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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF ROCKY MOUNTAIN POWER'S APPLICATION REQUESTING APPROVAL OF $16.1 MILLION NET POWER COST DEFERRAL (ECAM)	)))))))	**CASE NO. PAC-E-21-09** **COMMENTS OF THE COMMISSION STAFF**

STAFF OF the Idaho Public Utilities Commission, by and through its Attorney of record, Matt Hunter, Deputy Attorney General, submits the following comments.

BACKGROUND

On March 31, 2021, PacifiCorp dba Rocky Mountain Power ("Company") applied for Commission authorization to adjust its rates under the Energy Cost Adjustment Mechanism ("ECAM"). The ECAM allows the Company to adjust its rates each year to capture the difference between the Company's actual power supply expenses and the power expenses embedded in base rates. The adjustment is a separate line item on customer bills that increases if power supply costs are higher than the amount already included in base rates or decreases if power supply costs are lower. The ECAM does not affect the Company's earnings. The Company also seeks Commission approval of about $16.1 million of deferred costs.

The Commission approved the ECAM in 2009. Order No. 30904. 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. 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 later disposition 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. This year, the deferred NPC difference was about $14.3 million.

Besides the NPC difference, this year's ECAM includes: (1) the Load Change Adjustment Revenues ("LCAR"); (2) an adjustment for coal stripping costs; (3) a true-up of 100% of the incremental Renewable Energy Credit revenues; (4) Production Tax Credits; (5) the Lake Side 2 generation resource adder; and (6) a resource tracking mechanism. The ECAM includes a "90/10 sharing band" in which customers pay/receive 90% of the increase/decrease in the difference between actual NPC and base NPC, LCAR, and the coal stripping costs; and the Company incurs/retains the remaining 10%. The Company's Application includes the testimony of witnesses who explain each of these items in detail.

With this ECAM Application, the Company ultimately seeks an order approving the Company's: (1) deferral, for later recovery through rates, of $16.1 million in costs; and (2) revised Electric Service Schedule 94, Energy Cost Adjustment, which would reflect the ECAM adjustment and decrease the Company's Schedule 94 revenues by approximately $3.1 million.

As noted above, the Company states that if its proposal is approved, prices for customer classes would decrease as follows:

- Residential Customers – (0.8%)
- Residential Schedule 36, Optional Time-of-Day Service – (0.9%)
- General Service Schedule 6 – (1.1%)
- General Service Schedule 9 – (1.2%)
- Irrigation Customers – (1.0%)
- Commercial or Industrial Heating Schedule 19 – (1.0%)
- General Service Schedule 23 – (0.9%)
- General Service Schedule 35 – (1.3%)
- Public Street Lighting – (0.4%)
- Industrial Customer, Schedule 400 – (1.3%)
- Industrial Customer, Schedule 401 – (1.3%)

Application, Meredith Direct, Exhibit No. 2. The Company asks that its proposed Schedule 94 take effect on June 1, 2021.

STAFF ANALYSIS

Deferral Analysis

Staff believes the Company's overall methodology complies with previous Commission orders. However, Staff discovered an anomaly in data caused by a faulty meter between the Idaho and Utah jurisdiction that inflated the amount of energy used to allocate net power costs to Idaho used for net power costs. This inflated the amount of total Company net power costs allocated to Idaho, and thus inflated the ECAM balance to be recovered from rate payers. As requested, the Company provided a revised Exhibit 1, Exhibit 2, and Tariffs to Staff on May 11, 2021. *See* Attachment A. Staff includes the Company's revisions in our analysis below. With limited time to review these revisions, Staff requests the opportunity to provide supplemental comments no later than May 18, 2021 should any additional issues be discovered. Staff also has concerns about the method used to allocate cost to Idaho for the ECAM, which is discussed further below. Other than the faulty meter error, Staff believes that the Company used accurate actual loads and prudently incurred actual costs and revenues. With the adjustment mentioned above Staff recommends that the Commission authorize the 2020 ECAM deferral as shown below:

Table 1
Annual ECAM Calculation

Calendar Year 2020 ECAM Deferral		
NPC Differential	$	4,330,859
EITF 04-6 Adjustment		(127,464)
LCAR		(1,076,170)
Total Deferral Before Sharing	$	3,127,225
Sharing Band		90%
Customer Reponsibility	$	2,814,502
Lake Side 2 Resource Adder	$	5,431,705
Production Tax Credits		(100,831)
RTM Adjustment		4,431,885
REC Deferral		8,557
Interest on Deferral		482,919
Annual Deferral (Jan - Dec 2020)	$	13,068,738

The meter error dates to July 2019. Therefore, Staff believes that it is appropriate to adjust the beginning 2020 deferral balance for the change in load attributed to Idaho and therefore the NPC allocated to Idaho. This would reduce the beginning balance from $27.3 million to $24.4 million. This reduction of approximately $2.9 million as well as a summary of other changes due to this revision is shown on Table No. 2 below:

Table 2
Balancing Account Activity

ECAM Deferral Balance	**As Filed**	**Revised**	**Difference**
Deferral Balance - Dec 31, 2019	$ 27,286,382	$ 24,397,925	$ (2,888,457)
Annual Deferral (Jan - Dec 2020)	13,778,459	12,585,818	(1,192,641)
Interest	562,667	482,919	(79,748)
ECAM Revenue Collection - Schedule 94	(18,416,430)	(18,416,430)	0
Activity Through December 31, 2020	$ 23,211,078	$ 19,050,233	$ (4,160,845)
Depreciation Regulatory Asset Balance			
Beginning Balance	$ (76,878)	$ (76,878)	$ 0
Annual Deferral (Jan - Dec 2020)	2,039,800	2,039,800	(0)
ECAM Revenue Collection - Schedule 94	(2,113,434)	(2,113,434)	0
Activity Through December 31, 2020	$ (150,512)	$ (150,512)	$ 0
December 31, 2020 Balance For Collection	$ 23,060,567	$ 18,899,721	$ (4,160,846)
Schedule 94 Collection - Jan - May 2021	$ (6,994,766)	$ (6,994,766)	$ 0
Interest	81,345	63,979	(17,366)
Expected Balance as of June 1, 2021	**$ 16,147,146**	**$ 11,968,935**	**$ (4,178,211)**

Staff reviewed the Company's external audit reports, journal entries, invoices, contracts, and bills to customers. Staff also reviewed the Company's adjustment to actual costs. Staff reconciled the general ledger amounts to the NPC provided in Exhibit No. 1 of Mr. Painter's testimony. Staff reviewed the Company's hedge contracts and policies and believes they reasonably safeguard price and fuel stability. Staff also reviewed the transactions and invoices for the Energy Imbalance Market revenues. Additionally, Staff verified the calculations of the RTM adjustment, which is included in the ECAM. Staff concludes that the ECAM deferral shown in Attachment A revising Exhibit No. 1 is accurate and complies with ECAM orders.

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. Staff believes that with the adjustments correcting for the faulty meter the calculations and the methodology the Company used to determine the NPC deferral meet the intent of the ECAM and Commission orders and the deferral is calculated correctly.

For the 2020 deferral year, the NPC embedded in rates was set in Order No. 33668, Case No. PAC-E-16-12, at $26.90 per MWh. The revenue collected through base rates is calculated by multiplying $26.90 by 3,522,347 MWh of actual Idaho sales, for a total of $94.7 million. The difference between base rate revenue and Idaho's share of actual 2020 NPC of $99.0 million, is an under-collected balance of $4.3 million. This is approximately $1.3 million less than the Company had filed in its Application. The under collected balance is subject to a 90/10 customer sharing band, with the Company paying 10% of the NPC balance. After removing that 10%, the amount to be collected through Schedule 94 rates is $3.9 million.

Emerging Issues Task Force ("EITF") 04-6 Adjustment

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 as opposed to amortizing it over the coal produced from the section of open mines. The adjustment decreases the deferral by $127,464. Staff reviewed the adjustment and believes it is accurately calculated.

Load Change Adjustment Revenues

Staff believes the Company's LCAR adjustment complies with Order No. 33440. The LCAR adjusts for the under- or over- recovery of fixed energy-classified production cost (excluding NPC) because of the difference between sales used to determine base rates and the Idaho sales from the deferral year.

The LCAR of $5.54 per MWh was set in Case No. PAC-E-16-12 and adjusted due to changes in the corporate tax rate in Case No. GNR-U-18-01. Multiplying the LCAR by the actual Idaho sales of 3,522,347 MWh shows that the Company collected $19.5 million of energy-classified fixed production costs through base rates. The amount in base rates is greater than the actual amount of energy-classified fixed production costs, $18.4 million, which is a benefit of $1.1 million to customers.

Production Tax Credit ("PTC")

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

2020, base rates included a $7.0 million benefit from PTCs. However, the Company's actual PTCs in 2020 allocated $7.1 million to Idaho customers. The $0.1 million difference between the PTCs in base rates and the actual PTCs is a benefit to customers. Compared to last year's PTCs this is a significant increase to the amount of PTCs the Company received. This difference is explained by several new and repowered wind projects coming online in late 2019 and 2020.

Renewable Energy Credit ("REC")

In Case No. PAC-E-16-12, the Commission approved a $0.09 per MWh benefit to customers for the REC revenues included in base rates. The difference between the embedded amount and actual REC revenue is trued-up in the ECAM. In 2020, base rates included $316,068 in benefits from REC revenues. Idaho's share of the Company's actual REC revenues was $307,510. The difference of $8,557 is added to the deferral balance.

Lake Side 2 Resource Adder

In Order No. 32910, the Commission approved a settlement that allows the Company to recover its investment in the Lake Side 2 generation facility through the ECAM until its investment is included in base rates in a future rate case. The adder allows the Company to recover $1.99 per MWh of generation at Lake Side 2, up to $5.43 million per year. In 2020, the Company generated over 2.7 million MWh at Lake Side 2, allowing the Company to include the maximum of $5.43 million in the deferral balance.

RTM Adjustment

In Order No. 33954, the Commission approved a settlement allowing the Company to recover costs related to wind repowering projects through the ECAM. In 2020, all of these projects were online and generating electricity. The RTM adjustment properly reflects cost that offset the repowering projects' benefits to customers found elsewhere in the ECAM, PTC benefits, and NPC benefits. Based on the terms of the RTM settlement, the Company included $4.4 million in the deferral. Staff agrees with this number.

Tax Savings

The 2018 and 2019 ECAMs included a credit to the deferral balance from the Tax Cuts and Jobs Act ("TCJA"). In Case No. PAC-E-20-03 the Commission approved a settlement to modify the order for the treatment of the TCJA tax benefits. The remaining benefits will be used to offset the plant balance and closing costs of the Cholla 4 coal generating plant, and to offset the next rate increase. Therefore, there are no direct tax benefits included in the 2020 ECAM.

NPC Method Analysis

Staff evaluated the methods and inputs used to determine the base-to-actual deferral amounts for NPC-related costs. As a result of its analysis, Staff identified a significant discrepancy in Idaho's share of line losses that will require a total reduction of $4,178,211 in the deferral amounts for the 2019 and 2020 ECAM years. In addition, Staff has concerns regarding the Company's method for determining the amount of Actual Load at Input allocated to Idaho and the resulting line losses allocated to Idaho customers for calculating the ECAM.

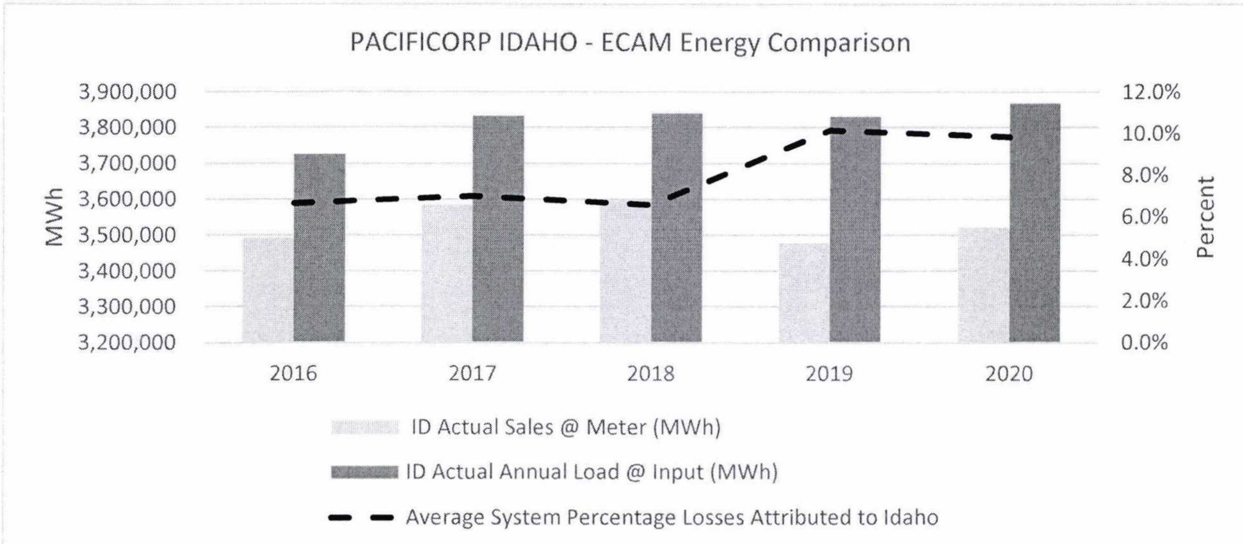
Faulty Meter Adjustments

Staff compared the difference between the amount of Idaho Actual Sales at Meter used to determine the Company's recovery of NPC through base rates and the amount of Idaho Actual Load at Input used to determine the unit cost of actual NPC, both of which are integral in calculating the NPC-related base-to-actual deferral amounts. *See* Application, Painter Direct, Exhibit 1. The difference between these two amounts of load provides the amount of line loss that the Company reflects in the ECAM as a necessary cost of delivering energy to Idaho ratepayers. In this case, Staff determined that the amount of line loss was not reasonable and required further investigation.

Actual Sales at Meter is the amount of energy included in Idaho customer's bills, while Actual Load at Input is the amount of energy that is metered into the State of Idaho at its borders that is assumed to be consumed by Idaho customers. The difference between the two amounts is the amount of line loss that occurs between energy provided to Idaho across its borders and the amount of energy consumed at the customer's meter. The amount of line loss in this year's filing was about 9.8 percent, which Staff did not believe was reasonable. By looking at the same data over the past five years, Staff noticed that line losses increased from about 7% to about 10%

starting in 2019, indicating that something had changed. Staff's analysis is illustrated in Figure No. 1 below.

Figure No. 1: 5-Year Historical Comparison of Idaho's Loads and Line Losses



Staff notified the Company of the issue and as a result of its root cause analysis, the Company determined that:

> A meter on the line between the Treasureton, Idaho and Wheelon, Utah substations had a partial failure on one phase of the three phases in July of 2019. Initially the failure occurred intermittently and continued to increase until ultimately the meter was only registering approximately 68 percent of the actual energy. The line flow on this line is typically from Idaho to Utah, resulting in the meter registering too little power leaving Idaho overstating Idaho load at input.[1]

Along with results of its root cause analysis, the Company provided Staff with recalculated exhibits for both this year's filing and last year's filing adjusting for the discrepancy in Idaho's Actual Load at Input caused by the faulty meter. With the adjustment, the end result is a $4,178,211 reduction in the deferral for both the 2019 and 2020 ECAM deferral years and is $2,888,457 and $1,289,754, respectively.

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[1] Email from Company Representative, Ted Weston, dated 5/11/2021.

Idaho's Share of Line Loss

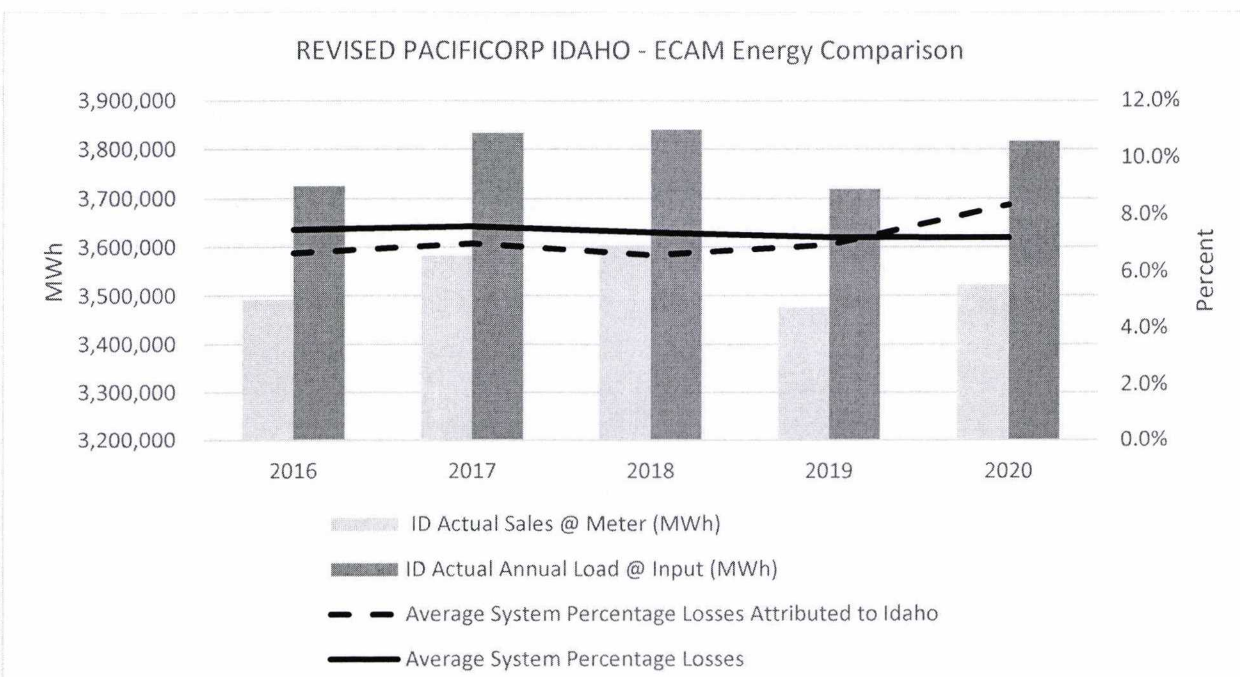
The Company uses a border method of allocation to determine each jurisdiction's share of Actual Load at Input. At the most basic level, the amount of actual load allocated to a jurisdiction is calculated by netting energy flow into and out of each jurisdiction while accounting for the amount of energy generated within its borders over the same time period. The Company's method can be depicted by the following equation:

Actual Load at Input = Input at borders + Generation within borders – Output at borders

Although the Company can account for 100% of the load for the whole system using this method, Staff is concerned that the energy flowing into and then out of the State to be consumed by customers in other jurisdictions may be unfairly allocating line-loss-related actual costs to Idaho for energy flowing through the State not consumed by Idaho customers.

Staff re-created Figure No. 1 with the adjustments due to the faulty meter as shown in Figure No. 2 below. The line losses for the Company's entire system have been added to show a comparison between system and Idaho line losses.

Figure No. 2: Revised 5-Year Historical Comparison of Idaho's Loads and Line Losses



Although the faulty meter has reduced line losses in Idaho from about 9.8% to about 8.3% in 2020, Staff believes that Idaho customers may still be receiving an unfair allocation of system line loss-related cost due to energy flowing through the State not consumed by Idaho customers. Staff has identified three possible inter-related reasons.

First, Idaho is uniquely positioned in the Company's system where a significant amount of its energy flows through the State in comparison to the amount of energy actually consumed in Idaho.[2] Second, Staff compared Idaho's line losses with the Company's line losses for its entire system. As can be seen in Figure No. 2, system line loss in 2020 was approximately 7.2% with Idaho's line loss being larger at about 8.3% (includes adjustments due to the faulty meter). Third, Staff expects that Idaho's line losses should be consistently below system line losses due to the amount of load being consumed at transmission level voltages. Approximately 40% of Idaho's load comes from a single industrial customer that takes service at transmission level voltages, which typically have line losses between 3% and 4%.

Staff plans to conduct a review of the Company's border method for allocating actual loads in the ECAM to determine if Idaho is being charged an unfair amount of system line loss. Any concerns found will be discussed with the Company with any agreed adjustments included in the deferrals. If the treatment remains at issue, Staff recommends the Commission allow this adjustment to be made for 2021 in the next ECAM filing.

NPC Analysis

Staff analyzed the Company's actual NPC to identify differences between base NPC and actual NPC driving base-to-actual deferral amounts in this year's ECAM. The results of Staff's analysis are reflected in the table below.

[2] Idaho's allocation of system energy is about 7%.

Source	Adjusted Actual	Base NPC	Base-to-Actual Difference	Percentage Difference
Wholesale Sales (revenue)	($173,806,710)	($334,520,634)	$160,713,923[3]	-48.0%
Purchased Power / Net Interchange (cost)	$644,183,157	$604,970,831	$39,212,326	6.5%
Coal (cost)	$631,640,957	$780,404,471	($148,763,514)	-19.1%
Gas (cost)	$263,097,477	$284,628,008	($21,530,532)	-7.6%
Other - Primarily Wind (cost)	$146,968,316	$149,965,098	($2,996,782)	-2.0%
Total System	**$1,512,083,197**	**$1,485,447,775**	**$26,635,422**	**1.8%**

During the deferral period, the amount of generation cost from its coal and natural gas-fueled generation resources has declined from quantities assumed in base rates (*see* Case No. PAC-E-16-12), which can be attributed to reduced generation output. Staff believes that these reductions are a major cause of reductions in the amount of wholesale sales revenue and an increase in the amount of purchased power used to serve the Company's load.

Proposed Rates

The Company provided Staff a revised Exhibit No. 2, showing the calculation of the new rates based on the adjustments discussed above. The revised Exhibit No. 2 is included in Attachment A to these comments. Staff verified that the rates in the Company's revised Schedule 94, Energy Cost Adjustment, are calculated using the methodology approved in Order No. 33440. The ending deferral balance is allocated on an equal cents per kilowatt-hour basis and then further allocated for line losses based on the voltage level at which each customer class receives service. This ensures that customers that take service at higher voltages (i.e., transmission) do not get charged for line losses that are lower than for primary and secondary distribution customers whose line losses are higher due to taking service at lower voltages. Using this method, the proposed rates in Schedule 94 are voltage-level specific: 0.354 cents per kWh for secondary service, 0.342 cents per kWh for primary service, and 0.333 cents per kWh for transmission service.

[3] 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.

The Company's provided Staff with revisions to Schedule 94, also included in Attachment A to these comments, decreasing Company revenue by approximately 2.2%. However, revenue decreases to specific classes will vary because of differences in rate design among the classes. The overall revenue decrease for residential customers is just under 2%. A typical residential customer using an average of 800 kWh per month would pay $1.74 less per month or $20.88 less annually under the proposed rates.

CUSTOMER NOTICE AND PRESS RELEASE

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. The notice was included with bills mailed to customers between April 2, 2021 and May 3, 2021, providing customers with a reasonable opportunity to file timely comments with the Commission by the May 13, 2021 deadline. As of May 12, 2021, the Commission has received no comments from customers.

STAFF RECOMMENDATION

If the potential additional Staff comments do not provide any adjustments to the deferral, Staff recommends the Commission:

- Approve the deferral amount of $12.0 million for recovery.
- Approve the rates as described in Attachment A, the revised Exhibit No. 2.
- Approve the revised Tariffs.

Respectfully submitted this 13TH day of May 2021.

Matthew Hunter

Matt Hunter
Deputy Attorney General

Technical Staff: Joe Terry
Rick Keller
Kevin Keyt
Curtis Thaden

Idaho Energy Cost Adjustment Mechanism Deferral
January 1, 2020 - December 31, 2020

Exhibit No. 1

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

Line No.			Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total	As Filed	Variance
4	NPC Rate Embedded in Base Rates ($/MWh)	Line 3	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90			
5	ID Actual Sales @ Meter (MWh)		253,898	244,010	213,504	213,460	306,791	388,284	432,246	379,685	285,414	263,264	238,057	303,734			
6	ID NPC Collected in Rates ($)	Line 4 x Line 5	$ 6,828,770	$ 6,562,813	$ 5,742,325	$ 5,741,147	$ 8,251,353	$ 10,443,156	$ 11,625,549	$ 10,211,898	$ 7,676,414	$ 7,080,677	$ 6,402,702	$ 8,169,142	$ 94,735,944	$ 94,735,944	$ -
7	Total Company Adjusted Actual NPC Excl. Integration Adj. ($)	Adjusted Actual NPC	$ 123,339,882	$ 122,232,788	$ 127,063,155	$ 104,812,359	$ 111,412,548	$ 123,937,016	$ 156,474,324	$ 153,659,771	$ 122,655,857	$ 121,105,556	$ 114,802,183	$ 130,587,758	$ 1,512,083,197	$ 1,512,083,197	$ -
8	Intra-Hour Wind Integration Cost ($/MWh)		$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 0.39			
9	Third Party Wind Sold to Wholesale (MWh)	Note (1)	171,547	129,482	119,032	104,396	100,978	94,479	87,369	81,043	81,221	137,066	127,896	100,655			
10	Third Party Wind Adjustment ($)	Line 8 x Line 9	$ 66,227	$ 49,988	$ 45,953	$ 40,303	$ 38,983	$ 36,474	$ 33,729	$ 31,287	$ 31,356	$ 52,915	$ 49,375	$ 38,859	$ 515,450	$ 515,450	$ -
11	Total Company Adjusted Actual NPC ($)	Line 7 - Line 10	$ 123,273,655	$ 122,182,800	$ 127,017,201	$ 104,772,056	$ 111,373,565	$ 123,900,541	$ 156,440,595	$ 153,628,484	$ 122,624,501	$ 121,052,641	$ 114,752,808	$ 130,548,899	$ 1,511,567,747	$ 1,511,567,747	$ -
12	Total Company Load @ Input (MWh)		5,157,135	4,726,803	4,695,850	4,166,661	4,395,668	4,728,054	5,589,932	5,673,186	4,657,759	4,586,289	4,767,808	5,294,469	58,439,613	58,439,613	-
13	Actual NPC ($/MWh)	Line 11 / Line 12	$ 23.90	$ 25.85	$ 27.05	$ 25.15	$ 25.34	$ 26.21	$ 27.99	$ 27.08	$ 26.33	$ 26.39	$ 24.07	$ 24.66	$ 25.87	$ 25.87	$ -
14	ID Actual Load @ Input (MWh)		292,158	276,164	232,036	235,623	355,265	406,911	469,188	378,030	301,857	283,711	270,773	314,660			
15	Actual ID NPC	Line 13 x Line 14	$ 6,983,601	$ 7,138,542	$ 6,276,298	$ 5,924,812	$ 9,001,401	$ 10,663,269	$ 13,130,751	$ 10,236,972	$ 7,946,972	$ 7,488,400	$ 6,517,022	$ 7,758,762	$ 99,066,803	$ 100,391,959	$ 1,325,156 $ -
16	NPC Differential	Line 15 - Line 6	**$ 154,831**	**$ 575,729**	**$ 533,973**	**$ 183,665**	**$ 750,049**	**$ 220,113**	**$ 1,505,202**	**$ 25,074**	**$ 270,558**	**$ 407,724**	**$ 114,320**	**$ (410,379)**	**$ 4,330,859**	**$ 5,656,015**	**$ 1,325,156**
	EITF 04-6 Adjustment																
17	Idaho Allocated EITF 04-6 Deferral Adjustment ($)		**$ 2,779**	**$ (5,302)**	**$ (12,460)**	**$ (17,565)**	**$ (26,376)**	**$ (67,306)**	**$ (48,681)**	**$ (34,653)**	**$ (15,123)**	**$ 50,325**	**$ 24,378**	**$ 22,521**	**$ (127,464)**	**$ (127,464)**	**$ -**
	LCAR																
18	Actual Idaho Jurisdictional ECPC minus NPC (Assume Actual =	PAC-E-16-12	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 18,434,143	$ 18,434,143	$ -
19	LCAR Rate @ Meter ($/MWh)	PAC-E-16-12	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54			
20	ID Actual Sales @ Meter (MWh)	Line 5	253,898	244,010	213,504	213,460	306,791	388,284	432,246	379,685	285,414	263,264	238,057	303,734			
21	LCAR Revenue Collected through Base Rates ($)	Line 19 x Line 20	$ 1,406,345	$ 1,351,573	$ 1,182,598	$ 1,182,356	$ 1,699,318	$ 2,150,707	$ 2,394,214	$ 2,103,081	$ 1,580,912	$ 1,458,224	$ 1,318,599	$ 1,682,387	$ 19,510,312	$ 19,510,312	$ -
22	LCAR Adjustment	Line 18 - Line 21	**$ 129,833**	**$ 184,606**	**$ 353,580**	**$ 353,823**	**$ (163,139)**	**$ (614,528)**	**$ (858,035)**	**$ (566,902)**	**$ (44,734)**	**$ 77,955**	**$ 217,580**	**$ (146,208)**	**$ (1,076,170)**	**$ (1,076,170)**	**$ -**
	ECAM Deferral																
23	Total ECAM Deferral (NPC Deferral, EITF 04-6 Adjustment, LCA	Sum of Lines: 16, 17, 22	287,443	755,033	875,094	519,923	560,534	(461,722)	598,485	(576,480)	210,701	536,003	356,278	(534,067)	3,127,225	4,452,381	1,325,156
24	**Total ECAM Deferral after 90% Sharing**	Line 23 x 90%	**$ 258,698**	**$ 679,530**	**$ 787,584**	**$ 467,930**	**$ 504,481**	**$ (415,550)**	**$ 538,637**	**$ (518,832)**	**$ 189,631**	**$ 482,403**	**$ 320,650**	**$ (480,660)**	**$ 2,814,502**	**$ 4,007,143**	**$ 1,192,640**
	Lakeside 2 Resource Adder																
25	Lake Side 2 Generation (MWh)	Adjusted Actual NPC	199,759	304,612	334,338	232,649	126,034	252,268	329,456	359,671	282,210	265,006	43,497	-			
26	Resource Adder Rate ($/MWh)	PAC-E-13-04	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99			
27	Total Lake Side 2 Resource Adder ($)	Line 25 x Line 26	**$ 397,520**	**$ 606,178**	**$ 665,333**	**$ 462,972**	**$ 250,808**	**$ 502,013**	**$ 655,617**	**$ 715,745**	**$ 561,598**	**$ 527,362**	**$ 86,559**	**$ -**	**$ 5,431,705**	**$ 5,431,705**	**$ -**
	Production Tax Credits (PTCs)																
28	ID Allocated PTCs in Rates ($/MWh)	PAC-E-16-12	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)			
29	ID Actual Sales @ Meter (MWh)	Line 5	253,898	244,010	213,504	213,460	306,791	388,284	432,246	379,685	285,414	263,264	238,057	303,734			
30	ID PTCs in Rates ($)	Line 28 x Line 29	$ (506,216)	$ (486,500)	$ (425,678)	$ (425,590)	$ (611,671)	$ (774,150)	$ (861,800)	$ (757,006)	$ (569,051)	$ (524,889)	$ (474,631)	$ (605,577)			
31	ID Allocated Actual PTCs ($)		(704,885)	(671,005)	(614,254)	(521,444)	(488,116)	(554,228)	(469,805)	(384,241)	(436,142)	(621,981)	(724,278)	(933,213)			
32	ID PTCs Deferral ($)	Line 31 - Line 30	**$ (198,669)**	**$ (184,505)**	**$ (188,577)**	**$ (95,853)**	**$ 123,555**	**$ 219,921**	**$ 391,995**	**$ 372,766**	**$ 132,909**	**$ (97,092)**	**$ (249,646)**	**$ (327,635)**	**$ (100,831)**	**$ (100,831)**	**$ -**
	RTM Adjustment																
33	ID RTM Adjustment ($)		**$ 289,767**	**$ 327,150**	**$ 389,170**	**$ 398,281**	**$ 368,483**	**$ 360,799**	**$ 372,186**	**$ 340,377**	**$ 347,764**	**$ 454,757**	**$ 390,068**	**$ 393,085**	**$ 4,431,885**	**$ 4,431,885**	**$ -**
	Renewable Energy Credits (REC) Revenue																
34	ID REC Revenue in Rates ($/MWh)	PAC-E-16-12	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)			
35	ID Actual Sales @ Meter (MWh)	Line 5	253,898	244,010	213,504	213,460	306,791	388,284	432,246	379,685	285,414	263,264	238,057	303,734			
36	ID REC Revenue in Rates ($)	Line 34 x Line 35	$ (22,785)	$ (21,898)	$ (19,160)	$ (19,156)	$ (27,532)	$ (34,846)	$ (38,791)	$ (34,074)	$ (25,614)	$ (23,626)	$ (21,364)	$ (27,258)			
37	ID Allocated Actual REC Revenue ($)		52,729	(796)	(74,572)	(46,132)	17,825	(2,472)	(983)	386	(39)	(44,535)	(191,640)	(17,319)			
38	REC Revenue Adjustment ($)	Line 37 - Line 36	**$ 75,514**	**$ 21,102**	**$ (55,412)**	**$ (26,976)**	**$ 45,357**	**$ 32,374**	**$ 37,808**	**$ 34,460**	**$ 25,575**	**$ (20,909)**	**$ (170,277)**	**$ 9,939**	**$ 8,557**	**$ 8,557**	**$ -**
39	**Total Deferral**	Sum of Lines 24, 27,	**$ 822,832**	**$ 1,449,455**	**$ 1,598,098**	**$ 1,206,353**	**$ 1,292,683**	**$ 699,558**	**$ 1,996,244**	**$ 944,516**	**$ 1,257,477**	**$ 1,346,521**	**$ 377,354**	**$ (405,271)**	**$ 12,585,818**	**$ 13,778,459**	**$ 1,192,640**
40	Interest Rate	Order No. 34204	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%			
	ECAM Balancing Account ($)																
41	Beginning Balance		$ 24,397,925	$ 24,612,203	$ 25,043,200	$ 25,716,429	$ 26,182,826	$ 26,581,223	$ 25,703,605	$ 25,095,659	$ 23,589,136	$ 22,799,497	$ 22,450,255	$ 20,494,803			
42	ECAM Deferral After Sharing	Line 24	258,698	679,530	787,584	467,930	504,481	(415,550)	538,637	(518,832)	189,631	482,403	320,650	(480,660)			
43	Lake Side 2 Resource Adder	Line 27	397,520	606,178	665,333	462,972	250,808	502,013	655,617	715,745	561,598	527,362	86,559	-			
44	PTCs Deferral	Line 32	(198,669)	(184,505)	(188,577)	(95,853)	123,555	219,921	391,995	372,766	132,909	(97,092)	(249,646)	(327,635)			
45	RTM Adjustment	Line 33	289,767	327,150	389,170	398,281	368,483	360,799	372,186	340,377	347,764	454,757	390,068	393,085			
46	REC Revenue Adjustment	Line 38	75,514	21,102	(55,412)	(26,976)	45,357	32,374	37,808	34,460	25,575	(20,909)	(170,277)	9,939			
47	Less: Monthly ECAM Rider Revenues allocated to ECAM		(649,362)	(1,059,802)	(967,134)	(783,170)	(938,219)	(1,620,711)	(2,646,487)	(2,491,576)	(2,085,740)	(1,733,439)	(2,368,564)	(1,072,226)			
48	Interest		40,808	41,345	42,264	43,213	43,933	43,534	42,297	40,537	38,625	37,677	35,758	32,927			
49	**ECAM Deferral Balance ($)**		**$ 24,612,203**	**$ 25,043,200**	**$ 25,716,429**	**$ 26,182,826**	**$ 26,581,223**	**$ 25,703,605**	**$ 25,095,659**	**$ 23,589,136**	**$ 22,799,497**	**$ 22,450,255**	**$ 20,494,803**	**$ 19,050,233**	**$ 19,050,233**	**$ 23,211,078**	**$ 4,160,845**
	Depreciation Regulatory Asset Balancing Account ($)																
50	Beginning Balance	PAC-E-13-02 / PAC-I	$ (76,878)	$ (78,406)	$ (86,462)	$ (91,713)	$ (93,922)	$ (97,060)	$ (107,202)	$ (121,928)	$ (134,933)	$ (141,737)	$ (144,824)	$ (155,003)			
51	Monthly Deferral		166,549	167,191	168,440	168,350	170,008	170,487	170,211	169,827	171,927	172,193	171,907	172,711			
52	Less: Monthly ECAM Rider Revenues allocated to Depreciation Regulatory Asset		(168,078)	(175,246)	(173,691)	(170,559)	(173,146)	(180,629)	(184,936)	(182,833)	(178,731)	(175,280)	(182,085)	(168,220)			
53	**Depreciation Regulatory Asset Ending Balance ($)**		**$ (78,406)**	**$ (86,462)**	**$ (91,713)**	**$ (93,922)**	**$ (97,060)**	**$ (107,202)**	**$ (121,928)**	**$ (134,933)**	**$ (141,737)**	**$ (144,824)**	**$ (155,003)**	**$ (150,512)**	**$ (150,512)**	**$ (150,512)**	**$ -**
54	**Total ECAM Deferral Balance**	Sum of Lines 49, 53	**$ 24,533,797**	**$ 24,956,739**	**$ 25,624,716**	**$ 26,088,904**	**$ 26,484,163**	**$ 25,596,402**	**$ 24,973,731**	**$ 23,454,202**	**$ 22,657,760**	**$ 22,305,431**	**$ 20,339,800**	**$ 18,899,721**	**$ 18,899,721**	**$ 23,060,567**	**$ 4,160,845**

Note:
(1) Recovery of non-owned wind integration costs pending future rate cases.

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

Line No.	Description	Sch.	Average Cust	MWH	Present Rev ($000)	At Meter MWh by Voltage S	At Meter MWh by Voltage P	At Meter MWh by Voltage T	At Generation MWh	ECAM Proposal Rev ($000)	ECAM Proposal Rate ¢/kWh S	ECAM Proposal Rate ¢/kWh P	ECAM Proposal Rate ¢/kWh T	Present ECAM Rev ($000)	Net Change ($000)	Net Change %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Residential Sales															
1	Residential Service	1	46,059	442,589	$49,602	442,589			487,503	$1,566	0.354	0.342	0.333	$2,527	($961)	-1.8%
2	Residential Optional TOD	36	13,484	235,152	$22,484	235,152			259,016	$832	0.354	0.342	0.333	$1,343	($511)	-2.1%
3	AGA Revenue				$3											
4	Total Residential		59,543	677,741	$72,090	677,741	0	0	746,519	$2,398				$3,870	($1,472)	-1.9%
5	**Commercial & Industrial**															
6	General Service - Large Power	6	1,036	303,011	$23,667	258,477	44,534		332,125	$1,067	0.354	0.342	0.333	$1,720	($653)	-2.6%
7	General Svc. - Lg. Power (R&F)	6A	214	30,600	$2,616	30,600			33,705	$108	0.354	0.342	0.333	$175	($66)	-2.4%
8	*Subtotal-Schedule 6*		*1,250*	*333,611*	*$26,283*	*289,077*	*44,534*	*0*	*365,830*	*$1,175*				*$1,895*	*($720)*	*-2.6%*
9	General Service - High Voltage	9	17	121,001	$7,626			121,001	125,363	$403	0.354	0.342	0.333	$644	($241)	-2.9%
10	Irrigation	10	4,969	602,488	$54,316	602,488			663,629	$2,132	0.354	0.342	0.333	$3,440	($1,308)	-2.3%
11	Comm. & Ind. Space Heating	19	103	5,151	$438	5,151			5,674	$18	0.354	0.342	0.333	$29	($11)	-2.4%
12	General Service	23	6,634	153,848	$14,913	152,484	1,364		169,411	$544	0.354	0.342	0.333	$878	($334)	-2.1%
13	General Service (R&F)	23A	2,314	33,450	$3,376	32,839	611		36,822	$118	0.354	0.342	0.333	$191	($73)	-2.0%
14	*Subtotal-Schedule 23*		*8,948*	*187,299*	*$18,289*	*185,323*	*1,975*	*0*	*206,233*	*$663*				*$1,069*	*($407)*	*-2.1%*
15	General Service Optional TOD	35	3	1,893	$123	1,893			2,085	$7	0.354	0.342	0.333	$11	($4)	-3.1%
16	Special Contract 1	400	1	1,443,926	$86,967			1,443,926	1,495,980	$4,806			0.333	$7,682	($2,876)	-3.0%
17	Special Contract 2	401	1	107,486	$6,264			107,486	111,361	$358			0.333	$572	($214)	-3.1%
18	AGA Revenue				$478											
19	Total Commercial & Industrial		15,293	2,802,855	$200,786	1,083,932	46,510	1,672,413	2,976,154	$9,561				$15,342	($5,781)	-2.7%
20	**Public Street Lighting**															
21	Security Area Lighting	7	193	267	$102	267			294	$1	0.354	0.342	0.333	$2	($1)	-0.6%
22	Security Area Lighting (R&F)	7A	136	107	$44	107			117	$0	0.354	0.342	0.333	$1	($0)	-0.5%
23	Street Lighting - Company	11	37	87	$40	87			95	$0	0.354	0.342	0.333	$0	($0)	-0.5%
24	Street Lighting - Customer	12	234	2,424	$436	2,424			2,670	$9	0.354	0.342	0.333	$14	($5)	-1.2%
25	AGA Revenue				$0											
26	Total Public Street Lighting		600	2,884	$621	2,884	0	0	3,177	$10				$16	($6)	-1.0%
27	**Total Sales to Ultimate Customers**		75,435	3,483,480	$273,497	1,764,558	46,510	1,672,413	3,725,850	$11,969				$19,228	($7,259)	-2.5%
28	**Total (w/o Sch 400, 401)**		75,433	1,932,068	$180,265	1,764,558	46,510	121,001	2,118,509	$6,806				$10,975	($4,169)	-2.2%
				Rev. Rqmt	Unallocated	Allocated					Proposed Rates			Current Rates		
29	Voltage Line Loss Factors applied to rates:					1.10148	1.06475	1.03605			S	P	T	S	P	T
30	Total Company Current Deferral Rate (cents/kWh) ECAM deferral			$11,969	0.321	0.354	0.342	0.333								
31									Total Tariff Customer Rate		0.354	0.342	0.333	0.571	0.549	0.532
32									Total Schedule 400 Rate				0.333			0.532
33									Total Schedule 401 Rate				0.333			0.532

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ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF IDAHO

Energy Cost Adjustment

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

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

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

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

		Delivery Voltage		
		Secondary	Primary	Transmission
Schedule	1	0.354~~571~~¢ per kWh		
Schedule	6	0.354~~571~~¢ per kWh	0.342~~549~~¢ per kWh	
Schedule	6A	0.354~~571~~¢ per kWh	0.342~~549~~¢ per kWh	
Schedule	7	0.354~~571~~¢ per kWh		
Schedule	7A	0.354~~571~~¢ per kWh		
Schedule	9			0.333~~532~~¢ per kWh
Schedule	10	0.354~~571~~¢ per kWh		
Schedule	11	0.354~~571~~¢ per kWh		
Schedule	12	0.354~~571~~¢ per kWh		
Schedule	19	0.354~~571~~¢ per kWh		
Schedule	23	0.354~~571~~¢ per kWh	0.342~~549~~¢ per kWh	
Schedule	23A	0.354~~571~~¢ per kWh	0.342~~549~~¢ per kWh	
Schedule	24	0.354~~571~~¢ per kWh	0.342~~549~~¢ per kWh	
Schedule	35	0.354~~571~~¢ per kWh	0.342~~549~~¢ per kWh	
Schedule	35A	0.354~~571~~¢ per kWh	0.342~~549~~¢ per kWh	
Schedule	36	0.354~~571~~¢ per kWh		
Schedule	400			0.333~~532~~¢ per kWh
Schedule	401			0.333~~532~~¢ per kWh

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 13TH DAY OF MAY 2021, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-21-09, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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Jo Nelson
SECRETARY