STAFF MEMORANDUM

TO: COMMISSIONERS AND ADVISORS

FROM: PATRICK STEFFENSEN, JOSEPH REZAC, AND AMANDA REISS

RE: Docket EL16-042 - In the Matter of Black Hills Power, Inc. dba Black Hills Energy's Application for Adjustment in its Cogeneration and Small Power Production Service Simultaneous Net Billing Generation Credit Rate(s)

DATE: May 19, 2017

Commission Staff (Staff) submits this Memorandum regarding its recommendations for the above captioned matter.

BACKGROUND

On December 30, 2016, Black Hills Power, Inc. dba Black Hills Power, Inc. dba Black Hills Energy (BHP or Company) filed with the Commission a request for approval of tariff revisions to update the Company's Cogeneration and Small Power Production Service Simultaneous Net Billing Generation Credit Rate(s).

The Commission officially noticed BHP's filing on January 5, 2017, and set an intervention deadline of January 20, 2017. On February 13, 2017, Richard A. Bell, PE, CEM filed a Petition to Intervene and requested a 90-day extension on the effective date of this matter. At its regularly scheduled meeting on February 28, 2017, the Commission granted intervention and the 90-day extension to Mr. Bell. On March 3, 2017, Mr. Bell filed a request for access to the Confidential Information contained in this docket in accordance with ARSD 20:10:01:43 and for the Commission to place a hold on the approved 90-day extension until the confidentiality treatment of this information is determined. On March 3, 2017, BHP filed a Petition for Confidential Treatment of Information and Exhibit A - Non-Disclosure Agreement. At its regularly scheduled meeting on March 14, 2017, the Commission granted the request for access to the Confidential Information on the condition that Mr. Bell signs the non-disclosure agreement provided by BHP and denied the hold on the approved 90-day extension.

Under Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), electric utilities are required to purchase energy offered by Qualifying Facilities (QFs), which are cogeneration facilities[1] and small power production facilities[2]. Utilities are required to purchase energy, capacity, or both from QFs at rates which are just and reasonable, non-discriminatory, in the public interest, and reflect the incremental costs of energy, capacity, or both, that the utility would have incurred to generate or purchase the energy if it was not supplied by the QF. These incremental costs are termed the utility's avoided costs.

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[1] Cogeneration facilities are generating units that produce electricity and steam simultaneously.

[2] Small power production facilities have a maximum size of 80 MW and have a primary energy source (75 percent or more) of biomass, waste, renewable resources, geothermal resources, or any combination thereof.

Federal Energy Regulatory Commission (FERC) regulations required states to establish standardized rates for QFs with an installed capacity of 100 kW or less. These standardized rates are included in BHP's tariff.

Pursuant to 18 CFR 292.302, at least every two years, each electric utility must provide to its State regulatory authority data from which avoided costs may be derived. The Commission affirmed this requirement for BHP in an Order Approving Tariff Sheets in Docket F-3365[3]. Historically, BHP has not filed every two years, but Staff didn't have significant concerns because 1) there were no small power production customers for the bulk of the time, 2) preparing such studies is expensive and covered by ratepayers, so it was determined to be in ratepayers' interests to not insist BHP file new rates every two years, and 3) when there were eventually customers under this rate, the tariff amounts, based on comparisons with other utilities, appeared to be similar or even greater than what other investor-owned utilities were paying[4]. And given the fact there were so few customers, it was deemed more efficient to not request these expensive filings. However, because of customer inquiries and the fact it had not been recently determined, Staff decided to request BHP begin filing these avoided cost studies and corresponding revisions to the generation credit rate. Although BHP has not updated its standardized rates in some time, this filing seeks to revise BHP's following schedules:

- Schedule 1 - Cogeneration and Small Power Production Service Simultaneous Net Billing
- Schedule 2 - Cogeneration and Small Power Production Service Simultaneous Purchase and Sale
- Schedule 3 - Cogeneration and Small Power Production Service Simultaneous Power

Further explanation regarding the application of each schedule can be found in BHP's response to Staff's data request 1-3. This filing updates the energy credits based on current data used to determine the avoided energy costs, which are more thoroughly explained below.

AVOIDED ENERGY COSTS

BHP calculates avoided energy costs for purchases from QFs using ABB's Planning and Risk (PAR) software. This production cost modeling software is used to analyze, report, and estimate the optimal hourly dispatch of a generation portfolio against market price inputs and load requirements. The modeling utilizes economy energy markets, purchase power agreements, and utility-owned generation, along with fuel and electric price forecasts from ABB's Fall 2016 Reference Case, to perform an hourly dispatch simulation. This allows BHP to predict the hourly avoided energy cost of a QF by comparing two simulations, one with the QF and one without the QF. The difference between the total system costs of the two scenarios is the avoided cost of energy.

PAR is driven by ABB's PROSYM chronological calculation engine for modeling power systems, which has been developed for over twenty years. BHP purchased PAR licenses in 1998 to do production cost modeling primarily to develop fuel and energy budgets, fuel consumption projections, generating unit cost projections, and electric resource planning, and it has since been used by BHP and other utilities alike to perform avoided cost calculations. The PAR algorithm is largely similar to those used in other industry production cost models, as it allows inputs of plant specific parameters like six heat rate points,

[3] In the Matter of the Investigation of the Implementation of Certain Requirements of Title II of the Public Utilities Regulatory Policy Act of 1978 Regarding Cogeneration and Small Power Production

[4] See Attachment 1 – Small Power Production Rates for a comparison of current avoided cost rates for South Dakota's investor-owned utilities

hourly chronological dispatch, zonal transmission limits, fuel limit modeling, hourly unit commitment, and up to five ancillary services modeling.

BHP's current generation credit rate is $0.0332 per kWh for energy BHP purchases from its customer's own generation which is in excess of the customer's simultaneous load. The initial filing proposed a new rate of $0.0270 per kWh, or a decrease of 18.7 percent, with a proposed effective date of March 1, 2017. In response to Staff's data request 1-17, BHP identified that several factors have contributed to the decrease in the generation credit rate, including changes in fossil fuel expense, purchased power expense, variable operations and maintenance production expense, and reduction or delay of future generation capacity additions. And, with a current BHP Fuel and Purchased Power Adjustment rate of $0.02174 per kWh[5], the proposed generation credit rate is indeed more representative of the recent historical costs BHP incurs to generate electricity.

AVOIDED CAPACITY COSTS

BHP has indicated in Exhibit 1 that they will have sufficient capacity resources to serve customer electricity demand, including a fifteen percent reserve margin, over the ten-year planning period. Thus, BHP does not include an avoided capacity cost in the calculation of avoided costs. BHP has captured avoided cost changes associated with the reduction of seasonal firm energy purchases in the production cost model. However, as shown in BHP's response to Staff's data request 2-3, the simulation does not show any seasonal firm market purchases being avoided until July 2019, outside the two-year window of this proposed generation credit rate.

OTHER ISSUES

On May 16, 2017, Mr. Bell filed comments based on his analysis performed. The following section will address a number of concerns he had in his filing.

1. In the second section Mr. Bell states, *"when qualifying facilities (QFs), like solar facilities, wind farms, and biomass plants are built, they enable utilities to avoid costs of building and operating a utility-owned power plant".* While this, in theory, is an accurate statement, the 35 small power production customers in aggregate only have an installed capacity of approximately .24 MW[6] and only supplied approximately 103 MWh[7] of energy to the grid in 2016. Given this and the fact BHP projects to have sufficient capacity resources over the ten-year planning period, the facilities of the small power production customers do not provide an avoided capacity benefit.

2. Under item "B" of the fourth section, Mr. Bell claims that the difference between the generation credit rate (GCR) he receives and the amount he pays for his electric usage represents a mark-up for BHP, and items like transmission and environmental improvements on power plants are not needed when customers produce their own power. However, this customer, and all small power production customers, still needs access to BHP-supplied generation and transmission. In fact, given the amount of their consumption that comes from self-generation, one could argue these customers are not paying their fair share of generation and transmission costs, since costs are

[5] Black Hills Power, Inc. d/b/a Black Hills Energy South Dakota Electric Rate Book, Section No. 3C, Sheet No. 12
[6] See BHP's response to Staff data request 1-2, Attachment 1-2 – Residential and Commercial Credit Charge
[7] See BHP's response to Staff data request 1-2, Attachment 1-2 – Amount Paid Data

shifted to non-self-generation customers due to BHP not recovering an adequate amount of their fixed costs imbedded in the variable energy rate from self-generation customers.

3. In that same section, Mr. Bell asserts there is *"excessive amount of profit to the company at the expense of the small generator"*. He also states under item "C" *"there are only 35 small power production customers in the BHE network who are affected by this proposed reduction"* and in the first paragraph of section five he states *"changes are driving utilities to propose new ways of collecting revenues from residential customers, or in this case, pay them less for the power they are putting back into the system"*. All these assertions go back to the common misnomer that only these 35 customers are affected by this rate. When, in fact, any expenses not recovered from these 35 customers (and costs BHP pays them for generation in excess of their simultaneous load) will, in theory, be passed on to the other 65,000 customers in BHP's South Dakota service territory. Thus, the Commission has a responsibility to ensure BHP is not paying too much for the generation it acquires from the QFs on behalf of its customers.

4. Under item "D" of the fourth section, Mr. Bell says *"the GCR rate should use the seasonal numbers that are based on peak rates rather than average rates"* for a GCR of $0.0286 per kWh. Since the model is run using the performance characteristics of a solar project, the GCR is weighted heavily toward on-peak production, as is evident in the numbers depicted in Table A-1. Using a GCR which is equivalent to the on-peak rate would assume all production from solar facilities are during on-peak hours, but one could also assume there would be some excess generation during off-peak weekend and holiday hours as well. It would also assume the GCR just applies to solar facilities, when there are actually eleven small power production customers with wind facilities[8] who would likely provide excess generation during off-peak hours.

5. Mr. Bell makes a number of statements regarding the benefits assessed to small power production facilities, the inputs used, and lack of transparency in the model. This type of modeling and software is nothing new to the Commission nor the electric industry as it is utilized by many electric companies, including companies this Commission regulates, to determine avoided cost rates and even Integrated Resource Planning.

RECOMMENDATION

Through this tariffed generation credit rate, small generators have the opportunity to sell power to a utility at a price which reflects the value of generation and is similar to the utility's wholesale cost of power. If utilities like BHP were to pay above market rates for substandard power, rates will eventually have to rise for all of BHP's customers to cover these increased expenses. Thus, Staff has a unique interest to ensure avoided costs adopted for the generation credit rate are properly calculated, because in the end, these costs are passed on to the more than 65,000 South Dakotans who are BHP customers.

The generation credit rate proposed by BHP assumes an effective date of March 1, 2017 and is calculated using the 24-month average of avoided cost outputs from March 2017 through February 2019. The revised generation credit rate submitted to the docket on May 11, 2017 uses a new 24-month average calculated over the period of June 2017 through May 2019, given the delayed effective date.

[8] See BHP's response to Staff data request 1-2, Attachment 1-2 – Residential and Commercial Credit Charge

The calculation is shown in BHP's response to Staff's data request 5-3 and arrives at an updated generation credit rate of $0.0275 per kWh, a decrease of 17.2 percent from the current rate.

BHP has satisfactorily responded to all of Staff's data requests, and the responses are filed online in the docket. Staff recommends the Commission approve the revised generation credit rate of $0.0275 per kWh with an effective date of June 1, 2017.