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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2018, THROUGH MAY 31, 2019.	**CASE NO. IPC-E-18-06** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Brandon Karpen, Deputy Attorney General, and in response to the Notice of Application and Notice of Modified Procedure issued in Order No. 34040 on April 23, 2018, in Case No. IPC-E-18-06 to submit the following comments.

BACKGROUND

On April 12, 2018, Idaho Power Company applied to the Commission for an Order authorizing the Company to adjust its Schedule 55 PCA rates. The Company's PCA Application, if approved, would decrease overall revenue collected from Customers by about $22.6 million or 1.90%. The Company requested that the new rates take effect on June 1, 2018. The Commission first approved the annual PCA mechanism in 1993, and it has been modified several times since then. *See* Commission Order Nos. 30715, 30978, 32206, 32424, 33149, 33307. The Company's actual cost to provide electricity (Net Power Supply Expense, or NPSE) varies from year-to-year depending on changes in stream flows, the amount of purchased power, fuel costs, the market price of power, and other factors. The PCA mechanism tracks annual differences between actual NPSE and NPSE recovered through base rates. The PCA is also used to provide revenue sharing benefits resulting from the revenue sharing mechanism approved in Order No. 33149. In this year's PCA, earnings were not sufficient to provide customers with a revenue sharing credit.

STAFF REVIEW

Summary

The Company's Schedule 55 Power Cost Adjustment tariff allows the Company to pass changes in fuel and purchased power costs, relative to costs established in the last rate case, to its customers.

The traditional annual PCA mechanism consists of three components: (1) a forecast of the difference between the NPSE embedded in base rates and the 2018-2019 projected NPSE; (2) a "true-up" that captures the difference between actual NPSE and base NPSE that was actually collected in that year and credits the revenue from the previous year's forecast rate; and (3) a reconciliation of the 2016-2017 true-up that captures any under-recovered or under-refunded amounts. This reconciliation is also called the "true-up of the true-up."

The Company proposes a 2018-2019 PCA rate of 0.4854 ¢/kWh using a forecast of 0.6315 ¢/kWh, a true-up of -0.1398 ¢/kWh, and a -0.0063 ¢/kWh true-up of the true-up.

Overall, the proposed 2018-2019 PCA rate is 0.2507 ¢/kWh less than the 2017-2018 PCA rate. Most of this decrease is due to a $20 million dollar credit for better than expected hydro generation sales realized during the 2017-2018 PCA year. Current Schedule 55 PCA rates are designed to collect approximately $90.1 million above the $305.7 million fuel and purchased power costs incorporated in base rates. However, last year's hydro generation was greater than forecast, resulting in higher-than-forecast surplus energy sales, and a $20 million credit to customers. After applying this credit to the results of its 2018-2019 fuel and purchased power forecasts, the Company will only need to collect $69.4 million via the Schedule 55 PCA mechanism.

Last year's Schedule 55 PCA rate included an Energy Efficiency Rider Transfer and a refund from the Rider balancing account. The transfer and refund were removed from the Schedule 55 PCA mechanism via Commission Order Nos. 33736 and 33775. This year's PCA includes only the three traditional components (forecast, true-up, and true-up of the true-up), resulting in a uniform 0.4854 ¢/kWh rate applied across all rate classes. The percentage change by rate class is summarized in Table 1:

Table 1: Overall Rate Impact (Excerpted from Company's Application, Attachment 2)

Class Description	Rate Schedule No.	Change
Residential	1	-1.29%
Master Metered Mobile Home Park	3	-1.40%
Residential Service Time of Day	5	-1.38%
Small General Service	7	-0.80%
Large General Service	9	-2.23%
Large Power Service	19	-3.10%
Irrigation	24	-1.91%
Micron	26	-3.66%
JR Simplot	29	-3.80%
DOE	30	-3.74%
Unmetered General Service	40	-1.66%
Street Lighting	41	-0.65%
Traffic Control Lighting	42	-2.73%
System Average Decrease		**-1.90%**

Staff audited the Company's sales and costs for the 2017-2018 PCA year, and reviewed the Company's sales and cost forecasting methodologies for the upcoming 2018-2019 PCA year. Staff also reviewed the Company's filing and methodologies for conformity with previous Commission orders. Staff's major findings are:

1. Actual loads, fuel consumption, fuel costs, purchased power costs, and kilowatt hour sales for the current PCA year (2017-2018) are accurate.
2. The Company's methodologies for forecasting kilowatt hour sales, loads, fuel consumption, fuel costs, and purchased power costs for the upcoming PCA year (2018-2019) are sound.
3. The Company's calculation of the incremental change in the upcoming year's PCA rates are consistent with Commission Order Nos. 30715, 30978, 32206, 32424, 33149, and 33307.

4. The Company's Idaho jurisdictional year-end Return on Equity (ROE) fell below the 10.0 percent ROE threshold for revenue sharing (Order No. 33149), so the 2018-2019 PCA does not include a revenue sharing component.

Forecast Analysis

System-wide monthly energy sales are forecast using the Company's predictions of load growth and weather. The Company predicts sales of approximately 14.3 billion kWh from its Idaho customers (Blackwell di, p 14).

Monthly load, fuel consumption, fuel costs, and purchased power costs were obtained from the Company's March 29, 2018 Operating Plan. Monthly load is determined using the Company's sales forecast, predicted PURPA power production, Purchased Power Agreements (PPAs), and the impact of the Company's demand response initiatives. For each month, the Company then determines the most economical way to dispatch its hydro, natural gas, and coal generation resources to meet its system-wide monthly load.

Under the Commission approved methodology, 100% of the difference between forecast and actual PURPA and Demand Response Initiative expenses are included in the PCA; however, only 95% of fuel and non-PURPA purchased power expenses are included in the calculation. The Company predicts that the costs of meeting the requirements of its Idaho customers will be approximately $90.3 Million greater than the costs used to establish base rates in the Company's last rate case (Blackwell di, p. 15). The forecast component of the Company's 2018-2019 PCA is thus $90.3 Million ÷ 14.3 Billion kWh = 0.6315 ¢/kWh, compared to the $0.4776 ¢/kWh used in the 2017-2018 PCA.

The Company explained that the factors contributing to forecast increases include the following: a decrease in hydro generation and reduced surplus sales, a significant increase in non-PURPA market purchases and expense, and a slight 1 percent increase in natural gas fuel expense. Large impacts to the 2018-2019 PCA forecast resulted from a 26 percent decrease of surplus sales revenue and the related 29 percent increase in market purchases and related expense (Blackwell di, p. 9). The forecast average market purchase price for energy is expected to drop almost 15 percent from the previous year's price, from $25.52 to $21.83 per MWh. Staff explains that although that drop in price helps mitigate the increase in planned market purchases, it also reduces surplus sales revenue for the Company and increases market purchase power expense.

Forecast energy production for coal, natural gas, and non-PURPA Purchased Power is predicted to decrease 26 percent due to the impact of reduced hydro generation and increased reliance on market purchased power. PURPA energy purchases are expected to remain the same or drop slightly; however, the costs of PURPA energy purchases are expected to increase $3.3 million (2%) as a result of maturing PURPA contract payments (Blackwell, di. p. 10).

With the forecast drop in natural gas and energy market price, the Company expects a 12 percent decrease in coal generation and a 1 percent decrease in coal fuel expense (Blackwell di, p. 12). The Company predicts that lower projected snowpack and inflow into the Brownlee reservoir will result in a 10 percent reduction in hydro generation. The Company plans to replace the loss of coal and hydro generation with a 23 percent increase in natural gas generation (Blackwell di, p. 12).

Staff thoroughly reviewed the Company's Operating Plan assumptions and methodology, and believes that the Company's forecast provided a reasonable basis for determining 2018-2019 Schedule 55 PCA rates.

Staff notes that the primary purpose of the forecasting mechanism is to provide real time recovery of next year's base-to-actual deferral balance. Any over or under-collected amounts due to forecast variance will be trued-up in subsequent years.

True-Up Analysis

The true-up deferral balance as shown on the line labeled "Ending True-up Balance" in Company Exhibit 2 is primarily made up of the differences between actual NPSE and NPSE recovered through base rates, and forecast revenues. It also includes 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 forecast PCA rate and monthly accrued interest.

The Company converts the true-up amount to a ¢/kWh rate by dividing it by projected energy sales. The Company calculates Idaho ratepayers' share of the true-up amount for a refund of approximately $20 million, and expects to refund that amount through a true-up rate of

-0.1398 ¢/kWh as compared to last year's rate of 0.3129 ¢/kWh. Table 2, below, summarizes the $19,993,280 true-up refund amount proposed by the Company

Staff's review of the true-up includes: (1) an on-site audit of the various components included in the true-up or deferral balance; (2) an analysis of the methods and basis used to calculate the cost deferrals and account balances; and (3) a review of actual NPSE including monthly Energy Risk Management Committee minutes, operating plans, and other reports that were presented to the Risk Management Committee. As a result of its review, Staff concludes that the Company's proposed true-up amount is accurate, that the methods used conform to past Commission Orders, and that actual costs incurred are reasonable and prudent.

Although there is no effect in this year's PCA, the Company will be including operation and maintenance expenses directly related to its participation in the Western Energy Imbalance Market (EIM) in next year's PCA. The Idaho Power recovery method for costs associated with participating in the EIM, has been filed in Case No. IPC-E-17-16. The benefits of the EIM market will 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.

Table 2: PCA True-Up Summary

Net Power Supply Expense Differential	**Deferral Amount**
Fuel Expense – Coal	$ (4,341,371)
Fuel Expense – Gas	363,728
Non-Firm Purchases	1,978,910
Surplus Sales	9,951,964
Third Party Transmission Expense	(1,229,653)
Water for Power (Leases)	(2,148,489)
Subtotal - Net Power Supply Expense	$4,575,089
Other PCA Items	
Emission Allowances & Renewable Energy Credit (REC) Sales	$(3,355,103)
Sales Based Adjustment	(5,116,501)
Qualifying Facilities	50,124,959
Demand Response Incentive Payments	(4,268,958)
Subtotal – Other PCA Items	$37,384,398
Total Expense Items	$41,959,488
Revenue from PCA Forecast	$(61,918,793)
Deferral Balance (Expense Items less PCA Forecast Revenue)	$(19,959,306)
Interest on the Deferral Balance	(33,975)
Total True-Up Deferral	(19,993,280)

Details of the different components in the PCA true-up, as shown in Table 2, are described below. Positive numbers represent a customer cost (recovery from customers), and negative numbers represent a customer benefit (credit to customers). All amounts are shown after jurisdictional allocation and sharing.

Net Power Supply Expense Differential

Staff believes the Company prudently incurred NPSE 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. During the 2017/2018 PCA year, increased availability of hydro generation allowed the Company to decrease power generation from coal and other fuels, and allowed the Company to increase surplus sales over what had been forecast. There was also an increase in market power purchases, displacing generation at the Company's coal and natural gas plants. Actual hydro-generation was higher than forecast and as a result the volume of surplus sales was 14 percent higher than expected. Actual coal and natural gas generation were lower than forecast. Market purchases were higher than forecast, and these market purchases partially offset generation from the coal and natural gas plants. 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 months of the coal expenses and performed an in-depth audit for the months of July and August 2017. The Company includes the increase or decrease in coal expense from base rates in the PCA for recovery from, or a credit to, customers. The Company included expenses of the 2015 test burn of Powder River Basin coal. The Company previously deferred this in conjunction with the ongoing evaluation of long-term fueling strategies. The company concluded that significant plant investments would be required to burn PRB coal. These deferred expenses are appropriately recorded in FERC account 501 as these costs reflect net fuel costs for providing generation to customers, as well as being used for evaluation of PRB as a fuel source. From April 2017 through March 2018, the total coal expense for the three plants was \$103,318,634. The total coal expense included in base rates is \$108,503,180. This year's PCA deferral balance, after jurisdictional allocation and sharing, includes a difference of \$4,341,371 and 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 all months of the natural gas expenses and performed an in-depth audit for October and December 2017. 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. For the 2017-2018 deferral period, the total variable gas and gas transportation expense for all the gas plants was \$33,654,349. The total gas and gas transportation expense included in base rates is \$33,367,563. This year's PCA deferral balance, after jurisdictional allocation and sharing, includes a difference of $363,728 for recovery from customers.

3. *Non-firm Purchases*. To supplement its own generation, the Company purchases power in the wholesale market based on its Energy Risk Management Policy and Standards, operating reserve margins, unit availability, and economics. Excluding PURPA purchases during the 2017-2018 PCA year, the Company bought $64,633,258 of power on the market. Base rates included $62,606,593 in non-PURPA power purchases. After jurisdictional allocation and sharing, actual non-PURPA power purchases exceeded base amounts by $1,978,910.

   The approximate $2 million of additional purchase power expense compared to the expense embedded in base rates is primarily driven by increased amounts of market purchases and lower electricity prices. The average unit cost of wholesale purchases in base rates was $50.65 per MWh compared to $43.57 per MWh in the deferral period. Although long-term contracts still reflect higher than spot market prices, the Company was able to take advantage of lower electricity prices overall to fulfill customer demand.

   Staff reviewed the purchases, and performed an in-depth audit of select transactions during the PCA deferral period. Staff compared the term purchase price to the forward market prices from the monthly Operating Plans and compared the day-ahead and real-time market prices to the Intercontinental Exchange Mid-C daily price index. The transactions appear reasonable and follow the Risk Management Committee's recommendations. These transactions were made with an assortment of credit-worthy partners on a timely basis.

4. *Off-System Sales*. During the 2017-2018 PCA year, the Company's off-system sales of surplus power totaled $40,633,415. The total surplus sales included in base rates is $51,735,153. The reduction in the amount of surplus sales compared to base amounts is driven primarily by lower market electricity prices. After jurisdictional allocation and sharing, actual surplus sales were less than base amounts by $9,951,964; this increases 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. Including transmission expenses in the PCA is a straightforward treatment of power supply costs that fluctuate with power purchases and sales. For the 2017-2018 PCA period, the actual third-party transmission expense is $4,077,351. The third-party transmission expense included in base rates is $5,455,955. After jurisdictional allocation and sharing, third-party transmission expense decreases the deferral balance by $1,229,653 and is a credit to customers.

6. *Water Leases.* The Company occasionally leases water to produce hydro power. There is $2,380,597 included in base NPSE for water leases. Any deviation from the amount included in base rates either increases or decreases the PCA deferral. This year the Company did not incur any water lease expenses. After jurisdictional allocation and sharing, $2,148,489 is returned to customers as an offset to the deferral balance.

Other PCA Expense Items

7. *Emission Sales & Renewable Energy Credit Sales*. In Order No. 30818, the Commission at that time required the sale of RECs with the benefits flowing to customers. The deferral balance includes $3,355,103 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. Staff notes that the only Emissions Sales of $37.62 occurred in the month of August 2017. In recent years Idaho Power has not had any emission sales.

8. *Sales-Based Adjustment*. The Company calculates a $5,166,501 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 (Case No. IPC-E-15-15). 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).

During the 2017-2018 PCA deferral year, actual sales were 201,564 MWh higher than sales used to set base rates, resulting in a credit back to customers. 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 was consistent with 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 2017-2018 PCA deferral period, the actual Idaho Jurisdictional PURPA expense is $177,286,136. The Idaho Jurisdictional PURPA expense included in base rates is $127,161,176. In this year's PCA deferral balance, the actual Idaho jurisdictional PURPA expense exceeded the PURPA expense included in base rates by $50,124,959. PURPA contracts are not subject to sharing, but they are subject to jurisdictional allocation. Staff audited the actual monthly PURPA expense 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 2017-2018 PCA deferral balance. Staff confirms there were $6,983,307 in actual DR Incentive expenditures in the deferral, which is $4,268,958 less than the $11,252,265 included in Base NPSE. 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-18-03). Any DSM prudency disallowance as a result of 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. *Revenue from the PCA Forecast*. The Company's forecast rates generated $61,918,793 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 2017-2018 deferral period. Staff verified the revenue collected during the PCA period.

12. <u>Interest on the Deferral Balance.</u> The deferral balance accrues interest at the customer deposit rate, currently 1%. The interest accrued during the current deferral period is a credit to customers of $33,975. Staff verified the interest calculations and agrees with the Company.

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. According to the Company, the true-up was over-collected by about $0.9 million, resulting in a proposed reconciliation of the true-up rate of -0.0063 ¢/kWh as compared to a rate of 0.1611 ¢/kWh in last year's PCA.

Table 3, below, summarizes the reconciliation of the true-up for the 2016-2017 PCA period. The $(898,592) 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 2.

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. As a result of its review, Staff believes the Company correctly reconciled the true-up. The specifics of Staff's review are discussed below.

Table 3: True-Up Reconciliation

2015-2016 True-Up Deferral (Order No. 33775)	$ 33,953,029
2015-2016 True-Up of the True-Up Ending Balance	2,257,651
DSM Rider Funds (Order 33526)	(13,000,000)
Net Amount Set for Recovery/(Refund)	$23,210,680
Collections from True-Up Rates	$(24,234,497)
Interest	125,225
Subtotal	(24,109,272)
True-Up Reconciliation	$(898,592)

1. 2016-2017 True-up Deferral Balance. The ending true-up deferral balance from the 2016-2017 PCA period was approved in Order No. 33775; Case No. IPC-E-17-06. The ending deferral balance in last year's PCA was $33,953,029. This amount is added to the beginning balance of the reconciliation of the true-up. This amount has been properly recorded in the month of April 2017 in the reconciliation of the true-up for recovery.
2. 2015-2016 Reconciliation of the True-Up Balance. The remaining balance in the reconciliation of the true-up that was under-recovered in the previous PCA period is the beginning balance of the reconciliation of the true-up for this PCA period. The amount of $2,257,651 was under-recovered in the previous period, and has been properly recorded in the reconciliation of the true-up as the beginning balance.
3. DSM Rider Funds. In Order No. 33736, the Commission approved a $13 million refund of previously collected Rider funds to customers through the PCA. This amount from last year's PCA filing is correctly recorded in May 2017 in the reconciliation of the true-up.
4. Collections from True-Up Rates and Interest. 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 and 33149. The terms are currently effective through 2019, or until otherwise modified or terminated by Commission Order, or the full $45 million of Accumulated Deferred Investment Tax Credits are amortized.

The Company's 2016 year-end Idaho jurisdictional ROE was 9.94%. Since the ROE was less than 10%, there is no revenue sharing for 2017. Staff has reviewed the work papers, source documents, and supporting documentation and agrees with the Revenue Sharing calculations.

Rate Calculations

Staff reviewed the components of this year's Schedule 55 PCA rates and concluded 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 complied with past Commission orders.

As noted previously, the Company calculated the overall PCA rate of 0.4854 ¢/kWh by summing the rates of the three traditional components: the forecast, the true-up, and the reconciliation of the true-up. Staff confirmed that the method used to allocate the revenue requirement across the customer classes was done on an equal cents per kilowatt-hour basis. This ensures that customers share the PCA revenue requirement based on the amount of energy consumed which is how NPSE is allocated in customer base rates.

Langley Gulch Investigation

Prior to this filing, the Company had not provided a report of its conclusions regarding the outage experienced by the Langley Gulch generating plant between October 24, 2016, and December 15, 2016. The Langley Gulch outage resulted in incremental replacement power costs of $733,532, and was a significant issue discussed by Staff in the Company's last PCA case (IPC-E-17-06).

Previously, the Commission has stated, "[w]e look forward to the Company providing reports and conclusions regarding the root cause of the failures and why the extended downtime occurred." Order No. 33775 at 4. At Staff's request, the Company summarized its findings in its response to Staff's Production Request No. 2. This is included as Attachment A to Staff's Comments. Staff has not had sufficient time to review the Company's report.

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. The notice was or will be included with bills mailed to customers beginning April 23 and ending May 22, 2018. Customers whose bills will be mailed on May 21 or May 22 were sent a direct mail postcard outlining the Company's filing on April 23. Unfortunately, even with the Company's attempt to provide earlier notice to some customers, many will not have a reasonable opportunity to file timely comments with the Commission by the May 10th comment deadline.

Because the Company is proposing a rate decrease, it is less likely that customers will not object to the proposed rate changes. However, all customers should have an opportunity to file comments and have their comments considered by the Commission. In this instance, Staff encourages the Commission to accept and consider late-filed customer comments. As of May 10, 2018, the Commission has not received any customer comments for this case.

STAFF RECOMMENDATIONS

Staff recommends the following:

1. That the Commission approve the Company's proposed PCA rates as filed.
2. That the Commission accept late filed customer comments.

Respectfully submitted this 10th day of May 2018.

Brandon Karpen
Deputy Attorney General

Technical Staff: Mike Morrison
Kathy Stockton
Johan Kalala-Kasanda
Johnathan Farley
Michael Eldred
Rachelle Farnsworth

REQUEST NO. 2: On page 4 of Commission Order No. 33775, the Commission discussed the December 2016 outage at Langly Gulch, and stated, "We look forward to the Company providing reports and conclusions regarding the root cause of the failures and why the extended downtime occurred." Has the Company completed its investigation? If so, please provide a copy of the Company's final report. If not, please explain why the Company has not completed its investigation.

RESPONSE TO REQUEST NO. 2: Idaho Power recently completed its investigation of the root cause analysis of the 2016 extended outage at Langley Gulch, the details of which are explained below. Although the Company devoted a significant amount of time to the investigation and reviewed a vast amount of data, a definitive root cause was not discovered.

During the planned fall outage for Langley Gulch, scheduled for October 24, 2016, through November 30, 2016, work was planned to replace the seals on the high-pressure steam turbine. This was being done in conjunction with the normal maintenance cycle for the gas turbine as part of the service provided in the Long-Term Service Agreement with Siemens. During inspections, additional wear and cracking was found on the blade roots, blade tip seals, and inter-stage seals on the turbine rotor. Due to these findings, the turbine rotor had to be shipped to the manufacturer's recommended maintenance facility located in Seattle, Washington, for repairs. Repairs for the turbine rotor occurred between November 11, 2016, and December 1, 2016. The high-pressure steam turbine was reassembled and plant maintenance was completed on December 15, 2016. Due to the turbine rotor seal wear found during inspection, the October 2016 scheduled outage was extended approximately two weeks beyond the target completion date of November 30, 2016, to December 15, 2016.

During last year's PCA proceeding, Idaho Power committed to determine the root cause of the turbine rotor seal wear. The Company's efforts to determine the root cause entailed reviewing plant operating data to pinpoint any conditions of excessive heating or cooling that may have occurred on the steam turbine seals.

In its efforts to determine the root cause, Idaho Power began working to retrieve historical plant operating data from the plant Distributive Control System ("DCS") historian. This process began in May 2017, and involved installing a new onsite computer, which was synched with Siemens' system, to retrieve historical operating data for Langley Gulch from 2011 through 2016. The data captured in the DCS historian includes numerous operating parameters, such as temperature, pressure, and steam flow readings for the steam turbine.

Embrittlement of seals or seal rubs, like those found during the extended outage, are typically caused by over-heating or cooling events. As a result, the Company examined the data for events or causes that could have resulted in an over-heating or cooling event on the steam turbine case or rotor, including wet insulation, temperature stratification within the steam turbine enclosure, and steam admitted to the turbine case.

Idaho Power reviewed plant data and maintenance records to determine if there were any instances in which the turbine operated with partial insulation installed or if there were any events that may have led to wetting of insulation on top or bottom of the turbine casing. A review of plant records showed no evidence of running the turbine under any of these conditions.

Idaho Power also reviewed the data for changes to the steam turbine room enclosure, such as removal/replacement of the roof or wall panels, to determine if the turbine case may have been exposed to an external temperature event. There were no recorded events of changes to the room enclosure from 2011 through 2016.

Finally, the Company inspected the Thermal Stress Evaluator ("TSE") program for any operational issues. The TSE program is designed to help limit and protect the steam turbine from any excessive heating or cooling events. The TSE program data is stored in the DCS historian. In reviewing the data, Idaho Power determined there were no instances in which the TSE experienced operational issues or loss of protection functionality. The Company also examined the TSE program's operational settings that admit steam into the turbine case. There were no findings or evidence that the settings would have allowed the turbine to operate outside the range of the TSE program parameters during commissioning activities prior to Idaho Power operating the plant or following turnover of the plant to Idaho Power through 2016.

Over the past several months, the Company spent a significant amount of time and reviewed a voluminous amount of data to find a root cause for the extended outage at Langley Gulch; however, a definitive root cause was not discovered nor did the Company find any evidence that the steam turbine operated beyond Original Equipment Manufacturer recommendations.

The response to this Request is sponsored by Mike Williams, Power Production Manager, Idaho Power Company.

DATED at Boise, Idaho, this 1st day of May 2018.

Lisa D. Nordstrom

LISA D. NORDSTROM
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 10TH DAY OF MAY 2018, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-18-06, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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