ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 West North Temple, Suite 330
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March 31, 2021

VIA ELECTRONIC DELIVERY

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

Re: CASE NO. PAC-E-21-09
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER REQUESTING APPROVAL OF $16.1 MILLON NET POWER COST DEFERRAL

Dear Ms. Noriyuki:

Please find Rocky Mountain Power's Application in the above referenced matter, along with the direct testimony and exhibits of Company witnesses Messers. Jack E. Painter, Robert M. Meredith, and Steven R. McDougal.

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

Very truly yours,

Joelle Steward

Joelle Steward
Vice President, Regulation

Enclosures

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	**CASE NO. PAC-E-21-09**
OF ROCKY MOUNTAIN POWER	)	
REQUESTING APPROVAL OF $16.1	)	**APPLICATION OF**
MILLON NET POWER COST DEFERRAL	)	**ROCKY MOUNTAIN POWER**

Rocky Mountain Power, a division of PacifiCorp ("Company" or "Rocky Mountain Power"), in accordance with Idaho Code §61-502, §61-503, and RP 052, hereby respectfully submits this application ("Application") to the Idaho Public Utilities Commission ("Commission") pursuant to the Company's approved energy cost adjustment mechanism ("ECAM"). The Company is requesting approval of approximately $16.1 million of deferred costs from the deferral period beginning January 1, 2020 through December 31, 2020 ("Deferral Period") with a 0.9 percent decrease to Electric Service Schedule No. 94, Energy Cost Adjustment ("Schedule 94") for standard tariff customers. Tariff Contract 400 and 401 customers will see a 1.3 percent decrease. In support of its Application, Rocky Mountain Power states as follows:

1. Rocky Mountain Power is a division of PacifiCorp, an Oregon corporation, which provides electric service to retail customers through its Rocky Mountain Power division in the states of Idaho, Wyoming, and Utah. Rocky Mountain Power is a public utility in the state of

Idaho and is subject to the Commission's jurisdiction with respect to its prices and terms of electric service to retail customers in Idaho pursuant to Idaho Code §61-129. Rocky Mountain Power is authorized to do business in the state of Idaho providing retail electric service to approximately 84,000 customers in the state.

BACKGROUND

2. The ECAM became effective July 1, 2009 pursuant to an agreement among parties.[1] The ECAM allows the Company to collect or credit the difference between the actual net power costs ("Actual NPC") incurred to serve customers in Idaho and the net power costs ("NPC") collected from Idaho customers through rates set in general rate cases ("Base NPC").

3. Included in the ECAM are NPC as defined in the Company's general rate cases and modeled by the Company's Generation and Regulation Initiative Decision ("GRID") production dispatch model.[2] Specifically, NPC include amounts booked to the following FERC accounts:

- Account 447 (sales for resale, excluding on-system wholesale sales and other revenues not modeled in GRID),
- Account 501 (fuel, steam generation, excluding fuel handling, start-up fuel/gas, diesel fuel, residual disposal and other costs not modeled in GRID),
- Account 503 (steam from other sources),
- Account 547 (fuel, other generation),
- Account 555 (purchased power, excluding BPA residential exchange credit pass-through if applicable), and
- Account 565 (transmission of electricity by others).

[1] *In the Matter of the Application of Rocky Mountain Power for Approval of an Energy Cost Adjustment Mechanism (ECAM)*, Case No. PAC-E-08-08, Order No. 30904 (September 29, 2009) ("ECAM Order").
[2] *Id.* at 2-3.

4. On a monthly basis, the Company compares the Actual NPC to the Base NPC and defers the difference into the ECAM balancing account. This comparison is on a system-wide, dollar per megawatt-hour basis.[3]

5. In addition to the difference between Actual NPC and Base NPC, the ECAM includes six additional components: the Load Change Adjustment Revenues ("LCAR"),[4] an adjustment for the treatment of coal stripping costs under Emerging Issues Task Force ("EITF") 04-6, a true-up of 100 percent of the incremental Renewable Energy Credit ("REC") revenues, Production Tax Credits ("PTC"),[5] the Lake Side 2 generation resource adder,[6] and a resource tracking mechanism ("RTM").[7] These components are described in more detail below.

6. This year, pursuant to Order No. 34384, the ECAM does not include additional components related to tax benefits arising from the Tax Cut and Jobs Act of 2017 ("TCJA").

7. The ECAM includes a symmetrical sharing band of 90 percent (customers) / 10 percent (Company) that shares the differential between Actual NPC and Base NPC, LCAR, and the EITF 04-06 coal stripping costs. The components of the ECAM subject to the sharing band are described in more detail below.

8. The ECAM deferral also includes a resource adder for the Lake Side 2 generation facility that is not subject to the sharing band.[8] This resource adder is to be recovered through the ECAM for the period that the investment in the facility is not reflected in rates as a component of

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[3] *Id.* at 3.
[4] *Id.* at 4.
[5] *In the Matter of PacifiCorp DBA Rocky Mountain Power's Application to Modify the Energy Cost Adjustment Mechanism and Increase Rates*, Case No. PAC-E-15-09, Order No 33440 at 5 (December 23, 2015) (2015 ECAM Order).
[6] *In the Matter of the Application of PacifiCorp DBA Rocky Mountain Power to Initiate Discussions with Interested Parties on Alternative Rate Plan Proposals*, Case No. PAC-E-13-04, Order 32910, at 2 (October 24, 2013) ("2013 Order").
[7] *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 (December 28, 2018).
[8] 2013 Order, at 2.

rate base. Inclusion of the Lake Side 2 resource adder in the ECAM began January 1, 2015. It is calculated by multiplying the actual megawatt-hours of generation from the Lake Side 2 generation facility by $1.99 per megawatt-hour and is capped at $5.4 million dollars or 2,729,500 megawatt-hours for the calendar year.[9]

9. PTCs are tracked in the ECAM without applying the sharing band.[10] Under the Internal Revenue Code ("IRC"), a wind facility generates a PTC equal to an inflation-adjusted 1.5 cents per kilowatt hour of electricity produced and sold to a third-party.[11] The PTC is in place for a period of 10 years beginning on the date the facility is placed in-service for income tax purposes.[12] In 2020, the inflation-adjusted PTC rate for electricity generated from qualifying wind facilities was 2.5 cents per kilowatt hour.[13] PTCs are reflected as a reduction to current income tax expense on the financial statements and for ratemaking purposes. A forecasted level of PTCs at the then current IRC value was included in base rates benefiting customers; however, the quantity and value of PTCs received is dependent on the inflation-adjusted rate effective when they are produced and the amount of generation at eligible facilities. Generation from these facilities is highly dependent on weather, varying from year to year as weather patterns fluctuate. To the extent that actual generation from these facilities varies from the level in base rates, the value of the energy is reflected in Actual NPC and a corresponding adjustment is made to the amount of PTCs that customers receive through the ECAM. Facilities that meet IRC qualifications are eligible for PTCs for the first ten years after becoming commercially operational. While many of the Company's wind facilities have reached their ten-year anniversary and would no longer be

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[9] *Id.*
[10] 2015 ECAM Order at 5.
[11] IRC section 45(a).
[12] IRC section 45(a).
[13] Credit for Renewable Electricity Production, Refined Coal Production, and Indian Coal Production, and Publication of Inflation Adjustment Factors and Reference Prices for Calendar Year 2020, 85 Fed. Reg. 28698 (May 13, 2020).

eligible for PTCs, the repowering program undertaken by the Company has extended this benefit for an additional ten years.

10. Calendar year 2020 is the last year that recovery of the 2013 incremental depreciation expense, that was authorized for deferral,[14] will be recovered through the ECAM.

11. While previous ECAM deferrals have netted tax savings from the Tax Cuts and Jobs Act, they were not netted against the 2020 ECAM deferral pursuant to the Commission's order in Case No. PAC-E-20-03. In that order, the Commission approved a settlement allowing the Company to retain TCJA savings to buy down or offset the net plant balance and closure costs of Cholla Unit No. 4 and to offset the January 1, 2022 rate increase.[15]

PROPOSED ECAM RATE

12. In support of this Application, Rocky Mountain Power has filed the testimony and exhibits of Company witnesses Messers. Jack Painter, Robert M. Meredith, and Steven R. McDougal. Mr. Painter's testimony describes the Actual NPC incurred by the Company to serve retail load for the Deferral Period and explains the differences between Actual NPC and Base NPC. Mr. Meredith's testimony describes how the Company's proposed rates to recover the 2020 ECAM deferral balances through Electric Service Schedule No. 94 - Energy Cost Adjustment ("Schedule 94") were developed. Mr. McDougal's testimony describes the recovery of expenses relating to wind repowering through the RTM and explains modification to the accounting treatment of excess deferred income tax.

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[14] *In the Matter of the Application of PacifiCorp dba Rocky Mountain Power to Initiate Discussions with Interested Parties on Alternative Rate Plan Proposals*, Case No. PAC-E-13-04, Order No. 32910 at 3 (October 23, 2013) (permitting deferral of 2013 incremental depreciation expense).

[15] *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, Order No. 34884 at 2 (December 31, 2020).

13. Exhibit No. 1 to Mr. Painter's testimony ("Exhibit 1") illustrates the detailed calculation of the ECAM deferral. The deferral is calculated on a monthly basis by comparing Idaho-allocated Actual NPC to the NPC collected in rates. For the Deferral Period, the NPC differential was approximately $5.7 million before the 90/10 percent sharing band.

14. Mr. Painter's testimony specifically addresses the LCAR, EITF 04-6 treatment of coal stripping costs, a true-up of 100 percent of the incremental REC revenues, PTCs, and the Lake Side 2 generation resource adder.

15. The LCAR is a symmetrical adjustment to offset over- or under-collection of the Company's energy-related production revenue requirement, excluding NPC, due to variances in Idaho load. The LCAR decreased the deferral balance by approximately $1.1 million before applying the sharing band due to higher usage during the Deferral Period.

16. The difference between including coal stripping costs recorded on the Company's books under the guidance of the accounting pronouncement EITF 04-6, and expensing coal stripping costs when the coal was excavated decreased the ECAM deferral by $127,464 before applying the sharing band.

17. The total NPC deferral adjusted for LCAR and EITF 04-6 was approximately $4.5 million for which customers are responsible 90 percent, and the Company is responsible for the remaining 10 percent. After accounting for the sharing band, the NPC deferral is approximately $4 million.

18. The total Lake Side 2 resource adder, described in paragraph 8 above and included on line 27 of Exhibit No. 1 for the Deferral Period, was $5.4 million based on 3,171,917 megawatt-hours ("MWh") of generation, but limited to 2,729,500 MWh due to the cap.

19. During the Deferral Period the PTC differential, as described in paragraph 9, decreased the deferral approximately $0.1 million.

20. The ECAM calculation also includes the RTM described in Mr. McDougal's testimony. For the Deferral Period the RTM increased the deferral by approximately $4.4 million on an Idaho basis, without application of the sharing band.

21. The ECAM also tracks the difference between actual REC revenues during the Deferral Period and the amount of REC revenues credited to customers in base rates. The REC revenue true-up included in the ECAM is symmetrical, but no sharing band is applied. During the Deferral Period actual REC revenue was approximately $8,557 higher than the amount credited to customers in base rates on an Idaho-allocated basis.

22. Interest is accrued on the uncollected balance at the Commission-approved interest rate for customer deposits. During the Deferral Period the interest rate was 2 percent. Interest of $562 thousand was added to the ECAM balance.

23. As described in paragraph 10, the ECAM includes 2013 incremental depreciation expenses. During the Deferral Period approximately $2.0 million was deferred associated with the 2013 incremental depreciation. The depreciation balancing account had a credit balance of $150,512 as of the end of the Deferral Period as summarized in Exhibit No. 1 to Mr. Painter's testimony.

24. The ECAM balance at the end of the Deferral Period was $23.2 million, including $13.8 million from the 2020 ECAM deferral, plus $8.9 million remaining balance from prior ECAM filings, and $0.6 million interest. This amount is reduced by $0.1 million credit balance in the depreciation deferred balance. The Company estimates the ECAM balance will be reduced approximately $7.0 million from Schedule 94 revenue collections less interest accrued from

January 1 through May 31, 2021 resulting with an expected ECAM balance of $16.1 million to be collected.

25. Mr. Meredith's testimony describes how Schedule 94 rates were designed to recover the May 31, 2021 estimated ECAM balance of $16.1 million. As a result, the Company proposes Schedule 94 rates of 0.477, 0.461 and 0.449 cents per kilowatt-hour for secondary, primary and transmission delivery service voltages, respectively, for all customers.

COMMUNICATIONS

Communications regarding this filing should be addressed to:

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In addition, Rocky Mountain Power requests that all data requests regarding this Application be sent in Microsoft Word to the following:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 Multnomah, Suite 2000
Portland, Oregon 97232

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

REQUEST FOR RELIEF

The ECAM allows the Company to collect or credit the difference between the Actual NPC incurred to serve customers in Idaho and the Base NPC collected through base rates assuring customers pay the actual NPC after sharing. To the best of the Company's knowledge it has accurately calculated the ECAM deferral with all the other associated Commission Orders in this Application.

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission issue an order: (1) authorizing that this matter be processed by Modified Procedure; (2) approving approximately $14.3 million ECAM deferral; and (3) approving a 1.3 percent decrease to Electric Service Schedule No. 94, Energy Cost Adjustment effective June 1, 2021.

DATED this 31st day of March 2021.

Respectfully submitted,
ROCKY MOUNTAIN POWER

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. PAC-E-21-09
OF ROCKY MOUNTAIN POWER	)	
REQUESTING APPROVAL OF $16.1	)	DIRECT TESTIMONY OF
MILLON NET POWER COST DEFERRAL	)	JACK PAINTER

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-09

March 2021

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 Jack Painter and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Net Power Cost Specialist.

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Bachelor of Arts degree in Business Administration with a Finance major from Washington State University in 2007. I have been employed by PacifiCorp since 2008 and have held positions in the regulation and jurisdictional loads departments. I joined the regulatory net power costs group in 2019 and assumed my current role as a net power cost specialist in 2020.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the Utah Public Service Commission.

PURPOSE OF TESTIMONY

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

A. My testimony presents and supports the Company's calculation of the Energy Cost Adjustment Mechanism ("ECAM") balancing account for the 12-month period of January 1, 2020 through December 31, 2020 ("Deferral Period"). More specifically, I provide the following:

- A summary of the ECAM calculation, including changes made to comply with Commission orders;
- Details supporting the addition of approximately $14.3 million to the deferral balance, including $4.0 million customers' share of ECAM costs, $5.4 million

Lake Side 2 Resource Adder, a $0.1 million increase in renewable energy production tax credits ("PTCs"), $4.4 million resource tracking mechanism ("RTM") deferral, $9 thousand renewable energy credit ("REC") revenue differential, and $0.6 million interest accrued;

- Discussion of the main differences between adjusted actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC"); and,
- Discussion about the Company's participation in the energy imbalance market ("EIM") with the California Independent System Operator ("CAISO") and the benefits from EIM that are passed through to customers.

Q. What other witnesses present testimony for the ECAM and Tariff Schedule 94 in this case?

A. Mr. Robert M. Meredith, Director, Pricing and Cost of Service, provides testimony on the proposed rates in Electric Service Schedule No. 94, Energy Cost Adjustment ("Schedule 94") and Mr. Steven R. McDougal, Director, Revenue Requirement, provides testimony on the RTM.

SUMMARY OF THE ECAM DEFERRAL CALCULATION

Q. Please briefly describe the Company's ECAM authorized by the Commission.

A. In general, the ECAM tracks deviations between Actual NPC and Base NPC and defers 90 percent of the difference for later recovery.[1] Other items, described in detail later in my testimony, are also tracked in the ECAM to true-up the amount in base rates to actuals. These items include a resource adder for the Lake Side 2 gas generation plant, PTCs, RTM deferral, and revenues from the sale of RECs.[2] The balance that

[1] *See* Order No. 30904 in Case No. PAC-E-08-08 and Order No. 33440 in Case No. PAC-E-15-09.
[2] *See* Order No. 33440 in Case No. PAC-E-15-09 pages 5–6.

accumulates over a deferral period is then passed on to customers as a rate surcharge or credit. Schedule 94, described in Mr. Meredith's testimony, appears as a separate line item on customer bills, collects from or credits to customers the balance of deferred costs. Schedule 94 is adjusted as needed in the Company's annual ECAM filings.

The Company is required to file an application with the Commission annually by April 1st to seek approval of the deferral amount and the new Schedule 94 rate, which becomes effective June 1st.

Q. Are there any changes to the ECAM calculation?

A. No.

ECAM DEFERRAL CALCULATION

Q. Please describe the calculation of the ECAM deferral included in this filing.

A. Table 1 provides a summary of the total ECAM deferral and a breakdown of the individual components of the ECAM. Exhibit No. 1 presents the detailed calculation of the ECAM deferral on a monthly basis.

Table 1 – 2020 ECAM Deferral

NPC Differential for Deferral	$ 5,656,015
EITF 04-6 Adjustment	(127,464)
LCAR	(1,076,170)
Total Deferral Before Sharing	4,452,381
Sharing Band	90%
Customer Responsibility	4,007,143
Lake Side 2 Resource Adder	5,431,705
Production Tax Credits	(100,831)
RTM Adjustment	4,431,885
REC Deferral	8,557
Interest on Deferral	562,667
Annual Deferral (Jan - Dec 2020)	14,341,126

The first section of Table 1 summarizes the Idaho-allocated share of those items for which Idaho customers and the Company share responsibility, including: NPC differential, EITF 04-6 adjustment, and load change adjustment revenue ("LCAR") costs. The next section calculates the 90 percent customers' share of the items above and adds the following items which are refunded or collected in full (i.e., 100 percent): the Lake Side 2 resource adder, PTCs, RTM deferral, REC revenues, and interest on the deferral. The total of these items equals the ECAM deferral.

Q. Does this filing reflect the regulatory asset associated with the 2013 Depreciation Study?

A. Yes. In Case No. PAC-E-18-01, the Commission ordered the Company to include the depreciation regulatory asset created in Case No. PAC-E-13-02 in future Idaho ECAM filings. As seen in Exhibit No. 1, the beginning balance, monthly deferral, and monthly amortization are included as part of the ECAM deferral balance.

Q. Based on your calculations, what is the balance expected to be in the ECAM deferral account as of June 1, 2021?

A. The projected balance in the ECAM deferral account as of June 1, 2021 is approximately $16.1 million. Table 2 summarizes the ECAM balancing account activity starting with the December 2019 ECAM deferral balance of $27.3 million approved in Case No. PAC-E-20-02. Approximately $14.3 million is added to the balance from the annual deferral and interest during the Deferral Period, offset by $18.4 million of ECAM revenue collections. Table 2 then summarizes the depreciation regulatory asset balance activity; the sum of the two is the balance for collection as of December 31, 2020.

Table 2 - Balancing Account Activity

ECAM Deferral Balance		
Deferral Balance - Dec 31, 2019	$	27,286,382
Annual Deferral (Jan - Dec 2020)		13,778,459
Interest		562,667
ECAM Revenue Collection - Schedule 94		(18,416,430)
Activity Through December 31, 2020	$	23,211,078
Depreciation Regulatory Asset Balance		
Beginning Balance	$	(76,878)
Annual Deferral (Jan - Dec 2020)		2,039,800
ECAM Revenue Collection - Schedule 94		(2,113,434)
Activity Through December 31, 2020	$	(150,512)
December 31, 2020 Balance For Collection	$	23,060,567
Schedule 94 Collection - Jan - May 2021	$	(6,994,766)
Interest		81,345
Expected Balance as of June 1, 2021	**$**	**16,147,146**

Q. Please describe the ECAM calculations in Exhibit No. 1.

A. The ECAM deferral is calculated by comparing Idaho-allocated Actual NPC to the NPC collected in rates on a monthly basis and deferring the differences into an ECAM balancing account. Exhibit No. 1 includes details of the ECAM calculation. I have also provided confidential work papers supporting this exhibit.

Q. How are the Base NPC and Actual NPC calculated?

A. The monthly Base NPC collected in rates, as set forth in Exhibit No. 1 line 6, is calculated by taking the dollar-per-megawatt-hour Base NPC rate multiplied by the actual Idaho retail sales. The Actual Idaho NPC, as set forth in Exhibit No. 1 line 15, is calculated by dividing the monthly total Company Actual NPC in the Deferral Period by the actual monthly system megawatt-hours ("MWh") in the Deferral Period. The total Company Actual NPC dollar-per-megawatt-hour basis is then multiplied by Idaho actual monthly MWh to calculate Actual Idaho NPC.

Q. Please describe how the NPC deferral is calculated.

A. The deferral is calculated on a monthly basis by subtracting the Base NPC collected in rates from the Actual Idaho NPC. For the Deferral Period, the NPC differential was $5.7 million before applying the 90 / 10 percent sharing.

Q. What costs are included in the NPC differential for deferral?

A. The NPC differential for deferral captures all components of NPC as defined in the Company's general rate case proceedings and modeled by the Company's production dispatch model the Generation and Regulation Initiative Decision Tool ("GRID"). Specifically, Base NPC and Actual NPC include amounts booked to the following FERC accounts:

Account 447 – Sales for resale; excluding on-system wholesale sales and other revenues that are not modeled in GRID

Account 501 – Fuel, steam generation; excluding fuel handling, start-up fuel (gas and diesel fuel, residual disposal), and other costs that are not modeled in GRID

Account 503 – Steam from other sources

Account 547 – Fuel, other generation

Account 555 – Purchased power; excluding the Bonneville Power Administration ("BPA") residential exchange credit pass-through if applicable

Account 565 – Transmission of electricity by others

Q. Are adjustments made to the Actual NPC before comparing them to Base NPC?

A. Yes. The Company adjusts Actual NPC to reflect the ratemaking treatment of several items, including:

- out of period accounting entries booked in the Deferral Period that relate to operations before implementation of the ECAM on July 1, 2009;
- buy-through of economic curtailment by interruptible industrial customers;
- revenue from a contract related to the Leaning Juniper wind resource;
- situs assignment of the generation from Oregon solar resources procured to satisfy Oregon Revised Statute ("ORS") 757.370 solar capacity standard;
- situs assignment of Oregon allocated amortization related to a prepaid wheeling expense;
- situs assignment of certain Utah solar resources and Schedule 32 and 34 contract costs;
- coal inventory adjustments to reflect coal costs in the correct period;
- legal fees related to fines and citations included in the cost of coal;
- adjustments related to liquidated damages that occurred outside the Deferral Period (all liquidated damage fees per a coal supply agreement are booked in accordance with generally accepted accounting principles ("GAAP"));
- situs assignment of Reasonable Energy Price adjustments to qualifying facilities ("QF"); and,
- an adjustment for reclassification of wholesale sales revenue above the FERC price cap. Sales pending refund are accounted for in FERC Account 449, a non-regulatory NPC account instead of FERC Account 447. Because

this transaction is recorded in a non-NPC account and the wholesale sales revenue is recorded in FERC Account 447, the adjustment should be included in the 2021 ECAM to align the pending refund with the matching sales revenue in accordance with GAAP.

Q. Why is the July 1, 2009 cutoff used to determine out of period entries?

A. Since the ECAM took effect, customers' rates have been adjusted to recover essentially all of the Company's actual net power costs, excluding any differences due to the 90 / 10 percent sharing band. Consequently, any accounting entries made during the current Deferral Period that relate to any operating period since the ECAM took effect, should also be reflected in customer rates, whether they increase or decrease Actual NPC. Accounting entries related to operating periods before the inception of the ECAM should not impact the ECAM deferral.

Q. In addition to comparing Actual NPC to Base NPC, what other components are included in the ECAM?

A. Six additional components are included in the ECAM calculations: (i) an adjustment for deferred costs associated with coal mine stripping activities recorded under the Financial Accounting Standards Board ("FASB") EITF 04-6; (ii) the LCAR adjustment; (iii) a resource adder to collect the investment in the Lake Side 2 natural gas generation facility; (iv) a true-up of PTCs; (v) the resource tracking mechanism deferral; and (vi) a true-up of REC revenues as authorized in Order No. 32196.

Q. How is the adjustment for accounting pronouncement EITF 04-6 included in the ECAM?

A. The calculation of coal stripping costs on Line 17 of Exhibit No. 1 reflects Idaho's allocated differences between the coal stripping costs incurred by the Company during excavation and recorded on the Company's books pursuant to the guidance of the accounting pronouncement EITF 04-6, and the amortization of the coal stripping costs as approved by the Commission in Case No. PAC-E-09-08, Order No. 30987. For the Deferral Period, the total EITF 04-6 coal stripping deferral adjustment is a $0.1 million decrease to the ECAM deferral balance before the 90 / 10 percent sharing.

Q. Please describe the LCAR adjustment.

A. The calculation of the LCAR adjustment is a symmetrical adjustment for over- or under-collection of the energy-related portion of the Company's embedded revenue requirement for production facilities as specified in Case No. GNR-E-10-03, Order No. 32206. The LCAR accounts for variances in Idaho load that cause the Company to collect more or less of these production-related costs. The LCAR rate of $5.54 per MWh is used for the Deferral Period.

Q. How is the LCAR adjustment calculated and what impact does it have on the Deferral Period?

A. The LCAR adjustment assumes that the actual production-related costs of the LCAR are equal to base, Exhibit No. 1 line 18. The actual production-related costs are then compared to the LCAR revenue collection in rates, calculated by multiplying the LCAR rate by the actual Idaho retail sales, Exhibit No. 1 line 21. The LCAR adjustment is the difference between the actual production-related costs and the LCAR revenue, line 22 of Exhibit No. 1, and is a $1.1 million decrease to the ECAM deferral balance before the 90 / 10 percent sharing.

Q. Please explain the sharing ratio between the Company and customers in the ECAM.

A. The ECAM includes a symmetrical sharing ratio in which customers either pay or receive 90 percent of the ECAM deferral balance, and the Company is responsible for the remaining 10 percent. Line 24 of Exhibit No. 1 represents the customers' 90 percent share of the monthly deferral shown on line 23 of Exhibit No. 1. For the Deferral Period, the customers' share of the deferred balance is $4.0 million. The remaining balance of $0.4 million associated with the Company's 10 percent share is not included in the deferral balance as it is not recoverable from customers.

Q. What is the amount of the Lake Side 2 resource adder in the current filing?

A. Pursuant to the stipulation in Case No. PAC-E-13-04, approved by Commission Order No. 32910, the Company included a resource adder to recover the investment in the Lake Side 2 generation plant which is not yet included in base rates. The resource adder amounts to $1.99/MWh of the Lake Side 2 generation capped at 2,729,500 MWh or $5.4 million for the calendar year. The total Lake Side 2 resource adder on line 27 of Exhibit No. 1 for the Deferral Period was $5.4 million based on 3,171,917 MWh of generation, but limited to 2,729,500 MWh due to the cap.

Q. What is the amount of the PTC true-up in the current filing?

A. The PTC Deferral, on line 32 of Exhibit No. 1, is calculated by comparing the actual Idaho-allocated PTC to the PTC customers receive through base rates. The PTC credit in base rates is calculated by multiplying the approved PTC rate of $1.99/MWh by Idaho retail sales. The difference is a $0.1 million decrease to the ECAM deferral.

Q. Please explain the RTM deferral.

A. The RTM deferral, on line 33 of Exhibit No. 1, is calculated per Exhibit No. 4 described in Mr. McDougal's testimony. The RTM deferral during calendar year 2020 is $4.4 million.

Q. What is the amount of REC revenue adjustment in the current filing?

A. The REC revenue adjustment, on line 38 of Exhibit No. 1, is calculated by comparing the actual Idaho-allocated REC revenue to the REC revenue credit customers receive through base rates. The REC revenue credit in base rates is calculated by multiplying the approved REC revenue rate of $0.09/MWh by Idaho retail sales. The difference is a $9 thousand increase to the ECAM deferral.

Q. What is the total ECAM deferred balance calculated in Exhibit No. 1?

A. The total ECAM deferred balance as of December 31, 2020 is $13.8 million, shown on line 39 plus $563 thousand of interest on line 48 of Exhibit No. 1, for a total deferral of $14.3 million.

Q. Does the calculation of the ECAM deferral in this application comply with the parameters of the Idaho ECAM as approved by the Commission?

A. Yes. Therefore, the Company recommends the Commission approve the ECAM application for recovery of the $14.3 million prudently incurred ECAM costs.

DIFFERENCES IN NPC

Q. On a total-Company basis, what was the difference between Actual NPC and Base NPC for the Deferral Period?

A. On a total-Company basis, Actual NPC for the Deferral Period were $1.512 billion, exceeding Base NPC for the Deferral Period by $27 million. Table 3 provides a high-level summary of the difference between Base NPC and Actual NPC by category on a total-Company basis.

Table 3 - Net Power Cost Reconciliation ($ millions)

		TOTAL
Base NPC	$	1,485
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue		161
Purchased Power Expense		39
Coal Fuel Expense		(149)
Natural Gas Expense		(22)
Wheeling and Other Expense		(3)
Total Increase/(Decrease)	$	27
Adjusted Actual NPC	$	1,512

Q. Please describe the Base NPC the Company used to calculate the NPC component of the ECAM deferral.

A. The Base NPC were set in Case No. PAC-E-16-12 and became effective January 1, 2017. Base NPC used the 12-month test period of January 2016 through December 2016 and set total-Company Base NPC at $1.485 billion.

Q. Please describe the primary differences between Actual NPC and Base NPC.

A. From an accounting perspective, and as shown in Table 3, Actual NPC were higher than Base NPC due to a $161 million reduction in wholesale sales and a $39 million increase in purchased power expense. The items were partially offset by a $149 million reduction in coal fuel expense, a $22 million decrease in natural gas expense, and a $3 million decrease in wheeling and other expenses.

Q. Please explain the changes in wholesale sales revenue.

A. Wholesale sales revenue declined relative to Base NPC due to higher market prices and a reduction in the wholesale sales volume of market transactions (represented in GRID as short-term firm and system balancing sales).

Of the $161 million decrease to wholesale sales, revenue from market transactions represents the largest change to Base NPC. Market transactions are $141 million lower than Base NPC due to higher market prices and lower volume of market sales transactions. The average price of actual market sales transactions was $11.46/MWh, or 49 percent, higher than the average price in Base NPC. Actual wholesale market volumes were 8,353 gigawatt-hours ("GWh"), or 64 percent, lower than the Base NPC. In addition, an expired contract accounted for $9 million of the decrease in wholesale sales revenue.

Q. Please explain the changes in purchased power expense.

A. Purchased power expense increased by $39 million with a $116 million increase (54 percent) in QF transactions as the most significant driver, partially offset by the expiration of a long-term purchase power contract. Actual QF transaction volumes were 1,884 GWh (53 percent) higher than Base NPC. The expiration of the Hermiston purchase power agreement ("PPA") reduced purchased power costs by $31.3 million.

Additionally, expenses from market transactions (represented in GRID as short-term firm and system balancing purchases) decreased by $33.5 million compared to Base NPC. Actual market purchases were 3,327 GWh (46 percent) lower than Base NPC, but the average price of actual market purchases transactions was $12.95/MWh (52 percent) higher than Base NPC.

Q. Please explain the changes in wheeling expenses.

A. Actual long-term wheeling expenses decreased by $11.5 million when compared to

Base NPC but were offset by an increase of $12.1 million of short-term wheeling expenses for a net increase of $0.6m.

Q. Please explain the changes in coal fuel expense.

A. Coal fuel expense decreased because coal generation volume decreased 8,465 GWh (22 percent) compared to Base NPC. The average cost of coal generation increased from $19.96/MWh in Base NPC to $20.62/MWh in the Deferral Period, but the lower generation volume results in an overall decrease of $149 million in coal fuel expense.

Q. Please explain the changes in natural gas fuel expense.

A. The total natural gas fuel expense in Actual NPC decreased by $22 million compared to Base NPC mainly due to a decrease in average cost of natural gas generation from $23.06/MWh in Base NPC to $21.85/MWh in the Deferral Period. Additionally, there was a decrease in gas generation volumes of 307 GWh (three percent).

IMPACT OF PARTICIPATING IN THE EIM

Q. Are the actual benefits from participating in the EIM with CAISO included in the ECAM deferral?

A. Yes. Participation in the EIM provides benefits to customers in the form of reduced Actual NPC. The EIM benefits are embedded in Actual NPC through lower fuel and purchased power costs. The Company is able to calculate the margin realized on its EIM imports and exports, the inter-regional benefit. The Company's EIM inter-regional benefit for the deferral period was $46.8 million.

Q. How does the Company calculate its actual EIM benefits?

A. Using actual information from the EIM, including five- and 15-minute pricing, the Company identifies the incremental resource that could have facilitated the transfer to an adjacent EIM area or the CAISO in each five-minute interval. The benefit is then calculated as the difference between the revenue received less the expense of generation assumed to supply the transfer. In the event of an import, the benefit is equal to the cost of the import minus the avoided expense of the generation that would have otherwise been dispatched.

Q. Please summarize your testimony.

A. The ECAM deferral of $14.3 million, including interest, for the Deferral Period, was accurately calculated in compliance with previous Commission orders. Therefore, I respectfully request that the Commission approve this application as filed with rates effective June 1, 2021.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-21-09
Exhibit No. 1
Witness: Jack Painter

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jack Painter

March 2021

Idaho Energy Cost Adjustment Mechanism Deferr
January 1, 2020 - December 31, 202(

Exhibit No. 1

Line No.			CY 2016
1	ID Base NPC Embedded in Rates ($	PAC-E-16-12	$ 91,646,727
2	Annual Idaho Base Load @ meter (MWh	PAC-E-16-12	3,407,488
3	NPC Rate Embedded in Base Rates ($/MWh	Line 1 / Line 2	$ 26.90

Line No.			Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
4	NPC Rate Embedded in Base Rates ($/MWh	Line 3	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	
5	ID Actual Sales @ Meter (MWh)	Line 5	253,898	244,010	213,504	213,460	306,791	388,284	432,246	379,685	285,414	263,264	238,057	303,734	
6	ID NPC Collected in Rates ($	Line 4 x Line 5	$ 6,828,770	$ 6,562,813	$ 5,742,325	$ 5,741,147	$ 8,251,353	$ 10,443,156	$ 11,625,549	$ 10,211,898	$ 7,676,414	$ 7,080,677	$ 6,402,702	$ 8,169,142	$ 94,735,944
7	Total Company Adjusted Actual NPC Excl. Integration Adj. ($	Adjusted Actual NPC	$ 123,339,882	$ 122,232,788	$ 127,063,155	$ 104,812,359	$ 111,412,548	$ 123,937,016	$ 156,474,324	$ 153,659,771	$ 122,655,857	$ 121,105,556	$ 114,802,183	$ 130,587,758	$ 1,512,083,197
8	Intra-Hour Wind Integration Cost ($/MWh)		$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	
9	Third Party Wind Sold to Wholesale (MWh)	Note (1)	171,547	129,482	119,032	104,396	100,978	94,479	87,369	81,043	81,221	137,066	127,896	100,655	
10	Third Party Wind Adjustment ($)	Line 8 x Line 9	$ 66,227	$ 49,988	$ 45,953	$ 40,303	$ 38,983	$ 36,474	$ 33,729	$ 31,287	$ 31,356	$ 52,915	$ 49,375	$ 38,859	$ 515,450
11	Total Company Adjusted Actual NPC ($	Line 7 - Line 10	$ 123,273,655	$ 122,182,800	$ 127,017,201	$ 104,772,056	$ 111,373,565	$ 123,900,541	$ 156,440,595	$ 153,628,484	$ 122,624,501	$ 121,052,641	$ 114,752,808	$ 130,548,899	$ 1,511,567,747
12	Total Company Load @ Input (MWh		5,157,135	4,726,803	4,695,850	4,166,661	4,395,668	4,728,054	5,589,932	5,673,186	4,657,759	4,586,289	4,767,808	5,294,469	58,439,613
13	Actual NPC ($/MWh)	Line 11 / Line 12	$ 23.90	$ 25.85	$ 27.05	$ 25.15	$ 25.34	$ 26.21	$ 27.99	$ 27.08	$ 26.33	$ 26.39	$ 24.07	$ 24.66	$ 25.87
14	ID Actual Load @ Input (MWh)		314,197	297,016	241,624	235,623	355,265	406,911	469,188	378,030	301,857	283,711	270,773	314,660	
15	Actual ID NPC	Line 13 x Line 14	$ 7,510,419	$ 7,677,543	$ 6,535,636	$ 5,924,812	$ 9,001,401	$ 10,663,269	$ 13,130,751	$ 10,236,972	$ 7,946,972	$ 7,488,400	$ 6,517,022	$ 7,758,762	$ 100,391,959
16	NPC Differentia	Line 15 - Line 6	$ 681,648	$ 1,114,729	$ 793,311	$ 183,665	$ 750,049	$ 220,113	$ 1,505,202	$ 25,074	$ 270,558	$ 407,724	$ 114,320	$ (410,379)	$ 5,656,015
	EITF 04-6 Adjustment														
17	Idaho Allocated EITF 04-6 Deferral Adjustment ($		$ 2,779	$ (5,302)	$ (12,460)	$ (17,565)	$ (26,376)	$ (67,306)	$ (48,681)	$ (34,653)	$ (15,123)	$ 50,325	$ 24,378	$ 22,521	$ (127,464)
	LCAR														
18	Actual Idaho Jurisdictional ECPC minus NPC (Assume Actual =	PAC-E-16-12	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 18,434,143
19	LCAR Rate @ Meter ($/MWh)	PAC-E-16-12	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	
20	ID Actual Sales @ Meter (MWh)	Line 5	253,898	244,010	213,504	213,460	306,791	388,284	432,246	379,685	285,414	263,264	238,057	303,734	
21	LCAR Revenue Collected through Base Rates ($	Line 19 x Line 20	$ 1,406,345	$ 1,351,573	$ 1,182,598	$ 1,182,356	$ 1,699,318	$ 2,150,707	$ 2,394,214	$ 2,103,081	$ 1,580,912	$ 1,458,224	$ 1,318,599	$ 1,682,387	$ 19,510,312
22	LCAR Adjustment	Line 18 - Line 21	$ 129,833	$ 184,606	$ 353,580	$ 353,823	$ (163,139)	$ (614,528)	$ (858,035)	$ (566,902)	$ (44,734)	$ 77,955	$ 217,580	$ (146,208)	$ (1,076,170)
	ECAM Deferral														
23	Total ECAM Deferral (NPC Deferral, EITF 04-6 Adjustment, LC/	Sum of Lines: 16, 17, 22	814,260	1,294,033	1,134,432	519,923	560,534	(461,722)	598,485	(576,480)	210,701	536,003	356,278	(534,067)	4,452,381
24	**Total ECAM Deferral after 90% Sharing**	Line 23 x 90%	$ 732,834	$ 1,164,630	$ 1,020,988	$ 467,930	$ 504,481	$ (415,550)	$ 538,637	$ (518,832)	$ 189,631	$ 482,403	$ 320,650	$ (480,660)	$ 4,007,143
	Lakeside 2 Resource Adde														
25	Lake Side 2 Generation (MWh	Adjusted Actual NPC	199,759	304,612	334,338	232,649	126,034	252,268	329,456	359,671	282,210	265,006	43,497	-	
26	Resource Adder Rate ($/MWh)	PAC-E-13-04	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	
27	Total Lake Side 2 Resource Adder ($	Line 25 x Line 26	$ 397,520	$ 606,178	$ 665,333	$ 462,972	$ 250,808	$ 502,013	$ 655,617	$ 715,745	$ 561,598	$ 527,362	$ 86,559	$ -	$ 5,431,705
	Production Tax Credits (PTCs)														
28	ID Allocated PTCs in Rates ($/MWh)	PAC-E-16-12	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	
29	ID Actual Sales @ Meter (MWh)	Line 5	253,898	244,010	213,504	213,460	306,791	388,284	432,246	379,685	285,414	263,264	238,057	303,734	
30	ID PTCs in Rates ($)	Line 28 x Line 29	$ (506,216)	$ (486,500)	$ (425,678)	$ (425,590)	$ (611,671)	$ (774,150)	$ (861,800)	$ (757,006)	$ (569,051)	$ (524,889)	$ (474,631)	$ (605,577)	
31	ID Allocated Actual PTCs ($		(704,885)	(671,005)	(614,254)	(521,444)	(488,116)	(554,228)	(469,805)	(384,241)	(436,142)	(621,981)	(724,278)	(933,213)	
32	ID PTCs Deferral ($)	Line 31 - Line 30	$ (198,669)	$ (184,505)	$ (188,577)	$ (95,853)	$ 123,555	$ 219,921	$ 391,995	$ 372,766	$ 132,909	$ (97,092)	$ (249,646)	$ (327,635)	$ (100,831)
	RTM Adjustment														
33	ID RTM Adjustment ($)		$ 289,767	$ 327,150	$ 389,170	$ 398,281	$ 368,483	$ 360,799	$ 372,186	$ 340,377	$ 347,764	$ 454,757	$ 390,068	$ 393,085	$ 4,431,885
	Renewable Energy Credits (REC) Revenue														
34	ID REC Revenue in Rates ($/MWh)	PAC-E-16-12	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	
35	ID Actual Sales @ Meter (MWh)	Line 5	253,898	244,010	213,504	213,460	306,791	388,284	432,246	379,685	285,414	263,264	238,057	303,734	
36	ID REC Revenue in Rates ($	Line 34 x Line 35	$ (22,785)	$ (21,898)	$ (19,160)	$ (19,156)	$ (27,532)	$ (34,846)	$ (38,791)	$ (34,074)	$ (25,614)	$ (23,626)	$ (21,364)	$ (27,258)	
37	ID Allocated Actual REC Revenue ($		52,729	(796)	(74,572)	(46,132)	17,825	(2,472)	(983)	386	(39)	(44,535)	(191,640)	(17,319)	
38	REC Revenue Adjustment ($)	Line 37 - Line 36	$ 75,514	$ 21,102	$ (55,412)	$ (26,976)	$ 45,357	$ 32,374	$ 37,808	$ 34,460	$ 25,575	$ (20,909)	$ (170,277)	$ 9,939	$ 8,557
39	**Total Deferral**	Sum of Lines 24, 27, 32,33, 38	$ 1,296,967	$ 1,934,555	$ 1,831,503	$ 1,206,353	$ 1,292,683	$ 699,558	$ 1,996,244	$ 944,516	$ 1,257,477	$ 1,346,521	$ 377,354	$ (405,271)	$ 13,778,459
40	Interest Rate	Order No. 34204	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
	ECAM Balancing Account ($														
41	Beginning Balance		$ 27,286,382	$ 27,980,004	$ 28,902,120	$ 29,815,379	$ 30,288,607	$ 30,693,848	$ 29,823,083	$ 29,222,003	$ 27,722,357	$ 26,939,607	$ 26,597,266	$ 24,648,725	
42	ECAM Deferral After Sharing	Line 24	732,834	1,164,630	1,020,988	467,930	504,481	(415,550)	538,637	(518,832)	189,631	482,403	320,650	(480,660)	
43	Lake Side 2 Resource Adde	Line 27	397,520	606,178	665,333	462,972	250,808	502,013	655,617	715,745	561,598	527,362	86,559	-	
44	PTCs Deferral	Line 32	(198,669)	(184,505)	(188,577)	(95,853)	123,555	219,921	391,995	372,766	132,909	(97,092)	(249,646)	(327,635)	
45	RTM Adjustment	Line 33	289,767	327,150	389,170	398,281	368,483	360,799	372,186	340,377	347,764	454,757	390,068	393,085	
46	REC Revenue Adjustment	Line 38	75,514	21,102	(55,412)	(26,976)	45,357	32,374	37,808	34,460	25,575	(20,909)	(170,277)	9,939	
47	Less: Monthly ECAM Rider Revenues allocated to ECAI		(649,362)	(1,059,802)	(967,134)	(783,170)	(938,219)	(1,620,711)	(2,646,487)	(2,491,576)	(2,085,740)	(1,733,439)	(2,368,564)	(1,072,226)	
48	Interest		46,017	47,362	48,891	50,045	50,776	50,389	49,163	47,414	45,514	44,577	42,669	39,850	
49	**ECAM Deferral Balance ($)**		$ 27,980,004	$ 28,902,120	$ 29,815,379	$ 30,288,607	$ 30,693,848	$ 29,823,083	$ 29,222,003	$ 27,722,357	$ 26,939,607	$ 26,597,266	$ 24,648,725	$ 23,211,078	$ 23,211,078

Depreciation Regulatory Asset Balancing Account ($

Rocky Mountain Power
Exhibit No. 1 Page 1 of 1
Case No. PAC-E-21-09
Witness: Jack Painter

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	**CASE NO. PAC-E-21-09**
OF ROCKY MOUNTAIN POWER	)	
REQUESTING APPROVAL OF $16.1	)	**DIRECT TESTIMONY OF**
MILLON NET POWER COST DEFERRAL	)	**ROBERT M. MEREDITH**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-09

March 2021

Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power ("the Company").

A. My name is Robert M. Meredith. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing and Cost of Service.

Qualifications

Q. Briefly describe your educational and professional background.

A. I graduated from Oregon State University with a Bachelor of Science degree in Business Administration and a minor in Economics. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 16 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over 10 years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of Service. In June 2019, I was promoted to my current position.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously filed testimony on behalf of the Company in regulatory proceedings in Idaho, Utah, Wyoming, Oregon, Washington and California.

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

A. My testimony presents and supports the Company's proposed rates to recover the 2020 Energy Cost Adjustment Mechanism ("ECAM") deferral balances through Electric Service Schedule No. 94 - Energy Cost Adjustment ("Schedule 94").

Background

Q. What level of revenues is Schedule 94 currently designed to collect?

A. Schedule 94 is currently designed to collect approximately $19.2 million—$7.7 million for Tariff Contract 400, $0.6 million for Tariff Contract 401, and $11.0 million for the standard tariff customers—based on Idaho loads from Case No. PAC-E-15-09.

Proposed Rate Change for Schedule 94

Q. Please describe the Company's proposed rate change in this case.

A. The 2020 ECAM application proposes to decrease Schedule 94 rates to recover approximately $16.1 million from June 1, 2021 to May 31, 2022. The $16.1 million includes $14.4 million for the 2020 ECAM Deferral, plus approximately $8.9 million remaining from the 2019 ECAM balance, for a total balance of $23.2 million as of December 31, 2020. This is offset by a net credit of $150,512 in the depreciation regulatory asset balance and $6.9 million Schedule 94 forecasted revenue collection from January 1, 2021 through May 31, 2021, as shown in Table 2 of Mr. Jack Painter's testimony. Mr. Painter explains in his testimony the components of the 2020 ECAM deferred balance.

Q. Please explain the proposed rate change for Tariff Contracts 400 and 401.

A. The proposed rate for Tariff Contracts 400 and 401 is the same as for standard tariff customers with transmission delivery service voltage.

Q. What is the impact of the proposed ECAM rates?

A. As summarized in my Exhibit No. 2, these rate change proposals result in a decrease of 1.3 percent for Tariff Contract 400 and Tariff Contract 401. Standard tariff customers will also see an average decrease of 0.9 percent, or $1.8 million.

Calculation of Proposed Rates for Schedule 94

Q. How were the proposed Schedule 94 rates developed for all customers?

A. The proposed rates for all customers were developed in four steps. First, I developed their kilowatt-hour ("kWh") consumption at the generation level by multiplying their retail loads at the delivery service voltage level with the corresponding line loss factors. Next, an overall average rate at the generation level was developed by dividing their total collection target identified above with their kWh consumption at the generation level. Finally, rates by delivery voltage level were developed by multiplying the above overall average rate at the generation level with the corresponding line loss factors. As a result, the Company proposes Schedule 94 rates of 0.477, 0.461 and 0.449 cents per kWh for secondary, primary and transmission delivery service voltages, respectively, for all customers.

Q. Please describe Exhibit No. 2.

A. Exhibit No. 2 shows the 2014 loads used to develop rates, the line loss adjusted loads, the allocation of the ECAM price change, and the percentage change by rate schedule.

Q. Please describe Exhibit No. 3.

A. Exhibit No. 3 contains clean and legislative copies of the proposed Electric Service Schedule No. 94, Energy Cost Adjustment. The Company requests that the proposed Schedule 94 rates become effective on June 1, 2021.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-21-09
Exhibit No. 2
Witness: Robert M. Meredith

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

March 2021

EXHIBIT NO. 2
ESTIMATED IMPACT OF PROPOSED ECAM ADJUSTMENT
FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
HISTORIC 12 MONTHS ENDED DECEMBER 2014

Line No.	Description	Sch.	Average Cust	MWH	Present Rev ($000)	At Meter MWh by Voltage S	At Meter MWh by Voltage P	At Meter MWh by Voltage T	At Generation MWh	ECAM Proposal Rev ($000)	ECAM Proposal Rate ¢/kWh S	ECAM Proposal Rate ¢/kWh P	ECAM Proposal Rate ¢/kWh T	Present ECAM Rev ($000)	Net Change ($000)	Net Change %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Residential Sales															
1	Residential Service	1	46,059	442,589	$49,602	442,589			487,503	$2,113	0.477	0.461	0.449	$2,527	($414)	-0.8%
2	Residential Optional TOD	36	13,484	235,152	$22,484	235,152			259,016	$1,123	0.477	0.461	0.449	$1,343	($220)	-0.9%
3	AGA Revenue				$3											
4	Total Residential		59,543	677,741	$72,090	677,741	0	0	746,519	$3,235				$3,870	($635)	-0.8%
5	**Commercial & Industrial**															
6	General Service - Large Power	6	1,036	303,011	$23,667	258,477	44,534		332,125	$1,439	0.477	0.461	0.449	$1,720	($281)	-1.1%
7	General Svc. - Lg. Power (R&F)	6A	214	30,600	$2,616	30,600			33,705	$146	0.477	0.461	0.449	$175	($29)	-1.0%
8	*Subtotal-Schedule 6*		*1,250*	*333,611*	*$26,283*	*289,077*	*44,534*	*0*	*365,830*	*$1,585*				*$1,895*	*($310)*	*-1.1%*
9	General Service - High Voltage	9	17	121,001	$7,626			121,001	125,363	$543	0.477	0.461	0.449	$644	($100)	-1.2%
10	Irrigation	10	4,969	602,488	$54,316	602,488			663,629	$2,876	0.477	0.461	0.449	$3,440	($564)	-1.0%
11	Comm. & Ind. Space Heating	19	103	5,151	$438	5,151			5,674	$25	0.477	0.461	0.449	$29	($5)	-1.0%
12	General Service	23	6,634	153,848	$14,913	152,484	1,364		169,411	$734	0.477	0.461	0.449	$878	($144)	-0.9%
13	General Service (R&F)	23A	2,314	33,450	$3,376	32,839	611		36,822	$160	0.477	0.461	0.449	$191	($31)	-0.9%
14	*Subtotal-Schedule 23*		*8,948*	*187,299*	*$18,289*	*185,323*	*1,975*	*0*	*206,233*	*$894*				*$1,069*	*($175)*	*-0.9%*
15	General Service Optional TOD	35	3	1,893	$123	1,893			2,085	$9	0.477	0.461	0.449	$11	($2)	-1.3%
16	Special Contract 1	400	1	1,443,926	$86,967			1,443,926	1,495,980	$6,483			0.449	$7,682	($1,198)	-1.3%
17	Special Contract 2	401	1	107,486	$6,264			107,486	111,361	$483			0.449	$572	($89)	-1.3%
18	AGA Revenue				$478											
19	Total Commercial & Industrial		15,293	2,802,855	$200,786	1,083,932	46,510	1,672,413	2,976,154	$12,898				$15,342	($2,444)	-1.1%
20	**Public Street Lighting**															
21	Security Area Lighting	7	193	267	$102	267			294	$1	0.477	0.461	0.449	$2	($0)	-0.2%
22	Security Area Lighting (R&F)	7A	136	107	$44	107			117	$1	0.477	0.461	0.449	$1	($0)	-0.2%
23	Street Lighting - Company	11	37	87	$40	87			95	$0	0.477	0.461	0.449	$0	($0)	-0.2%
24	Street Lighting - Customer	12	234	2,424	$436	2,424			2,670	$12	0.477	0.461	0.449	$14	($2)	-0.5%
25	AGA Revenue				$0											
26	Total Public Street Lighting		600	2,884	$621	2,884	0	0	3,177	$14				$16	($3)	-0.4%
27	**Total Sales to Ultimate Customers**		75,435	3,483,480	$273,497	1,764,558	46,510	1,672,413	3,725,850	$16,147				$19,228	($3,081)	-1.1%
28	**Total (w/o Sch 400, 401)**		75,433	1,932,068	$180,265	1,764,558	46,510	121,001	2,118,509	$9,181				$10,975	($1,793)	-0.9%

Line No.	Description		Rev. Rqmt	Unallocated		Allocated			Proposed Rates S	Proposed Rates P	Proposed Rates T	Current Rates S	Current Rates P	Current Rates T
29	Voltage Line Loss Factors applied to rates:				1.10148	1.06475	1.03605							
30	Total Company Current Deferral Rate (cents/kWh): ECAM deferral		$16,147	0.433	0.477	0.461	0.449							
31								Total Tariff Customer Rate	0.477	0.461	0.449	0.571	0.549	0.532
32								Total Schedule 400 Rate			0.449			0.532
33								Total Schedule 401 Rate			0.449			0.532

Rocky Mountain Power
Exhibit No. 2 Page 1 of 1
Case No. PAC-E-21-09
Witness: Robert M. Meredith

Case No. PAC-E-21-09
Exhibit No. 3
Witness: Robert M. Meredith

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

March 2021

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF IDAHO

Energy Cost Adjustment

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: This Schedule shall be applicable to all retail tariff Customers taking service under the Company's electric service schedules.

ENERGY COST ADJUSTMENT: The Energy Cost Adjustment is calculated to collect the accumulated difference between total Company Base Net Power Cost and total Company Actual Net Power Cost calculated on a cents per kWh basis.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied the following cents per kilowatt-hour rate by delivery voltage.

		Delivery Voltage		
		Secondary	Primary	Transmission
Schedule	1	0.477~~571~~¢ per kWh		
Schedule	6	0.477~~571~~¢ per kWh	0.461~~549~~¢ per kWh	
Schedule	6A	0.477~~571~~¢ per kWh	0.461~~549~~¢ per kWh	
Schedule	7	0.477~~571~~¢ per kWh		
Schedule	7A	0.477~~571~~¢ per kWh		
Schedule	9			0.449~~532~~¢ per kWh
Schedule	10	0.477~~571~~¢ per kWh		
Schedule	11	0.477~~571~~¢ per kWh		
Schedule	12	0.477~~571~~¢ per kWh		
Schedule	19	0.477~~571~~¢ per kWh		
Schedule	23	0.477~~571~~¢ per kWh	0.461~~549~~¢ per kWh	
Schedule	23A	0.477~~571~~¢ per kWh	0.461~~549~~¢ per kWh	
Schedule	24	0.477~~571~~¢ per kWh	0.461~~549~~¢ per kWh	
Schedule	35	0.477~~571~~¢ per kWh	0.461~~549~~¢ per kWh	
Schedule	35A	0.477~~571~~¢ per kWh	0.461~~549~~¢ per kWh	
Schedule	36	0.477~~571~~¢ per kWh		
Schedule	400			0.449~~532~~¢ per kWh
Schedule	401			0.449~~532~~¢ per kWh

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

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Schedule	6A	0.477¢ per kWh	0.461¢ per kWh	
Schedule	7	0.477¢ per kWh		
Schedule	7A	0.477¢ per kWh		
Schedule	9			0.449¢ per kWh
Schedule	10	0.477¢ per kWh		
Schedule	11	0.477¢ per kWh		
Schedule	12	0.477¢ per kWh		
Schedule	19	0.477¢ per kWh		
Schedule	23	0.477¢ per kWh	0.461¢ per kWh	
Schedule	23A	0.477¢ per kWh	0.461¢ per kWh	
Schedule	24	0.477¢ per kWh	0.461¢ per kWh	
Schedule	35	0.477¢ per kWh	0.461¢ per kWh	
Schedule	35A	0.477¢ per kWh	0.461¢ per kWh	
Schedule	36	0.477¢ per kWh		
Schedule	400			0.449¢ per kWh
Schedule	401			0.449¢ per kWh

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	**)**	**CASE NO. PAC-E-21-09**
OF ROCKY MOUNTAIN POWER	**)**	
REQUESTING APPROVAL OF $16.1	**)**	**DIRECT TESTIMONY OF**
MILLON NET POWER COST DEFERRAL	**)**	**STEVEN R. MCDOUGAL**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-09

March 2021

Q. Please state your name and business address with PacifiCorp, dba Rocky Mountain Power ("the Company").

A. My name is Steven R. McDougal, and my business address is 1407 W. North Temple, Suite 330, Salt Lake City, Utah 84116.

QUALIFICATIONS

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 with PacifiCorp and its predecessor, Utah Power and Light Company, since 1983. My experience includes various positions with regulation, finance, resource planning, and internal audit. My current position is the Director of Revenue Requirements.

Q. What are your current responsibilities with the Company?

A. My primary responsibilities include overseeing the calculation and reporting of the Company's regulated earnings and revenue requirement, assuring that the interjurisdictional 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 proceedings?

A. Yes. I have provided testimony in regulatory proceedings in California, Idaho, Oregon, Utah, Washington, and Wyoming.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I explain and support the Company's request, through this Energy Cost Adjustment Mechanism ("ECAM"), for recovery of collectively $4.43 million for repowering and Energy Vision 2020, before carrying charge, as calculated and deferred through the approved Resource Tracking Mechanism ("RTM"). These amounts are included in the ECAM as shown in Mr. Jack Painter's Testimony, Exhibit 1, line 33. I also summarize modifications to the accounting treatment of the excess deferred income tax ("EDIT") balances that resulted from the 2017 Tax Cuts and Jobs Act ("TCJA").

RESOURCE TRACKING MECHANISM

Q. Please briefly describe the background and purpose of the resource tracking mechanism, ("RTM").

A. In Case No. PAC-E-17-06, filed on July 3, 2017, the Company applied for approval of the plan to upgrade (or "repower") its existing wind resources and approval of associated ratemaking treatment. On November 21, 2017, the Company and intervening parties reached a stipulated agreement ("Stipulation") that allows the Company to use the ECAM to recover the replacement cost of certain assets, new investment, incremental energy production, and wind repowering project PTCs through the RTM. The RTM and ECAM will capture the costs and benefits of the repowered wind facilities until they are recovered in base rates through a general rate case. The Stipulation between the parties was approved by Commission Order No. 33954, dated December 28, 2017.

In Case No. PAC-E-17-07, filed on July 3, 2017, the Company applied for approval of the plan to build new wind projects and the proposed Aeolus-to-Bridger/Anticline transmission line. On July 20, 2018, the Company and intervening parties reached a stipulated agreement that allows the Company to use the ECAM to track new investment, energy production, and PTCs associated with the Stipulated Projects through the RTM. The ECAM will capture the costs up to the level of benefits of the new wind facilities and Energy Vision 2020 until they are recovered in base rates through a general rate case. The amount above the benefits will be deferred as a regulatory asset for recovery in the next general rate case. The is consistent with the stipulation in Case No. PAC-E-17-07, paragraph 14, that states:

> 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.[1]

Q. Which projects are included in the RTM and this ECAM?

A. The RTM is split into two parts, shown as Exhibit 4a and 4b, to account for the differences between the settlement for repowered wind assets approved as part of Case No. PAC-E-17-06 and the settlement for transmission and new wind assets approved as part of Case No. PAC-E-17-07. Below is a description of the assets included in both exhibits.

[1] *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-1707, Stipulation at 5 (May 9, 2018) ("2018 Settlement Stipulation"); Order No. 34104 (July 20, 2018) (approving May 9 stipulation).

- Exhibit 4a includes the repowered wind projects. Three repowering projects were completed and placed in service during 2020 that, combined with the projects completed in 2019 and included in the prior RTM, produced an Idaho-allocated net benefit of $2,718,684. The new projects are the Marengo 1 & 2 and Dunlap wind facilities.
- Exhibit 4b includes new wind projects and transmission. It includes three Energy Vision 2020 wind projects, Cedar Springs, TB Flats I & II, and Ekola Flats, along with the Energy Vision 2020 transmission project. In addition, Exhibit 4b includes the Prior Mountain wind project and will also include the Foote Creek I wind repowering project in future RTM deferrals, consistent with the settlement in Case No. PAC-E-20-03 that states:

> Ratemaking treatment for the Pryor Mountain wind resource and the repowering of Foote Creek I to match costs and benefits with a cost cap amount each year at the benefit level. The Company may propose to include these resources in the RTM/ECAM, consistent with the terms agreed to in Case No. PAC-E-17-07. Prudency will be determined during the next General Rate Case.[2]

The Combination of these Energy Vision 2020 projects produced an Idaho-allocated net benefit of $7,483 for customers.

[2] *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, Application of Rocky Mountain Power, Attachment 1 at 2 (July 2, 2020);Order No. 34884 (December 31, 2020) (approving settlement stipulation).

Q. Has the Company calculated the wind repowering deferral and Energy Vision 2020 under the RTM guidelines that were agreed to in the Stipulation and approved by the Commission?

A. Yes. The deferral calculations follow the design and operation of the RTM as submitted in the Direct Testimony of Jeffrey K. Larsen pages 6-16 and Exhibit 12 that was referenced and approved in the Stipulation and Final Order of Case No. PAC-E-17-06[3] and the approved in the Stipulation and Final Order of Case No. PAC-E-17-07.[4] The RTM, along with the ECAM, will capture and match all the costs and benefits of the repowered wind facilities and Energy Vision 2020 until such time as they are recovered in base rates.

Q. What are the costs and benefits associated with repowering and Energy Vision 2020 that the Company has included in the RTM deferral?

A. The Company has included the following items in the RTM on a monthly basis beginning when a repowered or new wind project is placed into service:

- The pre-tax return on investment;
- Operation and maintenance expense;
- Depreciation expense;
- Property taxes;
- Wind taxes, if assessed;
- Net Power Cost ("NPC") benefits;
- Wheeling Revenue; and

---

[3] *In the Matter of the Application Rocky Mountain Power for Binding Ratemaking Treatment for Wind Repowering*, Case No. PAC-E-17-06, Testimony of Jeffrey K. Larsen (July 5, 2017); Stipulation (November 24, 2017); Order No 33954 (December 28, 2017).
[4] 2018 Settlement Stipulation; Order No. 34104.

- PTC benefits.

Q. Has the Company prepared an exhibit showing the calculated amount of the wind repowering deferral and Energy Vision 2020 deferral under the approved RTM guidelines?

A. Yes. Exhibit No. 4a and 4b show the calculation of the December 31, 2020 RTM deferral balance which results in a $4.43 million charge to be collected from customers through the ECAM. This exhibit is structured similar to Exhibit 12 of Mr. Larsen's Direct Testimony referenced above.

Q. Line 18 of Exhibit No. 4a and Line 17 of Exhibit No. 4b shows that the repowered wind projects and Energy Vision 2020 projects produced a net revenue requirement of $936 thousand. Why is the Company seeking recovery of $4.43 million through the ECAM?

A. The RTM was approved to match all of the costs and benefits associated with the repowered wind projects and Energy Vision 2020 and pass those onto customers. Absent the RTM, the ECAM only captures some of the benefits and does not included any of the costs incurred to produce those benefits. The ECAM will return to customers 100 percent of the Production Tax Credits (PTC) of $6.44 million, and 90 percent of NPC benefit of $739 thousand, shown on lines 21 and 24 from Exhibit 4a and lines 20 and 23 from Exhibit 4b, respectively. Combined, the ECAM would return to customers $7.18 million, absent the RTM. Due to the sharing band in the ECAM, 10 percent of the NPC benefits would not have been passed onto customers absent the RTM. Further, the ECAM does not capture any of the costs incurred by the Company to repower the wind facilities and Energy Vision 2020 projects. The purposes of the RTM are to capture those costs and match them with the benefits. The $2.74 million, on line 27, represents Idaho's share of the net benefit produced by the repowered wind facilities and Energy Vision 2020. The $4.43 million RTM deferral allows the Company to recover the net costs that are not reflected in the ECAM.

Q. Has the Company included a carrying charge on the RTM deferral balance in Exhibit No. 4?

A. No. Although the RTM deferral balance is subject to a carrying charge, the monthly RTM deferral balance is summed with the other ECAM components and receives a carrying charge as part of the overall carrying charge calculation.

Q. What is the revenue requirement that is deferred for consideration in the next rate case?

A. The settlement in Case No. PAC-E-17-07 states that "Any costs above this cap will be deferred as a regulatory asset for recovery to be set in the next general rate case."[5] The settlement in Case No. PAC-E-20-03 has similar language, subject to a prudency review. Based on the language in these settlements, the Company is deferring for recovery in the next general rate case the $392,184 revenue requirement on line 17 of Exhibit 4b, less the $25,000 credit per the stipulation in PAC-E-17-07 on line 26 of Exhibit 4B, or $367,184.

TAX REFORM CREDIT

Q. Was a credit from the 2017 TCJA EDIT netted against the 2020 ECAM Deferral?

A. No. While tax savings from the federal tax reform Tax Cuts and Jobs Act ("TCJA") were netted against the 2018 and 2019 ECAM deferral balances as prescribed in Order

[5] 2018 Settlement Stipulation at 5, ¶ 14.

No. 34331[6] they were not netted against the 2020 ECAM deferral.

Q. Describe th,e treatment of the Tax Reform Credit approved in Order No. 34884[7].

A. In Case No. PAC-E-20-03 the Company filed a settlement with the Commission requesting authorization to modify the Tax Stipulation approved in Order No. 34331. The settlement requested authorization for the remaining EDIT balance savings from the TCJA to be retained and used to buy-down or offset the net plant balance and closure costs of Cholla Unit No. 4 and to offset the January 1, 2022 rate increase. Order No. 34884 authorized the Company to stop refunding the 2017 TCJA EDIT effective with the 2020 ECAM and use the remaining EDIT savings to offset the net plant balance, decommissioning, and closure costs for Cholla unrecovered plant and mitigate the rate impact of the January 1, 2022 rate increase.

Q. **Does this conclude your direct testimony?**

A. Yes.

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[66] *In the Matter of the Investigation into the Impact of Federal Tax Code Revisions on Utility Costs and Ratemaking,* Case No. GNR-U-18-01.

[7] *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.

Case No. PAC-E-21-09
Exhibit No. 4
Witness: Steven R. McDougal

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Steven R. McDougal

March 2021

PacifiCorp **Exhibit 4a**
Idaho
Wind Repowering - Monthly RTM Deferral Calculation
Revenue Requirement
For the Month Ending December 31, 2020

Line No.	**$-Dollars**	Reference	Jan.- Dec. 2020 Total Company	Factor	Factor %	Idaho Allocated
	Plant Revenue Requirement					
1	Capital Investment	Footnote 1	927,970,785	SG	6.0136%	55,804,451
2	Depreciation Reserve	Footnote 1	(18,117,827)	SG	6.0136%	(1,089,534)
3	Accumulated DIT Balance	Footnote 1	(61,996,180)	SG	6.0136%	(3,728,202)
4	Net Rate Base (previous month)	sum of lines 1-3	847,856,778			50,986,715
5	Pre-Tax Rate of Return	line 36	9.003%			9.003%
6	Pre-Tax Return on Rate Base	line 4 * line 5	76,328,451			4,207,580
7	Wholesale Wheeling Revenue	Footnote 4	-	SG	6.0136%	-
8	Operation & Maintenance	Footnote 3	(687,308)	SG	6.0136%	(41,332)
9	Depreciation	Footnote 3 & 6	31,247,868	SG	6.0136%	1,879,122
10	Property Taxes	Footnote 3	5,447,143	GPS	5.7978%	315,814
11	Wind Tax	Footnote 3	411,006	SG	6.0136%	24,716
12	**Total Plant Revenue Requirement**	sum of lines 6-11	**112,747,161**			**6,385,901**
	Net Power Cost					
13	NPC Incremental Savings	Footnote 3	(13,516,653)	SG	6.0136%	(812,837)
	PTC Benefit					
14	PTC Benefit	Footnote 3	(80,591,342)	SG	6.0136%	(4,846,441)
15	Gross- up for taxes	line 14 * (line 34 - 1)	(26,274,735)			(1,580,057)
16	PTC Revenue Requirement	sum of lines 14 and 15	(106,866,077)			(6,426,498)
17	Depreciation Expense Adjustment	Footnote 6 & 7	(37,377,882)	SG	6.0136%	(2,247,756)
18	**Rev. Requirement**	sum of lines 12, 13, 16, 17	(45,013,451)			(3,101,191)
	Adjustment for ECAM Pass-through					
19	PTC Revenue Requirement	line 16				(6,426,498)
20	Percentage included in ECAM (100%)	ID ECAM Sharing %				100%
21	ECAM Pass-through	line 19 * line20				(6,426,498)
22	NPC Incremental Savings	line 13				(812,837)
23	Percentage included in ECAM (90%)	ID ECAM Sharing %				90%
24	ECAM Pass-through	line 22 * line 23				(731,554)
25	**Rev. Reqt. after ECAM Pass-through**	line 18 - line 21 - line 24				4,439,368
25.5	**Authorized Capped Recovery**	line 26 - line 25				-
26	**Total Deferral - ID Share**	Footnote 5				4,439,368
27	**Net Customer (Benefit)**	sum of lines 21, 24, 26				(2,718,684)
	Deferral Balance - ID Share					
28	Beginning Deferral Balance	line 32 of previous year				439,595
29	Monthly Deferral	Footnote 5				4,439,368
30	Deferral Collection	Footnote 3				(256,430)
31	Carrying Charge	Footnote 2				-
32	**Ending Deferral Balance**	sum of lines 28-31				4,622,533
33	Federal/State Combined Tax Rate		24.5866%			
34	Net to Gross Bump up Factor = (1/(1-tax rate))	(1/(1-tax rate))	1.3260			
35	Deferred Balance Carrying Charge	Footnote 2	2.00%			
36	Pretax Return	Case No. PAC-E-15-09	9.003%			
37	Property Tax Rate	Rate as percent of net plant in PAC-E-15-09	0.78%			
38	Idaho SG Factor	Case No. PAC-E-15-09	6.0136%			
39	Idaho GPS Factor	Case No. PAC-E-15-09	5.7978%			

Footnotes:
1) Ending monthly capital balance of the previous month.
2) The RTM deferral balance is included in the ECAM carrying charge calculation and is therefore zero here.
3) Equals the monthly sum of all projects
4) Not Applicable for Repowering
5) The RTM is capped until the next general rate case so that, after taking into account the wind repowering benefits that will flow through the Company's ECAM, it will not operate to surcharge customers.
6) Actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study
7) Depreciation Expense for the replaced equipment currently in rates is removed as an incremental revenue requirement savings.

Exhibit 4b

PacifiCorp
Idaho
Energy Vision 2020 - Monthly RTM Deferral Calculation
Revenue Requirement
For the Month Ending December 31, 2020

Line No.	$-Dollars	Reference	Dec-20 Total Company	Factor	Factor %	Idaho Allocated
	Plant Revenue Requirement					
1	Capital Investment	Footnote 1	718,253,320	SG	6.0136%	43,192,882
2	Depreciation Reserve	Footnote 1	(1,122,399)	SG	6.0136%	(67,497)
3	Accumulated DIT Balance	Footnote 1	(1,101,804)	SG	6.0136%	(66,258)
4	Net Rate Base (previous month)	sum of lines 1-3	716,029,117			43,059,127
5	Pre-Tax Rate of Return	line 36	9.234%			9.234%
6	Pre-Tax Return on Rate Base	line 4 * line 5	5,509,807			331,338
7	Wholesale Wheeling Revenue	Footnote 4	(1,331,623)	SG	6.0136%	(80,079)
8	Operation & Maintenance	Footnote 3	135,552	SG	6.0136%	8,152
9	Depreciation	Footnote 3	2,381,349	SG	6.0136%	143,205
10	Property Taxes	Footnote 3	-	GPS	5.7978%	-
11	Wind Tax	Footnote 3	130,912	SG	6.0136%	7,873
12	**Total Plant Revenue Requirement**	sum of lines 6-11	**6,825,996**			**410,488**
	Net Power Cost					
13	NPC Savings	Footnote 3	(130,912)	SG	6.0136%	(7,873)
	PTC Benefit					
14	PTC Benefit	Footnote 3	(130,814)	SG	6.0136%	(7,867)
15	Gross- up for taxes	line 14 * (line 34 - 1)	(42,649)			(2,565)
16	PTC Revenue Requirement	sum of lines 14 and 15	(173,463)			(10,431)
17	**Rev. Requirement**	sum of lines 12, 13, 16	6,521,621			392,184
	Adjustment for ECAM Pass-through					
18	PTC Revenue Requirement	line 16				(10,431)
19	Percentage included in ECAM (100%)	ID ECAM Sharing %				100%
20	ECAM Pass-through	line 19 * line 20				(10,431)
21	NPC Savings	line 13				(7,873)
22	Percentage included in ECAM (90%)	ID ECAM Sharing %				90%
23	ECAM Pass-through	line 22 * line 23				(7,085)
24	**Rev. Reqt. after ECAM Pass-through**	line 17 - line 20 - line 23				409,701
24.5	**Authorized Capped Recovery**	line 25 - line 24				(392,184)
25	**Total Deferral - ID Share**	Footnote 5				17,517
26	Annual $300,000 Benefit provided by Company	Final Order No. 34104				(25,000)
27	**Net Customer (Benefit)**	sum of lines 20, 23, 25, 26				(25,000)
	Deferral Balance - ID Share					
28	Beginning Deferral Balance	line 32 of previous year				-
29	Monthly Deferral	Footnote 5				(7,483)
30	Deferral Collection	Footnote 3				-
31	Carrying Charge	Footnote 2				-
32	**Ending Deferral Balance**	sum of lines 28-31				(7,483)
33	Federal/State Combined Tax Rate		24.5866%			
34	Net to Gross Bump up Factor = (1/(1-tax rate))	(1/(1-tax rate))	1.3260			
35	Deferred Balance Carrying Charge	Footnote 2	1.00%			
36	Pretax Return	Case No. PAC-E-15-09	9.234%			
37	Property Tax Rate	Rate as percent of net plant in PAC-E-15-09	0.78%			
38	Idaho SG Factor	Case No. PAC-E-15-09	6.0136%			
39	Idaho GPS Factor	Case No. PAC-E-15-09	5.7978%			

Footnotes:
1) Ending monthly capital balance of the previous month.
2) The RTM deferral balance is included in the ECAM carrying charge calculation and is therefore zero here.
3) Equals the monthly sum of all projects
4) Wheeling Revenue is based on the 2021 IRP
5) The RTM is capped until the next general rate case so that, after taking into account the new wind generation benefits that will flow through the Company's ECAM, it will not operate to surcharge customers.
6) Annual $300,000 Benefit provided by Company stipulated in Final Order No. 34104

CUSTOMER NOTICES

ROCKY MOUNTAIN POWER

POWERING YOUR GREATNESS

FOR IMMEDIATE RELEASE
Media Hotline 800-775-7950

Price decrease proposed for Idaho customers

Annual energy cost adjustment

BOISE, Idaho (March 31, 2021) — Rocky Mountain Power proposes a 1.1 percent decrease overall for customers in its 2021 annual energy cost adjustment. Typical residential customers using 800 kilowatt-hours per month would see a decrease of approximately $9.00 on their annual electricity bill.

"Rocky Mountain Power is committed to bringing the best value to our customers for their hard-earned dollars," said Tim Solomon, regional business manager for Rocky Mountain Power in Rexburg. "As a provider of one of the most essential public services, we're pleased to pass on to customers the lower costs of providing service. This annual adjustment continues to ensure Rocky Mountain Power customers always pay some of the lowest prices in the nation for the energy they need."

The annual energy cost adjustment mechanism is designed to track the difference between the company's actual expenses for fuel and electricity purchased from the wholesale market, against the amount being collected from customers through current rates. If actual costs are lower, the amount is returned to customers on their monthly bill. During the past year the company's energy-related expenses decreased by $7.8 million. Pending commission approval, the changes would take effect June 1, 2021 with the following impact on each rate schedule:

Residential Schedule 1 – 0.8% decrease
Residential Schedule 36 – 0.9% decrease
General Service Schedule 6 – 1.1% decrease
General Service Schedule 9 – 1.2% decrease
Irrigation Service Schedule 10 – 1.0% decrease
Commercial & Industrial Heating Schedule 19 – 1.0% decrease
General Service Schedule 23 – 0.9% decrease
General Service Schedule 35 – 1.3% decrease
Public Street Lighting – 0.4% decrease
Tariff Contract 400 – 1.3% decrease
Tariff Contract 401 – 1.3% decrease

The public will have an opportunity to comment on the proposal as the commission studies the company's request. The commission must approve the proposed changes before they can take effect. A copy of the company's application is available for public review on the commission's website, www.puc.idaho.gov, under Case No. PAC-E-21-09. Customers may also subscribe to the commission's RSS feed to receive periodic updates via email. The request is also available at the company's offices in Rexburg, Preston, Shelley and Montpelier, although due to COVID-19 pandemic restrictions, the company urges customers to utilize online resources:

Idaho Public Utilities Commission
www.puc.idaho.gov
11331 W. Chinden Blvd. Building 8, Suite 201-A
Boise, ID 83714

Rocky Mountain Power offices
Rexburg – 127 East Main
Preston – 509 S. 2nd East
Shelley – 852 E. 1400 North
Montpelier – 24852 U.S. Hwy 89

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Annual energy cost adjustment

Proposed net price decrease

Rocky Mountain Power requests recovery of power costs.

On March 31, 2021, Rocky Mountain Power asked the Idaho Public Utilities Commission to approve the 2020 incremental energy related costs of $14.3 million, a net decrease of $3.1 million from the revenues currently collected through the energy cost adjustment mechanism. The energy cost adjustment mechanism is designed to track the difference between the company's actual costs to provide electricity to Idaho customers and the amount collected from customers through current prices.

Pending commission approval, the decrease would take effect June 1, 2021. All customer classes will see a net decrease to their rates resulting from the recent changes in costs of providing energy to customers. The proposed adjustment will allow Rocky Mountain Power to continue to provide safe, reliable electric service to its customers.

Typical residential customers using 800 kilowatt-hours per month would see a decrease of approximately $9.00 a year on their electricity bill. The following is a summary of the percentage impacts by customer class:

- Residential Schedule 1 – 0.8% decrease
- Residential Schedule 36 – 0.9% decrease
- General Service Schedule 6 – 1.1% decrease
- General Service Schedule 9 – 1.2% decrease
- Irrigation Service Schedule 10 – 1.0% decrease
- Commercial & Industrial Heating Schedule 19 – 1.0% decrease
- General Service Schedule 23 – 0.9% decrease
- General Service Schedule 35 – 1.3% decrease
- Public Street Lighting – 0.4% decrease
- Tariff Contract 400 – 1.3% decrease
- Tariff Contract 401 – 1.3% decrease

The public will have an opportunity to comment on the proposal during the coming months as the commission studies the company's request. The commission must approve the proposed changes before they can take effect.

A copy of the company's application is available for public review on the commission's website at www.puc.idaho.gov under Case No. PAC-E-21-09.

Customers may file written comments regarding the application with the commission or subscribe to the commission's RSS feed to receive periodic updates via email about the case. Copies of the proposal are also available for review at the company's offices in Rexburg, Preston, Shelley and Montpelier, although due to COVID-19 pandemic restrictions, the company encourages customers to utilize online resources.

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For more information about your rates and rate schedule, go to **rockymountainpower.net/rates.**

ROCKY MOUNTAIN POWER