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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF ROCKY MOUNTAIN POWER'S APPLICATION FOR APPROVAL OF $62.4 MILLION ECAM DEFERRAL	)))))))	**CASE NO. PAC-E-24-05** **COMMENTS OF THE COMMISSION STAFF**

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

BACKGROUND

On April 1, 2024, Rocky Mountain Power, a division of PacifiCorp ("Company"), applied for Commission authorization to adjust its rates under the Energy Cost Adjustment Mechanism ("ECAM"). Specifically, the Company seeks approval of approximately $62.4 million in ECAM deferral for the period of January 1, 2023, through December 31, 2023, with a 10.5 percent increase to Electric Service Schedule No. 94, Energy Cost Adjustment. The monthly bill for a typical residential customer using 783 kilowatt-hours of electricity per month would increase by $7.39. The Company requests its proposed adjustment be processed by Modified Procedure and become effective on June 1, 2024.

The ECAM allows the Company to increase or decrease its rates each year to reflect changes in the Company's power supply costs. These costs vary by year with changes in the Company's fuel (gas and coal) costs, surplus power sales, power purchases, and associated transmission costs. Each month, the Company tracks the difference between the actual net power costs ("NPC") it incurred to serve customers, and the embedded (or base) NPC it collected from customers through base rates. The Company defers the difference between actual NPC and base NPC into a balancing account for treatment at the end of the yearly deferral period. At that time, the ECAM allows the Company to credit or collect the difference between actual NPC and base NPC through a decrease or increase in customer rates. Neither the Company nor its shareholders will receive any financial return because of this filing.

Besides the NPC difference, this year's ECAM includes: (1) the Load Change Adjustment Revenues; (2) coal stripping costs under Emerging Issues Task Force 04-6; (3) Renewable Energy Credit revenues; (4) Production Tax Credits; (5) the reasonable energy price, as defined in the 2020 Protocol; (6) qualified facility costs; and (7) wind availability liquidated damages.

The Company seeks: (1) an order approving its request for \$62.4 million ECAM deferral; and (2) a 10.5 percent increase to Electric Service Schedule No. 94. The Company represents that, if its proposal is approved, prices for customer classes would *increase* as follows:

- Residential Schedule 1 – (7.6%);
- Residential Schedule 36, Optional Time-of-Day Service – (8.7%);
- General Service Schedule 6 – (10.7%);
- General Service Schedule 9 – (13.1%);
- Irrigation Service Schedule 10 – (9.5%);
- General Service Schedule 23 – (9.0%);
- General Service Schedule 35 – (10.3%);
- Public Street Lighting – (5.2%); and
- Tariff Contract, Schedule 400 – (13.5%).

STAFF ANALYSIS

Staff reviewed the Company's external audit reports, journal entries, invoices, contracts, and the Company's adjustment to actual costs. Staff reconciled the general ledger amounts to the NPC provided in Exhibit No. 1 of Jack Painter's testimony. In addition, Staff reviewed the Company's hedge contracts and policies, and believe they reasonably safeguard price and fuel stability. Staff also reviewed the transactions and invoices for the Energy Imbalance Market ("EIM") revenues. In this ECAM filing, the Company included additional costs related to the State of Washington's Climate Commitment Act ("CCA"). Staff removed Idaho's portion of CCA costs from the ECAM deferral. In Order No. 36015, the Commission found "that it is not fair, just, or reasonable to include the costs associated with CCA compliance in Idaho rates." This adjustment reduces the Company's Idaho jurisdictional request by $2.3 million and is reflected in Table No. 1 – ECAM Deferral.

Table No. 1 – ECAM Deferral

NPC Differential for Deferral	65,874,728
EITF 04-6 Adjustment	60,594
LCAR	268,994
Washinton CCA Adjustment	***(2,568,948)***
Total Deferral Before Sharing	63,635,368
Sharing Band	90%
Customer Responsibility	57,271,832
Production Tax Credits	907,177
REP QF Adjustment	1,450,130
Wind Liquidated Damages	(310,085)
REC Deferral	(357,308)
Interest on Deferral	1,157,387
Removing Interest on Washington CCA	***(25,172)***
Annual Deferral (Jan - Dec 2023)	60,093,960
Unamortized Previous Balance	41,941,478
ECAM Rider Revenues	(28,953,155)
Total Company Recovery	73,082,282

Net Power Cost Deferral

The NPC adjustment within the ECAM allows the Company to collect or credit the difference between NPC incurred to serve customers in Idaho and the NPC collected from Idaho customers through base rates during the deferral period. In Order No. 35277, the NPC embedded in rates was set at $24.54 per megawatt hour ("MWh").

The revenue collected through base rates is calculated by multiplying $24.54 by 3,495,580 MWh of actual Idaho sales, for a total of $85.7 million. The difference between base rate revenue and Idaho's share of actual 2023 NPC of $149 million, leaves an under-collected balance of $63.3 million[1] after removal of compliance costs associated with the CCA. The under-collected balance is subject to a 90/10 customer sharing band, with the Company paying 10% of the NPC balance.[2] After removing the Company's 10%, the amount customers are responsible to pay through Schedule 94 rates is $57.2 million.

Emerging Issues Task Force ("EITF")

The EITF 04-6 adjustment is the difference between coal stripping costs the Company incurred and recorded, as stated in the accounting pronouncement EITF 04-6, and the amortization approved by Order No. 30987 in Case No. PAC-E-09-08. The Company uses this account to "undo" the effects of EITF 04-6 that requires the Company to expense coal stripping costs opposed to amortizing it over the coal produced from the section of open mines. The adjustment increases the deferral by $60,594. Staff reviewed the adjustment and believes it was accurately calculated.

Load Change Adjustment Revenues ("LCAR")

Staff believes the Company's LCAR adjustment complies with Order No. 35277. The LCAR adjusts for the under-or over-recovery of fixed energy-classified production cost (excluding NPC) resulting from the difference between Idaho sales used to determine base rates and the sales from the deferral year. The LCAR of $8.74 per MWh was set in Case No. PAC-E-21-07. Multiplying the LCAR by the actual Idaho sales of 3,495,580 MWh shows that the

[1] See Table 1 $65.9 million less $2.6 million.
[2] Under the 90/10 sharing band customers pay 90% of the under-collected balances and the Company pays the remaining 10%. For over-collected balances, customers receive 90% of the benefit and the Company keeps 10%.

Company collected $30.5 million of energy-classified fixed production costs through base rates. The difference between the actual energy-classified fixed production costs collected and the $30.8 million embedded in base rates increases the ECAM deferral by $268,994.

Production Tax Credits ("PTC")

In Order No. 33440, the Commission approved a settlement in Case No. PAC-E-15-09 that moved the PTC true-up to the ECAM, with a $1.99 per MWh benefit to customers included in base rates. In Order No. 35277, the Commission approved a settlement increasing the PTC to $4.16 per MWh. In 2023, base rates included a $14.6 million benefit from PTCs; however, the actual PTCs allocated to Idaho customers in 2023 was $13.6 million. The $907,177 difference between the PTCs in base rates and the actual PTCs is a surcharge to the customers.

Reasonable Energy Price QF Adjustment

The 2020 Protocol, approved by Order No. 34640, included a provision that all QF contracts approved in 2020 and after would be subject to a reasonable price adjustment. The amount the Company paid for energy under each QF contract over a reasonable energy price would be SITUS allocated to the state that approved the QF contract. Painter Di. at 10.

In this case, there are 11 contracts requiring comparison for the reasonable energy price QF adjustment-with four incurring a SITUS allocation adjustment to Idaho. Staff reviewed the process for creating the reasonable energy price and the energy price for those contracts and Staff believes it complies with the 2020 Protocol. The reasonable energy price QF adjustment results in a $1.5 Million increase to the deferral to Idaho.

Renewable Energy Credits ("REC")

In Order No. 35277, the Commission approved $0.07 per MWh in REC revenues to be included in base rates. The difference between the embedded amount and actual REC revenue is trued-up in the ECAM. In 2023, base rates included $239,273 in benefits from REC revenues. Idaho's share of the Company's actual REC revenues was $596,582. The difference of $357,308 offsets the deferral balance.

Wind Availability Liquidated Damages

The Company included a $310,085 credit to customers for a wind availability liquidated damages credit. In the stipulation approved in Order No. 33954, Case No. PAC-E-17-06, the

Company agreed to pass on all liquidated damages received from suppliers in case the repowered equipment does not meet the specifications required. The Company allocated liquidated damages by the system generation ("SG") factor and then applied that credit to customers. Staff reviewed the supporting documentation provided by the Company and agree with the inclusion of this reduction to NPC.

Washinton CCA

In 2023, the Company incurred $42 million in costs, on a system basis, to comply with the Washington CCA. In Mr. Painter's testimony he stated, "These costs were necessary to comply with applicable law for continued operation of Chehalis…Idaho customers received the benefit of the generation from the Chehalis natural gas facility which reduced NPC. NPC would have increased by $23.6 million on a total Company basis if the generation from Chehalis were removed". (Painter, Di at 24 and 25).

In Order No. 36015, the Commission stated the following:

> Based upon a review of the CCA, the Commission finds that it is not fair, just, or reasonable to include the costs associated with CCA compliance in Idaho rates. *Idaho Code* §§ 61-301, 61-502. The CCA is a Washington specific policy initiative for which Washington has established a revenue generating market through the creation and distribution of allowances for Washington GHG emissions. Washington then requires Idaho customers to pay the costs associated with complying with the CCA while at the same time mitigating the costs of that compliance for Washington customers through no-cost allowances.
>
> The Commission is asked to weigh the interests of Washington's social and environmental policies, and its revenue generating market, against the interests of Idaho customers in having just and reasonable rates. The Commission finds that the interests of Idaho customers outweigh Washington's policy interests.
>
> The current application of the CCA provides for disparate treatment between Idaho and Washington ratepayers, and creates in essence, or perhaps in fact, a one-sided tax upon Idaho ratepayers to pay for Washington's social and environmental policies. The Commission cannot find it fair, just, or reasonable for Idaho customers to fund Washinton's policy initiatives when none of the alleged benefits will flow to Idaho customers.

Staff believes including the Washington CCA costs in the ECAM deferral is not fair, just, or reasonable because it creates a one-sided tax for Idaho ratepayers. For this reason and for the reasons mentioned above Staff recommends the Commission remove CCA costs from the ECAM deferral. This adjustment reduces total ECAM recovery by approximately $2.3 million.

Prudence of Actual NPC

Staff believes the Company generally dispatched its resources, purchased from the wholesale electricity market, and sold power into the market in a prudent manner while encountering difficult circumstances and constraints during the deferral period. Staff reviewed the Application, exhibits, and testimony to identify and understand the various contributors to this year's higher levels of actual NPC compared to base amounts set to be recovered through rates during the 2023 deferral period. Staff's conclusion is based on two types of analyses: (1) a comparison of the actual and base amounts of energy and cost from the Company's resources during the deferral period, and (2) an analysis of unit downtime of the Company's generation resources to ensure the amount and causes of downtime were reasonable.

From an Idaho perspective, the 2023 annual ECAM deferral amount was $62.4 million after applying the 90/10 sharing band (not including Staff's CCA cost adjustment), which is 75.3% higher than the amount recovered through base rates. On a total Company basis, the 2023 actual NPC was $2.53 billion and 85.2% higher than base NPC. The Company's base rates were established by the Commission in Case No. PAC-E-21-07, with the new base rates put into effect on January 1, 2022.

Comparison of Base and Actual NPC

Staff compared the amount and cost of energy embedded in base rates to the actual amount and cost of energy incurred during the deferral period for the different types of resources needed to meet load and to maximize the amount of wholesale sales to other utilities. Staff believes that the higher actual NPC is attributed to a combination of several factors such as increased power purchase expenses, lack of coal generation due to coal supply constraints, decreased wholesale sales, increased natural gas expense, and reduced hydro generation.

First, Staff compared the 2023 adjusted actual Company NPC with the NPC included in base rates by resource type, with the results of that analysis summarized in Table No. 2, below.

Table No. 2: Comparison between 2023 Adjusted Actual NPC and Base NPC.

Source	Adjusted Actual NPC ($)	Base NPC[3] ($)	Base-to-Actual Difference ($)	Percentage Difference
Wholesale Sales Revenue	(174,104,342)	(463,692,258)	289,587,917[4]	(62.5%)
Purchased Power Expense	1,421,234,074	844,451,804	576,782,270	68.3%
Coal Fuel Expense	557,291,331	599,876,421	(42,585,090)	(7.1%)
Natural Gas Expense	556,454,677	228,727,764	327,726,913	143.3%
Wheeling Expense	165,290,267	154,137,105	11,153,161	7.2%
Geothermal and Other Generation Expense	7,616,464	4,416,584	3,199,880	72.5%
Total System NPC	2,533,782,470	1,367,917,419	1,165,865,050	85.2%

The largest base-to-actual dollar differences contributing to higher actual NPC compared to base NPC stemmed from higher purchased power expense of approximately $577 million, higher natural gas expense of $328 million, and lower wholesale sales revenue of $290 million.

To understand the reasons for these reductions, Staff then compared the amount of generation from the Company's different resources that was assumed in base rates to the actual amounts as reflected in Table No. 3, below.

Table No. 3: Comparison of 2023 Actual Generation in Mega-Watt Hour ("MWh") and Base Generation (MWh).

	2023 Generation (MWh)	Base Generation (MWh)	Difference (MWh)	Percentage Difference
Purchased Power	18,753,118	18,280,773	472,345	2.6%
Coal Generation	21,951,022	29,875,118	(7,924,096)	(26.5%)
Gas Generation	14,049,912	8,487,500	5,562,412	65.5%
Geothermal and Other Generation	252,013	250,943	1,070	0.4%
Wind Generation	6,499,381	7,869,533	(1,370,152)	(17.4%)
Hydro Generation	3,000,399	4,440,989	(1,440,590)	(32.4%)
Total System Generation	64,505,845	69,204,856	(4,699,011)	(6.8%)

[3] Case No. PAC-E-21-07 PacifiCorp – General Rate Case.

[4] The positive amount for the wholesale sales base-to-actual difference represents a reduction in revenue from the total actual amount of sales relative to the base amounts; whereas positive amounts for base-to-actual cost components represent increases in actual cost as compared to base amounts.

As can be seen from the table, the amount of generation from hydro, coal, and wind, three of the Company's lowest cost energy resources, had significantly lower amounts of generation with Hydro being 32.4% less, coal being 26.5% less, and wind being 17.4% less, when compared to base amounts. The lower amounts of zero fuel cost hydro and wind generation was due to lack of availability of water and wind during the deferral period. As discussed in more detail below, the lower amount of coal generation was mostly due to coal supply issues, and transmission constraints between the Bridger coal plant and loads west of the facility. Case No. PAC-E-23-09 – 2022 ECAM Investigation Report at 13 and 19. Because of these issues, the Company had to rely on 65.5% more gas generation to meet customer load, the actual price of which was $39.61/MWh and 47% higher than the price assumed in base rates. The Company also had to rely heavily on market purchases; however, the price of market purchases was $75.79/MWh, 64.1% greater than prices assumed in base rates. Both of these resources were significant contributing factors to overall higher actual NPC costs.

Because of the lower amounts of generation from coal, wind, and hydro resources, the Company sold 62.5% less generation into the wholesale market than the amounts assumed in base rates. Revenue from Wholesale sales has traditionally been a method for the Company to offset its actual NPC to customers. However, some of this difference can be attributed to inaccuracies in the model the Company used to set its base rates. The Company stated that it plans to improve its modeling of NPC, which should provide a more precise estimation of wholesale sales revenues in the future. The Company expects to supply the details of its updated NPC model in its next general rate case. *See* Company's Response to Production Request No. 8.

Resource Downtime

Staff believes that the amount and causes of resource downtime were reasonable. Staff analyzed the amount of downtime and causes of downtime provided through discovery requests. *See* Company's Response to Production Request No. 5. Although Staff is not concerned about the amount of total resource downtime and understands that the Company made prudent decisions in taking its resources out of service based on various needs, Staff notes two of the major downtime events occurred with the "Prospect 3" hydro unit and five Swift hydro units. In both cases, Staff believes the reasons for the downtime were legitimate and that the amount of downtime for each of these projects were reasonable given the work that needed to be completed.

Proposed Rates

As shown in Table No. 4 below, the Company's proposed rates increase Schedule 94 rates by about 101.1% with an approximate 10.5% increase in base rate revenue. However, given Staff's recommended CCA adjustment, Staff proposes about a 93.7% increase in Schedule 94 rates, which results in an increase in base rate revenue of about 9.7%.

Table No. 4: Schedule 94 ECAM Adjustments.

	Current	Company Proposed			Staff Proposed		
Service Type	**Rates (¢/kWh)**	**Rates (¢/kWh)**	**Increase from Current (¢/kWh)**	**% Increase**	**Rates (¢/kWh)**	**Increase from Current (¢/kWh)**	**% Increase**
Secondary	0.934	1.878	0.944	101.1%	1.809	0.875	93.7%
Primary	0.917	1.844	0.927	101.1%	1.776	0.859	93.7%
Transmission	0.886	1.782	0.896	101.1%	1.717	0.831	93.8%

Staff verified that the methods for determining the Company's proposed Schedule 94 ECAM rates follow past Commission orders, and that the calculations were accurate. *See* Company Application – Exhibit 2. The method approved in Order No. 33440 was used to spread the increase appropriately across each of the customer classes; however, the Company's revenue increases from specific customer classes vary because of the rate design. The proposed ECAM rates in Schedule 94 are voltage-level specific, which considers line losses due to the type of service for each class of customer.

Under the Company's proposal, a typical Schedule 1 residential customer who receives service at the secondary distribution level would receive a $7.39 increase in their monthly bill. Under Staff's proposal, the same customer would see about a $6.85 in their monthly bill. A full summary of Staff's proposed rates is included in Staff Attachment No. 1.

NPC Coal

In 2022, the Company experienced supply problems for its Hunter Power Plant ("Hunter") and its Huntington Power Plant ("Huntington"), both coal plants in Utah. The

Company received force majeure letters from its coal suppliers including one relating to a fire in the Lila Canyon coal mine. The Lila Canyon coal mine produces more than 25% of the total coal supply for all of Utah. This continued into 2023, with additional force majeure letters, and notice that the Lila Canyon mine would remain permanently closed.

Through 2023, the Company scrambled to find all reasonably priced coal supplies that could be sent to Hunter and Huntington. The Company's attempts to find coal included a short-term coal supply contract with the Gentry Mountain Mining, using their supply at the Rock Garden Safety Pile, and even shipping some coal from the Gadsby Power Plant.

Additionally, the Company controlled the burn from both Hunter and Huntington to ensure there was coal available for the peak usage times by increasing the dispatch price above the cost of fuel for those plants. The Company used an internally created model to estimate the amount of coal the plants would have on hand at the end of the year at various dispatch prices. The dispatch price was then set to ensure there was a reasonable amount of coal in the pile at the end of the year. This model was updated weekly, and the price adjusted accordingly. The dispatch price ranged from the $30 range to over $80 per MWH.

Going forward, the Company has negotiated new contracts to supply coal to both Hunter and Huntington, but at a significant price increase. There are provisions in the contract that will help in attempting to restore supplies for the region and protections for the company paying too much for the coal in this contract. This price increase will prevent these plants from being the lowest price coal plant in the Company's fleet but will still make a reasonable hedge against high prices in the future. Staff estimates this will put the cost per MWH for coal from these plants to the midpoint of the Company's natural gas plants.

Overall, the last two years have been very difficult years for the Utah coal plants. Staff believes the Company operated the plants prudently and sought alternative coal supplies in a manner that mitigated costs while setting up its Utah plants to be a useful hedge against high prices in the future.

<u>Customer Notice and Press Release</u>

The Company's press release and customer notice were included with its Application. Staff reviewed the documents and determined that both meet the requirements of Rule 125 of the Commission's Rules of Procedure (IDAPA 31.01.01.125). The notice was included with bills mailed to customers beginning April 3, and ending May 2, 2024, providing customers with a reasonable opportunity to file timely comments with the Commission by the May 14, 2024 deadline. As of May 13, 2024, no customer comments had been filed.

STAFF RECOMMENDATION

Staff recommend the Commission:

1. Approve Staff's revised ECAM deferral of approximately $60.1 million.
2. Remove Washington CCA costs (approximately $2.3 million) from the ECAM deferral.
3. Order the Company to provide revised tariffs to include Staff's adjustments to NPC.

Respectfully submitted this 14th day of May 2024.

for Adam Triplett
Deputy Attorney General

Technical Staff: Ty Johnson
Joe Terry
Matt Suess
Shubhra Deb Paul
Curtis Thaden

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 14th DAY OF MAY 2024, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-24-05, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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Patricia Jordan
PATRICIA JORDAN, SECRETARY

STAFF EXHIBIT NO. 1
ROCKY MOUNTAIN POWER

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	P	T	At Generation MWh	ECAM Proposal Rev ($000)	Rate ¢/kWh S	P	T	Present ECAM Rev ($000)	Net Change ($000)	%
	(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	$9,462	1.809	1.776	1.717	$4,886	$4,576	7.0%
2	Residential Optional TOD	36	11,711	196,337	$19,448	196,337			214,128	$3,551	1.809	1.776	1.717	$1,834	$1,718	8.1%
3	AGA Revenue				$4											
4	**Total Residential**		67,370	719,444	$79,599	719,444	0	0	784,633	$13,014				$6,720	$6,294	7.3%
5	**Commercial & Industrial**															
6	General Service - Large Power	6	1,158	345,854	$27,087	303,007	42,847		376,344	$6,242	1.809	1.776	1.717	$3,223	$3,019	10.0%
7	General Svc. - Lg. Power (R&F)	6A	207	26,805	$2,326	26,656	149		29,231	$485	1.809	1.776	1.717	$250	$234	9.1%
8	*Subtotal-Schedule 6*		*1,365*	*372,659*	*$29,413*	*329,663*	*42,996*	*0*	*405,575*	*$6,727*				*$3,473*	*$3,253*	*9.9%*
9	General Service - High Voltage	9	17	222,699	$13,225	0	0	222,699	230,500	$3,823	1.809	1.776	1.717	$1,973	$1,850	12.2%
10	Irrigation	10	5,971	615,886	$55,363	615,886			671,691	$11,140	1.809	1.776	1.717	$5,752	$5,388	8.8%
11	General Service	23	7,734	183,016	$17,375	182,662	353	0	199,592	$3,310	1.809	1.776	1.717	$1,709	$1,601	8.4%
12	General Service (R&F)	23A	2,576	39,710	$3,922	38,626	1,084		43,287	$718	1.809	1.776	1.717	$371	$347	8.1%
13	*Subtotal-Schedule 23*		*10,310*	*222,726*	*21,298*	*221,289*	*1,437*	*0*	*242,879*	*4,028*				*2,080*	*1,948*	*8.3%*
14	General Service Optional TOD	35	2	278	$23	278			303	$5	1.809	1.776	1.717	$3	$2	9.6%
15	General Service Optional TOD (R&F)	35A	0	0	$0	0			0	$0	1.809	1.776	1.717	$0	$0	
16	*Subtotal-Schedule 35*		*2*	*278*	*23*	*278*	*0*	*0*	*303*	*5*	*1.809*	*1.776*	*1.717*	*3*	*2*	*9.6%*
17	Special Contract	400	1	1,369,716	$79,465			1,369,716	1,417,697	$23,730			1.733	$12,218	$11,512	12.6%
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	$49,454				$25,499	$23,954	10.7%
20	**Public Street Lighting**															
21	Security Area Lighting	7	188	274	$50	274			298	$5	1.809	1.776	1.717	$3	$2	4.6%
22	Security Area Lighting (R&F)	7A	132	106	$24	106			115	$2	1.809	1.776	1.717	$1	$1	3.7%
23	Street Lighting - Company	11	57	154	$61	154			168	$3	1.809	1.776	1.717	$1	$1	2.1%
24	Street Lighting - Customer	12	256	2,417	$368	2,417			2,636	$44	1.809	1.776	1.717	$23	$21	5.4%
25	AGA Revenue				$0											
26	**Total Public Street Lighting**		633	2,950	$503	2,950	0	0	3,218	$53				$28	$26	4.9%
27	**Total Sales to Ultimate Customers**		85,669	3,526,359	$279,491	1,889,511	44,433	1,592,415	3,756,496	$62,521				$32,246	$30,274	9.7%
28	**Total Excluding Special Contract 400**		85,668	2,156,643	$200,026	1,889,511	44,433	222,699	2,338,799	$38,791				$20,029	$18,762	8.5%

Line No.		Rev. Rqmt	Unallocated	Allocated S	Allocated P	Allocated T		Proposed Rates S	P	T	Current Rates S	P	T
29	Voltage Line Loss Factors applied to rates (2018 Study):			1.09061	1.07082	1.03503							
30	Tariff Customer ECAM deferral and Rate (cents/kWh):	$38,791	1.659	1.809	1.776	1.717	Tariff Customer Rate	1.809	1.776	1.717	0.934	0.917	0.886
31	REC Adjustment and Rate (cents/kWh):	($357)	-0.010	-0.010	-0.010	-0.010	Schedule 400 Rate			1.733			0.892
32	Total Idaho ECAM Rate (cents/kWh):	$62,521	1.664	1.815	1.782	1.723			REC Adj	-$135			

Attachment No. 1
Case Number PAC-E-24-05
Comments
May 14, 2024