ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

March 30, 2023

VIA ELECTRONIC FILING

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

Re: CASE NO. PAC-E-23-09
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER REQUESTING APPROVAL OF $32.5 MILLON ECAM 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 Jack Painter and Robert M. Meredith. The witnesses' work papers are confidential and will be provided through an encrypted file. You will receive a separate email with the password to access these files.

Informal inquiries may be directed to Mark Alder, Idaho Regulatory Manager at (801) 220-2313.

Very truly yours,

Joelle Steward
Senior Vice President of Regulation and Customer Solutions

Enclosures

CC: Ron Williams
Eric Olsen
TJ Budge

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Attorney for Rocky Mountain Power

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER REQUESTING APPROVAL OF $32.5 MILLON ECAM DEFERRAL	))))	**CASE NO. PAC-E-23-09** **APPLICATION OF 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 $32.5 million of deferred costs from the deferral period beginning January 1, 2022, through December 31, 2022, ("Deferral Period") with a 2.3 percent overall increase to Electric Service Schedule No. 94, Energy Cost Adjustment ("Schedule 94"). 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 89,365 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 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 includes 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).

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]

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[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.
[3] *Id.* at 3.

5. In addition to the difference between Actual NPC and Base NPC, the ECAM includes the following additional components: the Load Change Adjustment Revenues ("LCAR"),[4] coal stripping costs under Emerging Issues Task Force ("EITF") 04-6,[5] Renewable Energy Credit ("REC") revenues,[6] Production Tax Credits ("PTC"),[7] the reasonable energy price ("REP"), as defined in the 2020 Protocol, qualified facility ("QF") costs,[8] and wind availability liquidated damages.[9] These components are described in more detail below.

6. 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.

7. 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 2022 the inflation-adjusted PTC rate for electricity generated from qualifying wind

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[4] *Id.* at 4.

[5] *See In the Matter of the Application of PacifiCorp DBA Rocky Mountain Power for Approval of an Accounting Order Authorizing the Deferral of Costs Associated with Coal Mine Stripping Activities,* Case No. PAC-E-09-08, Order No. 30987 (January 22, 2010).

[6] *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 at 17 (February 28, 2011).

[7] *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").

[8] *In the Matter of the Application for Approval of the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol*, Case No. PAC-E-19-20, Order No. 34640 (April 22, 2020).

[9] *In the Matter of Application of Rocky Mountain Power for Binding Ratemaking Treatment for Wind Reporting,* Case No. PAC-E-17-06, Order No. 33954 at 5 (December 28, 2017).

[10] 2015 ECAM Order at 5.

[11] IRC section 45(a).

[12] IRC section 45(a).

facilities was 2.6 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 PTC 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 eligible for PTCs, the repowering program undertaken by the Company has extended this benefit for an additional ten years.

PROPOSED ECAM RATE

8. In support of this Application, Rocky Mountain Power has filed the testimony and exhibits of Company witnesses Jack Painter and Robert M. Meredith. 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 were set to recover the 2022 ECAM deferral balances through Electric Service Schedule No. 94 -Energy Cost Adjustment, ("Schedule 94").

[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 2021*, 86 Fed. Reg. 22300 (April 27, 2021).

9. Exhibit No. 1 to Mr. Painter's testimony illustrates the detailed calculation of the ECAM deferral. The deferral is calculated monthly by comparing Idaho-allocated Actual NPC to the Base NPC collected in rates. For the Deferral Period the NPC differential was approximately $35.3 million before the 90/10 percent sharing band.

10. 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, the REP QF charge, and wind availability liquated damages.

11. 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 $1.6 million before applying the sharing band due to higher usage during the Deferral Period.

12. 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 increased the ECAM deferral by $190,656 before applying the sharing band.

13. The total NPC deferral adjusted for LCAR and EITF 04-6 was approximately $33.9 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 $30.5 million.

14. During the Deferral Period the PTC differential, as described in paragraph 7, increased the deferral approximately $1.4 million.

15. 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 $130,679 higher than the amount credited to customers in base rates on an Idaho-allocated basis.

16. In accordance with Order No. 33954, wind availability liquidated damages were credited to customers in the amount of $295,039.

17. Interest is accrued on the uncollected balance at the Commission-approved interest rate for customer deposits. During the Deferral Period the interest rate was 1.0 percent. Interest of $327 thousand was added to the ECAM balance.

18. The ECAM balance at the end of the Deferral Period was $41.9 million, including $32.5 million from the 2022 ECAM deferral (inclusive of interest), plus $9.5 million remaining balance from prior ECAM filing. The Company estimates the ECAM balance will be reduced by $9.9 million from Schedule 94 revenue collections accrued from January 1 through May 31, 2023, resulting in an estimated ECAM balance of $32.2 million to be collected.

19. Mr. Meredith's testimony describes how Schedule 94 rates were designed to recover the May 31, 2023, estimated ECAM balance of $32.2 million. Based on this rate design, the Company proposes Schedule 94 rates of 0.934, 0.917, 0.886 and 0.892 cents per kWh for secondary, primary, transmission delivery service voltages and Schedule 400, respectively.

COMMUNICATIONS

Communications regarding this filing should be addressed to:

Mark Alder
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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 NE Multnomah St., Suite 2000
Portland, Oregon 97232

Informal questions may be directed to Mark Alder, Idaho Regulatory Affairs Manager at (801) 220-2313.

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 the ECAM deferral has been accurately calculated incorporating all 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 $32.5 million ECAM deferral; and (3) approving a 2.3 percent increase to Electric Service Schedule No. 94, Energy Cost Adjustment effective June 1, 2023.

DATED this 30th day of March 2023.

Respectfully submitted,

ROCKY MOUNTAIN POWER

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Attorney for Rocky Mountain Power

CUSTOMER NOTICES

Annual energy cost adjustment

PROPOSED NET PRICE INCREASE

Rocky Mountain Power requests recovery of power costs

On March 30, 2023, Rocky Mountain Power asked the Idaho Public Utilities Commission to approve the incremental energy related costs for 2022 of $32.2 million, a net increase of $6.9 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 expenses for fuel and electricity purchased from the wholesale market, against the amount being collected from customers through current rates.

Pending commission approval, the increase would take effect June 1, 2023. All customer classes will see a net increase to their rates due to the increased costs for fuel and wholesale electricity. Extreme weather conditions in 2022 increased the costs of fuel and purchased power on the wholesale market—two of the main components of the company's annual power cost adjustment. Multiple heat waves across Rocky Mountain Power's service area in July, August, and September significantly increased market prices. Increases in wholesale power prices during those months account for nearly half of the total cost adjustment requested. The proposed adjustment will allow Rocky Mountain Power to continue to deliver safe, reliable, affordable power now and for years to come.

A typical residential customer using 783 kilowatt-hours per month would see an increase of approximately $1.57 a month on their electricity bill. The following is a summary of the percentage impacts by customer class:

- Residential Schedule 1 – 1.6% increase
- Residential Schedule 36 – 1.9% increase
- General Service Schedule 6 – 2.3% increase
- General Service Schedule 9 – 2.9% increase

(continued)

- Irrigation Service Schedule 10 – 2.1% increase
- General Service Schedule 23 – 2.0% increase
- General Service Schedule 35 – 2.2% increase
- Public Street Lighting – 1.1% increase
- Tariff Contract 400 – 3.0% increase

We understand the impact that price increases have on our customers and will work to mitigate that impact as much as possible. Customers can visit **RockyMountainPower.net/Wattsmart** for energy- and money-saving tips and information.

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-23-09.

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 the company encourages customersto visit our website at **RockyMountainPower.net/Rates**.

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Rocky Mountain Power offices

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- Preston – 509 S. 2nd E.
- Shelley – 852 E. 1400 N.
- Montpelier – 24852 U.S. Hwy 89

ROCKY MOUNTAIN POWER®

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For information, contact: News Media Hotline 801-220-5018

Annual energy cost adjustment

Higher market costs in 2022 prompt price increase request for Idaho customers of Rocky Mountain Power

BOISE, Idaho (March 30, 2023) — Rocky Mountain Power's costs for fuel and wholesale electricity increased in 2022 because of higher energy market prices, which made purchased power to serve its customers more expensive. As part of an annual review of these costs, the company requested an average 1.7 percent price increase for Idaho residential customers. A typical residential customer using 783 kilowatt-hours per month would see a 1.6 percent increase of about $1.57 per month on their electricity bill.

"We recognize that in difficult economic conditions, a price increase is not good news," said Tim Solomon, regional business manager for Rocky Mountain Power in Rexburg. "Despite these difficulties, we remain committed to bringing the best value to our customers for their hard-earned dollars. We've worked diligently to keep our expenses low. We are strict with our budgets and continue our work to steadily improve our system to enhance reliability for our 89,365 customers in southeastern Idaho. We know how important reliable service is for business and homes alike.

"The energy costs in the annual adjustment are generally beyond the company's direct control," Solomon added. "This annual adjustment makes sure Rocky Mountain Power customers always pay a fair price for the energy they need."

Extreme weather conditions in 2022 increased the costs of fuel and purchased power on the wholesale market—two of the main components of the company's annual power cost adjustment. Multiple heat waves across Rocky Mountain Power's service area in July, August, and September significantly increased market prices. Increases in wholesale power prices during those months accounts for nearly half of total cost adjustment requested.

"The continuing drought in the West that began in the summer of 2020 has continued to impact the company's power costs because it reduces the availability of our hydroelectric resources," said Jack Painter, net power cost specialist for the utility. "Additionally, December 2022 saw a historic winter cyclone event across most of the United States, increasing both wholesale power prices and natural gas prices along due to increased demand. Natural gas prices across the region drastically rose—more that 400 percent at major delivery points last December, compared with 2021."

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. During the past year, the company's energy-related expenses have increased by $32.2 million. Pending commission approval, the changes would take effect June 1, 2023, with the following impact on each rate schedule:

Residential Schedule 1 – 1.6% increase
Residential Schedule 36 – 1.9% increase
General Service Schedule 6 – 2.3% increase
General Service Schedule 9 – 2.9% increase
Irrigation Service Schedule 10 – 2.1% increase
General Service Schedule 23 – 2.0% increase
General Service Schedule 35 – 2.2% increase
Public Street Lighting – 1.1% increase
Tariff Contract 400 – 3.0% increase

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-23-09. Customers may also subscribe to the commission's RSS feed to receive periodic updates via email. The request is required to be available at the company's offices in Rexburg, Preston, Shelley, and Montpelier, although the company urges customers to visit our website at rockymountainpower.net/rates.

Idaho Public Utilities Commission
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Rocky Mountain Power offices
Rexburg – 127 East Main
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Montpelier – 24852 U.S. Hwy 89

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About Rocky Mountain Power
Rocky Mountain Power provides safe and reliable electric service to more than 1.2 million customers in Utah, Wyoming and Idaho. The company supplies customers with electricity from a diverse portfolio of generating plants including hydroelectric, thermal, wind, geothermal and solar resources. Rocky Mountain Power is part of PacifiCorp, one of the lowest-cost electricity providers in the United States, with two million customers in six western states. For more information, visit: www.rockymountainpower.net

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	**)**	**CASE NO. PAC-E-23-09**
OF ROCKY MOUNTAIN POWER	**)**	
REQUESTING APPROVAL OF $32.5	**)**	**DIRECT TESTIMONY OF**
MILLON ECAM DEFERRAL	**)**	**JACK PAINTER**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-23-09

March 2023

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 public utility commissions in Idaho, Utah, Wyoming, Oregon, Washington, and California.

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, 2022 through December 31, 2022 ("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 $32.5 million to the deferral

balance, including $30.5 million customers' share of ECAM costs, a $1.4 million decrease in renewable energy production tax credits ("PTCs"), $634 thousand in reasonable energy price ("REP") qualified facility ("QF") costs, a credit of $295 thousand for wind availability liquidated damages, a $131 thousand renewable energy credit ("REC") revenue differential, and $327 thousand 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 Western Energy Imbalance Market ("WEIM") with the California Independent System Operator ("CAISO") and the benefits from the WEIM 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 & Tariff Policy, provides testimony on the proposed rates in Electric Service Schedule No. 94, Energy Cost Adjustment ("Schedule 94").

SUMMARY OF THE ECAM DEFERRAL CALCULATION

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

A. The ECAM tracks deviations between Actual NPC and Base NPC. When there is a difference between these two amounts, 90 percent of the difference is deferred for later recovery or return to customers.[1] In addition to tracking the difference between Actual

[1] *See* Order No. 30904 in Case No. PAC-E-08-08 and Order No. 33440 in Case No. PAC-E-15-09.

and Base NPC, the ECAM also tracks other items including PTCs, the Reasonable Energy Price QF adjustment, wind availability liquidated damages, and revenues from the sale of RECs.[2] The purpose for tracking these items is to true up base rates to actuals. The balance that 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 customers' bills and either 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 request approval of the deferral amount and the new Schedule 94 rates to become effective June 1.

Q. Are there any changes to the ECAM calculation?

A. Yes. The rates for Base NPC, PTCs, RECs, and the Load Change Adjustment Revenue ("LCAR") have been updated to reflect rates established in the Company's last general rate case ("GRC") Case No. PAC-E-21-07, which became effective January 1, 2022.[3] The wind integration costs for third party wind have been removed because PacifiCorp's Open Access Transmission Tariff ("OATT") Schedule 3 and 3A rates include intra-hour wind integration costs and offset Base rates in FERC Account 456. Liquidated damages for wind availability have been included and are passed to customers outside of the sharing band. Finally, the Resource Tracking Mechanism

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[2] *See 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 5–6 (December 23, 2015).

[3] *In the Matter of Rocky Mountain Power's Application for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations,* Case No. PAC-E-21-07, Order No. 35277 (December 30, 2021).

("RTM") and the Lake Side 2 Resource Adder have been eliminated as part of the Company's last GRC.

ECAM DEFERRAL CALCULATION

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

A. Table 1 summarizes the total ECAM deferral and provides a breakdown of the individual components of the ECAM. For a detailed monthly calculation of the ECAM deferral, please refer to Exhibit No. 1.

Table 1 – 2022 ECAM Deferral

Calendar Year 2022 ECAM Deferral		
NPC Differential	$	35,322,826
EITF 04-6 Adjustment		190,656
LCAR		(1,578,588)
Total Deferral Before Sharing	$	33,934,894
Sharing Band		90%
Customer Reponsibility	$	30,541,405
Production Tax Credits	$	1,388,020
REP QF Adjustment		634,305
Wind Liquidated Damages		(295,039)
REC Deferral		(130,679)
Interest on Deferral		326,544
Annual Deferral (Jan - Dec 2022)	$	32,464,556

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, Emerging Issues Task Force ("EITF") 04-6 adjustment, and the LCAR costs. The second section calculates the 90 percent customers' share of these items. Finally, the last section adds the following items that are either refunded or collected in full (i.e., 100 percent): PTCs, REP QF costs, wind availability liquidated damages, REC revenues, and interest on the deferral. The total of these items represents the ECAM deferral.

Q. Based on your calculations, what is the balance expected to be in the ECAM deferral account as of June 1, 2023?

A. Table 2 provides a summary of the ECAM balancing account activity starting with the December 31, 2021, ECAM deferral balance of $29.9 million approved in Case No. PAC-E-22-05. By June 1, 2023, the projected balance in the ECAM deferral account will be approximately $32.2 million. During the Deferral Period, approximately $32.5 million is added to the balance from the annual deferral and interest, which is offset by $20.5 million of ECAM revenue collections through the Deferral Period, and an estimated collection of $9.7 million of Schedule 94 revenues, net of interest, between January and May of 2023.

Table 2 - Balancing Account Activity

ECAM Deferral Balance		
Deferral Balance - Dec 31, 2021	$	29,925,543
Annual Deferral (Jan - Dec 2022)		32,138,012
Interest		326,544
ECAM Revenue Collection - Schedule 94		(20,448,621)
December 31, 2022 Balance For Collection	$	41,941,478
Schedule 94 Collection - Jan - May 2023	$	(9,853,367)
Interest		154,045
Expected Balance as of June 1, 2023	**$**	**32,242,155**

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

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

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

A. Exhibit No. 1 provides details of the ECAM calculation. 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 11, 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. To calculate Actual Idaho NPC, the total Company Actual NPC dollar-per-megawatt-hour basis is then multiplied by Idaho actual monthly MWh.

Q. Please describe how the NPC deferral is calculated.

A. The deferral is calculated monthly by subtracting the Base NPC collected in rates from the Actual Idaho NPC. For the Deferral Period, the NPC differential was $35.3 million before applying the 90 / 10 percent sharing band.

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 Federal Energy Regulatory Commission ("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;
- costs for situs-assigned resources/programs in Oregon and Utah;
- coal inventory adjustments to reflect coal costs in the correct period;
- legal fees related to fines and citations included in the cost of coal;
- 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);
- wind availability liquidated damages; and

- reasonable energy price adjustments to QFs.

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 be reflected in customer rates, whether they increase or decrease Actual NPC. However, 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. The ECAM calculation includes six additional components: (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 true-up of PTCs; (iv) Idaho allocated REP QF costs; (v) wind availability liquidated damages; 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. Line 13 of Exhibit No. 1 calculates coal stripping costs, reflecting Idaho's allocated differences between the coal stripping costs incurred by the Company during excavation, as 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. During the Deferral Period, the total EITF 04-6 coal stripping deferral adjustment results in a $191 thousand increase to the ECAM deferral balance, before the application of the 90 / 10 percent sharing band.

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. This adjustment accounts for variances in Idaho load that cause the Company to collect more or less of these production-related costs. The LCAR rate of $8.74 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 equivalent to the base amount on Exhibit No. 1 line 14. 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 on Exhibit No. 1 line 17. The LCAR adjustment, which is shown on line 18 of Exhibit No. 1, is the difference between the actual production-related costs and the LCAR revenue. This adjustment results in a $1.6 million decrease to the ECAM deferral balance before application of the 90 / 10 percent sharing band.

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

A. The ECAM includes a sharing band with 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 20 of Exhibit No. 1 represents the customers' 90 percent share of the monthly deferral shown on line 19. For the Deferral Period, the customers' share of the deferred balance is $30.5 million. The remaining balance of $3.4 million associated with the Company's ten percent share is not included in the deferral balance as it is not recoverable from customers.

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

A. The PTC Deferral, on line 25 of Exhibit No. 1, is calculated by comparing the actual Idaho-allocated PTC to the PTC credit customers receive through base rates. The PTC credit in base rates is calculated by multiplying the approved PTC rate of $4.16/MWh by Idaho retail sales. The difference results in a $1.4 million increase to the ECAM deferral.

Q. Please explain the REP QF Adjustment.

A. As set forth in the 2020 Inter-Jurisdictional Allocation Protocol ("2020 Protocol"): "For the Interim Period, the energy output of New QF PPAs will be dynamically allocated per this agreement using the SG Factor, priced at a forecasted reasonable energy price defined below, and any cost of a New QF PPA above the forecasted reasonable energy price will be situs assigned to and allocated to the State of Origin."[4] The Idaho situs-assigned cost, on line 26 of Exhibit No. 1, is $634 thousand.

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[4] *In the Matter of the Application for Approval of the 2020 PacifiCorp-Interjurisdictional Allocation Protocol,* Case No. PAC-E-19-20, Order No. 34640 at § 4.4.2.1, 31 (April 22, 2020).

Q. Please explain the wind availability liquidated damages credit.

A. Order No. 33954 in Case No. PAC-E-17-06 provides that "the Stipulation requires the Company to pass on to ratepayers all liquidated damages it receives from equipment suppliers in case the repowered equipment does not meet specified availability, performance, or installation schedule requirements." The Company first removes the wind availability liquidated damages from total-Company NPC and then allocates them to customers using the System Generation ("SG") allocation factor outside of the 90 /10 percent sharing band. The wind availability liquidated damages credited to customers in the ECAM is $295 thousand, as shown on line 27 of Exhibit No. 1.

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

A. The REC revenue adjustment shown on line 32 of Exhibit No. 1 is calculated by comparing the actual Idaho-allocated REC revenue with 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 $0.07/MWh by Idaho retail sales. The resulting difference is a $131 thousand decrease 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, 2022, is $32.1 million, shown on line 33 of Exhibit No. 1, plus $327 thousand of interest on line 42, for a total deferral of $32.5 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 that the Commission approve the ECAM application for recovery of the $32.5 million in 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 amounted to $2.018 billion, exceeding Base NPC for the Deferral Period by $650 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	$	1,368
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue		178
Purchased Power Expense		98
Coal Fuel Expense		(19)
Natural Gas Expense		382
Wheeling and Other Expense		11
Total Increase/(Decrease)	$	650
Adjusted Actual NPC	$	2,018

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-21-07 and became effective January 1, 2022. Base NPC used the 12-month test period of January 2021 through December 2021 and set total-Company Base NPC at $1.368 billion.

Q. Please describe some of the weather events that impacted NPC.

A. Similar to 2021, the year 2022 was also marked by several extreme and unforeseeable weather events that has a collective impact on Actual NPC during the year. Multiple heat waves across the Company's service territories throughout July, August, and September had a significant effect on market prices, ultimately leading to an increase in NPC. Cumulatively, the NPC differential for those months amounted to $16.5 million, which is almost half of the entire $35.3 million variance on an Idaho-allocated basis.

Additionally, ongoing drought in the West, which began in the summer of 2020, continued to impact Actual NPC because it reduced the availability of the Company's hydro resources. In 2022, actual generation from hydro resources were 1,505,231 MWhs, which was 34 percent lower than forecasted generation and needed to be replaced to meet customer demand either through system dispatch of other resources, reducing market sales, increasing market purchases, or any combination of these options. The estimated impact on total-Company NPC in 2022 due to decreased hydro MWhs due to drought is $151 million.

Finally, in December 2022 a historic winter cyclone event occurred across the majority of the United States, which impacted both market prices and natural gas prices, along with an increase in demand. Natural gas prices across the Company's delivery points drastically increased. At the Opal natural gas trading hub, the average market prices were 424 percent higher in December 2022 as compared to December 2021, while market prices at the Mid-Columbia and Four-Corners trading hubs were, on average, 406 percent higher across all load hours. The NPC differential in December alone is $6.7 million, or 19 percent, of the total Idaho-allocated NPC variance.

Q. How has the conflict in Ukraine impacted regional natural gas fuel prices?

A. The ongoing conflict in Ukraine has resulted in decreased availability of natural gas in

Europe, which was previously sourced from Russian imports. With decreased European supply, the associated European demand has turned to U.S. domestic supply to fill the gap. This has resulted in increased competition over domestic supply, which has driven regional natural gas fuel prices upwards due to domestic production being unable to keep pace with the increased demand. This increase in natural gas fuel prices correspondingly increases regional natural gas market prices and regional power market prices, in that order. It is difficult to predict (or forecast) how long, and in what direction, these factors will continue to impact regional prices.

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 $178 million reduction in wholesale sales, a $98 million increase in purchased power expense, a $382 million increase in natural gas expense, and a $11 million increase in wheeling and other expenses. These items were partially offset by a $19 million reduction in coal fuel expense.

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 $178 million decrease to wholesale sales, revenue from market transactions represents the largest change to Base NPC. Market transactions are $209 million lower than Base NPC, specifically due to the higher market prices and lower volume of market sales transactions mentioned above. The average price of actual market sales transactions was $22.65/MWh, which is 52 percent higher than the average price in Base NPC. Actual wholesale market volumes were 6,722 gigawatt-hours ("GWh"), or 64 percent, lower than the Base NPC.

Q. Please explain the changes in purchased power expense.

A. The expenses from market transactions (represented in GRID as short-term firm and system balancing purchases) increased by $412 million compared to Base NPC, making it the most significant driver. Actual market purchases were 1,039 GWh (13 percent) lower than Base NPC, but the average price of actual market purchases transactions was $65.03/MWh (182 percent) higher than Base NPC. The biggest impact to market transaction prices was tied to several heat waves throughout July, August, and September, further compounded by ongoing drought dating back to the summer of 2020.

During the summer 2022 heat waves, the Mid-Columbia market hub saw an average increase in heavy load hour market prices of 103 percent in August and September as compared to the same timeframe in 2021. This is significant considering 2021 also experienced an extreme heat dome and drought. The Four Corners market hub saw an average increase in heavy load hour market prices of 151 percent for the same period.

Q. Please explain the changes in wheeling expenses.

A. The increase in wheeling expenses relative to Base NPC was primarily due to an increase in short-term firm wheeling expense of $13.5 million.

Q. Please explain the changes in coal fuel expense.

A. Coal fuel expense decreased because coal generation volume decreased 1,484 GWh (5 percent) compared to Base NPC. Although the average cost of coal generation increased from $20.08/MWh in Base NPC to $20.47/MWh in the Deferral Period, the lower generation volume results in an overall decrease of $19 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 increased by $382 million compared to Base NPC. This was mainly due to an increase in average cost of natural gas generation from $26.95/MWh in Base NPC to $44.61/MWh in the Deferral Period caused by conflict in Ukraine and a historic winter weather event as discussed above. In addition, there was an increase in gas generation volumes of 5,198 GWh (61 percent).

IMPACT OF PARTICIPATING IN THE WEIM

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

A. Yes. Participation in the WEIM provides benefits to customers in the form of reduced Actual NPC. The WEIM benefits are embedded in Actual NPC through lower fuel and purchased power costs. According to CAISO's WEIM benefits report, PacifiCorp has received $200 million in benefits in 2022 and $591.4 million since the inception of the WEIM.

Q. Please summarize your testimony.

A. The ECAM deferral of $32.5 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, 2023.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-23-09
Exhibit No. 1
Witness: Jack Painter

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jack Painter

March 2023

Idaho Energy Cost Adjustment Mechanism Deferra
January 1, 2022 - December 31, 2022

Line No.			CY 2021
1	ID Base NPC Embedded in Rates ($	PAC-E-21-07	$ 86,534,565
2	Annual Idaho Base Load @ meter (MWh	PAC-E-21-07	3,526,359
3	NPC Rate Embedded in Base Rates ($/MWh)	Line 1 / Line 2	$ 24.54

Line No.			Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22
4	NPC Rate Embedded in Base Rates ($/MWh)	Line 3	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54
5	ID Actual Sales @ Meter (MWh)		298,043	243,523	271,234	259,804	311,132	391,286	494,237	350,269	297,140	251,618	238,833
6	ID NPC Collected in Rates ($	Line 4 x Line 5	$ 7,313,771	$ 5,975,885	$ 6,655,896	$ 6,375,417	$ 7,634,967	$ 9,601,916	$ 12,128,268	$ 8,595,383	$ 7,291,625	$ 6,174,536	$ 5,860,811
7	Total Company Adjusted Actual NPC ($)	Adjusted Actual NPC	$ 148,270,358	$ 126,512,756	$ 121,891,774	$ 131,742,131	$ 138,364,693	$ 133,568,842	$ 227,031,382	$ 216,086,211	$ 192,844,564	$ 138,951,543	$ 175,269,842
8	Total Company Load @ Input (MWh		5,391,997	4,739,803	4,840,508	4,575,977	4,647,513	4,993,203	6,116,032	5,796,650	4,935,652	4,610,941	5,039,738
9	Actual NPC ($/MWh)	Line 7 / Line 8	$ 27.50	$ 26.69	$ 25.18	$ 28.79	$ 29.77	$ 26.75	$ 37.12	$ 37.28	$ 39.07	$ 30.14	$ 34.78
10	ID Actual Load @ Input (MWh)		309,600	255,102	273,360	267,595	342,454	415,263	521,018	352,422	307,012	270,190	242,329
11	Actual ID NPC	Line 9 x Line 10	$ 8,513,452	$ 6,809,075	$ 6,883,636	$ 7,704,058	$ 10,195,462	$ 11,108,329	$ 19,340,560	$ 13,137,523	$ 11,995,480	$ 8,142,224	$ 8,427,600
12	NPC Differential	Line 11 - Line 6	**$ 1,199,681**	**$ 833,190**	**$ 227,741**	**$ 1,328,642**	**$ 2,560,494**	**$ 1,506,413**	**$ 7,212,291**	**$ 4,542,140**	**$ 4,703,855**	**$ 1,967,688**	**$ 2,566,789**
	EITF 04-6 Adjustment												
13	Idaho Allocated EITF 04-6 Deferral Adjustment ($		**$ (35,206)**	**$ 124**	**$ 23,090**	**$ 43,918**	**$ (65,172)**	**$ (89,614)**	**$ 79,342**	**$ 124,805**	**$ 7,959**	**$ 87,135**	**$ 21,544**
	LCAR												
14	Actual Idaho Jurisdictional ECPC minus NPC (Assume Actual = I	PAC-E-21-07	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242
15	LCAR Rate @ Meter ($/MWh)	PAC-E-21-07	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74
16	ID Actual Sales @ Meter (MWh)	Line 5	298,043	243,523	271,234	259,804	311,132	391,286	494,237	350,269	297,140	251,618	238,833
17	LCAR Revenue Collected through Base Rates ($	Line 15 x Line 16	$ 2,604,768	$ 2,128,285	$ 2,370,468	$ 2,270,577	$ 2,719,160	$ 3,419,681	$ 4,319,430	$ 3,061,208	$ 2,596,880	$ 2,199,034	$ 2,087,302
18	LCAR Adjustment	Line 14 - Line 17	**$ (36,525)**	**$ 439,957**	**$ 197,774**	**$ 297,665**	**$ (150,918)**	**$ (851,438)**	**$ (1,751,188)**	**$ (492,966)**	**$ (28,638)**	**$ 369,208**	**$ 480,940**
	ECAM Deferral												
19	Total ECAM Deferral (NPC Deferral, EITF 04-6 Adjustment, LCA	Sum of Lines: 12, 13, 18	1,127,950	1,273,271	448,605	1,670,225	2,344,404	565,360	5,540,446	4,173,979	4,683,175	2,424,031	3,069,273
20	**Total ECAM Deferral after 90% Sharing**	Line 19 x 90%	**$ 1,015,155**	**$ 1,145,944**	**$ 403,744**	**$ 1,503,203**	**$ 2,109,964**	**$ 508,824**	**$ 4,986,401**	**$ 3,756,581**	**$ 4,214,858**	**$ 2,181,628**	**$ 2,762,346**
	Production Tax Credits (PTCs)												
21	ID Allocated PTCs in Rates ($/MWh)	PAC-E-21-07	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)
22	ID Actual Sales @ Meter (MWh)	Line 5	298,043	243,523	271,234	259,804	311,132	391,286	494,237	350,269	297,140	251,618	238,833
23	ID PTCs in Rates ($)	Line 21 x Line 22	$ (1,241,025)	$ (1,014,008)	$ (1,129,395)	$ (1,081,802)	$ (1,295,527)	$ (1,629,285)	$ (2,057,965)	$ (1,458,494)	$ (1,237,267)	$ (1,047,716)	$ (994,482)
24	ID Allocated Actual PTCs ($)		(1,643,681)	(1,590,954)	(1,394,353)	(1,439,211)	(1,211,430)	(876,345)	(690,035)	(628,766)	(724,878)	(921,948)	(1,220,451)
25	ID PTCs Deferral ($)	Line 24 - Line 23	**$ (402,656)**	**$ (576,945)**	**$ (264,958)**	**$ (357,409)**	**$ 84,096**	**$ 752,941**	**$ 1,367,930**	**$ 829,728**	**$ 512,390**	**$ 125,769**	**$ (225,969)**
	Situs Assigned REP QF Adjustmen												
26	ID REP QF Adjustment ($)		**$ 3,642**	**$ 6,524**	**$ 5,277**	**$ 42,967**	**$ 78,488**	**$ 127,253**	**$ 68,564**	**$ 56,281**	**$ 37,079**	**$ 78,724**	**$ 44,193**
	Wind Liquidated Damages												
27	ID Allocated Wind Liquidated Damages ($		**$ (52,304)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (239,912)**
	Renewable Energy Credits (REC) Revenue												
28	ID REC Revenue in Rates ($/MWh)	PAC-E-21-07	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)
29	ID Actual Sales @ Meter (MWh)	Line 5	298,043	243,523	271,234	259,804	311,132	391,286	494,237	350,269	297,140	251,618	238,833
30	ID REC Revenue in Rates ($	Line 28 x Line 29	$ (20,401)	$ (16,669)	$ (18,566)	$ (17,784)	$ (21,297)	$ (26,784)	$ (33,831)	$ (23,976)	$ (20,339)	$ (17,223)	$ (16,348)
31	ID Allocated Actual REC Revenue ($		(33,363)	(15,420)	(103,577)	(98,901)	(16,738)	(29,836)	(21,885)	(3,551)	16,899	(2,231)	(2,696)
32	REC Revenue Adjustment ($)	Line 31 - Line 30	**$ (12,962)**	**$ 1,249**	**$ (85,011)**	**$ (81,117)**	**$ 4,560**	**$ (3,053)**	**$ 11,946**	**$ 20,425**	**$ 37,239**	**$ 14,992**	**$ 13,653**
33	**Total Deferral**	Sum of Lines 20, 25, 26, 27, 32	**$ 550,875**	**$ 576,772**	**$ 59,053**	**$ 1,107,644**	**$ 2,277,108**	**$ 1,385,966**	**$ 6,434,841**	**$ 4,663,014**	**$ 4,801,565**	**$ 2,401,113**	**$ 2,354,312**
34	Interest Rate	Order No. 34866	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
	ECAM Balancing Account ($												
35	Beginning Balance		$ 29,925,543	$ 29,605,861	$ 28,862,307	$ 28,422,828	$ 28,674,966	$ 30,048,805	$ 29,912,727	$ 32,244,610	$ 34,870,972	$ 37,291,823	$ 37,836,661
36	ECAM Deferral After Sharing	Line 20	1,015,155	1,145,944	403,744	1,503,203	2,109,964	508,824	4,986,401	3,756,581	4,214,858	2,181,628	2,762,346
37	PTCs Deferral	Line 25	(402,656)	(576,945)	(264,958)	(357,409)	84,096	752,941	1,367,930	829,728	512,390	125,769	(225,969)
38	REP Situs Adjustment	Line 26	3,642	6,524	5,277	42,967	78,488	127,253	68,564	56,281	37,079	78,724	44,193
39	Wind Liquidated Damages	Line 27	(52,304)	-	-	-	-	-	-	-	-	-	(239,912)
40	REC Revenue Adjustment	Line 32	(12,962)	1,249	(85,011)	(81,117)	4,560	(3,053)	11,946	20,425	37,239	14,992	13,653
41	Less: Monthly ECAM Rider Revenues allocated to ECAM		(895,351)	(1,344,678)	(522,392)	(879,287)	(927,727)	(1,547,017)	(4,128,846)	(2,064,606)	(2,410,769)	(1,887,566)	(1,911,839)
42	Interest		24,794	24,352	23,859	23,781	24,458	24,974	25,888	27,953	30,055	31,290	31,715
43	**Total ECAM Deferral Balance ($)**		**$ 29,605,861**	**$ 28,862,307**	**$ 28,422,828**	**$ 28,674,966**	**$ 30,048,805**	**$ 29,912,727**	**$ 32,244,610**	**$ 34,870,972**	**$ 37,291,823**	**$ 37,836,661**	**$ 38,310,848**

Idaho Energy Cost Adjustment Mechanism Deferral
January 1, 2022 - December 31, 2022

Line No.			Dec-22	Total
1	ID Base NPC Embedded in Rates ($)	PAC-E-21-07		
2	Annual Idaho Base Load @ meter (MWh)	PAC-E-21-07		
3	NPC Rate Embedded in Base Rates ($/MWh)	Line 1 / Line 2		
4	NPC Rate Embedded in Base Rates ($/MWh)	Line 3	$ 24.54	
5	ID Actual Sales @ Meter (MWh)		299,866	
6	ID NPC Collected in Rates ($)	Line 4 x Line 5	$ 7,358,512	$ 90,966,988
7	Total Company Adjusted Actual NPC ($)	Adjusted Actual NPC	$ 267,860,348	$ 2,018,394,444
8	Total Company Load @ Input (MWh)		5,589,475	61,277,488
9	Actual NPC ($/MWh)	Line 7 / Line 8	$ 47.92	$ 32.94
10	ID Actual Load @ Input (MWh)		292,816	
11	Actual ID NPC	Line 9 x Line 10	$ 14,032,416	$ 126,289,814
12	NPC Differential	Line 11 - Line 6	**$ 6,673,903**	**$ 35,322,826**
	EITF 04-6 Adjustment			
13	Idaho Allocated EITF 04-6 Deferral Adjustment ($)		**$ (7,269)**	**$ 190,656**
	LCAR			
14	Actual Idaho Jurisdictional ECPC minus NPC (Assume Actual = I	PAC-E-21-07	$ 2,568,242	$ 30,818,909
15	LCAR Rate @ Meter ($/MWh)	PAC-E-21-07	$ 8.74	
16	ID Actual Sales @ Meter (MWh)	Line 5	299,866	
17	LCAR Revenue Collected through Base Rates ($)	Line 15 x Line 16	$ 2,620,702	$ 32,397,497
18	LCAR Adjustment	Line 14 - Line 17	**$ (52,460)**	**$ (1,578,588)**
	ECAM Deferral			
19	Total ECAM Deferral (NPC Deferral, EITF 04-6 Adjustment, LCA	Sum of Lines: 12, 13, 18	6,614,175	33,934,894
20	**Total ECAM Deferral after 90% Sharing**	Line 19 x 90%	**$ 5,952,758**	**$ 30,541,405**
	Production Tax Credits (PTCs)			
21	ID Allocated PTCs in Rates ($/MWh)	PAC-E-21-07	$ (4.16)	
22	ID Actual Sales @ Meter (MWh)	Line 5	299,866	
23	ID PTCs in Rates ($)	Line 21 x Line 22	$ (1,248,617)	
24	ID Allocated Actual PTCs ($)		(1,705,514)	
25	ID PTCs Deferral ($)	Line 24 - Line 23	**$ (456,897)**	**$ 1,388,020**
	Situs Assigned REP QF Adjustment			
26	ID REP QF Adjustment ($)		**$ 85,311**	**$ 634,305**
	Wind Liquidated Damages			
27	ID Allocated Wind Liquidated Damages ($)		**$ (2,824)**	**$ (295,039)**
	Renewable Energy Credits (REC) Revenue			
28	ID REC Revenue in Rates ($/MWh)	PAC-E-21-07	$ (0.07)	
29	ID Actual Sales @ Meter (MWh)	Line 5	299,866	
30	ID REC Revenue in Rates ($)	Line 28 x Line 29	$ (20,526)	
31	ID Allocated Actual REC Revenue ($)		(73,125)	
32	REC Revenue Adjustment ($)	Line 31 - Line 30	**$ (52,599)**	**$ (130,679)**
33	**Total Deferral**	Sum of Lines 20, 25, 26, 27, 32	**$ 5,525,749**	**$ 32,138,012**
34	Interest Rate	Order No. 34866	1.00%	
	ECAM Balancing Account ($)			
35	Beginning Balance		$ 38,310,848	
36	ECAM Deferral After Sharing	Line 20	5,952,758	
37	PTCs Deferral	Line 25	(456,897)	
38	REP Situs Adjustment	Line 26	85,311	
39	Wind Liquidated Damages	Line 27	(2,824)	
40	REC Revenue Adjustment	Line 32	(52,599)	
41	Less: Monthly ECAM Rider Revenues allocated to ECAM		(1,928,544)	
42	Interest		33,425	
43	**Total ECAM Deferral Balance ($)**		**$ 41,941,478**	**$ 41,941,478**

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER REQUESTING APPROVAL OF $32.5 MILLON ECAM DEFERRAL	))))	**CASE NO. PAC-E-23-09** **DIRECT TESTIMONY OF ROBERT M. MEREDITH**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-23-09

March 2023

Q. Please state your name, business address and present position with PacifiCorp, d/b/a 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 Tariff Policy.

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 18 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over 12 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 February 2022, I assumed 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 2022 Energy Cost Adjustment Mechanism ("ECAM") deferral balances through Electric Service Schedule No. 94, Energy Cost Adjustment ("Schedule 94").

Background

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

A. Schedule 94 is currently designed to collect approximately $25.3 million—$9.6 million for the Electric Service Schedule No. 400 ("Schedule 400") customer and $15.7 million for standard tariff customers—based on Idaho loads from Case No. PAC-E-21-07.

Proposed Rate Change for Schedule 94

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

A. The 2022 ECAM application proposes to increase Schedule 94 rates to recover approximately $32.2 million from June 1, 2023 to May 31, 2024. This amount includes $32.5 million for the 2022 ECAM Deferral and approximately $9.5 million remaining from the 2021 ECAM balance, resulting in a total balance of $41.9 million as of December 31, 2022. This is offset by $9.9 million Schedule 94 forecasted revenue collection from January 1, 2023 through May 31, 2023, as shown in Table 2 of Mr. Jack Painter's testimony. Mr. Painter explains in his testimony the components of the 2022 ECAM deferred balance.

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

A. As summarized in my Exhibit No. 2, these rate change proposals result in an increase of 3.0 percent for Schedule 400. Standard tariff customers will see an average increase of 2.0 percent.

Renewable Energy Credit ("REC") Revenue Treatment for Schedule 400

Q. Did the Company make any adjustments to the Schedule 94 ECAM price for Schedule 400?

A. Yes. Consistent with the 2021 ECAM, the Company created a different ECAM rate for

Schedule 400 to exclude the REC revenues in the ECAM from Schedule 400's rates.

Q. Why are REC revenues excluded from Schedule 400 rates?

A. On March 29, 2021, PacifiCorp filed an application to the Commission requesting approval of an agreement the Company entered into with the sole Schedule 400 customer ("REC agreement"). Under this agreement, the Company will retire, rather than sell, this customer's allocated share of RECs generated post-2020 from system resources.[1] The Company discontinued sale of Idaho-allocated system RECs associated with the Schedule 400 load in 2021, so that the Schedule 400 customer's allocated share of system RECs could be retired on its behalf. As a result, the REC revenue that Schedule 400 would otherwise have been allocated from the sale of post-2020 system RECs is removed from Schedule 400's base rates. However, Schedule 400 will continue to receive REC revenue from the sale of any RECs generated prior to 2021.

On August 11, 2021, Commission Order No. 35131 approved the REC agreement. Based on the terms of the agreement, the Company withheld the Schedule 400 customer's share of 2021 RECs from any auctions or sales. Beginning on January 1, 2021, the Schedule 400 customer will no longer receive a REC revenue credit for RECs generated after December 31, 2020. However, if the Company was able to sell RECs generated prior to 2021, Schedule 400 will receive credit for its share of those REC revenues.

Q. How did you calculate the Schedule 400 ECAM rate?

A. To calculate the Schedule 400 ECAM rate, the Company removed REC revenue credits in the ECAM from the transmission voltage rate.

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[1] *In the Matter of the Joint Application Between Rocky Mountain Power and P4 Production, L.L.C. Requesting Approval of an Agreement to Retire RECS,* Case No. PAC-E-21-08, Order No. 35131.

Q. Did you remove all of the REC revenue credits in Schedule 400 rates through the ECAM?

A. No. The ECAM only tracks the incremental difference between actual REC revenues received during the deferral period and the REC revenue credit in base rates. The base rates were established in Case No. PAC-E-21-07 with a REC revenue credit of seven cents per megawatt hour. Base REC sales were removed from Schedule 400's base rates to reflect Schedule 400's agreement with the Company to retire its share of RECs on its behalf.

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 five steps. First, kilowatt-hour ("kWh") consumption at the generation level was developed by multiplying their retail loads at the delivery service voltage level with the corresponding line loss factors. Second, an overall average rate at the generation level was developed by dividing the total collection target identified above with their kWh consumption at the generation level. Third, rates by delivery voltage level were developed by multiplying the above overall average rate at the generation level with the corresponding line loss factors. Fourth, the rate for Schedule 400 was increased by 0.004 cents per kWh to account for the $0.1 million adjustment to REC revenue included in the 2022 ECAM, which Contract Tariff 400 had elected to forego per the terms of the REC agreement. This results in a proposed $12.2 million ECAM recovery from the Schedule 400 customer. Finally, the overall proposed collection of $32.2 million was reduced by the $12.2 million share for Schedule 400, and rates for standard tariff customers were developed to collect the remaining $20.0 million using similar logic to that described in the third step. As a result, the Company proposes Schedule 94 rates for standard tariff customers of 0.934, 0.917 and 0.886 cents per kWh for secondary, primary and transmission delivery service voltages, respectively. The rate for Schedule 400 is 0.892 cents per kWh.

Q. Please describe Exhibit No. 2.

A. Exhibit No. 2 shows the 2020 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, 2023.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-23-09
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 2023

EXHIBIT NO. 2
ROCKY MOUNTAIN POWER
ESTIMATED IMPACT OF PROPOSED ECAM ADJUSTMENT
FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
ADJUSTED HISTORICAL 12 MONTHS ENDED DECEMBER 2020

Line No.	Description	Sch.	Average Customers	MWH	Present Base ($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															
1	Residential Service	1	55,659	523,107	$60,147	523,107			570,505	$4,885	0.934	0.917	0.886	$3,834	$1,050	1.6%
2	Residential Optional TOD	36	11,711	196,337	$19,448	196,337			214,128	$1,833	0.934	0.917	0.886	$1,439	$394	1.9%
3	AGA Revenue				$4											
4	**Total Residential**		67,370	719,444	$79,599	719,444	0	0	784,633	$6,718				$5,274	$1,444	1.7%
5	**Commercial & Industrial**															
6	General Service - Large Power	6	1,158	345,854	$27,087	303,007	42,847		376,344	$3,222	0.934	0.917	0.886	$2,530	$693	2.3%
7	General Svc. - Lg. Power (R&F)	6A	207	26,805	$2,326	26,656	149		29,231	$250	0.934	0.917	0.886	$196	$54	2.1%
8	*Subtotal-Schedule 6*		*1,365*	*372,659*	*$29,413*	*329,663*	*42,996*	*0*	*405,575*	*$3,473*				*$2,726*	*$747*	*2.3%*
9	General Service - High Voltage	9	17	222,699	$13,225	0	0	222,699	230,500	$1,974	0.934	0.917	0.886	$1,550	$424	2.9%
10	Irrigation	10	5,971	615,886	$55,363	615,886			671,691	$5,751	0.934	0.917	0.886	$4,514	$1,237	2.1%
11	General Service	23	7,734	183,016	$17,375	182,662	353	0	199,592	$1,709	0.934	0.917	0.886	$1,341	$367	2.0%
12	General Service (R&F)	23A	2,576	39,710	$3,922	38,626	1,084		43,287	$371	0.934	0.917	0.886	$291	$80	1.9%
13	*Subtotal-Schedule 23*		*10,310*	*222,726*	*21,298*	*221,289*	*1,437*	*0*	*242,879*	*2,080*				*1,632*	*447*	*1.9%*
14	General Service Optional TOD	35	2	278	$23	278			303	$3	0.934	0.917	0.886	$2	$1	2.2%
15	General Service Optional TOD (R&F)	35A	0	0	$0	0			0	$0	0.934	0.917	0.886	$0	$0	
16	*Subtotal-Schedule 35*		*2*	*278*	*23*	*278*	*0*	*0*	*303*	*3*	*0.934*	*0.917*	*0.886*	*2*	*1*	*2.2%*
17	Special Contract	400	1	1,369,716	$79,465			1,369,716	1,417,697	$12,217			0.892	$9,588	$2,629	3.0%
18	AGA Revenue				$602											
19	**Total Commercial & Industrial**		17,666	2,803,964	$199,389	1,167,116	44,433	1,592,415	2,968,646	$25,497				$20,013	$5,484	2.5%
20	**Public Street Lighting**															
21	Security Area Lighting	7	188	274	$50	274			298	$3	0.934	0.917	0.886	$2	$1	1.1%
22	Security Area Lighting (R&F)	7A	132	106	$24	106			115	$1	0.934	0.917	0.886	$1	$0	0.9%
23	Street Lighting - Company	11	57	154	$61	154			168	$1	0.934	0.917	0.886	$1	$0	0.5%
24	Street Lighting - Customer	12	256	2,417	$368	2,417			2,636	$23	0.934	0.917	0.886	$18	$5	1.3%
25	AGA Revenue				$0											
26	**Total Public Street Lighting**		633	2,950	$503	2,950	0	0	3,218	$28				$22	$6	1.1%
27	**Total Sales to Ultimate Customers**		85,669	3,526,359	$279,491	1,889,511	44,433	1,592,415	3,756,496	$32,242				$25,308	$6,934	2.3%
28	**Total Excluding Special Contract 400**		85,668	2,156,643	$200,026	1,889,511	44,433	222,699	2,338,799	$20,025				$15,720	$4,305	2.0%

Line No.		Rev. Rqmt	Unallocated	Allocated				Proposed Rates			Current Rates		
29	Voltage Line Loss Factors applied to rates (2018 Study):			1.09061	1.07082	1.03503		S	P	T	S	P	T
30	Tariff Customer ECAM deferral and Rate (cents/kWh):	$20,025	0.856	0.934	0.917	0.886	Tariff Customer Rate	0.934	0.917	0.886	0.733	0.720	0.696
31	REC Adjustment and Rate (cents/kWh):	($131)	-0.003	-0.004	-0.004	-0.004	Schedule 400 Rate			0.892			0.700
32	Total Idaho ECAM Rate (cents/kWh):	32,242	0.858	0.936	0.919	0.888			REC Adj	-$49			

Case No. PAC-E-23-09
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 2023

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

Fourteenth~~Thirteenth~~ Revision of Sheet No. 94.1
I.P.U.C. No. 1 **Canceling Thirteenth~~Twelfth~~ Revision of Sheet No. 94.1**

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	0.934~~733~~¢ per kWh		
Schedule	6	0.934~~733~~¢ per kWh	0.917~~720~~¢ per kWh	
Schedule	6A	0.934~~733~~¢ per kWh	0.917~~720~~¢ per kWh	
Schedule	7	0.934~~733~~¢ per kWh		
Schedule	7A	0.934~~733~~¢ per kWh		
Schedule	9			0.886~~696~~¢ per kWh
Schedule	10	0.934~~733~~¢ per kWh		
Schedule	11	0.934~~733~~¢ per kWh		
Schedule	12	0.934~~733~~¢ per kWh		
Schedule	23	0.934~~733~~¢ per kWh	0.917~~720~~¢ per kWh	
Schedule	23A	0.934~~733~~¢ per kWh	0.917~~720~~¢ per kWh	
Schedule	24	0.934~~733~~¢ per kWh	0.917~~720~~¢ per kWh	
Schedule	35	0.934~~733~~¢ per kWh	0.917~~720~~¢ per kWh	
Schedule	35A	0.934~~733~~¢ per kWh	0.917~~720~~¢ per kWh	
Schedule	36	0.934~~733~~¢ per kWh		
Schedule	400			0.892~~700~~¢ per kWh

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF IDAHO

Energy Cost Adjustment

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

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		Delivery Voltage		
		Secondary	Primary	Transmission
Schedule	1	0.934¢ per kWh		
Schedule	6	0.934¢ per kWh	0.917¢ per kWh	
Schedule	6A	0.934¢ per kWh	0.917¢ per kWh	
Schedule	7	0.934¢ per kWh		
Schedule	7A	0.934¢ per kWh		
Schedule	9			0.886¢ per kWh
Schedule	10	0.934¢ per kWh		
Schedule	11	0.934¢ per kWh		
Schedule	12	0.934¢ per kWh		
Schedule	23	0.934¢ per kWh	0.917¢ per kWh	
Schedule	23A	0.934¢ per kWh	0.917¢ per kWh	
Schedule	24	0.934¢ per kWh	0.917¢ per kWh	
Schedule	35	0.934¢ per kWh	0.917¢ per kWh	
Schedule	35A	0.934¢ per kWh	0.917¢ per kWh	
Schedule	36	0.934¢ per kWh		
Schedule	400			0.892¢ per kWh