BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-21-07**
MOUNTAIN POWER FOR	)	
AUTHORITY TO INCREASE ITS	)	**Direct Testimony of Steven R. McDougal**
RATES AND CHARGES IN IDAHO	)	
AND APPROVAL OF PROPOSED	)	
ELECTRIC SERVICE SCHEDULES	)	
AND REGULATIONS	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-07

May 2021

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I. INTRODUCTION AND QUALIFICATIONS

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 Steven R. McDougal. My business address is 1407 W. North Temple, Suite 330, Salt Lake City, Utah 84116. My current position is the Director of Revenue Requirement.

Q. Please describe your education and professional background.

A. I received a Master of Accountancy from Brigham Young University with an emphasis in Management Advisory Services and a Bachelor of Science degree in Accounting from Brigham Young University. In addition to my formal education, I have also attended various educational, professional, and electric industry-related seminars. I have been employed by PacifiCorp and its predecessor, Utah Power and Light Company, since 1983. My experience includes various positions with regulation, finance, resource planning, and internal audit.

Q. What are your responsibilities with the Company?

A. My primary responsibilities include overseeing the calculation and reporting of the Company's regulated earnings or revenue requirement, assuring that the inter-jurisdictional cost allocation methodology is correctly applied, and explaining those calculations to regulators in the jurisdictions in which the Company operates.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony in many cases before the Idaho Public Utilities Commission ("Commission"). I have also testified on various regulatory matters in the states of California, Oregon, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My direct testimony addresses the calculation of the Company's Idaho-allocated revenue requirement and the revenue increase requested in the Company's filing. Specifically, I provide testimony on the following:

- The calculation of the $19.0 million overall rate increase requested in this general rate case ("GRC"), representing a total Idaho-allocated revenue requirement of $290.5 million;
- A description of the Test Period proposed in this case;
- The 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol methodology ("2020 Protocol") used to determine Idaho-allocated results, including treatment of irrigation demand side management ("DSM") costs;
- Other revenue requirement issues, including:
    - Federal Income Taxes included in the case;
    - The Resource Tracking Mechanism;
    - Cholla Unit 4 Plant closure;
    - Carbon Plant recovery;
    - Deer Creek Mine recovery;
    - Klamath Hydroelectric Facility;
    - 2018 Depreciation Study;
    - Lake Side 2; and

- ◦ Calculation of the Load Change Adjustment Rate ("LCAR") based on costs in this filing for use in the Energy Cost Adjustment Mechanism ("ECAM"); and
- The Results of Operations supporting the Test Period revenue requirement and a detailed explanation of the known and measurable adjustments made to the unadjusted 12-month historical period ended December 31, 2020 ("Base Period") data to arrive at the Test Period.

My direct testimony is accompanied by supporting exhibits including the detailed results of operations for the Test Period.

III. REVENUE REQUIREMENT SUMMARY

Q. What price increase is required to achieve the requested return on equity ("ROE") in this case?

A. The 10.20 percent ROE recommended by Ms. Ann E. Bulkley in this case produces an overall Idaho revenue requirement of $290.5 million and an overall requested price increase of $19.0 million. Exhibit No. 39 provides a summary of the Company's Idaho-allocated results of operations for the Test Period. The Company estimates that under existing rates the Company would earn an overall ROE of approximately 7.48 percent. Details supporting the revenue requirement by the Federal Energy Regulatory Commission ("FERC") account and the allocation of the various revenue requirement components to Idaho are provided in Exhibit No. 40.

Q. What are the major drivers behind the revenue requirement in this case?

A. The major revenue requirement components that are driving the Company's general rate case filing are the recovery of major new capital investments and the impact of changes in depreciation rates. More detail on these drivers are provided below and in the direct testimony of the other Company witnesses.

Q. Please explain the new capital investments the Company is seeking to recover as part of this case.

A. The Company expects to place into service a variety of new capital projects including those related to the Pryor Mountain wind project, repowering of the Foote Creek wind project, and the Energy Vision 2020 Projects. More specifically, the Energy Vision 2020 projects consist of: repowering existing wind resources ("Repowering Project"), the construction or acquisition of new wind resources and associated network upgrades, and the construction of the Aeolus-to-Bridger/Anticline transmission line ("New Wind and Transmission Projects"). The Pryor Mountain, Foote Creek and Energy Vision 2020 wind projects account for approximately $2.8 billion, total-Company, of the total projected plant additions. The calculation of Test Period electric plant-in-service including other capital additions included in the case are located in Exhibit No. 40.

Q. Please provide additional details regarding the major capital investments that include the Energy Vision 2020 Projects.

A. The Commission found the Energy Vision 2020 Projects to be prudent and in the public interest and adopted the settlements that were reached in the following cases:

- Repowering twelve wind facilities identified in the Repowering Project, Case No. PAC-E-17-06;[1] and

[1] 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) hereinafter "Repowering Order".

- The New Wind and Transmission Projects as described in Case No. PAC-E-17-07.[2]

In addition, the revenue requirement in this case includes the repowering of the Foote Creek I wind facility and the new Pryor Mountain wind facility. Additional details for these projects are described later in my testimony and in the testimonies of Mr. Timothy J. Hemstreet, Mr. Robert Van Engelenhoven, Mr. Richard A. Vail, and Mr. Rick T. Link.

Q. Does the revenue requirement in this case include any selective catalytic reduction ("SCR") retrofit projects that have not been included in prior cases?

A. Yes. The Base Period in this case includes the SCR projects at Craig, Hayden, and Jim Bridger described in the testimony of Mr. James C. Owen.

Q. Does the revenue requirement in this case include a change related to base net power costs ("NPC")?

A. Yes. NPC are included in the Test Period results to reset base NPC in customer rates. The Company also utilizes the ECAM which provides for an annual deferral and recovery of the difference between actual NPC, production tax credits ("PTCs") and renewable energy credits ("RECs") and the base NPC, PTC, and REC included in rates. The direct testimony of Mr. Michael G. Wilding provides the support for the base NPC included in the Test Period in this case, which will be used as the base NPC included in future ECAM filings. Further details of the calculation of base NPC, PTCs, and RECs are included as Exhibit No. 44.

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[2] 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) hereinafter "New Wind and Transmission Order".

IV. TEST PERIOD

Q. What test period did the Company use to determine revenue requirement in this case?

A. Revenue requirement in the Company's filing is based on the Base Period, the historical twelve-month period ending December 31, 2020, adjusted for known and measurable changes through December 31, 2021 (the "Test Period").

Q. Is the Test Period in this case consistent with test periods used by the Company in previous general rate cases?

A. Yes. The Test Period is prepared in a manner consistent with the Company's general rate cases filed previously in Idaho. Later in my testimony I provide additional support for major decisions made in the Test Period preparation, including treatment of rate base and treatment of depreciation rates. I also describe the process employed by the Company to prepare revenue requirement and provide brief descriptions of each normalizing adjustment made to revenue, operations and maintenance ("O&M") expense, NPC, depreciation, taxes, and rate base.

Q. What over-riding principle guided the Company's development of the Test Period in this case?

A. The primary objective in determining a test period is to develop normalized results of operations that best reflect the operating conditions during the time the new rates will be in effect ("rate effective period"). Multiple factors must be considered to determine which test period best reflects these conditions, including prior rate case filings. This case uses a historical test period adjusted for known and measurable changes that coincides with the rate effective period. This is consistent with prior cases where the

Company also relied on historical data with normalizing adjustments to reflect as closely as possible the rate effective period.

Q. When will a rate change become effective in this proceeding?

A. The Company is requesting that new rates become effective January 1, 2022, approximately seven months after filing, consistent with the Company's application.

Q. Why is it important that the Test Period and the rate effective period be aligned as closely as possible?

A. In an environment of significant capital investment and changing resource utilization, a test period that does not include capital additions in-service during the rate effective period cannot adequately capture the conditions that the Company will experience while rates are in effect. When a utility is in a significant investment cycle and experiencing other known and measurable cost changes such as a change in depreciation rates, a pure historical test period does not allow the utility to recover the true cost of service on a timely basis. The Company will continue to place assets into service during the test period. These assets will immediately provide benefits to the Company's customers in Idaho, but the Company will no longer be able to defer the cost of financing such assets in the form of allowance for funds used during construction ("AFUDC") and will begin to incur depreciation expense as soon as the asset is in service. The ECAM mitigates the under recovery on potential increased fuel costs, but it can also work against the Company by passing through the benefits of zero-fuel-cost energy and PTCs from new wind facilities while the fixed costs of these same facilities go unrecovered until they can be incorporated into a general rate case without a separate mechanism like the Resource Tracking Mechanism ("RTM").

Q. What has the Company done in this case to better align the Test Period with the rate effective period?

A. A significant cost driver in this application is the capital investment the Company has incurred to serve its retail customers. The Company has calculated rate base using an end-of-period basis for the Base Period. Any major capital additions or known and measurable changes to the Test Period rate base are reflected as of December 31, 2021. This treatment better aligns the case with the level of investment that will be used and useful during the rate effective period and sets the customer rates at a more appropriate level.

V. INTER-JURISDICTIONAL ALLOCATIONS

Q. What allocation methodology did the Company use to calculate the Idaho revenue requirement in this case?

A. The Company's requested price increase is based on the 2020 Protocol, as approved by the Commission on April 22, 2020, in Case No. PAC-E-19-20.[3] The most significant change from the prior allocation methodology, the 2017 Protocol, is the elimination of the $150,000, Idaho-allocated, 2017 Protocol Equalization Adjustment. The fixed embedded cost differential of $836,000 will continue and has been reflected in the revenue requirement of this case.

Q. What is the effective date for the 2020 Protocol?

A. The 2020 Protocol was effective beginning January 1, 2020.

[3] In the Matter of Rocky Mountain Power's Application for Approval of the 2020 PacifiCorp Interjurisdictional Allocation Protocol, Case No. PAC-E-19-20, Order No. 34640 (April 22, 2020).

Q. Is the Company treating Class 1 DSM programs in this case different from its past cases in Idaho?

A. Yes. In the 2010 general rate case, the Commission ordered the Company to treat load control, or Class 1, DSM programs as system resources which impacted the way the costs and benefits of these programs are reflected in the revenue requirement.[4] In the subsequent general rate case, the Company continued with this ordered treatment. The Company is now proposing to change the treatment of Class 1 DSM and include both the costs and benefits of these programs as situs resources to their respective states. This treatment would align Idaho with the methodology outlined in the 2020 Protocol. Section 3.1.2.1 within the 2020 Protocol agreement states:

> Demand-Side Management ("DSM") Programs: Costs associated with DSM Programs, including Class 1 DSM Programs, will be allocated on a situs basis to the State in which the investment is made. Benefits from these programs, in the form of reduced consumption and contribution to Coincident Peak, will be reflected in the Load-Based Dynamic Allocation Factors.[5]

Q. Do any other jurisdictions served by PacifiCorp have similar programs, and are those programs treated in a similar manner in this case?

A. Yes. The Company operates similar programs to control irrigation load in California, Oregon, and Utah and central air conditioning load in its Utah service territory. These programs are treated as situs resources, consistent with the 2020 Protocol where all Class 1 DSM programs are situs assigned, including the Idaho irrigation program in this filing.

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[4] In the Matter of the Application of PacifiCorp dba Rocky Mountain Power for Approval of Changes to its Electric Service Schedules, Case No. PAC-E-10-07, Order No. 32196 (Feb. 28, 2011).

[5] In the Matter of Rocky Mountain Power's Application for Approval of the 2020 PacifiCorp Interjurisdictional Allocation Protocol, Case No. PAC-E-19-20, Testimony of Joelle Steward, Exhibit 1 at 11 (Dec. 3, 2019).

Q. Where is the proposed treatment of Class 1 DSM programs reflected in the Company's revenue requirement calculation?

A. There are two components of the Class 1 DSM programs that are reflected in the Company's revenue requirement, the costs and the benefits of the programs. The costs of the Class 1 DSM programs consist of the administrative costs of running the program and the credits paid to the participants of the program. The cost of the programs are included on a situs basis in the Company's Base Period O&M data used in the revenue requirement calculation. The benefits of the Class 1 DSM programs occur in the load reductions by state as a result of program operations. The 2020 coincident peaks in the filing were adjusted to reflect situs treatment of Class 1 DSM load curtailment events. The calculation of the coincident peaks can be viewed in Exhibit No. 40 on page 9.13.

Q. What is the impact as a result of the change from a system to situs resource for all states Class 1 DSM programs?

A. The approximate impact after capturing both the change in costs and benefits have reduced the Idaho revenue requirement in this case by $1.4 million.

VI. OTHER ADJUSTMENTS AND ISSUES

Federal Income Taxes

Q. How has federal income tax expense been calculated in this case?

A. Federal income tax expense for ratemaking is calculated using the same methodology that the Company uses in preparing its filed income tax returns. On December 22, 2017, Congress passed and the president signed the Tax Cuts and Jobs Act ("TCJA") setting a new corporate income tax rate of 21 percent compared to the previous rate of

35 percent. Accordingly, the federal income tax rate has been updated in the Company's revenue requirement model to 21 percent.

Q. Has the Company deferred to a regulatory liability any balances associated with the tax savings as a result of the TCJA?

A. Yes. On March 30, 2018, the Company filed an application with the Commission requesting authorization to begin passing current tax savings back to customers and to create a regulatory liability to defer the incremental tax savings associated with the TCJA. The Commission consolidated the Company's application with those of the other regulated utilities in Idaho under Case No. GNR-U-18-01, ("TCJA Case"). After working with the parties to the case the Company was able to negotiate a settlement, approved by Commission Order No. 34331, that established a plan to return all the TCJA benefits to customers.

Q. How were the current tax savings from the TCJA returned to customers?

A. The Company began refunding to Idaho customers an annual credit of $6.2 million on June 1, 2018, through Tariff Schedule 197. Beginning June 1, 2019, the credit was increased to an annual amount of $7.6 million, or 100 percent of the calculated current tax savings. Since the Company began realizing the current tax savings from the TCJA January 1, 2018, the Company accrued a current tax savings balance from January 1, 2018, through May 31, 2019, of $4.6 million. This amount was then reduced by $3.4 million to offset the regulatory asset balance related to deferred depreciation expense and resulted in a remaining regulatory liability balance for current tax of approximately $1.1 million.

The stipulation reached in the TCJA case further agreed to refund the remaining current tax savings of $1.1 million over two years, beginning June 1, 2019, through May 31, 2021. The amortization of the full current tax deferred balance was refunded to customers as of May 31, 2021, through the ECAM, Tariff Schedule 94.

Q. Under the stipulation, how were Excess Deferred Income Taxes ("EDIT") amounts to be refunded to customers?

A. There are three different classifications of EDIT: protected property, non-protected property, and non-protected non-property. The Commission order specified that the EDIT savings based on the Average Rate Assumption Method ("ARAM") for calendar years 2018, 2019, and 2020 would be returned to customers through the ECAM. The protected property would be used to offset the deferred ECAM balance for the respective years and the non-protected EDIT savings would be used to offset the incremental depreciation expense from the 2013 depreciation study.

Q. Is any EDIT included in the revenue requirement in this case?

A. Yes. The Company began amortizing all protected property balances using the Reverse South Georgia Method ("RSGM") rather than the originally assumed ARAM. Accordingly, the amortization of the protected property EDIT for the Test Period using RSGM has been included in the revenue requirement of this case.

Q. What is the total regulatory liability balance as a result of the TCJA and how was this calculated?

A. Based on the RSGM amortization, approximately $19.5 million of protected property amortization for calendar years 2018 through 2021 has been deferred to a regulatory liability. Idaho customers have, or will have, received protected property amortization for calendar years 2018 and 2019 based on a preliminary estimated ARAM calculation through Schedule 94 of $4.9 million, leaving a remaining deferred balance of $14.6 million. Although the settlement agreement in the TCJA case also agreed to refund customers the preliminary calendar year 2020 ARAM protected-property amortization through Schedule 94, the Company reached a settlement in Case No. PAC-E-20-03 to use that deferred balance toward the rate mitigation efforts instead of refund through the Schedule 94. Furthermore, non-protected property and non-protected non-property ("Non-Protected") EDIT regulatory liability balances were being amortized back to customers over seven years beginning June 1, 2019, but have since discontinued for use in rate mitigation efforts as part of the settlement reached in Case No. PAC-E-20-03.

In total, the TCJA regulatory liability balance that was available for refund was comprised of $14.6 million of deferred protected property amortization and $13.6 million of non-protected property EDIT, or $28.2 million. Table 1 below provides and summary and references for this balance as further detailed in Exhibit No. 43.

TABLE 1

Description	Exhibit No. 43 Reference	Amount
Non-EDIT Tax Benefits	B13	(30,354,500)
TCJA Schedule 197 Refund	H31	25,788,948
TCJA Schedule 94 Refund	H32	1,140,528
2013 Depreciation Reg Asset	H33	3,425,024
Remaining Non-EDIT Tax Benefits		**0**
Protected EDIT Deferred Amortization	F13	(19,483,906)
ECAM Offset - Deferred Protected EDIT Amortization	H34	4,916,718
Remaining Protected EDIT Deferred Amortization		**(14,567,188)**
Non-Protected EDIT - Property	D18	(16,237,157)
Non-Protected EDIT - Non-Property	E18	(1,610,816)
ECAM Offset - 7 Year Amortization	H35	4,252,430
Remaining Non-Protected EDIT		**(13,595,543)**
GRAND TOTAL		**(28,162,731)**

Q. What is the Company's Proposal to return the $28.2 million available for refund to customers

A. Order No. 34384, Case. No. PAC-E-20-03, authorized the Company to use a portion of the available EDIT balance to buy-down the remaining unrecovered plant balances at the Cholla Unit 4 plant. After updating for actual plant balances upon closure, the Company bought-down approximately $16.4 million, Idaho-allocated, of the unrecovered plant balances. The Company is proposing to use the remaining $11.8 million for the following additional rate mitigation efforts:

- Approximately $2.8 million of Idaho-allocated closure costs, net of savings, and decommissioning costs related to Cholla Unit 4;
- Approximately $2 thousand to fully recovery Powerdale decommissioning costs;

- Approximately $88 thousand to buy-down the remaining balances of the electric plant acquisition adjustment for the Craig and Hayden plants that would have otherwise amortized through April 2022;
- $300 thousand for the deferred balances due to the 2017 Protocol equalization adjustment; and
- Approximately $103 thousand of deferred intervenor funding costs.

Assuming each of these balances would have otherwise been amortized over a period of three years, buying them down using TCJA dollars reduces the revenue requirement in this case by approximately $6.6 million. An exhibit supporting the calculation of the remaining deferred tax balance is provided as Exhibit 43. The details regarding the treatment for the remaining deferred tax balance of $8.5 million is described in the testimony of Ms. Joelle R. Steward.

Q. Are there any additional tax items you want to discuss?

A. Yes. Federal tax law changes are under consideration by Congress, including changes to the federal corporate income tax rate. If a change in the federal corporate income tax rate is enacted during the pendency of this proceeding, the Company will propose updating the tax rate in the case and recovery of the Deficient Accumulated Deferred Income Taxes ("DADIT") in a manner consistent with the give back associated with the tax change passed in the TCJA. If a change in the federal corporate income tax rate is enacted after the pendency of this proceeding, or too late in the process to incorporate the change in this filing, the Company will initiate a new filing to address the impact.

Resource Tracking Mechanism

Q. Please describe the Resource Tracking Mechanism.

A. The RTM was established to track the revenue requirement for the Energy Vision 2020 Projects. More specifically, the RTM was calculated as the incremental impact on revenue requirement from the costs and benefits of the Energy Vision 2020 Projects. This difference was deferred and collected as part of the Company's annual ECAM filings, with the amount in excess of benefits associated with the new wind and transmission deferred for recovery in this rate case (see adjustment 8.16 described below).

Q. Why is the Company separately addressing the RTM in this case?

A. As part of stipulations in the Energy Vision 2020 cases, the parties agreed that the use of the RTM would be re-evaluated as part of the next general rate case.[6] The Company has included the costs and benefits of each of the Energy Vision 2020 Projects in the revenue requirement calculated as part of this case and proposes to discontinue the RTM deferral upon the rate effective date of this case.

Q. Since the RTM would capture annual changes in revenue requirement as a result of the Energy Vision 2020 Projects, why is the Company proposing to discontinue this mechanism?

A. Although the Company is supportive of 100 percent recovery of the Idaho-allocated revenue requirement, continuation of the RTM mechanism would result in on-going recovery of the capital components of only the Energy Vision 2020 Projects while excluding recovery of any other changes to capital components. For example, the

[6] *Repowering Order* at 3; *New Wind and Transmission Order* at 11.

Company continually makes investment in generation, transmission, and distribution resources for system load and reliability. These new investments will more than offset any declining balance of Energy Vision 2020 investments due to depreciation. Once the Energy Vision 2020 Projects are included in base rates the Company does not believe they should be treated differently than other rate base items. If a tracking method is implemented, it should be an annual tracking mechanism for full recovery of all capital related costs.

Q. Does the Company have any other concerns with continuing the RTM for Energy Vision 2020 Projects?

A. Yes. The Energy Vision 2020 Projects are included in LCAR described later in my testimony. Since they are included in the calculation of the LCAR, the amount included in rates will vary every year making any future calculations of the RTM unusually complex.

Q. Why did the Company seek to establish the RTM only for Energy Vision 2020 Projects and not all capital resources?

A. Energy Vision 2020 was an opportunity to construct zero-fuel cost resources to help meet a system need while providing customers significant PTCs benefits. While the benefits of the NPC and PTCs are considered variable costs and included in the Company's ECAM mechanism, the substantial fixed capital costs associated with these projects would have been left unrecovered. Due to the magnitude of investment required in the Energy Vision 2020 Projects, leaving this capital cost unrecovered would have resulted in a negative financial impact. Additionally, the timing of the investments going into service over two years would have necessitated back-to-back rates cases to incorporate them into base rates. The RTM matched the customer benefits with the costs required to generate them and smoothed customer rate impacts by allowing the Company to consolidate the key case drivers into one rate case.

More commonly, the Company makes investment in capital resources at a rate that mimics depreciation expense. In other words, the investment in capital is being largely offset by the accumulated depreciation balance. Table 2 below illustrates that the growth in net plant has historically been around 1 percent annually, however, the increase is much higher recently due to the investment in the Energy Vision 2020 projects.

TABLE 2

$ - Millions	GRC*	2018 ROO Pro-Forma 2019	2017 ROO Pro-Forma 2018	2016 ROO Pro-Forma 2017	2015 ROO Pro-Forma 2016	2014 ROO Pro-Forma 2015
Gross EPIS	$ 1,741	$ 1,737	$ 1,656	$ 1,605	$ 1,552	$ 1,524
Accum. Depr.	(523)	(583)	(554)	(516)	(480)	(465)
Net Plant	$ 1,218	$ 1,155	$ 1,102	$ 1,089	$ 1,073	$ 1,059
% Change from Previous Year	5.22%	4.55%	1.19%	1.48%	1.30%	

*The Company prepared a general rate case filed in PAC-E-20-03 in lieu of the 2019 Results of Operations

Q. Would the continued use of the RTM impact the timing of future rate cases?

A. Yes. The RTM only captures a limited portion of the Company's net plant in service, and the portion it captures is likely to decline over time rather than increase consistent with the total Idaho net plant as shown in Table 2 above. This disparity, with total Idaho net plant increasing and the RTM only capturing decreases would increase the impact of lag on the Company and would force the Company to file more frequent rate cases, which is in contrast to one of the reasons supporting the RTM—the ability to avoid more frequent rate cases.

Q. What is the Company's recommendation regarding the RTM?

A. The Company recommends that the RTM be discontinued with the rate effective date of this case. Between rate cases the RTM is an important tool to balance the costs and benefits of new resources. Without the RTM, customers would get the NPC benefits of low or zero cost resources along with the PTC benefits and any REC sales, without the opportunity for the Company to get recovery of the costs necessary for customers to receive those benefits without a rate case. Once new projects are included in a rate case, they should be treated similar to all other existing resources.

Cholla Plant Retirement

Q. How is the retirement of Cholla Unit 4 reflected in the Test Period in this case?

A. Cholla Unit 4 was retired December 31, 2020. Accordingly, the Company has reflected the removal of the on-going operations of the plant. The Company received authorization in Case No. PAC-E-20-03 to defer to a regulatory asset balances associated with the unrecovered plant investment, closure costs, and decommissioning costs. Case No. PAC-E-20-03 approved use of deferred TCJA funds to offset the remaining net plant investment, however, additional details regarding the Company's proposed treatment, including the buy-down using the TCJA regulatory liability balances for the remaining costs, are discussed elsewhere in my testimony.

Carbon Plant

Q. How is the Carbon plant closure treated in this case?

A. As described in the Company's application in Case No. PAC-E-12-08, the Carbon plant (a coal-fired generation facility located in Carbon County, Utah) was retired in April 2015, to comply with environmental and air quality regulations. The Company requested a deferred accounting order to transfer the remaining net plant balance to a regulatory asset and amortize through calendar year 2020. The Company further requested to transfer the decommissioning costs to a regulatory asset for future recovery, which was approved in Order No. 32701. The Company is, in this case, seeking to recover the remaining deferred closure costs which include the final decommissioning costs and material and supplies inventory. Further details of this adjustment are described later in my testimony.

Deer Creek Mine

Q. How is the 2014 closure of the Deer Creek mine treated in this case?

A. In Case No. PAC-E-14-10, the Company filed a notice of closure and requested an accounting order to defer costs associated with the closure of the Deer Creek Mine. The Commission issued an order that allowed continued recovery of the undepreciated mine investment at the then current depreciation rates through the ECAM. All other costs associated with the closure of the mine were approved to be deferred to a regulatory asset with recovery treatment determined in the next general rate case. The Company is proposing to recover the remaining Deer Creek costs that have been deferred to regulatory assets. Additional details including the regulatory treatment proposed in this case are provided later in my testimony.

Klamath

Q. What changes are reflected in this case for the Klamath Hydroelectric Facilities?

A. PacifiCorp is a signatory to the Klamath Hydroelectric Settlement Agreement ("KHSA"), which provides for the transfer PacifiCorp's license for four main-stem Klamath Hydroelectric Project facilities to a third-party dam removal entity. Depreciation rates for the Klamath assets were approved by the Commission as part of the depreciation study settlement in Case No. PAC-E-13-02 ("2013 Depreciation Study") to provide for full depreciation of the Klamath assets by December 31, 2022.

FERC is currently evaluating an application to transfer the license for the Lower Klamath Project from PacifiCorp to the Klamath River Renewal Corporation and the States of California and Oregon as co-licensees. FERC is also evaluating an application by PacifiCorp and the Klamath River Renewal Corporation to surrender the license for the Lower Klamath Project and remove the developments. The timing of when FERC will transfer the license, when PacifiCorp's operations would ultimately cease, and when dam removal will begin remains uncertain.

As the current project licensee, PacifiCorp's obligations under the license and FERC regulations continue to require capital investments to support ongoing project operations, ensure compliance with dam safety and other regulatory requirements, and to make other capital expenditures necessary to fulfill obligations under the KHSA to mitigate impacts of ongoing project operations.

Because the timing of license transfer and the cessation of generation from the Klamath assets remains uncertain, PacifiCorp has selected a depreciation rate of 20 percent per year for ongoing capital additions to the Klamath asset starting on January 1, 2020. PacifiCorp will seek regulatory approval to update the depreciation rate in the next depreciation study.

Q. Are the costs of the Klamath facility considered final?

A. No. The Company has accrued an estimate for future decommissioning costs; however, this amount was removed from this case as it is a high-level estimate. The Company will seek to include decommissioning costs, likely in a future general rate case or other regulatory proceeding, for recovery once more information is known.

2018 Depreciation Study

Q. Were the results of the 2018 Depreciation Study included in the case?

A. Yes. The Company filed an application to update depreciation rates with a proposed rate effective date of January 1, 2021, in Case No. PAC-E-18-08 ("2018 Depreciation Study").[7] On June 15, 2020, the Company filed a Stipulation for Phase I, new depreciation rates, and requested that the Commission establish Phase II to facilitate additional discussion on the treatment of the incremental costs identified in the 2020 decommissioning studies.[8] On August 18, 2020, the Commission approved the depreciation rates as filed in the Stipulation and authorized Phase II.[9] This case includes depreciation rates consistent with the settlement stipulation.

Q. Are any other changes being proposed with regard to depreciation rates?

A. The Company is also proposing to include updated incremental decommissioning costs which is discussed later in my testimony.

Lake Side 2

Q. Is the Company currently recovering costs for Lake Side 2?

A. Yes. On March 1, 2013, the Company filed an application requesting that the Commission open a case to identify interested parties that would like to participate in settlement discussions regarding alternatives to the Company filing a general rate case. One of the outcomes from that case was an all-party settlement that included a resource adder for the Lake Side 2 generation facility recovered through the ECAM for the

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[7] In the Matter of the Application of Rocky Mountain Power for Authorization to Change Depreciation Rates Applicable to Electric Property, Case No. PAC-E-18-08, Rocky Mountain Power's Application (Sept. 11, 2018).
[8] Case No. PAC-E-18-08, Stipulation on Depreciation Rate Changes (June 15, 2020).
[9] Case No. PAC-E-18-08, Order No. 34754 (Aug. 18, 2020).

period that the investment in the facility is not reflected in rates as a component of rate base, beginning January 1, 2015.

Q. How is Lake Side 2 treated in this filing?

A. Since Lake Side 2 was placed in-service in 2014, prior to the base period used in this rate case, it is included in the unadjusted results of operations. The Lake Side 2 adder will not be included in the ECAM deferrals after the rate effective date of this case.

Load Change Adjustment Rate ("LCAR")

Q. Has the Company updated the calculation of the LCAR that is applied to the calculation of net power costs to be recovered through the ECAM?

A. Yes. Exhibit 44 provides the calculation of the LCAR. To calculate the LCAR I have incorporated the applicable elements from this case, including production-related return on investment and non-NPC expenses, into the template approved by the Commission in Case No. PAC-E-08-08. The LCAR itself does not affect revenue requirement in this case but is applied to the difference of Idaho load in this case and actual Idaho load with the result deferred and recovered through the ECAM. The LCAR is to be updated each time base net power costs are updated in a general rate case. Using the revenue requirement in the Company's filing results in an increase in the LCAR from $5.54 per MWh to $8.59 per MWh. The Company will also provide an updated calculation of this rate based on the Commission-approved outcome of this case.

VII. IDAHO RESULTS OF OPERATIONS

Q. Please describe Exhibit No. 40.

A. Exhibit No. 40, which was prepared under my direction, is Rocky Mountain Power's Idaho results of operations report (the "Report"). The historical period for the Report is the 12 months ended December 31, 2020, which has been adjusted for known and measurable changes through December 31, 2021. The Report provides totals for revenue, expenses, net power costs, depreciation, taxes, rate base and loads in the Test Period. The Report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit No. 40 is organized.

A. The Report is organized into sections marked with tabs as follows:

- Tab 1 Summary contains a summary of normalized Idaho-allocated results of operations.
- Tab 2 Results of Operations details the Company's overall revenue requirement, showing unadjusted costs for the year ended December 2020 and fully normalized results of operations for the Test Period by FERC account.
- Tabs 3 through 8 provide supporting documentation for the normalizing adjustments required to reflect on-going costs of the Company. Each of these sections begins with a numerical summary that identifies each adjustment made to the 2020 actual results and the adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit No. 40, which contains a lead sheet showing the adjusted FERC account(s), allocation factor, dollar amount and a brief description of the adjustment. The specific adjustments included in each of these tab sections are described in more detail below.

- Tab 9 contains the calculation of the 2020 Protocol allocation factors as well as the development of peak and energy loads.

Tab 3 – Revenue Adjustments

Q. Please describe the adjustments made to revenue in Tab 3.

A. **Temperature Normalization (page 3.1)** – This adjustment recalculates Idaho revenue based on temperature normalized historical load assuming average temperature patterns.

Revenue Normalization (page 3.2) – This adjustment normalizes base year revenue by removing items that should not be included to determine retail rates, such as ECAM revenues, normalization of special contracts, etc. Full detail of each item excluded in this adjustment can be found on page 3.1.3 and 3.1.4 of Exhibit No. 40.

Revenue Annualization (page 3.3) – This adjustment annualizes the revenues for the differences between the actual revenues from the customer billing system and the calculated revenue based on the billing determinants.

REC Revenues (page 3.4) – RECs represent the environmental attributes of electricity produced from renewable energy facilities and can be detached from the electricity commodity and sold separately. RECs may also be used to meet renewable portfolio standards ("RPS") in various states. To comply with current or future year RPS requirements in California, Oregon, and Washington, the Company does not sell RECs that are eligible for RPS requirements in those states. This adjustment ensures Base Period REC revenues are correctly allocated among the Company's jurisdictions after considering the banking of eligible RECs for RPS compliance purposes. Any differences between the projected REC revenues in this adjustment and actual REC revenues, including any sales associated with the new wind projects, will be accounted for in the Company's ECAM filings as ordered by the Idaho Commission in Order No. 32196, Case No. PAC-E-10-07.

In addition, this adjustment also removes REC deferrals reflected in the Base Period results consistent with the treatment of NPC deferrals in the Net Power Cost Adjustment, No. 5.1 and includes the retirement of RECs associated with the Bayer contract. Bayer RECs are retired based on a ratio of the Idaho System Generation allocation factor and a calculated Bayer specific System Generation allocation factor.

Wheeling Revenue (page 3.5) – During 2020, there were various transactions regarding wheeling revenue that the Company does not expect to occur in the Test Period. These transactions relate to various prior period adjustments and contract terminations. This adjustment also includes pro forma wheeling revenue for the Test Period.

Ancillary Services and Other Revenue (page 3.6) – This adjustment reflects ancillary revenue changes that are consistent with the forecast NPC treatment reflected in adjustment 5.1 discussed below. The ancillary revenue booked in the 12 months ended December 2020 is adjusted to reflect the Test Period revenue expected per the terms of contracts in effect during the Test Period. Ancillary revenue contracts expected to terminate in the Test Period are normalized out to reflect appropriate revenues consistent with the proposed rate effective date.

Joint Use Revenue (page 3.7) – The Company entered into an agreement with ExteNet and Cingular Wireless to attach wireless devices to Company owned assets. This adjustment adds into results the joint use revenues expected to be realized during the Test Period.

Ash Sales Revenue (page 3.8) – In October 2020, the Company executed a new contract to sale ash from the Jim Bridger plant. This adjustment reflects the revised level of ash sales revenues consistent with the terms of the contract. In addition, this adjustment also normalizes ash sale revenues on the Craig, Naughton, and Cholla plant in the Test Period.

Tab 4 – O&M Adjustments

Q. Please describe the adjustments made to O&M expense in Tab 4.

A. **Miscellaneous General Expense & Revenue (page 4.1)** – This adjustment removes from the Base Period results certain miscellaneous expenses that should have been charged below-the-line to non-regulated accounts or were related to prior periods. It also reallocates gains and losses on property sales to reflect the appropriate allocation.

Wages and Employee Benefits (page 4.2) – Labor related costs for the Test Period are computed by adjusting salaries, incentives, health benefits, and costs associated with pension, post-retirement benefits, post-employment benefits, and other benefits for changes expected beyond the actual costs experienced in the Base Period.

Collective bargaining agreements are used to escalate union wages where increases are specified, and other wage increases for non-union and exempt employees are based on the Company's targets. Annual incentive plan compensation and bonuses and awards for non-union employees is included in Test Period results using a three-year average of the actual cash payout. Other employee benefit costs are adjusted to the planned expense levels for the Test Period, based on actuarial reports, where available, or by escalating actual costs.

Page 4.2.1 of the Report provides further description of the procedure used to compute Test Period labor costs. Page 4.2.2 contains a numerical summary of actual labor costs in the Base Period and summarizes the adjustments made to project costs through the Test Period. This summary is followed by detailed worksheets on pages 4.2.3 through 4.2.11.

Remove Non-Recurring Entries (page 4.3) – Two accounting entries were made to an expense account during the Base Period that are non-recurring in nature. The first entry relates to reliability coordinator fees and represent a refund that was for calendar year 2019 expenses. The second entry relates to a Klamath Settlement Obligation expense which was described earlier in my testimony. These entries are removed to normalize Test Period results.

Schedule 300 Fees and Paperless Billing (page 4.4) – This adjustment adds into the Test Period results the pro forma reduction to revenues for the proposed paperless bill credits. This adjustment also adds into the Test Period results the pro-forma increase to revenues for the changes to the returned check fees and temporary service charges. For details on these proposals, please refer to the testimony of Ms. Melissa S. Nottingham.

Outside Services (page 4.5) – The Company adjusted the 2020 outside services expense to a three-year historical average consistent with the Commission's Order No. 32196.

Generation Expense Normalization (page 4.6) – This adjustment normalizes generation overhaul expense using a four-year historical average using the 12-month periods ending December 2017 through December 2020. Annual expense is restated to December 2020 dollars prior to averaging. A four-year average is consistent with the normalized outages assumed in the GRID model to compute Test Period NPC.

Use of a four-year historical average to set overhaul costs in customer rates was consistent with the treatment used in several of the Company's Idaho general rate cases. However, the Company agreed in the rebuttal testimony in Case No. PAC-E-10-07 to remove the restatement to constant dollars. The Company continues to believe that the purpose of averaging is to adjust for uneven costs, and that without the restatement to constant dollars in the average calculation, overhaul expenses reflected in rates will be systematically understated. More specifically, averaging is intended to reduce year-to-year variance in expense, but not adjust for the time value of money and the issue of inflation.

A simple example below shows the impact of averaging, assuming a 2.5 percent inflation rate, a $100 amount in year one, and a four-year average of years one through four used to project costs in year five. Using this assumption, Example 1 shows the impact without adjusting for inflation and Example 2 shows the impact when years one through four are stated in real or constant dollars.

As shown in the first example, with no restatement to account for inflation, a four-year average of costs is $103.8, much less than the projected costs in year five, resulting in an expense level that is 2.5 years old compared to the current expenses. In Example 2, the average is equal to the year five amount resulting in an accurate forecast.

Example 1

Year	Amount	
1	$ 100.0	
2	102.5	Average
3	105.1	$103.8
4	107.7	
5	110.4	

Example 2

Year	Amount	Escalation	Adjusted Amount	
1	$ 100.0	1.104	$ 110.4	
2	102.5	1.077	$ 110.4	Average
3	105.1	1.051	$ 110.4	$110.4
4	107.7	1.025	$ 110.4	
5	110.4			

Insurance Expense (page 4.7) – This adjustment normalizes insurance expense related to third-party liability, less amounts not requested, for injuries and damages as well as damage to Company property. Injury and damages expense are set at the three-year historical average using a cash paid method consistent with Idaho's treatment of pension expense. In the Company's previous general rate case, insurance expense was normalized using accounting accruals. However, the Company recorded accruals during the base period that were significantly above historical levels due to several potential liabilities where the impact is still uncertain. Due to the significant impact these potential expenses have on results, the Company is proposing to move from a three-year average using accounting accruals to known cash payments. This change will make sure that only the amounts above insurance are included in regulatory results, and the amounts will be included after the amounts are known and actual cash payments are recorded. This adjustment also removes the insurance reserve associated with the accounting accruals booked in the Base Period since they are related to the difference between the accounting accruals and actual payments.

Insurance expense for damage to Company transmission, distribution, and non-transmission and distribution property is currently accrued to a reserve account. This treatment for property damage expense was included in Case No. PAC-E-11-12. The balance of the reserve account at December 2020 was $1.0 million. This adjustment updates the property damage accrual to a three-year average of actual losses.

This adjustment also addresses the premiums related to general liability and property insurance which are anticipated to be incurred for coverage during the Test Period. The current estimates were developed using Company forecasts and will be updated in rebuttal as actual insurance premiums become known.

Uncollectible Expense (page 4.8) – Consistent with the Commission Order No. 32196, uncollectible expense is adjusted to a three-year historical average. This adjustment also adjusts transmission power delivery uncollectible expense to a three-year historical average and normalizes regulatory commission expense consistent with the weather normalized revenues.

Memberships and Subscriptions (page 4.9) – This adjustment removes expense in excess of Commission policy as stated in Order No. 29505. National and regional trade organizations are recognized at 75 percent of above the line costs. Other membership dues are removed.

Pension Non-Service Expense (page 4.10) – Pursuant to Idaho Commission Order No. 32196, this adjustment removes the 2020 accrual basis pension expense for the PacifiCorp Retirement Plan (PRP) and replaces it with a 3-year average on a cash basis. Also, this adjustment walks forward the Post-Retirement Welfare Plan (PRW) non-service expense to the 2021 forecast and removes the Supplemental Executive Retirement Plan (SERP) non-service expense.

Credit Facility Fees (page 4.11) – The Company incurs banking fees consisting of the upfront and quarterly commitment fees on revolving credit facilities which support the

Company's Commercial Paper issuances by providing a secondary source of repayment for the Commercial Paper. This adjustment correctly accounts for these fees.

Tab 5 – Net Power Cost Adjustments

Q. Please describe the adjustments included in Tab 5.

A. **Net Power Costs (page 5.1)** – The net power cost adjustment presents normalized Test Period steam and hydro power generation, fuel, purchased power, wheeling expense and sales for resale based on the Company's GRID model. It also normalizes hydro power generation, weather conditions and plant availability as described in Mr. Wilding's testimony.

Nodal Pricing (page 5.2) – This adjustment adds in pro forma capital and incremental O&M expenses for the new Nodal Pricing Model, as agreed to in PacifiCorp's Nodal Pricing Model Memorandum of Understanding as filed under Appendix D in the 2020 Protocol, Case No. PAC-E-19-20.

Tab 6 – Depreciation and Amortization Expense Adjustments

Q. Please describe the adjustments included in Tab 6.

A. **Depreciation and Amortization Expense (page 6.1)** – This adjustment adds into the Test Period results depreciation and amortization expense for the major plant added to rate base in adjustment 8.5.

Depreciation and Amortization Reserve (page 6.2) – This adjustment adds into Test Period results depreciation and amortization reserve for the major plant additions added to rate base in adjustment 8.5.

Hydro Decommissioning (page 6.3) – Based on the Company's latest depreciation study approved in Case No. PAC-E-18-08, the annual accrual required for the decommissioning of various hydro facilities is being reduced. The change in hydro decommissioning expense is included in the Depreciation Study Adjustment (6.5). This adjustment includes the change in reserve and walks the reserve balance to the Test Period.

Depreciation Allocation Correction (page 6.4) – The Company established a regulatory asset to track and defer any aggregate net increase in allocated depreciation expense in dockets in Wyoming, Utah, and Idaho, for depreciation rates that became effective January 1, 2014, in the 2013 depreciation study. The deferred amount and the associated amortization is reflected in historical data on a system-allocated basis, but should be situs-assigned to Wyoming, Utah, and Idaho. This adjustment corrects the allocation of this historical data. Also, this adjustment removes the steam plant give-back reversal in Oregon established as part of the 2013 depreciation study.

New Depreciation Study (page 6.5) – This adjustment incorporates into Test Period results the incremental impacts of the 2018 deprecation study as agreed in Case No. PAC-E-18-08. Specifically, this adjustment calculates the incremental difference between the approved depreciation rates from the last depreciation study and those approved in the 2018 depreciation study. This incremental difference in the composite depreciation rate is multiplied by the year-ending December 2020 gross plant balance to calculate the incremental impact of depreciation expense. The depreciation reserve associated with the incremental depreciation expense is adjusted for the Test Period. In addition, this adjustment also incorporates into the Test Period results the amount associated with the change in hydro decommissioning and vehicle depreciation.

Decommissioning Costs (page 6.6) – On January 17, 2020, pursuant to the 2020 Protocol, the Company filed a contractor-assisted engineering study of decommissioning costs ("January 2020 Decommissioning Study") for the Hunter, Huntington, Dave Johnston, Jim Bridger, Naughton, Wyodak, and Hayden generating plants in Case No. PAC-E-18-08. On March 16, 2020, the Company filed a contractor-assisted engineering study of decommissioning costs for the Colstrip generating plant in the same case. These decommissioning costs include plant demolition, ash pile and ash pond abatement and closure, asbestos and other hazardous materials abatement and remediation, and final site cleanup and restoration as applicable to each plant. This adjustment includes the incremental costs by plant beginning with the rate effective date of the 2018 deprecation study, or January 1, 2021, and spread evenly over the remaining life of the last retired unit. Parties reached a settlement in Case No. PAC-E-18-08 to defer the 2021 incremental decommissioning costs to a regulatory asset and amortize this over 15 years beginning with the rate effective date of this general rate case. Accordingly, the Company has included this amortization as well as the amount proposed to be collected in the Test Period. The Company is proposing all amounts collected will be deferred to a regulatory liability account and will be reduced for actual decommissioning costs once known.

The studies also identified other plant closure costs that are necessary for the Company to fully recover all costs associated with closing a plant. For example, each generation plant has a certain level of materials and supplies inventory that is required to operate the plant. In the event of a plant closure, those material and supplies will no longer be required and often cannot be absorbed for use at a different generation facility.

Given those circumstances, the Company would seek recovery of these unusable material and supplies inventory in addition to all of the other incurred or expected plant closure costs at the time a plant is closed. As identified in the decommissioning studies, there are a significant amount of other plant closure costs that will need to be addressed in a future proceeding. No regulatory treatment for recovery of these costs have been included in this filing.

Tab 7 – Tax Adjustments

Q. Please describe the adjustments included in Tab 7.

A. **Interest True Up (page 7.1)** – This adjustment details the true up to interest expense required to synchronize the Test Period expense with rate base. This is done by multiplying normalized net rate base by the Company's weighted cost of debt in this case.

Property Tax Expense (page 7.2) – Property tax expense for the Test Period was computed by adjusting calendar year 2020 property tax expense for known and anticipated changes in assessment levels through the end of the Test Period. Please refer to Confidential Exhibit No. 42 for details supporting the Test Period expense.

Production Tax Credit (page 7.3) – The Company is entitled to recognize certain tax credits as a result of placing qualifying renewable generating plants into service. The federal tax credit is based on the generation of a qualifying facility during the facility's first ten years of service. The Test Period renewable electricity production credit is 2.5 cents per kilowatt hour of the electricity produced from wind energy. This adjustment reflects the credit based on the qualifying production as reflected in the net power costs adjustment, page 5.1.

PowerTax ADIT Balance (page 7.4) – This adjustment reflects the accumulated deferred income tax balances for property on a jurisdictional basis as maintained in the PowerTax System.

Wyoming Wind Generation Tax (page 7.5) – This adjustment normalizes the Wyoming Wind Generation Tax, which became effective January 1, 2012, into Test Period results. The Wyoming Wind Generation Tax is an excise tax levied upon production of electricity from wind resources in the state of Wyoming. The tax is on the production of any electricity produced from wind resources for sale or trade on or after January 1, 2012 and is to be paid by the entity producing the electricity. New wind facilities are exempt from the tax for three years following the date the facility first produces electricity for sale. The tax is one dollar for each megawatt-hour of electricity produced from wind resources at the point of interconnection with an electric transmission line.

TCJA Tax Deferrals (page 7.6) – This adjustment reflects the removal of the Non-Protected tax deferral balances as a result of the TCJA that was enacted on December 22, 2017. This adjustment also reflects the appropriate level of protected EDIT amortization using the RSGM.

Tab 8 – Rate Base Adjustments

Q. Please describe the adjustments included in Tab 8.

A. **Update Cash Working Capital (page 8.1)** – This adjustment supports the calculation of cash working capital based on the normalized results of operations for the Test Period. Cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net lag days in this case are based on a lead lag study prepared by the Company using calendar year 2015 information. Based on the results of the lead lag study the Company experiences 0.68 net lag days in Idaho and requires a cash working capital balance of $0.4 million in rate base.

Trapper Mine Rate Base (page 8.2) – The Company owns a 29.0 percent share of the Trapper Mine, which provides coal to the Craig generating plant. This investment is accounted for on the Company's books in account 123.1, investment in subsidiary company, which is not included as a rate base account. The normalized coal cost from Trapper Mine in net power costs includes operation and maintenance costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine net plant investment to rate base in order for the Company to earn a return on its investment.

Jim Bridger Mine Rate Base (page 8.3) – The Company owns a two-thirds interest in the Bridger Coal Company which supplies coal to the Jim Bridger generating plant. Due to the ownership arrangement, the mine investment is not included in the Company's unadjusted results of operations, and the normalized coal costs for Bridger include all operating and maintenance costs but do not include a return on investment. This adjustment adds the Company's portion of the Bridger Mine net plant investment to rate base in order for the Company to earn a return on its investment.

Customer Advances for Construction (page 8.4) – Refundable customer advances for construction are booked to FERC account 252. Base Period balances do not reflect the proper allocation because amounts were recorded to a corporate cost center location rather than state specific locations in the Company's accounting system. This adjustment corrects the allocation of customer advances.

Major Plant Additions (page 8.5) – To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be completed by the end of the Test Period. The Company identified capital projects with expenditures over $5 million that will be used and useful by December 31, 2021. Additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. The associated depreciation expense and accumulated reserve impacts are accounted for in adjustment 6.1 and 6.2. Capital additions associated with the Energy Vision 2020, Pryor Mountain, and Foote Creek projects are included under adjustment 8.15 discussed later in my testimony.

Miscellaneous Rate Base (page 8.6) – This adjustment reflects the Test Period level of fuel stock balance in results based on projected inventory by plant, along with offsetting working capital deposits. In addition, prepaid overhaul balances in FERC Account 186 for Lake Side Units 1 and 2, Chehalis, and Currant Creek gas plants are walked forward to reflect the continued payments and the transfer of these costs into plant in-service through the end of the Test Period.

Powerdale Hydro Decommission (page 8.7) – Powerdale is a hydroelectric generating facility located on the Hood River in Oregon. This facility was scheduled to be decommissioned in 2010; however, in 2006 a flash flood washed out a major section of the flow line. The Company determined that the cost to repair this facility was not economical and determined it was in the ratepayers' best interest to cease operation of the facility.

The Commission approved[10] the Company to defer to a regulatory asset any actual decommissioning costs and amortize these balances over ten years. Final decommissioning costs were spent in December 2013. At the end of 2021, the Company had an estimated Idaho-allocated balance of $2.4 thousand to be collected. The Company has proposed to buy-down this remaining balance using deferred balances from the Tax Cuts and Jobs Act. This adjustment removes any balances related to remaining Powerdale Hydro decommissioning.

FERC 105 (PHFU) (page 8.8) – This adjustment removes all plant held for future use ("PHFU") assets from FERC account 105. The Company is making this adjustment in compliance with Idaho Code §61-502A.

Regulatory Asset and Liability Amortization (page 8.9) – This adjustment incorporates known and measurable changes to regulatory assets and liabilities from the Base Period to the Test Period. Impacted regulatory assets and liabilities include the electric plant acquisition adjustment, Trojan decommissioning costs, and the balance associated with the deferred depreciation from the 2013 depreciation study. This adjustment also includes the Company's proposal to fully amortize the balances associated with the electric plant acquisition adjustment specific to the Craig and Hayden plants, 2017 Protocol equalization deferral, and deferred intervenor funding. Lastly, the approved 2018 depreciation study included a change in depreciation rates effective January 1, 2021. In a settlement reached in that case, the Company was approved to defer the costs associated with the change in depreciation expense and elimination of the excess reserve amortizations, or approximately $13.9 million on an

[10] Case No. PAC-E-07-04.

Idaho-allocated basis. This adjustment also adds into results a four-year amortization of the 2018 Depreciation Study deferral balance.

Klamath Hydroelectric Settlement Agreement (Page 8.10) – This adjustment reflects the appropriate treatment of Klamath related items in the Test Period. Paragraph 24 of the stipulation in the 2013 depreciation study, specifies that the stipulating parties agree to adjust Klamath accelerated depreciation to an end date of December 31, 2022. This adjustment also adds in the expense and rate base amounts associated with on-going capital additions based on the proposed treatment discussed previously in my testimony.

Cholla 4 (page 8.11) – Consistent with the Company's 2019 Integrated Resource Plan, Cholla Unit 4 (a coal-fired generation facility located in Joseph City, Arizona) ceased operations December 31, 2020. The Commission approved the Company's application in Case No. PAC-E-20-03 to transfer the remaining balances to a regulatory asset and buy-down, on December 31, 2020, the remaining net plant balance with the deferred regulatory liability balances that were established with the TCJA. In addition to the remaining plant balances, below are additional costs related to the Cholla Unit 4 closure. The Company is proposing to buy-down the remaining balances associated with the closure of Cholla Unit 4 using TCJA amounts.

- Approximately $1.0 million, total-Company, of Construction Work in Progress that are assumed no longer necessary given the revised retirement date of the plant;
- Approximately $5.9 million, total-Company, of materials and supplies that are deemed to be specific to the plant and unusable after retirement of the plant;

- Approximately $19.6 million, total-Company, of liquidated damages as a result of issuing the 365-day notice to Peabody Energy for early termination of the Coal Supply Agreement;
- Approximately $2.1 million, total-Company, of severance pay;
- Approximately $47.3 million, total-Company, of decommissioning costs; and
- Approximately $0.8 million, total-Company, of a GE safe harbor lease termination payment required due to early closure of the plant.

Per the terms of the stipulation, this adjustment has included an offset of approximately $28.1 million, total-Company, related to the operations and maintenance expense that was included in customer rates but no longer necessary. The Company agreed to include an offset related to avoided depreciation expense, however, that has been accounted for in the depreciation deferral as approved in Case No. PAC-E.18-08. This adjustment removes from rate base the December 31, 2020 plant balances related to Cholla Unit 4 and regulatory asset balances due to the proposed buy-downs. It also removes from expense the cost related to the operations and maintenance and depreciation of this generation resource. For additional details on the closure of the Cholla Unit 4 plant, please refer to the testimony of Mr. Link.

Carbon Plant Closure (page 8.12) – As described earlier in my testimony, the Carbon plant was retired in April 2015 to comply with environmental and air quality regulations. A deferred accounting order was approved in which the Company could seek recovery of these costs in the next general rate case. This adjustment adds in Test Period results the associated impacts for recovery of the deferred balances associated with decommissioning costs and obsolete materials and supplies. The Company is proposing, in this case, to amortize these balances over three years. Additionally, this adjustment removes from the base period the expense associated with a regulatory asset that was established to track and defer any aggregate net increase in allocated depreciation expense in dockets in Wyoming, Utah, and Idaho for depreciation rates that became effective January 1, 2014.

Prepaid Pension Asset (page 8.13) – This adjustment removes from the Base Period the rate base balances associated with the prepaid pension asset. Idaho currently recovers pension costs using a cash basis method which is adjusted for on page 4.10.

Deer Creek Mine (page 8.14) – As described in the Company's filing in Case No. PAC-E-14-10, the Deer Creek mine (a coal mine located in Emery County, Utah) was closed at the end of 2014. The Company reached a settlement in which approval was requested for the following:

- Transfer the remaining net book value, excluding CWIP, to a regulatory asset and continue to recover the balance at an amortization rate equal to the then current depreciation rates;
- Transfer the loss related to the sale of the Cottonwood Preparation Plant, the Central Warehouse, and the Trail Mountain Mine to a regulatory asset and continue to recover the balance at an amortization rate equal to the then current depreciation rate;
- Include an offset at the approved rate of return on rate base for the Fossil Rock coal leases, fuel inventory savings, and the return on assets sold;
- Defer balances associated with the settlement of the Retiree Medical Obligation; and

- Defer to a regulatory asset amounts associated with the closure costs and CWIP of the Deer Creek Mine.

This adjustment corrects the Base Period to reflect removal of amounts associated with recovery of the Deer Creek Mine which should have been booked situs to other states or have been recovered from Idaho customers. As described above, unrecovered plant has been fully amortized. The Company is including in this case all other mine closure costs and savings that have been deferred. The Company is proposing to include all deferred costs and savings as a result of the mine closure in rate base to be amortized over three years.

New Wind and Repowering Capital Additions (Page 8.15) – This adjustment adds into the Test Period the capital additions, depreciation impacts, and changes in operations and maintenance expense for the Energy Vision 2020 Projects and Pryor Mountain, discussed previously in my testimony. The adjustment also adds into the Test Period the capital addition and associated depreciation impacts for the Foote Creek I wind repowering project which went in-service in March 2021. For additional details on these projects, please refer to the testimonies of Mr. Hemstreet, Mr. Van Engelenhoven, and Mr. Vail.

RTM Adjustment (page 8.16) – Per Case No. PAC-E-17-06 and PAC-E-17-07, the Commission approved deferral to a regulatory asset any costs related to the Repowering and Energy Vision 2020 Projects above the cap, which was set not to exceed the project benefits. Accordingly, the Company has calculated that all repowering projects will be fully recovered in the ECAM. The Energy Vision 2020 Projects, notably due to the necessary transmission investment, have costs more than the benefits included in the

ECAM used to establish the cap, which the Company is seeking to recover in this case. Using forecasted balances and generation data, the Company has calculated a total regulatory asset balance of approximately $1.6 million, Idaho-allocated, as the end of 2021. This adjustment adds into rate base the regulatory asset balance and a three-year amortization. The Company will true-up any differences between the actual deferred balances and estimated deferred balances in the next general rate case.

VIII. SUMMARY

Q. Do you have any final comments regarding the revenue requirement requested by the Company in this proceeding?

A. Yes. In my opinion, the revenue requirement requested in this proceeding is fair, reasonable and in the public interest. I respectfully recommend that the Commission approve the revenue requirement as proposed in this testimony.

Q. Does this conclude your direct testimony?

A. Yes.