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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF ROCKY MOUNTAIN POWER'S APPLICATION TO INCREASE ITS RATES AND CHARGES IN IDAHO AND FOR APPROVAL OF PROPOSED ELECTRIC SERVICE SCHEDULES AND REGULATIONS	**CASE NO. PAC-E-20-03** **REDACTED COMMENTS OF THE COMMISSION STAFF**

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

BACKGROUND

On March 26, 2020, Rocky Mountain Power ("Company"), a division of PacifiCorp, filed a Notice of Intent to file a General Rate Case. The Company later decided that, due to the impacts of the Covid-19 pandemic, it would instead develop a rate plan allowing it to delay filing a general rate case.

On May 28, 2020, the Company, Commission Staff, Bayer, Idaho Conservation League, Idaho Irrigation Pumper Association ("IIPA"), and PacifiCorp Idaho Industrial Customers stipulated that the Company would delay filing a general rate case and instead apply for an accounting order (the "Stipulation").

On July 2, 2020, the Company submitted this Application with the Stipulation and asked for: (1) an accounting order authorizing the Company to create a regulatory asset to transfer decommissioning and plant closure costs of Cholla Unit No. 4 when it is retired; (2) approval of modifications to Phase II of the settlement stipulation to implement tax reform (the "Tax Stipulation") approved in Order No. 34431;[1] and (3) approval of ratemaking treatment for Pryor Mountain and Foote Creek I wind resources.

On July 20, 2020, the Commission issued a Notice of Application and Notice of Intervention Deadline setting a 21-day intervention deadline. Order No. 34731. IIPA timely intervened. Order No. 34743.

On November 30, 2020, the Commission issued a Notice of Modified Procedure establishing public comment and Company reply deadlines. Order No. 34847.

STAFF REVIEW

Staff reviewed the Company's Application and information provided through discovery. From its review, Staff concludes the following:

1. Early retirement of Cholla Unit No. 4 in 2020 is reasonable and has the opportunity to provide a net economic benefit to Idaho customers;
2. The dollar amounts the Company has requested to defer for the closure of Cholla Unit No. 4 are reasonable;
3. The Tax Stipulation approved in Order No. 34431 should be modified to reserve the benefits to offset the Cholla Unit No. 4 closure costs in the next general rate case, and allow the Company to discontinue the amortization of the Tax Cuts and Jobs Act ("TCJA") benefits in the Energy Cost Adjustment Mechanism ("ECAM");
4. The Pryor Mountain and Foote Creek I wind projects are likely to provide a net economic benefit to Idaho customers;
5. Pryor Mountain and Foote Creek I wind projects should be included in the Resource Tracking Mechanism ("RTM") with the appropriate provisions included in the stipulation approved by Order No. 34104, Case No. PAC-E-17-07; and
6. Staff will continue to evaluate the prudence of the Foote Creek I and Pryor Mountain wind projects as new information becomes available. Staff will evaluate the continued use of the RTM in the next general rate case.

Each of the conclusions will be discussed in more detail in the sections below along with Staff's recommendations.

[1] *See* Case No. GNR-U-18-01.

Cholla Unit 4 Economic Analysis

Retiring Cholla Unit No. 4 in 2020 compared to retiring it in 2025 is reasonable and is likely to provide a net economic benefit to customers. The economic analysis performed by the Company is robust and the method and assumptions used in the analysis are reasonable. Staff evaluated the economic analysis by reviewing the method, input assumptions, and the results of the analysis.

<u>Cholla Unit No. 4 Analysis Method, Assumptions, and Results</u>

Staff believes the Company's method is robust because it compares two viable options for retiring Cholla Unit No. 4, evaluates the economics over an appropriate timeframe, and provides scenario analysis over a range of potential futures. The Company's analysis method compares the system costs for the 2019 IRP preferred portfolio retiring Cholla Unit No. 4 in April 2025 to retiring Cholla Unit No. 4 in December 2020. The analysis was evaluated over a timeframe covering 2019 through 2025. The analysis was also performed over three price-policy scenarios including medium natural gas price ("gas")/medium carbon dioxide price ("CO_2"), low gas/no CO_2, and high gas/no CO_2 to measure risk by determining how the portfolio without Cholla Unit No. 4 performs over a range of potential futures.

Evaluating a December 2020 early retirement against an April 2025 retirement date is appropriate because the Company is required—by environmental compliance rulings—to cease operation at Cholla Unit No. 4 or convert it to natural gas by April 30, 2025. Prior IRPs have shown continuing Cholla Unit No. 4 beyond 2025 does not provide benefits and that it is economical to pursue earlier retirement.

Staff reviewed the input assumptions including natural gas prices, load forecast, CO_2 prices, and early retirement costs. The input assumptions are reasonable because most of the assumptions are based on up-to-date information vetted in the 2019 IRP and were further reviewed in this case without any identifiable issues. An important assumption used in the early retirement case is the retirement cost related to the early termination payments of a safe harbor lease in the amount of $3.3 million. *See* Production Request Response No. 5. When the Company acquired Cholla Unit No. 4, it was subject to a pre-existing safe harbor lease. Under the early retirement scenario, the Company is obligated to pay the early termination payment. This early retirement cost is the main cause of an increase in system costs in 2020 for the early retirement case, but this cost is offset in the following years due to savings generated by avoiding fixed and variable operation and maintenance cost.

The results from the Company's analysis show a net system benefit in the range of $96 million to $123 million when retiring Cholla Unit No. 4 in 2020 compared to continuing to operate Unit 4 until 2025. Application at 7. A summary of the analysis results for each scenario are provided in Table No. 1. Because of the Company's rigorous methods of analysis, the reasonableness of inputs and assumptions, and the resulting savings, Staff believes early retirement of Cholla Unit No. 4 in 2020 is justified.

Table No. 1: Summary of Cholla Unit No. 4 Economic Analysis

Price-Policy Scenario	**Retire Cholla 2020 Portfolio Cost** ($million)	**Retire Cholla 2025 Portfolio Cost** ($million)	**Net Benefit** ($million)
Low Gas, No CO_2	[redacted]	[redacted]	[redacted]
Medium Gas, Medium CO_2	[redacted]	[redacted]	[redacted]
High Gas, No CO_2	[redacted]	[redacted]	[redacted]

Modifications to the Phase II Settlement Tax Stipulation in Case No. GNR-U-08-01

On March 5, 2019, the Company filed an all-party stipulation with the Commission resolving how the tax savings from the TCJA would be returned to customers. The TCJA resulted in Idaho-allocated protected property Excess Deferred Income Taxes ("EDIT") grossed up for taxes of $105,924,604 to be returned to customers over the average remaining life of the associated property. An additional Idaho-allocated, non-protected EDIT of $14,883,505 would be returned to Idaho customers amortized over 7 years. The parties to the Tax Stipulation agreed that changes to the 7-year amortization period could be addressed in the Company's next general rate case. However, the Company proposes to modify the Tax Stipulation by using some of remaining tax benefits to pay off the Cholla Unit No. 4 unrecovered balances. The Company also requests authorization to cease the refund of tax savings in the ECAM filing in 2021 and use any remaining EDIT savings to mitigate the rate impact from the 2021 general rate case.

The Company has $24.3 million in tax reform benefits available as of December 31, 2020–enough to offset the $15.9 million unrecovered balances of Cholla Unit No. 4. Staff supports modifying the Tax Stipulation to use of the EDIT tax reform benefits to offset the Cholla Unit No. 4 balances. Using this benefit to pay off the Cholla Unit No. 4 balances will prevent future customers from paying for the unrecovered balances associated with a resource that is no longer available to them. The remaining $8.4 million in deferred TCJA benefits should be addressed in the Company's 2021 general rate case.

Pryor Mountain and Foote Creek I Economic Analysis

Staff believes the Pryor Mountain and Foote Creek I wind projects are resource decisions based primarily on a time-limited economic opportunity and not reliability requirements. The projects are time-limited because they rely on production tax credits ("PTCs") available for a limited time. The justification needs to be primarily based on economics—providing a net benefit to Idaho customers—because the resources are not needed to meet load until the Company's capacity deficiency date in 2028. 2019 IRP Volume 1 at 16. Staff evaluated the economic analysis of both projects. Staff reviewed the analysis method, input assumptions, and the results of the analysis.

<u>Pryor Mountain Analysis Method, Assumptions, and Results</u>

Staff believes that the Pryor Mountain wind project is likely to provide net benefits to Idaho customers. However, before the cost of the project is included in base rates, Staff plans to reevaluate the prudence of the project. This will happen in the next general rate case. At this time, Staff believes the Company's analysis method is reasonable because it evaluates the project over its life span and the scenario analysis analyzed a range of potential futures.

The Company's analysis method is like the method used in Case No. PAC-E-17-07, which evaluated new wind and transmission projects. To determine the system net benefit of incremental wind energy over a 20-year timeframe (2019-2038), the method compares a least cost portfolio with Pryor Mountain included, to a least cost portfolio that does not include Pryor Mountain. The Company extended the net benefits of the project to 2050 by extrapolating the wind energy net benefits over two different timeframes. The two timeframes used as a basis for extrapolation include 2034-2038 and 2028-2038. This is important because depending on the timeframe used, the Company's results as shown in Table No. 2 show either a small net benefit or a cost to customers in the low gas/no CO_2 case.

During Staff's review of the low gas/no CO_2 case, Staff found an error in the Company's formula for extrapolating the 2028-2038 timeframe. Staff recalculated the net benefits for the 2028-2038 low gas/no CO_2 case using the correct formula. The results, shown in Table No. 2, show a net benefit of [redacted] million instead of a [redacted] million cost.

Finally, the Pryor Mountain wind project costs over its 30-year life is compared to the wind energy net benefits calculated in the prior steps to determine the net system costs or benefits. This comparison is also performed on two price-policy scenarios including medium gas/medium CO_2 and low gas/no CO_2. Higher gas and higher CO_2 scenarios were not included in the analysis because it was identified in Case No. PAC-E-17-07 that higher gas and CO_2 prices show increased benefits when evaluating a zero-fuel-cost resource like the Pryor Mountain project.

The results from the Company's analysis show a net system cost of [redacted] million to a net system benefit of [redacted] million. A summary of the analysis results for each scenario are provided in Table No. 2. The largest contributor to net benefits from the Pryor Mountain project is the increase in zero-fuel-cost energy resulting in reduced net power costs. Staff believes these results provide a reasonable estimate because of the input assumptions used in the analysis and the results are in the same range of benefits calculated for the new wind projects in Case No. PAC-E-17-07.

Table No. 2: Summary of Pryor Mountain Economic Analysis

Price-Policy Scenario	**Company's 2034-2038 Net Benefit/(Cost)** ($million)	**Company's 2028-2038 Net Benefit/(Cost)** ($million)	**Staff's 2028-2038 Net Benefit/(Cost)** ($million)
Low Gas, No CO2	[redacted]	[redacted]	[redacted]
Medium Gas, Medium CO2	[redacted]	[redacted]	[redacted]

Foote Creek I Analysis Method, Assumptions, and Results

Based on the Company's analysis, Staff believes that the Foote Creek I wind project is likely to provide net benefits to Idaho customers. Like Pryor Mountain, Staff will reevaluate the prudence of Foote Creek I in the next general rate case. At this time, Staff believes the Company's analysis method is reasonable because it evaluates the project over the project life span and the scenario analysis was performed over a range of potential futures.

The Company's analysis method is consistent with the method used in Case No. PAC-E-17-06 to evaluate the wind repower projects. To determine the system net benefit of incremental wind energy over a 20-year timeframe (2019-2038), the method first compares a least cost portfolio with the Foote Creek I wind project included, to a least cost portfolio that does not include Foote Creek I. Next, the Company extended the net benefits of the wind energy to 2050 by extrapolating the wind energy net benefits over a single nine-year timeframe (2030-2038). Staff did an additional analysis to evaluate the longer extrapolation timeframe (2028-2038) used in the Pryor mountain analysis because the longer time frame affected the results of the Pryor Mountain analysis. The additional analysis shows the longer timeframe has a minimal affect and still provides a net benefit for the Foote Creek I project. Finally, the Foote Creek I wind project costs over the 30-year life of the project is compared to the wind energy net benefit calculated in the prior steps to determine the net system costs or benefits. This comparison is also performed on two price-policy scenarios including medium gas/medium CO_2 and low gas/no CO_2. Higher gas and higher CO_2 scenarios were not included in the analysis because it was identified in Case No. PAC-E-17-06 that higher natural gas and CO_2 prices show increased benefits when evaluating a zero-fuel cost resource like the Foote Creek I wind project.

Staff reviewed input assumptions such as project costs, natural gas prices, CO_2 prices, operation and maintenance costs, production tax credits ("PTCs"), Wyoming wind tax, wind integration cost, and renewable energy credits ("RECs"). Staff believes the input assumptions are reasonable because most of the assumptions are based on current information vetted in the 2019 IRP process and were further reviewed in this case which did not identify any issues with the assumptions.

Consistent with the method used in Case No. PAC-E-17-06, the Company did not include the value of RECs in its analysis for the Foote Creek I wind project. Staff believes withholding the REC values generates a conservative estimates since there will likely be REC value associated with the project.

The results from the Company's analysis show a net system benefit in the range of [redacted] million to [redacted] million. A summary of the analysis results for each scenario are provided in Table No. 3. The largest benefit from the Foote Creek I wind project is an increase in zero-fuel-cost energy resulting in reduced net power costs. Staff believes these results are a reasonable estimate because of the input assumptions used in the analysis and the results are in the same range of benefits calculated for the repower projects in Case No. PAC-E-17-06.

Table No. 3: Summary of Foote Creek I Economic Analysis

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Pryor Mountain and Foote Creek I Ratemaking Treatment

Based on the current analysis showing economic benefit for Idaho customers in most scenarios and the inclusion of provisions from the stipulation in Case No. PAC-E-17-07 being applied to the ratemaking treatment for the Pryor Mountain and Foote Creek I wind projects, Staff believes it is appropriate to include these projects in the RTM because the risk protection that the mechanism provides. Staff will evaluate the prudence of the Pryor Mountain and Foote Creek I wind projects with updated information in the next general rate case when the projects are in service and the final project costs are known. In addition, Staff plans to evaluate continuing the RTM for both projects during the next general rate case—at least until the projects are needed to meet system reliability requirements—if cost risk remains an issue.

Even with the economic analyses showing benefit for Idaho customers, there is still risk associated with both projects that should be mitigated by including provisions from the stipulation in Case No. PAC-E-17-07. Some examples of risks include project cost overruns, risk related to capturing 100 percent PTC benefits, life cycle performance, and availability of wind assets through proper operation and maintenance. The provisions included in the stipulation in Case No. PAC-E-17-07 provide benefit to Idaho customers by mitigating the risk factors associated with these sources of risk.

Staff believes all applicable provisions from the stipulation in Case No. PAC-E-17-07 should be applied to the Pryor Mountain and Foote Creek I projects since the projects are based primarily on a time-limited economic opportunity and not on the need of the resource to meet reliability requirements. The Company is intending to calculate the ratemaking treatment for the Pryor Mountain and Foote Creek I projects consistent with paragraphs 10, 11,12, 14, 19, and 20 of the stipulation in Case No. PAC-E-17-07, which is included as Attachment A to these comments. Production Request Response No. 10.

Staff recommends that paragraphs 13 and 18 also be included as part of ratemaking treatment for both projects. The provisions in paragraph 13 will limit the capital cost in the RTM to the project cost estimates provided in this case and is appropriate since the current economic analysis is based these cost estimates. Paragraph 13 would limit the capital costs tracked in the RTM to the construction cost estimates—[redacted] million for Pryor Mountain and [redacted] million for Foote Creek I. Production Request Response Nos. 3 and 4. These project cost estimates represent total system costs, but the costs flowing through the RTM will be based on Idaho's jurisdictional allocation. The Company will have an opportunity to recover any project cost higher than the estimates when the costs are reviewed in the next general rate case.

Paragraph 18 is appropriate since the PTCs are the main reason for both projects providing benefit to Idaho customers. Including this provision will reduce the risk of the Company not implementing the project on schedule to fully qualify for PTCs.

CUSTOMER NOTIFICATION AND CUSTOMER COMMENTS

Rule 125 of the Commission's Rules of Procedure does not require direct customer notification unless the Company is requesting a rate change. IDAPA 31.01.01.125. Accordingly, the Company did not directly notify customers of this Application.

As of the December 15, 2020, there have been no comments submitted to this case.

STAFF RECOMMENDATIONS

After reviewing the Company's Application, the early closure analysis of Cholla Unit No. 4, and the economic analysis of the Pryor Mountain and Foote Creek I wind projects, Staff recommends the Commission:

1. Approve the deferral of the costs to close Cholla Unit No. 4;
2. Approve the use of the TCJA benefits to offset the Cholla deferral;

3. Approve the proposed modification to the Tax Stipulation, allowing the Company to cease the amortization of the non-protected EDIT benefits in the 2021 ECAM and reserve it for the Company's 2021 general rate case;
4. Include the Pryor Mountain and Foote Creek I projects in the RTM consistent with paragraphs 10, 11, 12, 13, 14, 18, 19, and 20 from the stipulation in Case No. PAC-E-17-07.

Respectfully submitted this 16th day of December 2020.

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Deputy Attorney General

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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** **STIPULATION**

This stipulation ("Stipulation") is entered into by and between Rocky Mountain Power, a division of PacifiCorp ("Rocky Mountain Power" or "the Company") and the Staff of the Idaho Public Utilities Commission ("Staff"). The Stipulation refers to the Company and the Staff as a "Party," and collectively, as the "Stipulating Parties."

I. INTRODUCTION

1. The terms and conditions of this Stipulation are set forth below. The Stipulating Parties agree that this Stipulation represents a fair, just and reasonable compromise of identified issues raised in this proceeding, and that this Stipulation is in the public interest. The Stipulating Parties, therefore, recommend that the Idaho Public Utilities Commission ("Commission") approve the Stipulation and all of its terms and conditions. *See* IDAPA 31.01.01.271, 272, and 274.

II. BACKGROUND

2. On July 3, 2017, the Company filed its application for a certificate of public convenience and necessity ("CPCN") to (1) construct or acquire four new wind projects with a total combined capacity of 860 megawatts ("MW"), and the 140-mile, 500 kV Aeolus-to-Bridger/Anticline transmission line, plus network upgrades, associated with the Company's Gateway West transmission project; and (2) approval of binding ratemaking treatment for the investment in the combined projects.

3. On July 27, 2017, the Commission issued a Notice of Application and invited interested persons to intervene by no later than August 8, 2017.

4. Monsanto Company ("Monsanto") petitioned to intervene July 12, 2018, Idaho Irrigation Pumpers Association ("IIPA") petitioned to intervene August 9, 2018, and PacifiCorp Idaho Industrial Customers ("PIIC") petitioned to intervene July 25, 2017, and the Commission authorized all petitions.

5. On November 3, 2017, the Company requested an extension of the deadline for the Company to pre-file rebuttal testimony from December 8, 2017 to December 18, 2017, and to change the date of the technical hearing from April 6, 2018 to March 12-14, 2018.

6. Pre-filed testimony was filed as follows: on November 20, 2017, intervenors and Staff filed direct testimony; on December 18, 2017, the Company filed rebuttal testimony; on January 16, 2018, and February 16, 2018, the Company filed supplemental testimony related to the request for proposals ("RFP") results; on April 11, 2018, intervenors and Staff filed supplemental direct RFP testimony; and on April 30, 2018, the Company filed supplemental rebuttal RFP testimony.

7. In its January 16, 2018 first supplemental direct testimony, the Company described its preliminary selection of the final four wind projects selected from the RFP results, and in its February 16, 2018 second supplemental direct testimony, the Company described its final selection of the four winning wind projects that included 1,311 MW, consisting of 1,111 MW of Company-owned facilities including three benchmark facilities (TB Flats I and II combined as a single project and Ekola Flats), and two new facilities including Cedar Springs, a one-half build-transfer agreement ("BTA") and one-half power purchase agreement, and Uinta, a BTA.

8. With the intent of resolving the issues raised in the Company's application filed in this proceeding, the Stipulating Parties, Monsanto, IIPA and PIIC met on February 28, 2018, March 26, 2018, April 5, 2018, April 25, 2018, April 30, 2018, and on May 2, 2018, under IDAPA 31.01.01.271 and 272 for settlement discussions. Based upon the settlement discussions, as a compromise of the positions in this proceeding, and for other considerations as set forth below, the Company and Staff reached an agreement on all issues in this case, except as expressly stated in this Stipulation. The Stipulating Parties did not reach an agreement with Monsanto, IIPA and PIIC. The Stipulating Parties stipulate and agree as follows, subject to Commission approval of the terms and conditions of this Stipulation.

III. TERMS OF THE STIPULATION

9. The Stipulating Parties request that the Commission issue an order granting a CPCN for the proposed Aeolus-to-Bridger/Anticline transmission line; the Ekola Flats, TB Flats I and II, and Cedar Springs wind projects ("Wind Projects"); and the related network upgrades as described in the Second Supplemental Direct Testimony of Rocky Mountain Power ("Stipulated Projects"). The Stipulating Parties request that the Commission find that: (1) the Stipulated Projects are prudent and in the public interest, and (2) in accordance with Idaho Code § 61-526, the Stipulated Projects are a reasonable way to meet the present or future public convenience and necessity.

10. The Stipulating Parties request that the Commission approve the Company's proposed ratemaking treatment for recovery of the new investment, energy production, and production tax credits ("PTC") associated with the Stipulated Projects. The Stipulating Parties further agree that the Commission should enter an order approving the Company's proposed Resource Tracking Mechanism ("RTM") as a component of the Energy Cost Adjustment

Mechanism ("ECAM"). *See* Direct Testimony of Jeffrey K. Larsen and Exhibit 62 (describing design and operation of RTM), with modifications incorporated herein. The RTM, along with the ECAM, will capture the costs and benefits of the Stipulated Projects until the Company's next general rate case, at which time the Stipulating Parties will re-evaluate the use of the RTM going forward.

11. Under the ECAM's existing sharing bands, 90 percent of the net power cost ("NPC") benefits associated with the energy production from each of the wind facilities listed above will be credited to customers and 10 percent will be assigned to the Company. For purposes of this settlement, the Company would agree to pass that 10 percent of the NPC benefits of these new wind facilities that would otherwise be assigned to the Company through the ECAM, back to customers. Thus, customers will receive 100 percent of the benefit of the energy produced by the Wind Projects.

12. The Stipulating Parties further agree that 100 percent of the full gross-up pre-tax value of all the PTCs generated by each of these new wind facilities will be credited to customers through the existing ECAM, consistent with the current treatment of PTCs. The Stipulating Parties further agree that there will be no return on any deferred tax assets that may be created as a result of the Company's inability to contemporaneously monetize PTCs to full value. The Company will begin deferring the costs and benefits associated with the Stipulated Projects in the first month following actual in-service dates, until those costs and benefits are included in base rates through a general rate case. The Stipulating Parties agree that a 9.2 percent pre-tax rate of return on investment will be utilized in the RTM calculation. This equates to an after-tax return on investment of 6.96 percent. Following the next general rate case, the return on the net plant balance

will be consistent with the rate of return authorized by the Commission in that case. The Stipulating Parties reserve all rights to challenge the rate of return in future rate cases.

13. The Company will include the actual costs and benefits it incurs for the Stipulated Projects in the RTM for recovery in the ECAM. Actual capital costs included in the RTM, before the next general rate case, cannot exceed [redacted], which are the estimated costs for the Stipulated Projects included in the Second Supplemental Direct Testimony of Rocky Mountain Power in this proceeding. Parties will have the opportunity to verify these costs as part of the annual audit of the ECAM deferred balance. Although the Stipulating Parties agree that the Commission should find that the Company's decision to build the Stipulated Projects is prudent and in the public interest, the Stipulating Parties agree that a Party may challenge the prudence of actual costs incurred in constructing the projects in a later proceeding. The Stipulating Parties further agree that the Company will include the costs and benefits that are tracked in the RTM in its quarterly ECAM filing updates beginning after the in-service date of the first facility placed in-service.

14. 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.

15. In recognition of receiving timely investment recovery through the ECAM and RTM, the Company will provide $300,000 annually until the next general rate case, that will be

deferred as a regulatory liability, beginning in 2020 in the month the first facility's costs are included in the RTM, with the ratemaking treatment to be set in the next general rate case. If the RTM deferral period is a partial year, the annual $300,000 will be pro-rated for the deferral period.

16. The Stipulating Parties reserve all rights to argue in this case for or against an overall capital cost cap for construction of the Stipulated Projects. The Stipulating Parties agree that such a cap, if any, would be applied at the time of the Company's next general rate case, or when the Stipulated Projects are placed into base rates.

17. The Stipulating Parties agree that the Company will bear the risks related to construction cost overruns associated with the Stipulated Projects. As such, the Company will not be allowed to recover any imprudent costs or costs due to Company mismanagement. Further, the Company has the burden of going forward and the burden of proof regarding the recovery of any of the costs associated with the Stipulated Projects. However, the Stipulating Parties agree not to challenge RMP's prudence related to the decision to build the Stipulated Projects or recovery of the actual capital costs associated with the Stipulated Projects except to the extent (1) the actual costs of constructing the Stipulated Projects, exceeds [redacted], or (2) there is evidence of mismanagement. The standard audit function to verify actual costs and to review operational prudence will continue to apply for all costs.

18. The Stipulating Parties agree that the Company will bear the risks related to any portion of the Wind Projects that do not qualify for PTCs due to completion delays beyond the timelines associated with the five-percent safe harbor. To the extent any of these wind projects fail to qualify for PTCs, in whole or in part, PTCs will be imputed to each such project based on that project's actual wind output for equipment placed in service and included in rate base at full revenue value (*i.e.*, including full gross up for federal and other applicable taxes). The only

exceptions are the failure to qualify for PTCs as a result of either: a) a change in law; or b) a Force Majeure Event. In the event of a change in law, the Company will make all commercially reasonable efforts to mitigate the loss of value to customers including, but not limited to, cancelling the acquisition or construction of facilities to the extent practical and cost effective from the customers' perspective. In the event of a change in law or a Force Majeure event, the Company will promptly file a notice with the Commission describing the change or event, its impact, and the Company's assessment of the ability to complete the Stipulated Projects in whole or in part, and other relevant information regarding the change or event and any possible remediation. If the Company encounters a Force Majeure Event, or there is any dispute regarding the applicability of this provision or the extent of its applicability to a particular facility, or any dispute about the Company's actions in the face of a change of law or Force Majeure Event, such dispute will be resolved by the Commission in the first general rate proceeding where the Company seeks to include the capital costs of the facility into rates.

19. The Company will negotiate availability guarantees for the Wind Projects in any third-party provided maintenance, as provided by the competitive market, which is currently 97 percent. The Stipulating Parties agree that all liquidated damages received by the Company under contractual agreements with vendors for these facilities will be passed onto customers through the ECAM including, but not limited to, liquidated damages received due to the equipment not meeting specified availability and performance.

20. In each ECAM filing until base NPC is reset either in the next general rate case or in another appropriate proceeding, the Company will report the NPC and PTC benefits associated with the Wind Projects. A Party's support of this Stipulation does not waive or limit their right to contest these costs or benefits when the Company seeks recovery of such items in the Company's

next ECAM or general rate case, except as expressly provided in the Stipulation. The Stipulating Parties agree to meet and determine by December 31, 2018, the appropriate RTM and ECAM schedules and documentation to be filed to separately reflect the Repower and Stipulated Projects.

21. If there is a material change in circumstance, such as a change in the projected costs or benefits, or for some other reason, the Stipulating Parties agree that the Company may make a filing with the Commission to allow for additional review and a determination of whether the Company should proceed with the implementation of the Stipulated Projects under the terms and conditions of this Stipulation and the ratemaking treatment for costs incurred prior to such filing.

22. The Stipulating Parties agree to reconvene and to reconsider and amend the terms and conditions of this Stipulation if the Company executes and obtains approval of a settlement agreement with parties in Utah Docket No. 17-035-40 and that settlement agreement includes more favorable terms and conditions for customers, recognizing that differences exist in current regulatory treatment or mechanisms between the states that will impact any settlement structure achieved in other states, than those set forth in this Stipulation including, without limitation, a lower overall rate of return on the new investment. If after reconvening, the overall terms of a settlement agreement reached and approved in any state, where pre-approval was requested, is more favorable than the agreement reached herein, the Company will file with the Commission to align the overall outcome of this Stipulation with the other state.

IV. GENERAL TERMS

23. The Stipulating Parties agree that this Stipulation represents a compromise of their positions on all but one issue—an overall capital cost cap—in this proceeding. All negotiations relating to this Stipulation will not be admissible as evidence in this or any other proceeding regarding this subject matter.

24. The Stipulating Parties submit this Stipulation to the Commission and recommend approval in its entirety pursuant to IDAPA 31.01.01.274.

25. The Stipulating Parties hereby waive any right they may have to appeal any portion of this Stipulation or the Order approving the same. If this Stipulation is challenged by any person not a party to the Stipulation, the Stipulating Parties reserve the right to file reply comments as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlement embodied in this Stipulation. Notwithstanding this reservation of rights, the Stipulating Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

26. In the event the Commission rejects or modifies any part or all of this Stipulation, or imposes any additional material conditions on approval of this Stipulation, each Party reserves the right, upon written notice to the Commission and the other Stipulating Parties to this proceeding, within 15 days of the date of such action by the Commission, to withdraw from this Stipulation. In such case, no Party will be bound or prejudiced by the terms of this Stipulation, and each Party will be entitled to seek reconsideration of the Commission's order, file testimony as it chooses, and do all other things necessary to put on such case as it deems appropriate.

27. The Stipulating Parties agree that this Stipulation is in the public interest and that all of its terms and conditions are fair, just and reasonable.

28. Neither Party is bound, benefited or prejudiced by any position asserted in the negotiation of this Stipulation, except to the extent expressly stated herein, nor will this Stipulation be construed as a waiver of the rights of any Party unless such rights are expressly waived herein. Execution of this Stipulation is not, and will not be construed as, an acknowledgment by any Party of the validity or invalidity of any particular method, theory or principle of regulation or cost

recovery. No Party will be deemed to have agreed that any method, theory or principle of regulation or cost recovery employed in arriving at this Stipulation is appropriate for resolving any issues in any other proceeding in the future. No findings of fact or conclusions of law other than those explicitly stated herein may be implied or inferred from this Stipulation.

29. The obligations of the Stipulating Parties under this Stipulation are subject to the Commission's approval hereof in accordance with its terms and conditions and, if judicial review is sought, upon such approval being upheld on appeal by a court of competent jurisdiction.

Respectfully submitted this 8th day of May, 2018.

Rocky Mountain Power	**Idaho Public Utilities Commission Staff**
By	By
Name: R. Jeff Richards	Name: Brandon Karpen
Title: Vice President and General Counsel	Title: Deputy Attorney General

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 16TH DAY OF DECEMBER 2020, SERVED THE FOREGOING **REDACTED COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-20-03, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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Jo Nelson
SECRETARY