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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2020 THROUGH MAY 31, 2021	)	**CASE NO. IPC-E-20-21** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Idaho Power Company's Application.

BACKGROUND

On April 15, 2020, Idaho Power Company filed its annual power cost adjustment (PCA) Application. The Company seeks an Order approving an update to Schedule 55 reflecting a $58.7 million increase in the PCA rates now in effect (or an average increase of approximately 5.21% of current billed revenue), effective June 1, 2020 through May 31, 2021. The PCA mechanism permits Idaho Power to adjust its PCA rates upward or downward to reflect the Company's annual power supply costs. With its Application, the Company included proposed tariffs, supporting exhibits, and the pre-filed direct testimonies of Nicole Blackwell and Timothy Tatum.

Idaho Power has proposed to implement the PCA rates on June 1, 2020. The Commission approved the Company's request to process the PCA Application using Modified Procedure in Order 34656 dated April 30, 2020.

STAFF ANALYSIS

Staff recommends approval of the Company's proposed update to Schedule 55 reflecting a $58.7 million increase in billed revenue, effective June 1, 2020 through May 31, 2021. This recommendation is based on Staff's audit review, examination of the testimony and workpapers of Company witnesses Timothy Tatum and Nicole Blackwell and Company responses to audit requests.

If the PCA Application is approved as filed, the monthly bill for a typical residential customer using 950 kWh would increase by about $4.01 per month, effective June 1, 2020. The Company has also proposed a change to its annual Fixed Cost Adjustment (FCA), also effective June 1, 2020. The proposed FCA adjustment increases the typical customer's monthly bill by $0.02, resulting in a combined $4.03 monthly increase. If the PCA and the FCA are approved as filed, the combined impact is an overall increase from current billed revenue of $58.8 million, or 5.22%.

The Company stated that it considered the effects that its PCA proposal would have on customers during the Covid-19 pandemic and responded by temporarily suspending late payment fees for applicable billings and service disconnections for non-payment for Idaho and Oregon residential and small/medium business customers. However, the Company chose to request that it be allowed to implement the full proposed PCA increase, effective June 1, 2020. The Company stated that deferring some or all of the proposed increase risks stacking this increase on top of future rate increases. The Company also stated that deferring the increase could create financial problems related to its ability to access cash for operations. Tatum Direct at 30-32.

Staff shares the Company's concerns about future stacked rate increases and cash flow, but is also concerned about the many customers who may have lost jobs or are working reduced hours because of the pandemic. These customers may struggle with bill increases typically exceeding 4%. Staff believes that the Company should continue to work with customers who are having trouble paying bills.

The impacts by class from the Company's PCA proposal are shown in Table No. 1.

Table No. 1: Overall Rate Impact

Class Description	Rate Schedule No.	Change
Residential	1	4.20%
Master Metered Mobile Home Park	3	4.37%
Residential Service Time of Day	5	4.33%
Residential Service On-Site Generation	6	3.99%
Small General Service	7	3.47%
Small General Service On-Site Generation	8	3.38%
Large General Service	9	5.80%
Dusk to Dawn Lighting	15	2.52%
Large Power Service	19	7.25%
Irrigation	24	5.32%
Micron	26	8.09%
JR Simplot	29	8.36%
DOE	30	8.29%
Unmetered General Service	40	4.94%
Street Lighting	41	3.48%
Traffic Control Lighting	42	6.64%
System Average Increase		5.21%

Components of Proposed PCA Increase

The components of the $58.7 million increase in the PCA rates are shown in Table No. 2:

Table No. 2: Revenue Impact by PCA Rate Component

Rate Component	2019-2020 PCA	2020-2021 PCA	Difference
PCA Forecast	$83,775,043	$112,441,726	$28,666,683
PCA True-up	($64,855,320)	($ 42,648,330)	$22,206,990
PCA Total	$18,919,723	$ 69,793,396	$50,873,673
Revenue Sharing	($ 5,096,850)	$ 0	$ 5,096,850
Tax Reform	($ 2,715,902)	$ 0	$ 2,715,902
PCA Total	$11,214,205	$ 69,793,396	$58,686,425

Due to its diverse generation portfolio, Idaho Power's actual power supply costs vary each year depending on changes in river streamflow, the amount of purchased power, fuel costs, the market price of power, and other factors. Because of potentially large differences in actual cost as compared to the amount of Net Power Supply Expense (NPSE) collected through base rates, the

PCA mechanism is designed to true-up these annual differences so that customers are paying no more and no less than actual NPSE (minus sharing).

The annual PCA mechanism consists of three major components. First, projected power costs for the coming PCA year (June 1, 2020 to May 31, 2021) are calculated using the Company's most recent Operating Plan. The projected power costs include fuel costs, transmission costs for purchased power, Public Utility Regulatory Policies Act of 1978 (PURPA) contract expenses, surplus sales revenues, and revenues from the sale of renewable energy credits and sulfur dioxide allowances. The Company may recover 95% of the difference between the non-PURPA projected power costs and the approved base power cost, 100% of the costs of its PURPA contracts, and 100% of its demand-side management incentive and conservation costs. *See* Order No. 30715; *see generally* Order No. 32426.

Second, because the PCA includes forecasted costs, the preceding year's forecasted costs are trued-up based upon the actual costs incurred during the prior year. The Company includes its actual costs of Western Energy Imbalance Market participation from April 2019 through March 2020 in the true-up. *See* Order No. 34100.

Finally, the Company reconciles the previous year's true-up by crediting to or collecting from customers through the PCA rate any surplus or deficit from the prior year's true-up. This third component (sometimes referred to as the "true-up of the true-up") ensures the Company recovers its actual approved costs while ratepayers pay only for the actual amount of power that the Company sold to meet native load requirements. In other words, ratepayers receive a rate credit when power supply costs are low and are assessed a rate surcharge when power supply costs are high.

This year's PCA Application requests a total revenue increase of about $58.7 million for the 2020-2021 PCA year. The Company attributes this year's PCA increase to several factors. Surplus power sales revenue is expected to decrease due to an expected reduction in hydro generation and lower market energy prices. When market energy prices are high, as they were for last year's PCA, the Company's NPSE tends to be low because the resulting increased surplus sales revenue help to offset power supply costs. In contrast, this year's lower market energy prices are significantly reducing forecasted surplus sales revenue compared to last year's forecast. Lower surplus sales revenue is also increasing the PCA true-up component. Also, the Company will likely decrease coal-fired generation because it is less economically viable for load service and off-system sales. The 2020-2021 PCA revenue collection is in the same range as revenue collection over three of the four previous PCA years, with the significantly lower collection last year (2019-2020 PCA) being the outlier.

Another factor contributing to the PCA increase is the removal of the revenue-sharing credit received last year. Under Order No. 33149, the Commission requires the Company to share revenue with its customers if the Company's Idaho jurisdictional year-end return on equity (ROE) is 10.0% or greater. The Company's Idaho jurisdictional year-end ROE in 2019 was 9.8% and therefore does not meet the threshold for revenue sharing.[1]

Unlike the 2018-2019 and the 2019-2020 PCA tariff schedules, this year's PCA tariff schedule does not include a credit to customers reflecting the Company's savings from federal tax reform and Idaho state tax rate changes. Under a settlement stipulation approved by the Commission in Order No. 34071, Case No. GNR-U-18-01, Idaho Power applied a $7,818,624 credit to its 2018-2019 PCA tariff schedule, and a $2,680,957 credit to its 2019-2020 PCA tariff schedule. Under the settlement stipulation, the credit will be reduced to $0 beginning June 1, 2020.

Audit Review

Staff examined the Company's sales and costs for the 2019-2020 PCA year and the Company's sales and cost forecasting methodologies for the upcoming 2020-2021 PCA year. Staff also reviewed the Company's filing and methodologies to ensure compliance with prior Commission Orders, including Orders pertaining to Revenue Sharing and Tax Reform benefits. As a result, Staff concludes that:

a. The Company complied with Commission Order Nos. 24806, 30715, 30978, 32206, 32424, 33149, and 33307 when calculating the incremental change in the upcoming year's PCA rates;
b. The actual loads, fuel consumption, fuel costs, purchased power costs, and kilowatt-hour sales for the current PCA year (2019 -2020) are accurate;
c. For the upcoming PCA year (2020-2021), the Company conducted a reasonable forecast of kilowatt-hour sales, loads, fuel consumption, fuel costs, and purchased power costs;

[1] By comparison, the 2019-2020 PCA included a revenue-sharing component of $5,024,562. *See* Case No. IPC-E-19-16, Order No. 34351.

d. The Company incurred a reasonable and prudent amount of actual NPSE to serve its customer load; and
e. The Company's Idaho jurisdictional 2019 year-end Return on Equity (ROE) was 9.8%. Since this was under the 10.0% ROE threshold for revenue sharing that was set in Order No. 33149, there isn’t a credit this year.

Forecast Analysis

Staff believes that the Company’s forecast for the 2020-2021 PCA is reasonable and any over or under-collected amounts due to forecast variance will be trued-up in next year’s PCA.

For this PCA year forecast, the Company used its March 26, 2020 Operating Plan to forecast the difference between NPSE embedded in base rates and NPSE the Company expects to recover in the coming year. The Company uses a dispatch simulation model to analyze projected load, resource balance, and energy supply to create a monthly forecast for the upcoming PCA year. Additional considerations for the forecast include forward market energy prices, hydro generation, fuel prices, existing hedge transactions, and costs associated with PURPA and non-PURPA contracts.

The 2020-2021 PCA forecast component to be collected from Idaho customers is $112,436,598. Blackwell Direct at 5. This is composed of FERC accounts shared at 100% and those shared at 95% as more fully discussed below.

Accounts Shared at 95% Customers and 5% Company (95%/5%)

The accounts shared at 95%/5% include Power Supply Costs and Surplus Sales. The Commission created a methodology that assigns purchased power costs or benefits to customers and shareholders as incentive to the Company to make careful resource acquisition decisions. Thus, in the PCA, annual deviations between actual and normalized power supply costs are shared 95%/5% by customers and Company shareholders. Order No. 30715. If costs are below those anticipated, customers receive 95% of the difference. If costs are above those anticipated, customers pay 95% of the excess costs and the Company absorbs 5%.

A return to more normal market energy price levels in this year’s PCA forecast, as well as a reduction in forecasted hydro generation, means surplus sales are expected to decrease. The decrease in market energy prices is also contributing to a reduction in forecasted coal-fired generation as it is less economic for load service as well as off-system sales. Conversely, due to the lower market energy prices, the Company is expected to increase its market power purchases. In total, the PCA forecast for shared power supply accounts for the upcoming 2020-2021 PCA year has increased by $30.9 million (total system) compared to 2019-2020.

True-Up Analysis

The true-up deferral balance, shown in Table No. 2, is composed of the differences between actual NPSE and NPSE recovered through base rates and forecasted revenues. It also includes the participation costs in the Western Energy Imbalance Market (EIM), Renewable Energy Credit (REC) sales, and the difference between actual demand response incentive payments and amount recovered in base rates. The ending balance of the true-up also includes collections through the current forecasted PCA rate and monthly accrued interest.

Staff reviewed the true-up components. Based on its review, Staff believes that the Company's proposed true-up amount is accurate, conforms to the Commission's past orders, and the actual costs incurred are reasonable and prudent. The review conducted by Staff entailed: (i) an on-site examination of the components included in the true-up or deferral balance; (ii) an analysis of the methods and the basis used to calculate the cost deferrals and account balances; (iii) an examination of the actual NPSE, which included a review of the monthly Energy Risk Management Committee minutes, operating plans, and other reports presented to the Energy Risk Management Committee; and (iv) an analysis to determine if the Company prudently dispatched resources, purchased power, and sold power in the wholesale market.

For its Idaho jurisdiction, the Company calculated a true-up component refund of about $31.9 million, and expects to refund this amount through a true-up rate of -0.2220 cents per kWh as compared to last year's rate of -0.3806 cents per kWh. Table No. 3 provides a summary of the Company's proposed $31.9 million true-up refund amount followed by explanations of significant line items

Table 3: PCA True-Up Summary

Net Power Supply Expense Deferral	Deferral Amount
Fuel Expense – Coal	$ (23,206,559)
Fuel Expense – Gas	17,290,323
Non-Firm Purchases	12,645,405
Off-System Sales / Surplus Sales	(2,171,440)
Third Party Transmission Expense	1,337,038
Water for Power (Leases)	(237,279)
Subtotal - Net Power Supply Expense	$5,657,487
Other PCA Expenses	
Emission Allowances & Renewable Energy Credit (REC) Sales	(4,908,073)
Sales Based Adjustment	(8,348,721)
Qualifying Facilities	59,193,327
Demand Response Incentive Payments	(4,256,029)
EIM Participation Costs	3,182,908
Subtotal – Other PCA Items	$44,863,411
Total PCA Expenses	$50,520,898
PCA Forecasted Revenue	$(81,993,706)
Ending Deferral Balance (Expense Items minus PCA Forecasted Revenue)	$(31,472,808)
Interest on the Deferral Balance	(396,838)
Total True-Up Deferral	$(31,869,646)

Net Power Supply Expense Deferral

Staff believes the Company's NPSE were prudently incurred to meet customer load. The Company's NPSE primarily consists of costs related to coal and other fuels, non-PURPA purchased power, and surplus sales. The main NPSE components are described below:

1. *Fuel Expense – Coal*: The Company owns an interest in, and receives electricity from, three coal plants: Bridger, Valmy, and Boardman. Staff reviewed all coal expenses in a 6-month sample of the PCA deferral period and believes the amount the Company reported is accurate. The Company includes the increase or decrease in coal expense from base rates in the PCA for recovery from, or a credit to, customers. This year's PCA deferral balance, after jurisdictional allocation and sharing, includes a coal expense difference of *negative* $23,206,559, which is a credit to customers.
2. *Fuel Expense - Gas*. The Company owns and operates gas-fired combustion turbine generating plants at the Evander Andrews Power Complex (Danskin),

Bennett Mountain, and Langley Gulch. Staff reviewed a 6-month sample of the natural gas expenses. The transactions appear reasonable and follow the Idaho Power Energy Risk Management Committee's policies and standards. The Company includes the increase or decrease in natural gas expense from base rates in the PCA for recovery from, or a credit to, customers. This year's PCA deferral balance, after jurisdictional allocation and sharing, includes a gas expense difference of $17,290,323 to be recovered from customers.

3. *Non-firm Purchases*. To supplement its own generation, the Company buys wholesale power based on its Energy Risk Management Policy and Standards, operating reserve margins, unit availability, and economics. In addition, the Company has entered the EIM, and all EIM purchases are included as non-firm purchases. After jurisdictional allocation and sharing, actual non-PURPA power purchases exceeded base amounts by $12,645,405. Staff reviewed the purchases and transactions made during the PCA deferral period. The transactions appear reasonable and follow the Risk Management Committee's recommendations. These transactions were made with an assortment of credit-worthy partners in a timely manner.
4. *Off-System Sales*. After jurisdictional allocation and sharing, actual surplus sales were $2,171,440 more than the amount included in base rates. This decreases the deferral balance to be recovered from customers.
5. *Third-Party Transmission*. In Order No. 30715, the Commission directed the Company to track third-party transmission costs associated with market purchases and off-system sales through the PCA like other variable power supply costs. After jurisdictional allocation and sharing, third-party transmission expense amounted to $1,337,038 to be recovered from customers.
6. *Water Leases*. The Company sometimes incurs lease expenses for water to produce hydro power. After jurisdictional allocation and sharing, a *negative* $237,279 was incurred, which decreases the deferral balance.

Other PCA Expenses

7. *Emission Sales & Renewable Energy Credit (REC) Sales*. In Order No. 30818, the Commission required the Company to sell RECs and apply the benefits to

customers. The deferral balance includes an amount of $4,908,073 in revenue from Emission and REC sales, after allocation and sharing. This increase in revenues decreases the deferral balance recovered from customers. Staff reviewed the Emission and REC transactions included in the PCA deferral period and verified that the amount included in the deferral period is accurate.

8. *Sales-Based Adjustment*. The Company calculates a $8,348,721 Sales-Based Adjustment (SBA) credit to customers from the Company's over-recovery of actual NPSE collected through base rates due to differences in base versus actual sales. The SBA uses the $26.72/MWh SBA rate established in Order No. 33307. When multiplied by the difference in actual and base rate sales, it calculates the over or under recovery of actual NPSE due to sales that are higher or lower than sales used to determine base rates (subject to 95% customer sharing). Staff audited and analyzed the Company's SBA calculations by: (1) auditing actual sales; (2) confirming the SBA rate and sales used to set base rates; and (3) verifying the Company's method for calculating the SBA followed the Commission's prior orders. Staff believes the Company calculated the SBA adjustment consistently with past Commission orders, and that the adjustment is accurate.

9. *Qualifying Facility/PURPA Expense*. For the 2019-2020 PCA deferral period, the actual Idaho Jurisdictional PURPA expense totaled $59,193,327. PURPA contracts are not subject to sharing, but they are subject to jurisdictional allocation. Staff audited a sample of the actual monthly PURPA expense incurred during the deferral period and believes the amount reported is accurate.

10. *Demand Response Incentive Payments*. Staff reviewed the Company's actual Demand Response (DR) incentive payments included in the 2019-2020 PCA deferral balance. Staff confirms there was a decrease of $4,256,029 in actual DR incentive expenditures in the deferral. DR incentive payments are allocated 100% to Idaho and are not subject to sharing. The prudency of the DR incentive payments will be determined in Idaho Power's annual DSM prudency filing currently before the Commission (Case No. IPC-E-20-15). Any DSM prudency disallowance in that case will be reflected in next year's PCA deferral balance. This reduced level of DR incentive payments reduces the deferral balance to be recovered from customers.

11. *EIM Participation Costs*. The Company has included operation and maintenance expenses which are directly related to its participation in the EIM. The Idaho Power recovery method for costs associated with participating in the EIM was approved in Order No. 34100. The benefits of the EIM market automatically flow through the PCA, matching costs with benefits until the next general rate case, at which point the costs and benefits will be built into rates. Staff has reviewed these costs and believes they are appropriately recorded and accurate. The Idaho share of the EIM expenses is $3,182,908.
12. *Revenue from the PCA Forecast*. The Company's forecast rates generated $81,993,706 in revenue during the deferral period. The forecast rate changes each June when the new PCA rates are established. Therefore, the deferral period reflects the rate set in the two previous PCA periods. This amount is credited to customers in the calculation of the overall deferral balance for the 2018-2019 deferral period. Staff verified the revenue collected during the PCA period.
13. *Interest on the Deferral Balance.* The deferral balance accrues interest at the customer deposit rate, which was at 1% for 2018 when it changed to 2% for 2019 per Order No. 34204. The interest accrued during the current deferral period is a credit to customers of $396,838. Staff verified the interest calculations and agrees that the Company's calculation is accurate.

Reconciliation of the True-up (True-up of the True-up) Analysis

The reconciliation of the true-up tracks the recovery of the prior year's true-up amounts. It nets the actual revenue collected from the true-up rates, and any other line items collected in the PCA such as revenue sharing, against the amounts set for recovery. Any difference is carried into the next year's true-up reconciliation along with the true-up difference.

The *negative* $10,778,801.08 ending balance amount is the revenue requirement used to form the reconciliation of the true-up portion of the overall PCA rate. The reconciliation is shown on the line labeled "Ending True-Up of the True-Up Balance" in Company Exhibit No. 1. Staff audited the amounts booked to the reconciliation of the true-up, verified the Company's calculations, and reviewed the method used to ensure it complies with past Commission orders. Because of its review, Staff believes the Company correctly reconciled the true-up.

1. <u>2018-2019 True-up Deferral Balance.</u> The ending true-up deferral balance from the 2018-2019 PCA period was approved in Order No. 34351. The ending deferral balance in last year's PCA was *<u>negative</u>* $53,933,956. This amount is added to the beginning balance of the reconciliation of the true-up. This amount has been properly recorded in April 2019 in the reconciliation of the true-up for recovery.
2. <u>Collections from True-up Rates and Interest</u>. Staff reviewed and verified the collections from customers and the interest calculations. Staff has also verified that the collections and interest are properly reflected in the reconciliation of the true-up.

Revenue Sharing

The Commission established a mechanism in 2010 that required the Company to share revenue with customers based on the Company's actual Idaho jurisdictional year-end ROE. *See* Order No. 30978. The Commission subsequently modified the revenue-sharing mechanism and extended it in Order Nos. 32424, 33149, and 34701. The Company's 2019 year-end Idaho jurisdictional ROE was 9.8 percent. This is below the 10 percent threshold for revenue sharing resulting in no revenue sharing with customers. Staff has reviewed the work papers, source documents, and supporting documentation and agrees with the revenue-sharing calculations.

Tax Reform Benefits

As part of a settlement stipulation approved in Order No. 34701, Parties agreed to a $7.8 million PCA credit from June 1, 2018 through May 31, 2019. The total tax credit benefits reflect the $4.2 million one-time adjustment and an additional $3.6 million credit that is scheduled to decrease to $2.7 million on June 1, 2019 and reach $0 on June 1, 2020. The expiration of the credit in this case causes a $2.7 million increase in the PCA revenues to be collected in the coming PCA year.

Rate Calculations

The Company calculated the proposed increase by combining the three standard PCA components for the 2020-2021 PCA: projected power cost at 0.7833 cents per kWh, the true-up at *<u>negative</u>* 0.2220 cents per kWh, and the reconciliation at *<u>negative</u>* 0.0751 cents per kWh. These three standard PCA components added together equal the 0.4862 cents per kWh charge for all rate classes, which is reflected in the Company's proposed Schedule 55 PCA rates.

Staff reviewed the components that make up this year's Schedule 55 PCA rates and has concluded that they are fair, just, and reasonable. Staff's review of all the rate components included verification that: (1) the rates were calculated accurately; (2) the methods used to spread the rates across the customer classes provided a fair allocation; and (3) the methods comply with Commission orders. Staff confirmed that the revenue requirement was allocated across customer classes on an equal cents per kilowatt-hour basis. This ensures that customers share the PCA revenue requirement based on amount of energy consumed, which is how NPSE is allocated in customer base rates.

Annual Fluctuations in the PCA Rate Due to the Company's PCA Methodology

Staff believes the Company's PCA could be simplified, while not diminishing its purpose, by removing the forecast component which has contributed to significant rate fluctuations for customers. Staff points out that Avista and Rocky Mountain Power have mechanisms similar to Idaho Power's PCA that provide recovery of annual changes in power supply expenses, but do not include forecasts.

Since 2011, the Company's PCA rate has varied considerably, from a credit of 0.0629 cents per kWh in 2011 to a surcharge of 1.2306 cents per kWh in 2013. If applied to current rates, this difference would represent a 14.6% fluctuation in annual charges for a residential customer using 800 kWh per month. Staff believes it likely that fluctuations in the annual PCA rate could be reduced by simplifying the PCA mechanism without affecting the Company's long-term ability to fully collect its revenue requirement.

The current PCA mechanism consists of three components: A forecast of the power supply costs that will be incurred during the next April through March operating year; a true-up, which corrects for over or under-collection in the previous year; and a true-up to the true-up, which corrects for over or under-collection of the previous year's true-up of power supply costs incurred two years earlier.

For the time period 2011 through 2019, Staff compared each year's forecasted power supply cost to the subsequent year's true-up. The true-up represents the error between the actual power supply costs incurred by the Company over the April-March operating year, and the Company's forecasted power supply costs for the same time period. Staff notes that if the Company's forecasts were perfect, the true-up would be zero. Staff's comparison of each year's forecasted power costs to the subsequent year's true-up and found that on average, the true-up was 67% of the previous year's forecasted PCA value.

It is not Staff's intention to criticize the Company's operational forecasting methodology. Staff believes this methodology to be more than satisfactory for most business purposes; however, Staff questions the need for this or any other forecasting methodology as part of the PCA mechanism. Staff believes that the large relative forecasting error may contribute to year-to-year fluctuations in the PCA rate, and that a PCA mechanism that does not rely on forecasts could create more rate stability than the current method.

Although Staff was unable to fully investigate this matter during the 29-day period between the Company's April 15 filing date and the May 14 comment deadline, Staff plans to conduct a study of the current PCA mechanism's stability prior to next year's filing. Staff believes that it would be beneficial for Staff to meet with the Company during this process, and therefore recommends that the Commission order the Company to meet with Staff to discuss simplifications to the PCA mechanism.

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, IDAPA 31.01.01.125. The notice was or will be included with bills mailed to customers beginning April 23, 2020 and ending May 21, 2020. Customers whose bills will be mailed on May 18, 19, 20, and 21 were sent a direct mail postcard, mailed no later than May 15, 2020, outlining the Company's filing on April 15, 2020. Unfortunately, even with the Company's attempt to notify some customers earlier, many will not have a reasonable opportunity to file comments by the May 14, 2020 comment deadline.

Because the Company is proposing a rate increase, it is likely that some customers may object to the proposed rate changes. All customers should have an opportunity to comment and have their comments considered by the Commission. Staff thus recommends the Commission accept and consider late-filed customer comments. As of May 13, 2020, the Commission had received no comments from customers.

STAFF RECOMMENDATIONS

Staff recommends that the Commission:

1. Approve the Company's update to Schedule 55 (Application, Attachment 1), effective June 1, 2020, for the period June 1, 2020 through May 31, 2021;
2. Order the Company to meet with Staff to discuss simplifications to the PCA mechanism; and
3. Accept and consider late-filed customer comments.

Respectfully submitted this 14th day of May 2020.

Matt Hunter
Deputy Attorney General

Technical Staff: Bentley Erdwurm
Mike Morrison
Johan Kalala-Kasanda
Curtis Thaden

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 14th DAY OF MAY 2020, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-20-21, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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