ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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July 2, 2020

*VIA ELECTRONIC DELIVERY*

Diane Hanian
Commission Secretary
Idaho Public Utilities Commission
11331 W Chinden Blvd.
Building 8 Suite 201A
Boise, ID 83714

**Re: Case No. PAC-E-20-03**
**IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES IN IDAHO AND APPROVAL OF PROPOSED ELECTRIC SERVICE SCHEDULES AND REGULATIONS**

Dear Ms. Hanian:

Please find enclosed for electronic filing Rocky Mountain Power's Application in the above-referenced matter along with a Stipulation provided as Attachment 1 to postpone the general rate case and request Commission authorization for: 1) an accounting order authorizing the Company to create a regulatory asset to transfer the decommissioning and plant closure costs of Cholla Unit No. 4 ("Unit 4") when it is retired; 2) approval of modifications to Phase II of the settlement stipulation to implement tax reform ("the Tax Stipulation");[1] and 3) approval of ratemaking treatment for Pryor Mountain and Foote Creek I wind resources to match costs with benefits, with cost recovery capped at the level of benefits until the prudence of the resources can be determined in the next general rate case. Work papers supporting the Excess Deferred Income Tax balances are also included.

Informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at (801) 220-2963.

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[1] *In the Matter of the Investigation into the Impact of Federal Tax Code Revisions on Utility Costs and Ratemaking, Case No. GNR-U-18-01, Final Order No. 34431 (May 3, 2019).*

Very truly yours,

Joelle Steward

Joelle Steward
Vice President, Regulation

Enclosures
CC:
Terri Carlock – Commission Staff
Randy Budge – Bayer
Ben Otto – Idaho Conservation League
Eric Olsen – Idaho Irrigation Pumper Association
Ron Williams – PacifiCorp Idaho Industrial Customers

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*Attorneys for Rocky Mountain Power*

**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

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|---|---|---|
| **IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES IN IDAHO AND APPROVAL OF PROPOSED ELECTRIC SERVICE SCHEDULES AND REGULATIONS** | ) | **CASE NO. PAC-E-20-03**<br><br>**APPLICATION OF ROCKY MOUNTIAN POWER** |

Rocky Mountain Power, a division of PacifiCorp, ("Rocky Mountain Power" or the "Company"), hereby applies to the Idaho Public Utilities Commission ("Commission") for: 1) an accounting order authorizing the Company to create a regulatory asset to transfer the decommissioning and plant closure costs of Cholla Unit No. 4 ("Unit 4") when it is retired; 2) approval of modifications to Phase II of the settlement stipulation to implement tax reform ("the Tax Stipulation");[1] and 3) approval of ratemaking treatment for Pryor Mountain and

[1] *In the Matter of the Investigation into the Impact of Federal Tax Code Revisions on Utility Costs and Ratemaking, Case No. GNR-U-18-01, Final Order No. 34431 (May 3, 2019).*

Foote Creek I wind resources to match costs with benefits, with cost recovery capped at the level of benefits until the prudence of the resources can be determined in the next general rate case.

In support of this Application, Rocky Mountain Power states as follows:

## I. INTRODUCTION

1. Rocky Mountain Power is authorized to do and is doing business in the state of Idaho. The Company provides retail electric service to approximately 84,000 customers in the state of Idaho and is subject to the jurisdiction of the Commission.

2. Rocky Mountain Power files this application pursuant to Idaho Code §61-524 and RP 52, which authorizes the Commission to prescribe the accounting to be used by public utilities subject to its jurisdiction.

## II. COMMUNICATIONS

3. Communications regarding this Application should be addressed to:

Ted Weston
Idaho Regulatory Affairs Manager
Rocky Mountain Power
1407 W North Temple Suite 330
Salt Lake City, Utah 84116
E-mail: ted.weston@pacificorp.com

Emily Wegener
Senior Attorney
Rocky Mountain Power
1407 W North Temple, Suite 320
Salt Lake City, Utah 84116
E-mail: emily.wegener@pacificorp.com

In addition, Rocky Mountain Power requests that all data requests regarding this application be addressed to:

By email (preferred) datarequest@pacificorp.com

By regular mail Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries related to this application may be directed to Ted Weston, (801) 220-2963.

## III. CASE NO. PAC-E-20-03 SETTLEMENT TERMS

4. On March 26, 2020, pursuant to Idaho Public Utilities Commission Rule of Procedure 122, the Company filed a Notice of Intent to file a General Rate Case with the Commission. Recognizing the impact that the COVID-19 pandemic has on its customers and knowing a rate increase at this time in particular would be challenging for customers, the Company developed a rate plan that would allow it to delay filing a general rate case.

5. The Company, Commission staff, Bayer, Idaho Conservation League, Idaho Irrigation Pumper Association, and PacifiCorp Idaho Industrial Customers, the ("Parties") were able to reach an agreement to delay a general rate case so no change to general rates would be effective prior to January 1, 2022. In return for the Company agreeing to delay the rate case, the Parties agreed to support the Company's application to request Commission authorization for:

- A regulatory asset to transfer Cholla Unit 4 net book balance upon closure of the plant in December 2020. The regulatory asset will also include other closure-related and decommissioning costs.
- Modifications to the Phase II Settlement Stipulation in Case No. GNR-U-18-01, on the ratemaking treatment for the 2017 Tax Cut and Jobs Act ("TCJA"). The Company may propose that the remaining balance from

excess deferred income tax savings from the TCJA be retained to buy-down the Cholla Unit 4 and be deferred to offset the January 1, 2022 rate increase.

- Ratemaking treatment for the Pryor Mountain and Foote Creek I wind resource to match costs and benefits with a cost cap amount each year at the benefit level. The Company may propose to include these resources in the Resource Tracking Mechanism/Energy Cost Adjustment Mechanism ("RTM/ECAM"), consistent with the terms agreed to in Case No. PAC-E-17-07. Prudency will be determined during the next General Rate Case.
- There will be no change to the ECAM baseline NPC of $26.90/MWh (on a sales-basis) established in PAC-E-16-12, until the base is reset in the next general rate case.
- The Company will make its results of operations and cost of service models developed in anticipation of filing a rate case on June 1, 2020, available to parties and the Company will respond to the parties' reasonable data requests regarding the same.

6. The Company will provide the annual Results of Operations report and a Cost of Service study separately to the Parties. The Results of Operations will fulfil the requirements of Commission Order 29708 that requires the Company to file an Annual Earnings Report. On April 7, 2020, the Company notified the Commission of its intent to utilize the Results of Operations report from the rate case to meet this requirement. The agreement signed by the Parties is provided as Attachment 1 to the Application.

## IV. CLOSURE OF CHOLLA UNIT NO. 4

7. The Cholla power plant consists of four units located near Joseph City, Arizona, with a combined generating capability of 995 megawatts ("MW"). Arizona Public Service Company ("APS") owns Cholla Units 1 and 3 (Unit 2 was retired in October 2015) and operates the entire Cholla facility. PacifiCorp owns approximately 37 percent of Cholla's common facilities and 100 percent of Unit 4, which was commissioned in 1981 with a generating capability of 395 MW.

8. In February 2011, the Arizona Department of Environmental Quality ("ADEQ") submitted a regional haze state implementation plan ("SIP") to the Environmental Protection Agency ("EPA"). The SIP submittal included a best available retrofit technology ("BART") analysis and determination for the need to install nitrogen oxides ("NOx") emission controls on Cholla Unit 4. In December 2012, EPA rejected the state's BART determination for NOx controls on the Cholla units and issued a federal implementation plan ("FIP") in place of the SIP. The EPA's FIP required installation of low-NOx burners ("LNB"), separated over-fire air ("SOFA"), and selective catalytic reduction ("SCR") systems for NOx control on the Cholla units by December 5, 2017.

9. In January of 2015, APS and PacifiCorp prepared and submitted a BART reassessment for the Cholla Units to ADEQ and requested that ADEQ revise its BART analysis due to the substantial costs associated with the compliance requirements of EPA's FIP. As part of the reassessment, APS and PacifiCorp committed to operate LNB and SOFA on Unit 4, and permanently cease burning coal in the Unit by April 30, 2025 (with an option to convert to natural gas combustion by July 31, 2025). In October 2015, ADEQ submitted a SIP revision

to EPA adopting the requirements of the BART reassessment, including the cease operations or convert requirement. EPA proposed approval of the SIP revision in July of 2016, and issued final approval in March of 2017.

10. Due to these environmental compliance rulings, PacifiCorp is required to cease operations at Cholla Unit 4 or convert it to natural gas by April 30, 2025. However, the Company's most recent IRPs have indicated that it was economic to pursue earlier retirement. On December 27, 2019, the Company announced its decision to retire Unit 4 by December 31, 2020. The Company's decision to initiate the process of retiring Unit 4 is supported by the economic analysis it conducted.

11. PacifiCorp's 2019 IRP preferred portfolio reflects customer benefits associated with Cholla Unit 4's retirement as early as 2020. Given the unique ownership structure at the Cholla plant, PacifiCorp's action plan committed to initiating the process of retiring Cholla Unit 4 and removing it from service no later than January 2023 and earlier if possible.

12. PacifiCorp has initiated the process of retiring Unit 4 and anticipates being able to achieve retirement by year-end 2020, earlier than the January 2023 timeframe initially set forth in the 2019 IRP action plan. Further economic analysis building on the IRP studies confirmed that early closure at the end of 2020 is expected to generate more present-value customer benefits relative to Unit 4 continuing operation through April 2025.

13. The IRP economic analysis relies on an assessment of system value which compares the outcomes of the Planning and Risk model ("PaR") scenarios with a simulation period covering the 2019 through 2025 timeframes. Consistent with the 2019 IRP preferred portfolio, the simulations utilize a range of natural gas price and carbon policy scenarios which

incorporate a $CO_2$ price beginning in 2025 (medium natural gas price and medium $CO_2$ price assumptions (the "MM" price-policy scenario); low natural gas price and no $CO_2$ price assumptions (the "LN" price-policy scenario), and high natural gas price and no $CO_2$ price assumptions (the "HN" price-policy scenario)).[2]

14. Each price-policy scenario was run twice: once to update the 2019 preferred portfolio where Cholla Unit 4 is assumed to retire at the end of December 2020, and the other assuming Unit 4 continues operation through the April 2025 timeframe. Each price-policy scenario showed an increase in net system costs when it was assumed that Unit 4 operated as a coal-fired facility through April 30, 2025.

15. The updated economic analysis confirmed PacifiCorp's ongoing IRP analyses and demonstrated that retirement of Unit 4 by year-end 2020 will produce net customer benefits relative to a case where Unit 4 continues operating through April 2025. This outcome is consistent across a range of price-policy scenarios. This holds true even with incremental costs, such as the closure-related costs, in part because PacifiCorp will no longer incur the operating costs associated with running Unit 4.

16. Early closure at the end of 2020 is expected to generate between $96 million and $123 million in present-value customer benefits relative to an alternative where Unit 4 continues to operate through April 2025. All three price-policy scenarios report an increase in

[2] For both PaR runs produced under the MM price-policy scenario, price assumptions were developed from PacifiCorp's September 2019 official forward price curve. LN and HN price-policy scenarios are derived from third-party sources. Natural gas prices in the LN price-policy scenario do not drop below prices in the MM scenario until 2026-beyond the early retirement study period. Consequently, the primary difference between the MM and LN price-policy scenario is the absence of a $CO_2$ price in 2025 in the LN scenario.

net system costs when it is assumed that Unit 4 operates as a coal-fired facility through April 30, 2025, relative to the case where it is assumed to retire at the end of 2020. Attachment 2 to this application summarizes the results of each of these price-policy scenarios.

17. Early retirement of Cholla Unit 4 will increase costs in 2020, followed by decreased costs between 2021 and 2025. The 2020 cost increases are primarily associated with early termination payments of a safe harbor lease. PacifiCorp is the legal owner of Cholla Unit 4, but for income tax purposes only, PacifiCorp is treated as leasing portions of Unit 4 that are subject to a safe harbor lease. With the early retirement, certain payments may be required to be made by PacifiCorp to the tax lessor. The Company has estimated the high range of a potential payment at approximately $3.3 million.

18. When PacifiCorp acquired Cholla Unit 4, the Company paid APS prepaid availability and transmission charges in April 1994 and April 1996. The charges are related to the construction of transmission facilities that enable an additional 150 MW of northbound firm transmission capability on the Phoenix-Mead transmission line. The prepaid transmission service cost began amortization over a fifty-year life in May 1997, and PacifiCorp began receiving transmission credits on its bill from APS. Under the early retirement case, it is assumed the unamortized balance would be written off.

19. Early retirement of Unit 4 by December 2020 will reduce net system costs through the assumed April 2025 retirement date. Over this period, projected generation from Unit 4 declines, and the value of energy net of fuel costs is insufficient to offset annual fixed operating costs.

20. As of December 31, 2020, Unit 4's net book value is expected to be

approximately $284 million. Because the Company anticipated filing a general rate case with rates effective January 1, 2020, Cholla Unit 4 was removed from the 2018 Depreciation study. If the Commission approves the 2018 Depreciation stipulation depreciation of Cholla will end December 31, 2020. However, current rates include approximately $0.9 million in annual depreciation expense. The Company provided an offset to the regulatory asset balance by that amount to account for one additional year during 2021 of Cholla depreciation expense in Idaho rates.

21. The Company anticipates retiring Unit 4 by December 31, 2020, and requests Commission approval to use tax benefits to buy-down the net plant balance as explained below and transfer the remaining balances for Cholla Unit 4 from the respective FERC accounts and record a regulatory asset in FERC account 182.3 (Other Regulatory Assets) on the date the plant is removed from service. Idaho's share of the regulatory asset will be established based on the system generation ("SG") allocation factor for the calendar year 2019. Table 1 summarizes the estimated plant balances as of December 31, 2020.

**TABLE 1**

| Cholla Unit #4 Retirement - December 31, 2020 Estimated Balances | | | | |
|---|---|---|---|---|
| **Description** | | **Total Company** | | **Idaho Allocated** |
| Gross EPIS | $ | 552.7 | $ | 32.7 |
| Accumulated Depreciation | $ | (268.4) | $ | (15.9) |
| CWIP | $ | 1.8 | $ | 0.1 |
| M&S | $ | 6.1 | $ | 0.4 |
| Liquidated damages | $ | 19.6 | $ | 1.2 |
| GE safe harbor lease termination payment | $ | 3.3 | $ | 0.2 |
| Savings due to O&M Expense | $ | (27.3) | $ | (1.6) |
| Savings due to Depreciation Expense | $ | (15.2) | $ | (0.9) |
| Estimated Decommissioning Costs | $ | 47.3 | $ | 2.8 |
| **Estimated December 31, 2020 Balances** | **$** | **319.9** | **$** | **18.9** |

22. Since Cholla Unit 4 was not included in the 2018 depreciation rates not only will plant balances stop being depreciated, recovery of estimated decommissioning costs will also stop. The Company currently estimates the cost of decommissioning Cholla Unit 4 and remediating the site to be approximately $47 million. The Cholla plant is operated by APS so the Company isn't certain when the plant will be retired and decommissioned.

23. As further discussed below the Company recommends using some of the available Excess Deferred Income Tax ("EDIT") benefits to buy-down or offset the Cholla Unit No. 4 unrecovered plant balances and closure costs to mitigate future rate impact to Idaho customers.

## V. MODIFICATION OF FEDERAL TAX REFORM ACT SETTLEMENT

24. On March 5, 2019, the Company filed an all-party stipulation with the Commission resolving how the tax savings from the federal "act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018" (the "Tax Reform Act") for the period of 2018 through 2020 would be returned to customers.[3]

25. Parties to the Tax Stipulation agreed to the ratemaking treatment for the deferred balances associated with the tax savings arising from the Tax Reform Act, which included refunding certain tax savings through the ECAM and offsetting the 2013 incremental depreciation expense with some of those tax savings. The Order approved the $1,141,000 deferred balance of current tax savings for the period of January 1, 2018, through May 31, 2019, that had not been returned to customers through Schedule 197. This balance was tracked and amortized over two years ($570,500 per year), beginning June 1, 2019,

[3] *In the Matter of the Investigation into the impact of Federal Tax Code Revisions on Utility Costs and Ratemaking,* Case No. GNR-U-18-01, Order No. 34331 (May 3, 2019).

through the ECAM.

26. The Tax Reform Act resulted in Idaho-allocated EDIT composed of the following amounts, grossed-up for taxes: 1) Protected property-related EDIT of $105,924,604[4], with estimated annual amortizations through the average rate assumption method ("ARAM") of $2,564,410 in 2018, $2,352,309 in 2019, and $2,306,632 in 2020; and Non-protected property and non-property EDIT of $14,883,505.[5]

27. During 2019 the Company determined that it was necessary to use a different method to amortize the protected EDIT balances. The Tax Stipulation was based on the ARAM, but on further review the Company determined that it didn't have the necessary records to support that accounting method and had to switch to the Reverse South Georgia Method ("RSGM"). The RSGM did not change the balances available but it did modify the annual amortization of those balances as compared to the ARAM.

28. The Tax Stipulation included an estimate of the annual protected property EDIT in the amount of $2,564,364 for 2018, $2,352,309 for 2019 and $2,306,632 for 2020, less the associated rate base offset, that would be refunded to retail customers through a cents per kilowatt-hour credit netted against the ECAM rate.

29. Lastly, the Tax Stipulation provided that the non-protected and non-property EDIT, arising from the Tax Reform Act would be amortized over seven years, approximately $2,126,215 annually less the rate base offset, and used to offset the 2013 incremental depreciation expense through the ECAM, not subject to the sharing band and until the rate

[4] The protected property EDIT is $79,881,345, or $105,924,604 grossed up for taxes.

[5] The non-protected property EDIT is $10,009,386, or $13,272,689 grossed up for taxes, and non-protected non-property total EDIT is $1,214,771, or $1,610,816 grossed up for taxes.

effective date in the next general rate case.

30. In the Tax Stipulation the parties agreed they could propose to change the seven-year amortization period for the unamortized portion of the non-protected property and non-property EDIT balance in the next Idaho general rate case. In the agreement with parties to not file a general rate case in 2020, parties agreed the Company could propose modifications to the Tax Stipulation outside of a general rate case.[6]

31. Under the RSGM protected-property EDIT was $4,571,790 for 2018 and $4,602,855 for 2019, increasing the Tax Savings amortization of protected-property EDIT by $4,257,972 over the two-year period. The Company also identified the need to reclassify EDIT between protected property and non-protected and transferred $2,964,471 from the protected property to the non-protected EDIT balance which increased the unamortized balance to $17,847,973 for non-protected EDIT benefits.

32. Combining the increased amortization of protected property under the RSGM for 2018 and 2019 with the 2020 EDIT amortization that hasn't been returned to customers and the unamortized non-protected EDIT balance produces a total EDIT balance available to customers of $24,305,381. Table 2 is a summary of the EDIT savings available to customers. Work papers supporting these amounts are provided with the Application.

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[6] *See* Attachment 1.

**Table 2**

| Tax Reform Act Benefits | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|
| Protected EDIT Deferral - RSGM | $ (4,571,790) | $ (4,602,855) | $ (6,451,861) | $(15,626,506) |
| Protected EDIT Deferral - ARAM | $ 2,564,364 | $ 2,352,309 | | $ 4,916,673 |
| | $ (2,007,426) | $ (2,250,546) | $ (6,451,861) | $(10,709,833) |
| | | | | |
| Non-Protected EDIT - Estimate | | | | $(14,883,504) |
| Amortization | $ 2,126,215 | $ 2,126,215 | | $ 4,252,430 |
| Non-Protected EDIT - Reclassification | | | | $ (2,964,474) |
| Balance December 31, 2020 | | | | $(13,595,548) |
| | | | | |
| **Tax Reform Act Benefits Available December 31, 2020** | | | | **$(24,305,381)** |

33. The Company requests authorization to use approximately $15.9 million of the $24.3 million EDIT Tax Reform Act benefits to pay off the Cholla Unit No. 4 unrecovered balances. The Cholla regulatory asset will be used to transfer the GE Safe Harbor lease payment and track actual decommissioning costs. The Company also requests authorization to cease the refund of tax savings in the ECAM filing in 2021 in order to use any remaining EDIT savings as of December 31, 2021 to mitigate the rate impact from the 2021 general rate case. As of December 31, 2020 this results in approximately $8.4 million in deferred Tax Reform Act benefits available to use to offset the next general rate case increase. The current refund of $7.6 million in current tax savings on Schedule 197 would continue until new rates are effective from the next general rate case.

34. The Company's decision to retire Cholla Unit 4 and use EDIT Tax Reform Act benefits to buy-down the remaining plant balance accelerates the availability of Idaho-allocated Cholla EDIT benefits as reflected in the 2020 Protected EDIT Deferral amount. Table 3 summarizes the items the Tax Benefit buy-down would be used for and the items tracked in the regulatory asset.

**TABLE 3**

| Cholla Unit #4 Tax Buy-Down / Regulatory Asset | | | | |
|---|---|---|---|---|
| **Description** | | **Total Company** | | **Idaho Allocated** |
| Gross EPIS | $ | 552.7 | $ | 32.7 |
| Accumulated Depreciation | $ | (268.4) | $ | (15.9) |
| CWIP | $ | 1.8 | $ | 0.1 |
| M&S | $ | 6.1 | $ | 0.4 |
| Liquidated damages | $ | 19.6 | $ | 1.2 |
| Savings due to O&M Expense | $ | (27.3) | $ | (1.6) |
| Savings due to Depreciation Expense | $ | (15.2) | $ | (0.9) |
| **Estimated Tax Benefit Buy-Down** | **$** | **269.3** | **$** | **15.9** |
| | | | | |
| **Transferred to Regulatory Asset** | | | | |
| GE safe harbor lease termination payment | $ | 3.3 | $ | 0.2 |
| Estimated Decommissioning Costs | $ | 47.3 | $ | 2.8 |
| **Estimated Regulatory Asset Balance** | **$** | **50.6** | **$** | **3.0** |

## VI. RATEMAKING FOR PRYOR MOUNTAIN AND FOOTE CREEK I

35. The Company requests the Pryor Mountain and Foote Creek I wind resources be included in the RTM authorized by the Commission for other Company wind projects in Order No. 34104 to match the costs with the benefits these resources produce for customers.[7] Consistent with the stipulation[8] for ratemaking treatment approved in that proceeding, the costs would be capped at the benefit levels passed back through the ECAM so customers would not see a net cost for these projects through the RTM or ECAM. Net costs, if any, would be deferred for later recovery to be determined in the next general rate case when a full prudence

[7] *In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity and Binding Ratemaking Treatment for new Wind and Transmission Facilities.* Case No. PAC-E-17-07, Order No. 34104 (July 20, 2018).

[8] *The Stipulating Parties agree that the Company will maintain a cap on the annual total cost of the Stipulated Projects not to exceed the annual project benefits in the ECAM and RTM. Costs that are passed on to customers through the RTM, before the next general rate case, will be capped at the level of benefits that will flow through the ECAM, as such, on a combined basis, the ECAM and the RTM will not result in a net cost to customers associated with the Stipulated Projects. Any costs above this cap will be deferred as a regulatory asset for recovery to be set in the next general rate case.* Case No. PAC-E-17-07, paragraph 14 of the Stipulation.

review for these resources is expected to occur.

36. The Pryor Mountain Wind Project will have a nameplate capacity of 240 MW and is located in Carbon County, Montana, approximately 60 miles south of Billings, Montana. The project consists of 57 Vestas Model V110-2.0 MW safe harbor, 21 Vestas Model V110-2.2 MW safe harbor, four General Electric Model 2.3-116 MW safe harbor, and 32 Vestas model V110-2.2 MW follow-on wind turbine generators ("WTGs").

37. The Pryor Mountain Wind Project is similar to the new wind facilities included in the Energy Vision 2020 Project. The time-sensitive nature of the Pryor Mountain Wind Project is primarily driven by the pending phase-out of the federal Production Tax Credits ("PTCs") for new wind resources. With an in-service date before the end of 2021, the Pryor Mountain Wind Project will be eligible for the full 100 percent PTCs rate. The Company's acquisition and implementation plan for the Pryor Mountain Wind Project is designed to meet the year-end 2020 in-service schedule and provide customers the full economic benefit of the project.

38. Through its wind repowering efforts, PacifiCorp is leveraging past investments in its wind fleet and enhancing the future value of these resources for the benefit of its customers. The Company's repowering efforts now include all of its owned wind resources, including the Foote Creek I facility that was not subject to the Commission's prior order[9] related to repowering. By taking advantage of the unique opportunity to repower this facility, the Company is able to provide efficiency and reliability improvements in wind generation

[9] *In the Matter of the Application of Rocky Mountain Power for Binding Ratemaking Treatment for Wind Repowering*, Case No. PAC-E-17-06, Order No. 33954 (Dec. 28, 2017).

technology to its customers, and return the entirety of its wind fleet to like-new condition, all while enhancing performance, reducing ongoing maintenance expenditures, and reducing customer costs.

39. Foote Creek I, the Company's oldest wind facility, began commercial operation in April 1999. The facility served as a demonstration project to evaluate the feasibility of utility-scale wind energy. The facility was developed in partnership with the Eugene Water & Electric Board ("EWEB") and the Bonneville Power Administration ("BPA"). As developed, Foote Creek I was co-owned by EWEB's 21.21 percent ownership and PacifiCorp's 78.79 percent ownership, with BPA taking 37 percent of the facility's output through a 25-year cost-based Purchase Power Agreement ("PPA"). As the first utility-scale wind energy project in Wyoming, Foote Creek I was sited at one of the most favorable wind sites in the United States and enjoys the highest wind speeds of any of the Company's wind projects. Unlike the remainder of the facilities the Company is repowering, the Foote Creek I project is unique in that it was co-owned and also had a third-party PPA associated with the resource.

40. The Foote Creek I facility currently consists of 68 turbines, each with a 600-kilowatt generating capacity, a rotor diameter of 42 meters, and towers that support a 40 meter hub height. Although employing the latest technology when originally installed, the existing turbines are costly to operate and maintain relative to the Company's more modern turbines that have a much higher nameplate capacity, larger rotor diameters, and taller towers. Since the maintenance requirements for these smaller turbines are similar to those of larger turbines, the operation and maintenance costs of the Foote Creek I facility are the highest of all of the Company-owned wind resources on a per-MW basis.

41. The costs associated with continued operation of the existing turbines at Foote Creek I for both the Company and EWEB would have increased after the expiration of the BPA PPA in April 2024 since 37 percent of these costs would no longer be covered through the cost-based PPA. Similarly, BPA was required to take higher cost energy from the project until the PPA expired. For these reasons, PacifiCorp, EWEB, and BPA were all motivated to explore whether the existing Foote Creek I contract could be unwound in order to achieve an outcome more favorable to customers as compared to continuing to operate the facility through its planned 30-year asset life. Repowering the facility presented the opportunity to realize this outcome for all customers.

42. Repowering Foote Creek I re-qualifies it for PTCs, which are benefits that are passed through to customers. Additionally, repowering increases the amount of zero-fuel-cost energy produced from the repowered facilities given the much larger energy production capability of the new turbines. Further, by replacing older WTG equipment, which is subject to more failure and maintenance issues than newer equipment, repowering will reduce PacifiCorp's ongoing operating costs. Finally, repowering the wind facilities with new WTG equipment will extend the useful lives of the facilities by up to 21 years, creating substantial energy and capacity benefits for customers in the future when this wind facility would otherwise have been retired from service.

43. Repowering Foote Creek I will lower the ongoing capital costs of operating the facility. PacifiCorp's turbine-supply contract for repowering, consistent with wind industry standards for new equipment, includes a two-year warranty on the new equipment. This will reduce capital costs associated with replacing or refurbishing turbine components currently in

service.

44. Repowering will also result in more certainty related to ongoing O&M costs of the facility. PacifiCorp will operate the repowered facility under a full service agreement with the turbine equipment supplier who will be responsible for operating and maintaining the new turbines for a fixed cost while guaranteeing availability of the turbines. Under this agreement, failure to meet the guaranteed availability, if not the result of an excusable event defined in the contract, will result in the payment of liquidated damages to the Company. Customers will benefit by having operation and maintenance costs fixed for the term of the agreement. Thus, there is greater cost certainty related to the run-rate capital expenditures and operation and maintenance costs as compared to continued operation of older turbines that are near the end of their useful life.

45. The Company's wind repowering efforts leverage past investments in PacifiCorp's wind fleet to enhance the future value of these resources for the benefit of its customers. By taking advantage of the unique opportunity to repower this facility, the Company is able to deliver its customers efficiency and reliability improvements in wind generation technology, extend its life by returning the wind fleet to like-new condition, all while enhancing performance, reducing ongoing maintenance expenditures, and re-qualifying the facility for PTCs — all of which reduces customers' rates.

## VII. MODIFIED PROCEDURE

46. Rocky Mountain Power believes that a hearing is not necessary to consider the issues presented herein and respectfully requests that this Application be processed under Modified Procedure, i.e., by written submissions rather than by hearing, in accordance with

Idaho Public Utilities Commission Rules of Procedure 201 - 204.

## VIII. REQUEST FOR RELIEF

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission issue an order authorizing the Company to: 1) establish a regulatory asset to transfer and recover the decommissioning and closure costs of Cholla Unit 4 when it is retired; 2) approve modifications to Phase II of the Tax Reform Stipulation authorizing the Company to use those funds to buy-down the Cholla net plant balances and offset the 2021 rate increase; and 3) approve RTM ratemaking treatment for Pryor Mountain and Foote Creek I wind resources to match costs with benefits.

DATED: July 2, 2020

Respectfully submitted by,
ROCKY MOUNTAIN POWER

Emily Wegener

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*Attorney for Rocky Mountain Power*

Attachment 1

Rocky Mountain Power - Settlement Terms

# Rocky Mountain Power
## Case No. PAC-E-20-03 Settlement Terms

May 28, 2020

***Settlement Terms in lieu of Idaho General Rate Case***

The Company recognizes the impact that the COVID-19 pandemic has on its customers and is ready to face the challenges it presents with its Idaho customers and communities. The Company has suspended residential disconnections for non-payments and is helping accommodate all customers with payment plans. Recognizing any rate increase at this time in particular can be challenging for customers in light of the economic impact of the COVID-19 public health emergency, the Company is proposing two ratemaking measures to delay a general rate increase.

In consideration of COVID-19 and the financial impact to customers the Parties agree to the following approach in lieu of the Company filing a general rate case June 1, 2020:

1. **Case No. PAC-E-18-08 - 2018 Depreciation Study:**
   - The Parties will support adding language in the pending Depreciation stipulation recommending that the Commission authorize the Company to create a regulatory asset to defer the incremental annual depreciation expense of $13,940,303.
   - The deferral would be $1,161,692 per month ($13,940,303 / 12) beginning January 2021 until the incremental depreciation expense is included in base rates.
   - No carrying charge will apply to the regulatory asset until the next general rate case. A carrying charge or rate base treatment and period for amortization of the balance will be determined in the next general rate case and begin at the rate effective date.
   - The depreciation expense tracked in the RTM will be calculated using the depreciation rates approved in Case No. PAC-E-13-02, Order No. 32926, to eliminate any double counting with the $13,940,303.
   - The Company will stop deferring incremental depreciation expense from PAC-E-13-02 currently recovered in the ECAM effective December 31, 2020, because this incremental depreciation expense is included in the $13,940,303 referenced above.
   - Parties agree to support establishment of Phase 2 in Case No. PAC-E-18-08 to evaluate the incremental Decommissioning costs filed with the Commission on January 17, 2020 and March 16, 2020. The Idaho Parties will make all reasonable

efforts to complete Phase 2 in time to allow the Commission to issue a final order before December 31, 2020.

- Ratemaking treatment for the incremental decommissioning costs will be determined in Phase 2, including potentially incorporating any approved incremental expense into depreciation rates and the depreciation deferral for 2021.

2. **Case No PAC-E-20-03 RMP NOI to File a General Rate Case:**
   - The Company agrees not to file a general rate case for rates to be effective prior to January 1, 2022.
   - The Parties agree that in lieu of a general rate case with rates to be effective January 1, 2021, the Company will file for an accounting order to authorize:
     - A regulatory asset to transfer Cholla Unit 4 net book balance upon closure of the plant in December 2020. The regulatory asset will include other closure-related and decommissioning costs.
     - Modifications to the Phase II Settlement Stipulation in Case No. GNR-U-18-01, on the ratemaking treatment for the 2017 Tax Cut and Jobs Act (TCJA). The Company may propose that the remaining balance from excess deferred income tax savings from the TCJA be retained to buy-down the Cholla Unit 4 and be deferred to offset the January 1, 2022 rate increase.
     - Ratemaking treatment for the Pryor Mountain wind resource and the repowering of Foote Creek I to match costs and benefits with a cost cap amount each year at the benefit level. The Company may propose to include these resources in the RTM/ECAM, consistent with the terms agreed to in Case No. PAC-E-17-07. Prudency will be determined during the next General Rate Case.
   - There will be no change to the ECAM baseline NPC of $26.90/MWh (on a sales-basis) established in PAC-E-16-12, until the base is reset in the next general rate case.
   - The Company will make its results of operations and cost of service models developed in anticipation of filing a rate case on June 1, 2020, available to parties and the Company will respond to the parties' reasonable data requests regarding the same.

[*Signature page follows*]

Dated: June 3, 2020

Rocky Mountain Power

/s/ *Terri Carlock*

Staff for the Idaho Public Utilities Commission

Idaho Irrigation Pumper Association, Inc.

Bayer

PacifiCorp Idaho Industrial Customers

*/s/ Benjamin J. Otto*
Idaho Conservation League

Dated: June 3, 2020

Rocky Mountain Power

/s/ Terri Carlock

Staff for the Idaho Public Utilities Commission

Idaho Irrigation Pumper Association, Inc.

Bayer

PacifiCorp Idaho Industrial Customers

Idaho Conservation League

Dated: June 3, 2020

Julie Steward

Rocky Mountain Power

Staff for the Idaho Public Utilities Commission

Idaho Irrigation Pumper Association, Inc.

Bayer

/s/ Ronald L. Williams

PacifiCorp Idaho Industrial Customers

Idaho Conservation League