate at no more than 2.5 aMW in any calendar month." However, both the Energy Delivery Schedule section and the Exhibit A of the proposed Agreement shows that the months of April, May, June, and July exceed the 2.5 aMW.

The Company stated in its Response to Staff's Production Request No. 14 that the 2.5 aMW figure in the Application was an error, and it should have been 3.5 aMW. Staff agrees with this statement and believes no changes need to be made to the monthly estimates in the Agreement.

<u>Advanced Notice Timeframe</u>

The Agreement uses a 10-day advanced notice to revise future monthly estimates. Staff believes any timeframe between a month and five days in advance is reasonable, and recommends approval of the proposed 10-day advanced notice. 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 five-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, e.g.,* Case Nos. IPC-E-19-01, IPC-E-19-03, IPC-E-19-04, IPC-E-19-07, and IPC-E-19-12).

Market price

Staff believes the Company's determination of firm market price is fair and reasonable, but the price needs to be discounted to convert to non-firm market price for the purpose of the 90/110 rule.

Firm Market Price Index is defined on Page No. 4 of the Agreement as:

> [T]he hourly value calculated based on the average prices reported by the Intercontinental Exchange, Inc. ("ICE") Day-Ahead PV On-Peak Index and the ICE Day-Ahead PV Off-peak Index (each an ICE Index) for a given day, weighted by the count of hours for each ICE Index on such day, multiplied by the hourly [California Independent System Operator] ("CAISO") day-ahead market locational marginal price for the "PACE. DGAP_PACE-APND" location and divided by the average of the same CAISO index over all hours in such day.

In this definition, PV refers to the Palo Verde Hub. The Company explained through Response to Staff's Production Request No. 10 that the Idaho service territory is located within the PacifiCorp East balancing authority area, which is more closely connected to Palo Verde than Mid-Columbia. Therefore, the Company uses the Palo Verde Hub instead of the Mid-Columbia Hub. The ICE On-Peak Index at the Palo Verde Hub, however, spans a wide range of conditions that are not adequately represented by an average value, so the Company further adjusts the numbers with the CAISO day-ahead market index to provide hourly granularity. The adjustment is based on the locational marginal price for "PACE.DGAP_PACE-APND" location, which is the Default Generation Aggregate Price for the PacifiCorp East balancing authority area. This price reflects an average of generation resources in PacifiCorp East. Lastly, the hourly prices are averaged over a month to arrive at a monthly value for the purpose of the 90/110 rule. Staff believes that this method reflects the Company's actual operations and transactions and is a fair representation of firm market price values.

If the Facility delivers more than 110 percent of the estimated amount, energy delivered in excess of 110 percent is priced at the lesser of 85 percent of the market price or the contract price. If the Facility delivers less than 90 percent of the estimated amount, total energy delivered is priced at the lesser of 85 percent of the market price or the contract price. Order No. 29632.

However, the market price referred to in Order No. 29632 is a non-firm market price, not a firm market price. Originally, in Order No. 29632, market price was defined as "the monthly weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Index (Dow Jones Mid-C Index) prices for non-firm energy." However, the Dow Jones Mid-C Index was discontinued in 2013, and Case No. IPC-E-13-25 was initiated to find a replacement market index for non-firm energy. Because firm energy is more valuable than non-firm energy, the Commission authorized that 82.4% of the monthly arithmetic average of each day's ICE daily firm Mid-C Peak Avg and Mid-C Off-Peak Avg index prices can be used as a replacement market index for non-firm energy. Order No. 33053. Since then, the 82.4% discount has been used in Idaho Power's and Avista's PURPA contracts when non-firm market prices are not available. Staff recommends using 82.4% as a fair and reasonable generic discount to be applied to convert firm market price to non-firm market price.

In addition, the Company stated through its Response to Staff's Production Request No. 11 that the term "Mid-C-85" in Exhibit K should have been changed to "PV-85" to reflect the use of the Palo Verde Hub. Therefore, Staff recommends amending Exhibit K to correct the mistake and incorporate the use of the 82.4% discount for converting firm market price to non-firm market price throughout the Agreement.

<u>Method to Determine Payments Outside the 90/110 Performance Band</u>

As stated above, when the Facility produces energy outside of the 90/110 performance band for a given month, the total energy delivered in that month is priced at the lesser of 85 percent of the market price or the contract price. (*See* Order No. 29632). However, given the need for two sets of contract rates, one set for each powerhouse until the Company is capacity deficient, a method is needed to ensure that the contract rate is appropriate and reasonable when it is compared against the market rate if the Facility falls outside of the 90/110 band. If the

Commission allows for additional time for discovery and analysis, Staff believes it will be able to find an alternative that is appropriate for purposes of the 90/110 rule and will include its recommendations in its supplemental comments.

STAFF RECOMMENDATION

The current contract between the Company and Fall River will not expire until March 31, 2021. To identify a fair and reasonable methodology to determine capacity payments until the next capacity deficiency date, Staff requests additional time to conduct additional discovery and to file supplemental comments on October 1, 2020. Based on its analysis so far, Staff recommends that the Company file an amended Agreement that includes the following updates:

1. Incorporate the 82.4% discount for purposes of converting firm market prices to non-firm market prices throughout the Agreement; and
2. Change the term "Mid-C-85" in Exhibit K to "PV-85" to reflect the use of the Palo Verde Hub.

Respectfully submitted this 17th day of August 2020.

Dayn Hardie
Deputy Attorney General

Technical Staff: Yao Yin
Mike Louis

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 17th DAY OF AUGUST 2020, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-20-10, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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