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UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO CLOSE THE NET METERING PROGRAM TO NEW SERVICE & IMPLEMENT A NET BILLING PROGRAM TO COMPENSATE CUSTOMER GENERATORS FOR EXPORTED GENERATION	)	**CASE NO. PAC-E-19-08** **DIRECT TESTIMONY OF DANIEL J. MACNEIL**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-19-08

June 2019

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company").

A. My name is Daniel J. MacNeil. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position is Resource and Commercial Strategy Adviser.

Qualifications

Q. Briefly describe your education and professional experience.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining the Company, I completed internships with the U.S. Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by the Company since 2008, first as a member of the net power costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to the Company's resource portfolio and obligations, including oversight of the calculation of avoided cost pricing in the Company's jurisdictions.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony in California, Oregon, Utah, Wyoming, and FERC dockets.

Purpose of Testimony and Recommendation

Q. What is the purpose of your testimony?

A. My testimony supports the Company's proposal to create Electric Service Schedule

No. 136 – Net Billing Services, ("Schedule 136"), under which customers would be compensated for generation in excess of their own load that is exported to the Company' s system based upon the Company' s avoided cost. I address three primary issues. First, I describe the elements, methodology, and calculation of the export credit value. Second, to better ensure compensation is consistent with exported volumes, I describe on-peak and off-peak time of export definitions that differentiate between periods of higher and lower avoided costs; and finally, I address how the export credit will be updated going forward.

Q. Have you prepared a summary of the proposed export credit values?

A. Yes. A summary of the export credit results is shown in Exhibit No. 1. My calculations support an average annual export credit of $24.86 per megawatt-hour ("MWh").

Export Credit Methodology

Q. What elements are included in the $24.86 per MWh value of the customer generation export credit?

A. The export credit includes the following elements related to the impact of exported energy on the Company' s system dispatch:

- **Avoided Energy Cost:** when customer generation is exported to the grid, the Company can reduce the output of its generation resources or reduce the volume of its market purchases. The resulting reduction in fuel expense and purchased power cost is the avoided energy cost.
- **Avoided Line Losses:** line losses are the difference between the total generation injected into the grid, and the total metered volume at customer sites. As a result, a kilowatt-hour produced by a generator is not equivalent to a

kilowatt-hour delivered to a customer. The Company's avoided energy costs are typically measured based on generation and market purchases at transmission voltages, while the metered volumes for residential generation exports are measured at the secondary voltage level. It is appropriate to adjust exported energy values from customer generation to account for the resulting avoided line losses.

- **Integration Cost:** The Company uses flexible resources to accommodate fluctuations in the load and resource balance of its system attributable to load, wind, solar, and other non-variable energy resources that are not under the Company's control. Integration costs represent the cost of holding reserves with flexible resources to reliably maintain the load and resource balance.

Q. How does the Company propose calculating exported energy costs?

A. The Commission has approved the Surrogate Avoided Resource ("SAR") Methodology for determining avoided costs for standard qualifying facility resources up to at least 100kW in nameplate capacity.[1] Under the SAR Methodology, avoided energy costs reflect forecast prices for natural gas and the assumed heat rate of a combined cycle combustion turbine. Monthly weighting factors are used to differentiate avoided costs by month, and an adjustment of 85 percent is applied to non-firm resources.

Q. Why is non-firm pricing appropriate?

A. Firm contracts would include credit terms, security deposits, performance guarantees,

[1] *In the Matter of the Commission's Review of PURPA QF Contract Provisions Including the Surrogate Avoided Resource and Integrated Resource Planning Methodologies for Calculating Avoided Cost Rates,* Case No. GNR-E-11-03, Order No. 32697 at 7-8 (Dec. 18, 2012).

liquidated damages, default provisions, and termination rights that are not found in the Schedule 136 tariff. Those contractual terms protect the utility and non-participating customers from non-performance and are essential to mitigating the risks associated with long-term contracts. Since customers are under no obligation to deliver any energy, non-firm valuations are appropriate. If a customer desires a firm or longer term contractual arrangement for their generation, they have the option of self-certifying as a QF and obtaining a contract under the applicable QF tariff. Non-firm treatment is consistent with Commission Order 32846: "The net metering tariff is for those who wish to offset a portion of their load. Those wishing to be wholesale power providers should look to Schedule 86 as the vehicle for that type of transaction."[2]

Q. Do the monthly avoided energy costs from the SAR Methodology provide sufficient granularity for determining an export credit?

A. No. To more accurately value export energy, the Company is proposing distinct on-peak and off-peak rates, as discussed later in my testimony. Since the SAR Methodology does not have hourly granularity, an alternative hourly price shaping methodology is required to identify the difference in value across the day.

Q. What hourly price shaping methodology do you propose?

A. To create an hourly shape, the Company proposes using the results of Energy Imbalance Market (EIM) operations. Specifically, the Company proposes using 15-minute PacifiCorp east (PACE) EIM load aggregation point (LAP) prices for the most recent 12 month period, in this instance, the 12 months ending December 2018. The

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[2] *In the Matter of Idaho Power Company's Application for Authority to Modify its Net Metering Service and to Increase the Generation Capacity Limit*, Case No. IPC-E-12-27, Order No. 32846 at 15 (July 3, 2013).

historical data is used to create a market price "scalar" based on the average market prices in a month during a given hour, relative to the average market price in that month during all hours. For instance, if the average market price during hour-ending 10 in May is $18/MWh, and the average market price during all hours in May is $20/MWh, then the scalar for hour-ending 10 in May would be 90 percent.[3] The average of the 24 hourly scalars for a given month is always 100 percent.

Q. What is the proposed exported energy value for customer generators?

A. Based on the proposed SAR energy values to be effective June 1, 2019, the average value of exported energy during the proposed rate effective period of 12 months ending May 2020 is $23.39 per megawatt-hour. Values are further distinguished by season and on-peak/off-peak period, as discussed later on in my testimony.

Q. Regarding the proposed rate effective period, will this affect customers' retail rates?

A. No. The Company is not proposing to make any changes to customers' retail rates. The proposed rate effective period that I discuss in my testimony deals only with the Company's proposed export credit rate.

Q. How does the Company propose calculating avoided line losses?

A. The line losses incorporated in the Company's current rates are from its 2009 Analysis of System Losses for Idaho. That study identified line losses in Idaho specific to the following interconnection levels:

- Transmission: 4.53 percent
- Primary: 7.448 percent

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[2] $18/MWh / $20/MWh = 90%.

- Secondary: 11.466 percent

The Company has used the results from power flow studies to calculate a marginal loss by load level and then fitted it to a 12 month by 24-hour profile for each of the interconnection levels referenced above. The result is an estimate of avoided line losses that can be differentiated by time of day and can be used to determine specific on-peak and off-peak values.

Q. What level of avoided line losses are included in the export credit calculation?

A. The Company expects to apply the export credit to resources interconnected at secondary voltage levels. However, the exported energy must be transferred across the secondary distribution system to other customers. As a result, they will incur some line losses, but will not be avoiding the entire line losses associated with serving load on the secondary distribution system. Therefore, the Company proposes crediting exports for only avoiding the next higher level or the primary line losses.

Q. What is the proposed value of avoided line losses?

A. The average value of avoided line losses during the rate effective period of 12 months ending May 2020 is $2.11 per megawatt-hour. Values are further distinguished by season and on-peak/off-peak period, as discussed later on in my testimony.

Q. What integration cost does the Company propose incorporating in the export credit value?

A. The Company anticipates that most of the resources exporting under the proposed program will be solar generators. The Company' s 2017 IRP includes a Flexible Reserve

Study,[4] which identifies the amount of flexible capacity required to compensate for variations in load and resources, as well as the cost of that capacity. The Company proposes that the solar integration cost of $0.60/MWh (2016$) assumed in the 2017 IRP be included in the export credit calculation. After adjusting for inflation, the proposed integration cost is $0.64/MWh during the rate effective period.

On-Peak and Off-Peak Definitions

Q. What is the purpose of distinguishing between on-peak and off-peak hours?

A. The Company's marginal costs vary significantly over the course of the day. In addition, a customer's export output will also vary over the course of the day. If a customer exports more during a part of the day with a relatively high value, it will provide greater benefits than if that customer exports during a part of the day with a relatively low value. Distinguishing periods with different value ensures that exporting customers receive appropriate compensation consistent with the value they provide to the system. This also provides customers with an incentive to adjust their load profiles to make better use of their own generation resources, as their avoided purchases still avoid the full cost-based retail rate.

Q. Are any on-peak and off-peak definitions currently in place that are applicable to residential customers?

A. Yes. Schedule 36 includes Optional Time of Day rates for residential service. The definitions in Schedule 36 are as follows:

[4] 2017 Integrated Resource Plan. Volume II, Appendix F: Flexible Reserve Study, *available at* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf.

On-Peak:

- Summer (May-October): 8:00 A.M. to 11:00 P.M., Monday through Friday, except holidays.
- Winter (November-April): 7:00 A.M. to 10:00 P.M., Monday through Friday, except holidays.

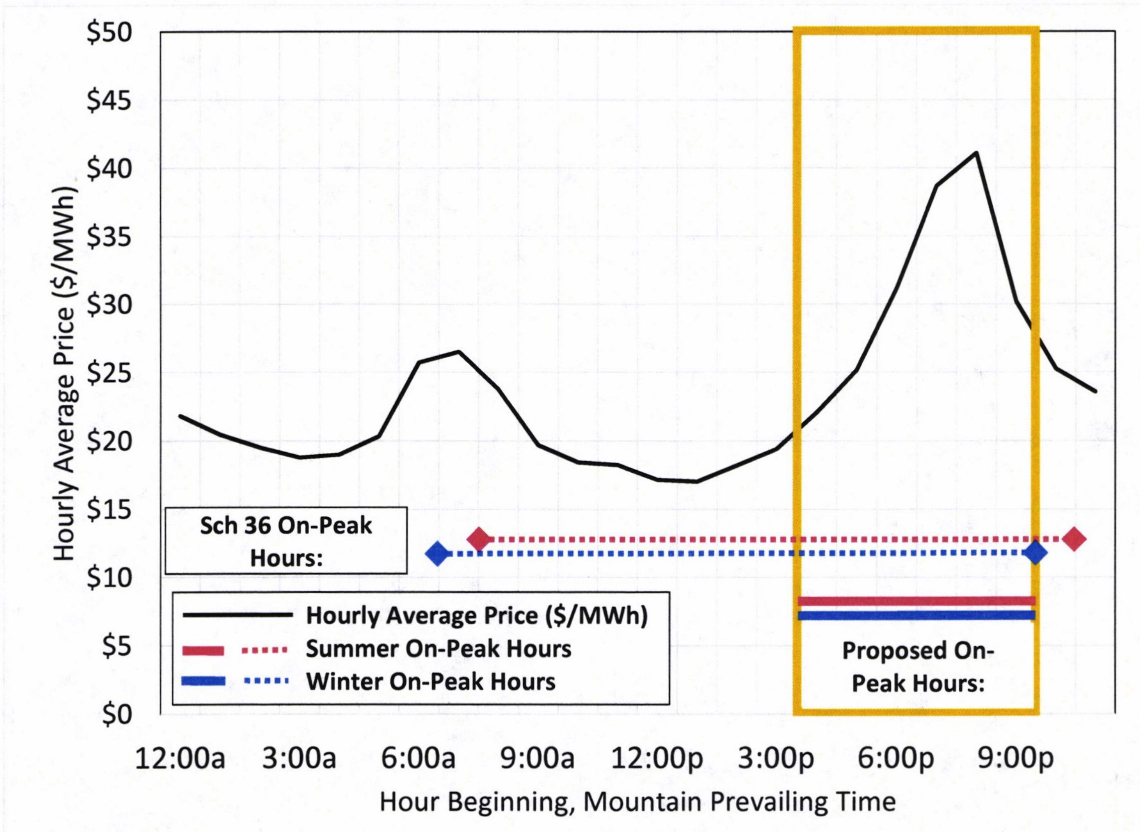
Off-Peak:

- All other hours, including the following holidays: New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Q. Do the on-peak and off-peak definitions in Schedule 36 align well with the Company's marginal costs?

A. No. The 2018 average EIM scalars by hour during the rate effective period ending May 2020 shows a wide variation in prices across the day, as shown in Figure 1. A large portion of the on-peak hours under Schedule 36 have prices that are closer to off-peak.

Figure 1: Hourly Energy Price Shape



Q. What on-peak and off-peak definitions do you propose?

A. Ideally the value within each period should be as uniform as possible, so that whenever a customer exports in a given period, the benefits are similar. At the same time, good ratemaking principles would suggest that the on-peak and off-peak definitions be easy for customers to understand and aligned with existing programs. With that in mind, the Company proposes that on-peak be defined as 4:00 p.m. to 10:00 p.m. Mountain Prevailing Time ("MPT"). To maintain consistency with Schedule 36, on-peak hours only apply to Monday through Friday, not including holidays. All hours other than on-peak hours are considered off-peak hours.

Q. Is Rocky Mountain Power proposing different definitions for on-peak and off-peak when compared to the existing Schedule 36?

A. Yes.

Q. Are these definitions an improvement over the Schedule 36 definitions?

A. Yes, these definitions have a wider spread between on-peak and off-peak than the existing definitions. For instance, under the existing Schedule 36 definitions, prices for on-peak hours are only 16 percent higher than off-peak. This occurs because the current on-peak definition includes hours in the middle of the day when prices are less than or equal to the middle of the night, which is the largest portion of the off-peak period. By comparison, the proposed definitions have prices for on-peak hours that are 52 percent higher than off-peak hours. This indicates that the proposed definitions are more uniformly distinguishing between periods of high value and low value, so that deliveries during the proposed periods provide more uniform benefits regardless of the specific time of delivery within the on-peak or off-peak period.

Q. Are all of the export credit elements differentiated between on-peak and off-peak periods?

A. Yes. Energy and line losses are readily differentiated as the underlying source data has hourly granularity. Integration costs are based on annual average values that reflect the cost of holding back flexible resources that could otherwise be used to serve customer load or support wholesale sales. Higher hourly energy prices imply higher costs for integration, so this element has been differentiated using the same ratios as the energy element.

Q. Are you proposing a change to the summer and winter season definitions, relative to the Schedule 36 definitions?

A. Yes. The proposed summer season definition spans June through September, whereas the Schedule 36 summer season definition also includes May and October. The proposed definition results in higher prices that provide a stronger price signal during the summer periods when the Company' s resource needs and avoided costs are highest. A June start of the summer season also aligns with the proposed process for updating export credit values each year.

Q. What are the proposed export credit values?

A. Details on the proposed export credit values by season and by on-peak/off-peak are shown in Exhibit No. 1.

Updating Export Credit Rates

Q. Will a customer's export credit be fixed or will it be updated?

A. The Company proposes to update the export credit annually. This will ensure that the export credit payments continue to be consistent with the Company' s avoided cost and that they are consistent with the non-firm nature of the output. This will also allow all customers participating under Electric Service Schedule No. 136 – Net Billing Services to receive the same export credit rates, reducing the administrative complexity of assorted vintages of export credit rates and on-peak/off-peak definitions.

Q. What factors drive the timing of an annual export credit update?

A. Avoided costs under the SAR Methodology are updated annually, typically on June 1. Since avoided energy costs represent the majority of the export credit value, it would be reasonable to update the export credit rates at the same time. Data for avoided line losses, integration costs, or other inputs would be updated to reflect the most recent information available for inclusion in the annual update. The Company proposes to automatically update export credit values at the same time updates are proposed for SAR avoided energy prices.

Q. Please provide an example of how the annual export credit update would work.

A. The first update to export credit rates would occur in 2020. The case for the annual update to avoided energy costs under the SAR methodology updates is opened annually in early April, and the Company provides comments two weeks later in mid-April. The Company proposes that its comments also include recalculated and updated export credit values. The updated export credit values could be considered either within the annual update to avoided cost rates case, or in a separate case. The target effective date for the updated export credit values would be the same as the SAR methodology, at the start of the summer season on June 1, 2020.

Q. Where would the cost of the export credit be booked and how would it be treated for regulatory purposes?

A. The Company recommends that export credit payments be recorded in FERC Account 555 and tracked in the energy cost adjustment mechanism. Excess energy from customer owned generation is fed into the grid offsetting some of the need for energy from other sources. Customers that produce more energy than they use during the month would receive a credit on their bill at the export credit rate for any excess energy supplied to the grid. This credit would be treated just like any other purchased power expense by debiting FERC Account 555 with an offsetting credit to the customer' s bill.

Conclusion

Q. Please summarize your recommendations for the Commission.

A. The Company recommends that the Commission set the export credit at $24.86/ MWH during the first rate effective period ending May 31, 2020. This value should be differentiated by on-peak / off-peak and summer / winter periods that reflect higher and lower avoided costs values, with on-peak defined as 4:00 p.m. to 10:00 p.m., MPT, Monday through Friday, not including holidays, and all other hours considered off-peak. Finally, I recommend that the export credit be updated on an annual basis, on June 1.

Q. Does this conclude your direct testimony?

A. Yes.