BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF IDAHO POWER COMPANY FOR	)	CASE NO. IPC-E-23-11
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC SERVICE	)	
IN THE STATE OF IDAHO AND FOR	)	
ASSOCIATED REGULATORY ACCOUNTING	)	
TREATMENT.	)	
	)	

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

LISA A. GROW

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Lisa A. Grow. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the President and Chief Executive Officer ("CEO").

Q. Please describe your educational background.

A. I received a Bachelor of Science in Electrical Engineering from the University of Idaho in 1987 and an Executive Master of Business Administration from Boise State University in 2008, in addition to numerous industry and leadership courses and trainings over the past 36 years.

Q. Please describe your work experience with Idaho Power.

A. I have held 14 positions in my 36 years with Idaho Power. I became President & CEO in June 2020. Before that I held several officer positions: Senior Vice President & Chief Operating Officer, Senior Vice President of Power Supply, and Vice President of Engineering and Construction. I was also the General Manager, Grid Operations & Planning, and Senior Manager, Grid Operations, and Control Area Operations Leader. In the early part of my career, I held many engineering positions throughout the Company.

Q. What is the purpose of your testimony in this matter?

A. The purpose of my testimony is to 1) provide a general overview of Idaho Power and its core business practices, 2) generally discuss Idaho Power's business management and other financial considerations, 3) present the Company's request in this case and inform the Idaho Public Utilities Commission ("Commission") of the financial and economic factors driving the need for the requested base revenue adjustment, and 4) detail proposed rate mitigation steps taken by the Company and the options available to customers seeking assistance in managing their energy costs.

Q. Are you the witness that can address overall Company policy?

A. Yes.

Q. Please summarize your testimony.

A. The Company's last general rate case ("GRC") was in 2011, and the number of Idaho Power customers has increased by about 23 percent over the past decade. To serve that growing customer base, the Company has made significant investments in its infrastructure to maintain, improve, and protect the electrical system. Idaho Power will continue to have considerable ongoing investments in response to rapid customer and load growth, as well as aging infrastructure.

The Company has worked hard to keep Operations & Maintenance ("O&M") expenses low for the past decade, with an average annual growth rate of only 1 percent since 2012. This equates to a total increase of just over $50 million to serve approximately 117,000 new customers, which represents an average annual growth rate of 2 percent since Idaho Power's last GRC. The request in this case is largely focused on the rate base additions needed to reliably serve our customers and, to a lesser extent, growth in O&M expenses.

Our case demonstrates a strong track record of managing expenses and presents the necessary investments to continue providing safe, reliable electric service to our growing customer base. In recognition that price increases can be difficult for customers to manage in today's economic environment, Idaho Power will present several ways it was able to mitigate the requested increase in this case.

I. COMPANY OVERVIEW

Q. Please provide an overview of Idaho Power.

A. Idaho Power Company is headquartered in Boise, Idaho, and has been a locally operated energy company since

1916. The Company has approximately 2,000 employees that proudly serve approximately 620,000 customers over a 24,000-square-mile service area in Idaho and Oregon. With 17 low-cost hydropower projects at the core of its diverse energy mix, Idaho Power’s residential, business, and agricultural customers pay among the nation's lowest prices for electricity.

Q. What is Idaho Power’s overall business focus?

A. Idaho Power endeavors to remain a financially strong, independent, vertically integrated utility supported by a safe and engaged work force dedicated to providing safe, reliable, and affordable electric service to our customers.

Q. What are the key elements that guide Idaho Power’s company culture?

A. Idaho Power’s culture is guided by our purpose, values, and our commitment to each other. We are passionate about powering lives with reliable, affordable, clean energy, while developing innovative solutions every day. Serving those who depend on us is at the center of everything we do. We prosper by committing to the needs, safety and success of our customers, communities, employees, and owners.

Our Company’s three core values are Safety First, Integrity Always, and Respect for All. Safety First - We are committed to the safety of our employees, our customers, and the communities we serve. Integrity Always - Customers, owners, and employees can count on us to be fair and ethical. Respect for All - We treat our customers, partners, employees, and the environment with care and dignity.

And finally, we are committed to an inclusive environment where we are all valued, respected, and given equal consideration for our contributions. We believe that to be successful as a company we must be able to innovate and adapt, which only happens when we seek out and value diverse backgrounds, opinions, and perspectives.

Q. What is Idaho Power's philosophy regarding safety?

A. Because safety is a core value at Idaho Power, the Company embraces and fosters a Safety First culture. The Safety First culture recognizes that Idaho Power's family of employees is the Company's greatest asset and emphasizes that each employee's most important responsibility in their daily work is safety and that no work is so critical that safety should be disregarded. The Company is committed to the safety of its employees, customers, and the public.

Q. How does Idaho Power measure the reliability of its distribution system?

A. Idaho Power primarily uses four reliability indices to measure reliability of the system:

SAIFI: System Average Interruption Frequency Index

SAIDI: System Average Interruption Duration Index

CEMI: Customers Experiencing Multiple Interruptions

MAIFI: Momentary Average Interruption Frequency Index.

SAIFI, SAIDI, and CEMI are indices that measure sustained outages. A sustained outage is defined as customers out of power for five minutes or longer. MAIFI is an index that measures momentary interruptions. Momentary interruptions are when customers are out of power for fewer than five minutes.

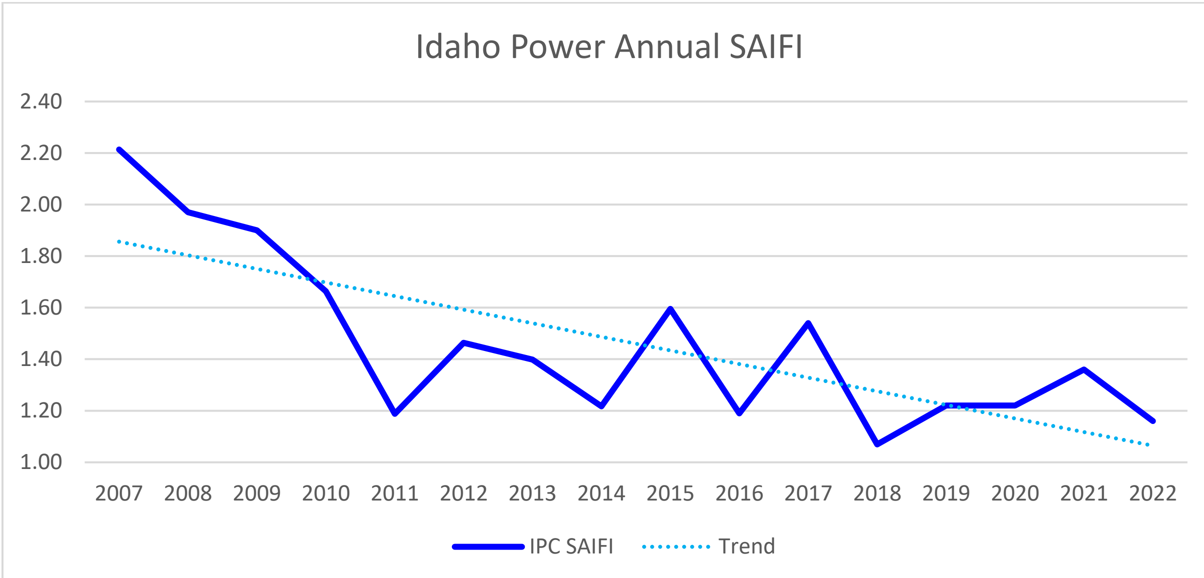
Idaho Power tracks performance for all of the indices I just noted, but the primary focus of Idaho Power’s distribution reliability programs over the years has been to reduce the number of customer outages as measured by SAIFI.

Q. What are Idaho Power’s reliability results?

A. Figure 1 shows Idaho Power’s improvement in annual SAIFI since 2007. In 2022, Idaho Power customers experienced an average of 1.16 sustained outages, which was about 47 percent lower than 2007 when SAIFI was about 2.20 and 20 percent lower than in 2013 (10 years prior) when SAIFI was 1.40.

FIGURE 1

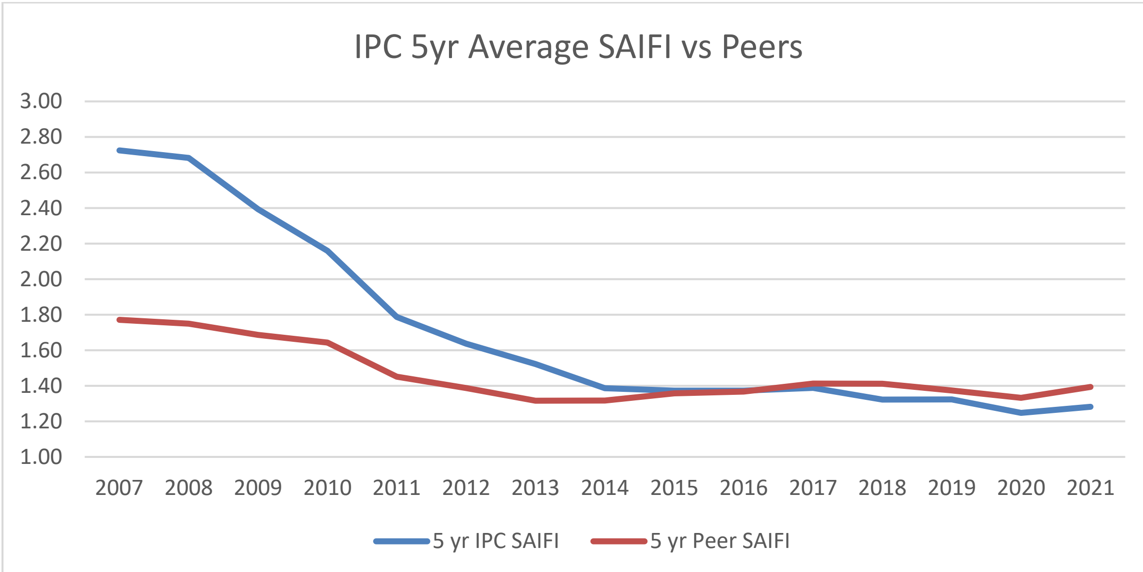
IDAHO POWER ANNUAL SAIFI



System reliability can be dependent on major weather events, specifically major wind or winter storms. Because of the variation in reliability results due to weather, it is helpful to look at five-year average SAIFI values to see trends in performance.

Idaho Power also performs annual reliability benchmarking with its northwest peer utilities. FIGURE 2 shows the five-year average of Idaho Power's SAIFI compared to the five-year average SAIFI of our seven peer utilities: NorthWestern Energy, Pacific Power, Rocky Mountain Power, Avista, Sierra Pacific Power, Portland General Electric, and Puget Sound Energy. In the earlier years, shown on Figure 2, Idaho Power lagged behind its peer utilities by more than 50 percent and by about 15 percent in 2013. Over the past four years, Idaho Power leads the peer utility group by an average of 11 percent.[1]

FIGURE 2
FIVE-YEAR AVERAGE SAIFI: IDAHO POWER VS PEERS



Q. Where does Idaho Power focus its efforts to maintain and improve reliability?

A. Idaho Power makes significant efforts toward, and investment in, improving and maintaining reliable service to its customers. The Company recognizes that providing safe, reliable service is among its highest operational priorities for our customers. Idaho Power has completed many projects in recent years to either maintain or improve reliability.

At the generation level, Idaho Power must ensure it has sufficient resources to fulfill its obligation to reliably and safely serve customers, especially in light of

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[1] The data is through 2021. Idaho Power does not have all peer data through 2022 at this point in time.

the unprecedented growth Idaho Power has experienced over the past decade. In their testimonies, Company Witnesses Mr. Eric Hackett and Ms. Lindsay Barretto provide detailed discussions of investments Idaho Power has made in new and existing generation resources to ensure sufficient, reliable generation capacity to serve customers.

With regard to the transmission and distribution ("T&D") systems, Idaho Power has made significant investments to maintain aging infrastructure while accommodating growth at the local level. These projects include work such as the replacement of distribution wood cross-arms and associated wood pins, the injection and replacement of certain underground distribution cables, vegetation management, and improvements to portions of the transmission system and substations. Company Witness Mr. Mitch Colburn describes in greater detail the Company's reliability-related investments and activities in his testimony.

Q. What is the Company's overall approach to providing a positive customer experience?

A. Idaho Power strives to be regarded as an exceptional utility by the customers it serves. To accomplish this, the Company must provide superior and satisfying customer service and experiences that meet or exceed its customers' needs and expectations.

The Company continually focuses on ways to cost-effectively improve its relationships with customers by assessing customer perception of the Company, identifying performance and experience gaps based on customer feedback, and reviewing industry best practices and trends.

Q. What recent initiatives has Idaho Power undertaken to enhance customer satisfaction?

A. The Company has recently implemented enhancements to its digital offerings and solutions to better align with industry trends and evolving customer preferences and expectations. Most notably, the Company's investment in modernizing its My Account platform stemmed from customers' desire to digitally self-serve and manage their accounts. By customers using their preferred method of self-service through My Account, the Company was able to manage customer service employee growth while our number of customers grew over the past decade. Further, in early 2022, the Company released a Mobile Application ("App") on the Apple and Google Play stores in response to the increasing shift in customers' preferences toward accessing their account and service-related information on the go. The App provides enrolled customers with real-time alerts regarding important billing information and connection or outage status affecting one of their registered addresses.

The Direct Testimony of Company Witness Mr. Bo

Hanchey describes more fully the Company's efforts to enhance customers' experiences with our Company.

II. IDAHO POWER'S BUSINESS MANAGEMENT OVERVIEW AND FINANCIAL STATUS

Q. When was Idaho Power's last GRC in Idaho?

A. Idaho Power's last Idaho GRC, Case No. IPC-E-11-08, was filed on June 1, 2011, with rates becoming effective January 1, 2012.

Q. What are the primary factors that have contributed to the Company's ability to avoid filing a general rate case for the last 12 years?

A. There are a number of factors that have contributed to the Company's ability to avoid a GRC over the last 12 years. First, the Company has diligently managed its O&M expenses by creating a cost-conscious culture among employees. As I mentioned earlier in my testimony, O&M increased an average of 1 percent since 2012, while inflation averaged approximately 2 percent a year and customers grew by approximately 2 percent a year—for a combined 4 percent increase.

Second, customer growth, and the associated growth in sales revenue, has helped reduce the financial impact of increasing costs over that period. Third, the Company's annual adjustment mechanisms, the Power Cost Adjustment ("PCA") and Fixed Cost Adjustment ("FCA"), have provided timely revenue support addressing increases in power costs and decreases in residential use-per-customer, respectively. Finally, the Commission has approved several single-issue adjustments to rate recovery, including, but not limited to, the addition of the Langley Gulch natural gas-fired power plant, the establishment of rate mechanisms to recover the cost of early coal plant exits, recovery of Energy Imbalance Market costs, as well as deferred accounting treatment for certain incremental costs, including those related to wildfire mitigation.

Q. Beyond the benefit to customers of avoiding filing a GRC for the last 12 years, will the factors you listed impact this case?

A. Yes, customers benefit from each of the items that I listed in this case, as each of those benefits are built into our request.

Q. Please describe the Company’s efforts to reduce expenses related to hiring employees.

A. All new, un-budgeted positions must be reviewed and approved by the vice president responsible for each business unit. Despite adding approximately 117,000 customers between 2012 and 2022, employee headcount has actually decreased by a total of 17 people over the same time period.

Q. What is Idaho Power's general compensation philosophy?

A. As described more fully by Company Witness Ms. Sarah Griffin in her testimony, Idaho Power's compensation philosophy is to provide a balanced, competitive, and sustainable total compensation or "total rewards" package, ensuring it attracts and retains high quality employees and motivates them to achieve performance goals that benefit customers and shareholders. Maintaining a competitive total rewards package allows the Company to recruit and retain its highly skilled workforce. The competitiveness of Idaho Power's total rewards package also supports the Company's intent to maintain a flexible workforce that can easily adjust work duties and assignments to meet changing demands and operational needs, which in turn keep the Company's costs of service lower.

Q. Please describe the Company's efforts to control budgets.

A. Idaho Power employs a robust capital and O&M budgeting process. The capital budget process begins with maintenance personnel, planners, and others within the business identifying needs and submitting projects to business unit management. Business unit management reviews submitted projects and prioritizes them based on spending guidelines provided by senior management.

O&M budgets are established based on extensive discussions between the business units and senior management and represent a combination of prior year experience plus or minus identified changes and adjustments. As the Company prepared its O&M budgets for 2023, the target was based on holding to a 2022 budget adjusted down for known items and with only identified unavoidable increases allowed as an adjustment.

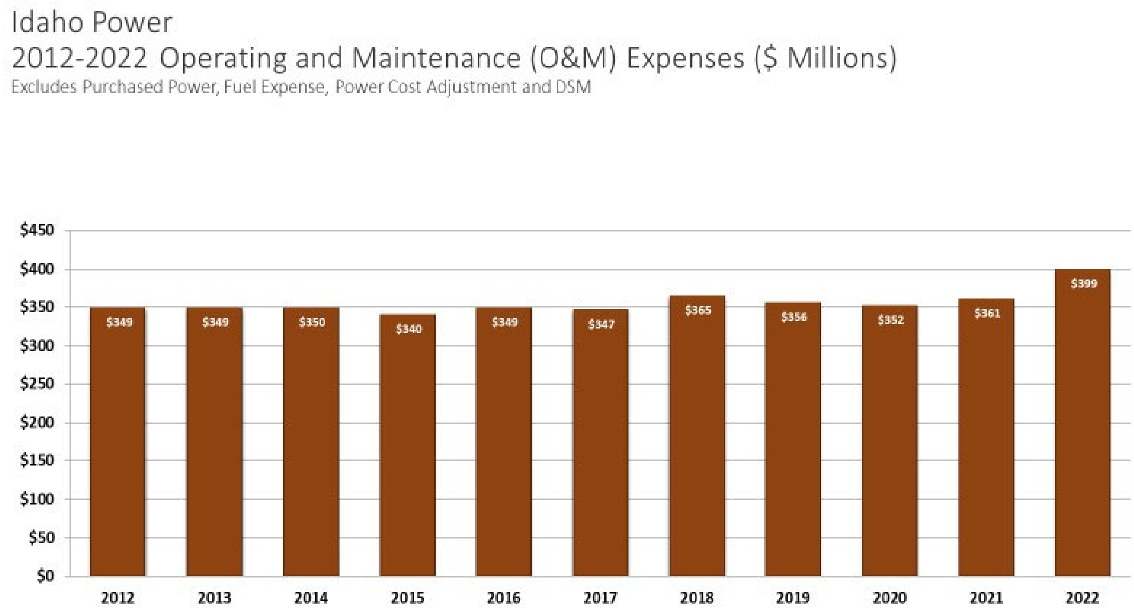
Throughout the year, senior management reviews the status of spending for both O&M and capital against updated estimates as well as original budget. Variances are reviewed and analyzed in order to determine changes that may need to be made during the year to manage to budgeted levels of spend.

Q. Have the Company's cost-control measures applied over the last decade been successful?

A. Yes, very much so. As can be seen in Figure 3, the Company's overall O&M expenses, excluding power supply expenses and demand-side management expenses, have remained relatively flat between 2012 and 2021, with an uptick in 2022 resulting from recent inflationary pressures. Even with those recent inflationary factors, the Company has held O&M expenses to an average annual growth rate of just 1 percent over the last decade.

FIGURE 3

2012-2022 OPERATING AND MAINTENANCE EXPENSES



Q. Are there any other factors that have contributed to Idaho Power's ability to avoid a GRC over the last decade?

A. Yes. Since 2009, the Company has been subject to an Accumulated Deferred Investment Tax Credits("ADITC")/Revenue Sharing Mechanism that includes provisions for the accelerated amortization of ADITC to help achieve a minimum specified percent Idaho-jurisdiction return on year-end equity ("Idaho ROE"), currently set at 9.4 percent. The mechanism also provides for the potential sharing between Idaho Power and Idaho customers of Idaho-jurisdictional earnings in excess of a 10.0 percent Idaho ROE. Under the current mechanism, the ADITC and sharing thresholds are to be reset at a GRC to align the sharing threshold with the then-authorized ROE and the use of accelerated amortization of ADITC at 95 percent of the authorized ROE.

In addition to sharing earnings with customers over the 10.0 percent Idaho ROE threshold, this mechanism has created an additional incentive to the Company to preserve ADITCs to be available to support earnings for as long as possible. While the Company endeavors to thoughtfully manage its costs as a standard practice, this additional financial incentive has been beneficial for customers, because the Company has continually looked for creative ways to maximize its Idaho ROE without filing a GRC. Because the Company has not used the full $45 million of ADITC available, as of December 31, 2022, the credits can be utilized in future periods under the mechanism or the historical standard ITC amortization method.

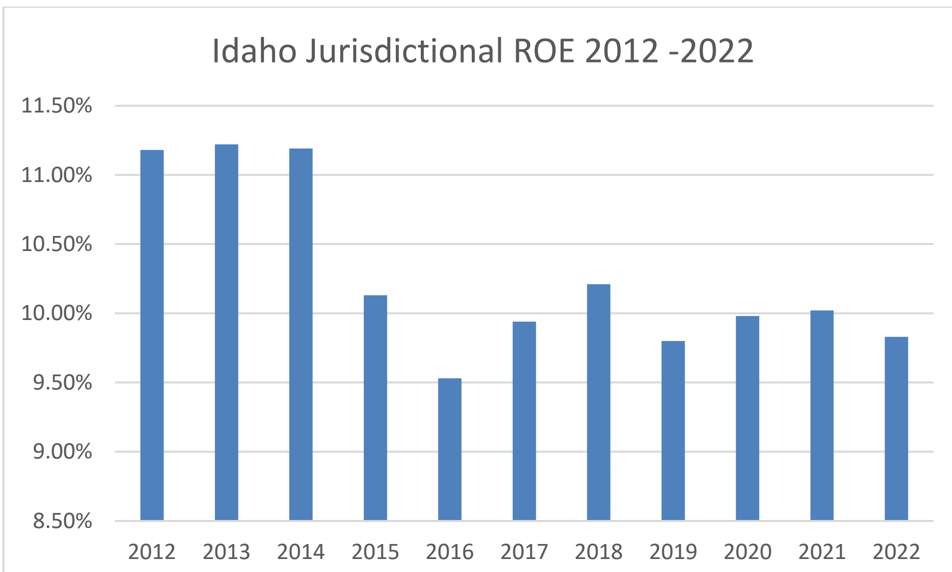
Q. What is the amount of earnings Idaho Power has shared with its customers under the earnings sharing mechanism since its last general rate case?

A. Since the Company's last general rate case the Company has shared $126,752,809 of earnings with its customers under the ADITC/Revenue Sharing Mechanism.

Q. Have Idaho Power's cost management efforts, along with the other factors just described, resulted in the Company earning a reasonable rate of return on equity between 2012 and 2022?

A. Generally, yes. As can be seen in Figure 4, the Company has earned between a 9.5 percent and 10 percent Idaho jurisdictional ROE on an actual basis over that time period.

FIGURE 4
IDAHO JURISDICTIONAL ROE 2012-2022



Q. Considering the earnings performance presented on the above chart, why do you believe it is necessary to increase rates for customers now?

A. As I will detail later in my testimony, since 2012, the Company has invested approximately $1.7 billion dollars on new property, plant, and equipment to serve its customers safely and reliably. In addition, in 2023, the Company expects to invest up to $700 million in additional capital projects with nearly $400 million in O&M expense.

Considering the incremental depreciation and interest expense associated with this significant capital investment, Idaho Power will no longer be able to maintain a reasonable rate of return without the requested rate relief.

Q. Could Idaho Power utilize accelerated amortization of ADITC to avoid the need for a GRC for at least one more year?

A. Unfortunately, no. As noted in the Company's first quarter 2023 earnings release, Idaho Power plans to utilize at least $15 million of accelerated amortization of ADITC to reach a 9.4 percent Idaho ROE. In 2024, the year rates would go into effect from this case, [redacted]

III. <u>CASE OVERVIEW AND DRIVERS</u>

Q. What is Idaho Power's requested revenue increase in this case?

A. As discussed further in the Direct Testimonies of Company Witnesses Mr. Timothy Tatum and Ms. Kelley Noe, the Company is requesting rate relief of approximately $111.3 million, which is net of a corresponding proposed PCA decrease of $173.4 million and a reduction to annual Energy Efficiency Rider collection of $3.5 million. If approved, this request would result in an overall increase to adjusted base revenue of 8.61 percent effective January 1, 2024.

Q. Why do you believe this increase is necessary?

A. This increase is important for Idaho Power to achieve fair and timely recovery of its prudently incurred expenses and a reasonable return on the Company's investment in its electrical system, which today's rates will not fully provide. High customer growth in demand for electricity, aging infrastructure, and higher compliance and reliability requirements are driving the need to invest large amounts of capital to expand and improve electricity supply, delivery, and reliability. This increases the Company's need to access both the debt and equity markets to fund large amounts of capital investment in the system. In this environment, timely and fair recovery of the Company's prudently incurred expenses and investments is critically important to helping it attract capital investment and manage financing costs.

Q. What is the Company's proposed cost of capital?

A. The Company's request is based on a proposed rate of return of 7.702 percent, with a capital structure comprised of 51 percent equity and 49 percent debt, a 4.895 percent cost of debt, and a 10.4 percent return on equity ("ROE"). Company Witnesses Mr. Adrien McKenzie and Mr.

Brian Buckham provide support for this recommendation in their respective testimonies.

Q. What are the challenges facing the Company?

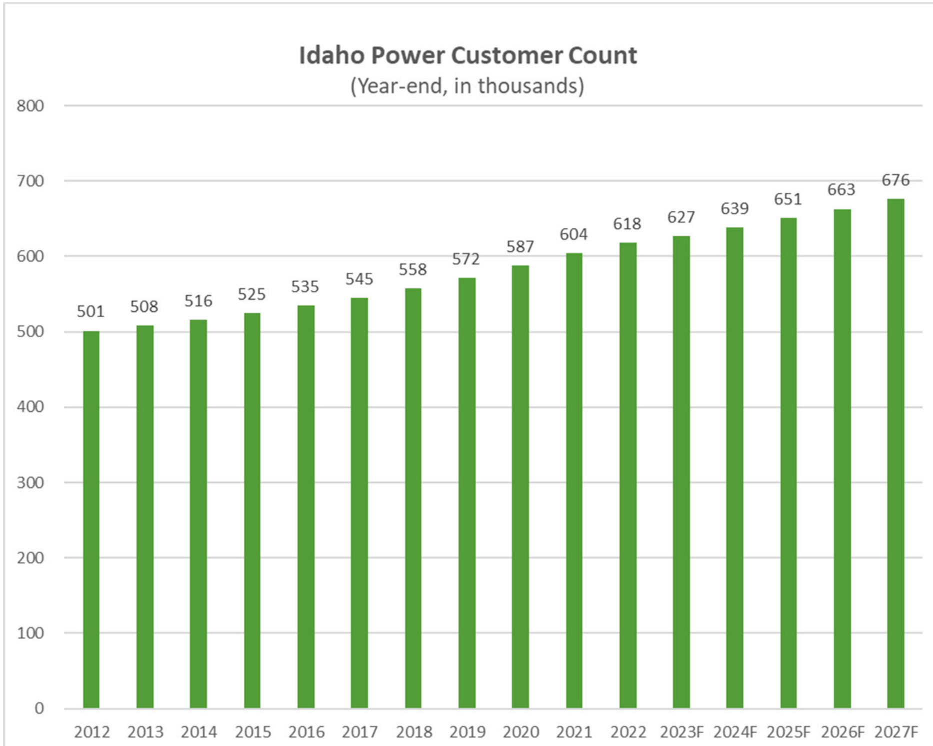
A. Rising prices and costs and constrained system capacity are challenges facing many utilities in the West, and Idaho Power is no different. Despite considerable investment and expansion in recent years, much of the Company's system today is fully utilized by our current customers and the Company continues to experience sustained customer growth. To provide safe, reliable service to all customers, the Company must continue to make major investments in both new and existing infrastructure. Supply chain constraints and worldwide demand for the materials and services required to build needed infrastructure has driven up prices dramatically in recent years.

Idaho Power's credit quality, as measured by the national credit rating agencies, has recently been downgraded and is now at the lower end of investment grade. Rates in effect today will not provide the Company a sufficient opportunity to earn the rate of return necessary to assure access to the capital markets to finance needed investments in 2024 and beyond. Any delay in or lack of recovery of prudent operating or financing costs is seen as risk by the financial community, including the credit rating agencies, during this period of plant expansion and difficult economic times. These pressures combine to present a formidable challenge to sustaining the financial health, operational excellence, and, ultimately, the independence of the Company.

Q. You mentioned growth in investment over the past few years. What is driving the growth in investment since rates went into effect following the Company’s last general rate case?

A. As can be seen on Figure 5, Idaho Power has added approximately 117,000 customers between 2012 and 2022 and forecasts it will experience customer growth of another 58,000 customers over the next five-year period.

FIGURE 5
IDAHO POWER CUSTOMER COUNT

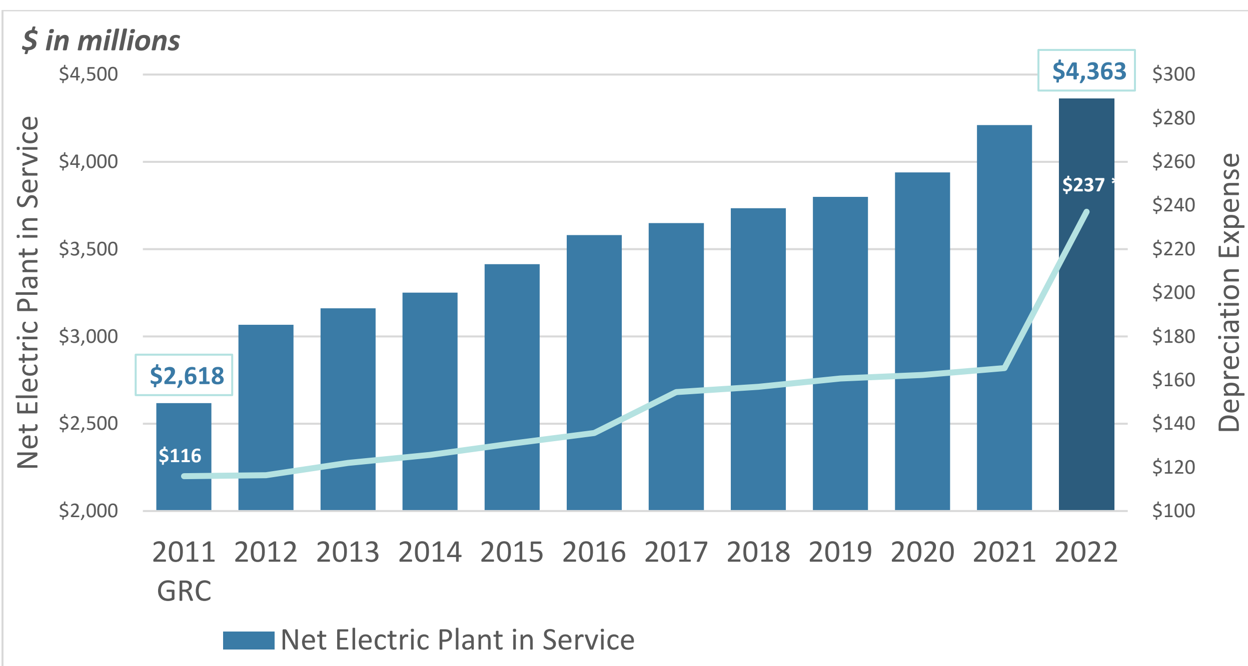


The Company must be financially prepared to serve that growth as it occurs. To provide safe, reliable service to all customers, the Company must make investments in both new and existing infrastructure. The Company is adding capacity to its generation fleet, transmission system, and distribution facilities to ensure an adequate supply of electricity to customers, to provide service to new customers, and to maintain system reliability.

Idaho Power's aging T&D infrastructure requires continued investment in upgrades and replacement to maintain their operational viability. The Company's aging hydroelectric and thermal generation facilities also require continuing investment in upgrades and component replacement. In addition, environmental mandates require the replacement or retrofitting of aging equipment with technology that is often more expensive. Further, the Company is operating in an environment of ever-increasing reliability and compliance standards that also require increased levels of investment.

As can be seen in Figure 6, since the Company's last GRC in 2011, Idaho Power's net plant in service has increased by approximately $1.7 billion reflecting new infrastructure investment of around $3.3 billion. During the same time period, annual depreciation expense has grown from $116 million in 2012 to approximately $237 million in 2022.

FIGURE 6
NET ELECTRIC PLANT IN SERVICE

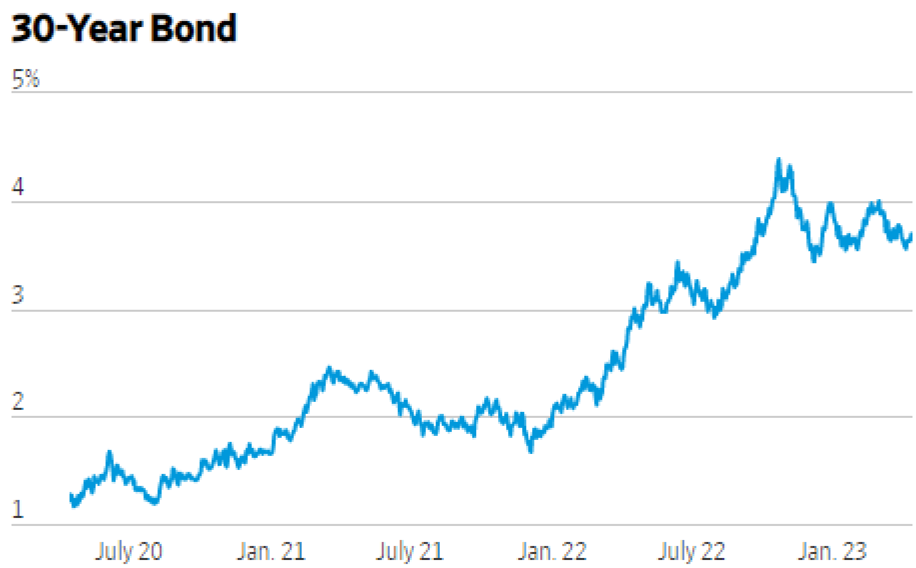


The Company can no longer absorb the depreciation and financing expense associated with the incremental plant investment without the requested rate relief in this case.

Q. How have rising interest rates impacted Idaho Power's financing costs?

A. Over the last decade, Idaho Power has taken advantage of historically low interest rates to lower its long-term debt interest rate by almost 100 basis points over that period. However, borrowing costs have risen dramatically since December 2021, as the Federal Reserve has taken action to address inflation in the United States ("US") economy. As seen in Figure 7 from the Wall Street Journal below, as of May 12, 2023, 30-year US Treasury bond yields have risen from around 1.8 percent near the start of 2022 to as high as 4.38 percent in late 2022 and have recently been between 3.6 to 3.8 percent, a 100 percent increase over that period.

FIGURE 7
30-YEAR BOND



Rapidly rising interest rates during an environment of rapid economic growth not only increases the cost of financing but also challenges Idaho Power's ability to raise efficient capital in the public and private debt markets.

It should also be noted that when borrowing costs rise, the ripple effects make their way into all of Idaho Power's commodities, materials, purchased services, and other costs. This happens because all of the Company's vendors and counterparties need to price their rising borrowing costs into the prices they charge to Idaho Power. And while macro-economic inflation seems to be curbing from recent highs, higher borrowing costs are more likely to persist over the longer term.

Q. Can you cite examples that show how inflation has impacted the procurement of supplies?

A. A combination of supply and demand factors have resulted in persistent high inflation since early 2020. Idaho Power is continuing to see escalated pricing across most commodities: Since 2020, core steel is up 203 percent, aluminum pricing is up 78 percent, and high-grade copper has increased 47 percent.

These increases translate directly into price escalations for key pieces of equipment needed to serve our customers and maintain the reliability of our system. The average cost of transformers has increased by 47 percent, wood poles by 31 percent, and electrical cable by 58 percent.

Other factors driving procurement pricing escalations are the cost of labor and the cost of freight. In addition, capacity availability among manufacturers in our industry has not been able to meet demand, causing the Company to go to new suppliers that are charging higher prices.

Q. Can you cite examples of how supply chain disruptions have been a challenge?

A. Supply chain disruptions continue to affect business operations, creating an environment of scarcity where manufacturers are unable to manage costs or lead times. For example, lead times for transformers have increased by almost five times since 2020—from 32 weeks to 156 weeks. Meter packages have increased sixfold, from 12 weeks to 72 weeks, and breaker lead times have grown from 32 weeks to 72 weeks. These challenges are expected to continue for the next several years. They have caused delays in project execution, increased costs, and created additional workload as the Company works to find other vendors that can support its needs on a timely basis. All of these factors have combined to cause the Company to increase its inventory to levels necessary to support its obligation to serve at an escalating cost.

Q. Are the supply chain disruptions unique to Idaho Power?

A. No. Cost increases and longer lead times are not just being seen at Idaho Power. In June 2022, an Idaho Power supplier delivered a Utility Market Commodity Impacts and Outlook presentation to the Company, highlighting several key themes including those previously discussed. In addition, the presentation noted that utilities are likely to continue to see significant disruption from changing weather patterns. Further, sweeping energy policy changes—such as the US Department of Energy’s recent Notice of Proposed Rulemaking on transformer efficiency—could further add significant disruption for all utilities.

Q. What is Idaho Power doing to actively manage supply chain disruptions?

A. Idaho Power monitors its inventory closely and takes action to mitigate the concerns regarding the tracking of more than 80,000 items and 30,000 unique catalog identifiers. In addition, the Company works with suppliers and others to ensure they are taking the proper actions, such as rationing inventory, providing alternative and substitute products, managing lead times, and investing in forward-looking buys.

Q. How have recent changes to Idaho Power's credit ratings impacted its cost of doing business?

A. While Idaho Power's credit ratings continue to be investment grade, a recent downgrade by Moody's from A3 to Baa1 and a recent note from Standard and Poor's ("S&P") downgrading its liquidity assessment of the Company from "strong" to "adequate" provide a backdrop for Idaho Power's need to increase its cash collections from customers.

While credit rating changes impact both short-term and long-term borrowing costs, as lower ratings drive higher risk premiums, those changes also impact Idaho Power's wholesale commodity contracts, and the perception of suppliers, contractors, and other vendors on our ability to pay for normal O&M costs, as well as construction contracts.

Q. Has Idaho Power taken any actions to improve its credit rating in recent years?

A. Yes. The Company began increasing the equity ratio immediately following the last GRC. In fact, the year-end 2012 equity ratio was 53 percent, and it grew from that level to 55 percent at year-end 2022. The increased equity ratio has had a significant positive impact to the Company's credit ratings, partially offsetting some of the lower ratios the rating agencies use for calculating applicable ratings.

Q. What rationale was given by the ratings agencies to support their recent actions regarding Idaho Power's credit downgrades?

A. Moody's stated, "without the benefit of more incremental and timelier rate relief through riders or cost tracking mechanisms, more frequent base rate increases and lower imputed debt from pension obligations, IPC's credit metrics will not improve materially, and the utility will have limited financial cushion at its current rating level to manage unforeseen events." And S&P cited our reliability and economic growth-driven capital spending needs as reflecting its liquidity downgrade, as it perceives "elevated capital spending that will result in a modest weakening of the company['s] liquidity throughout the forecast period."

Q. Do you believe the relief requested in this case will serve to stabilize or improve the Company's credit ratings going forward?

A. Yes, it should stabilize the credit ratings but likely will not improve the ratings. The credit rating agencies have built their models and assumptions, in part, based on forecasts Idaho Power has discussed with them over the past few years. Those forecasts have contemplated the rate relief requested in this case. In addition, this case requests additional return of and return on rate base that has been placed into service since the last GRC that have carried regulatory lag from a cash flow perspective over several years. Finally, the request in this case seeks to address cash collections related to regulatory deferrals such as those related to wildfire mitigation and pension expenses that, if approved by the Commission, will be viewed by the credit rating agencies as positive for their assumed liquidity and other credit metrics.

IV. RATE MITIGATION AND CUSTOMER ASSISTANCE

Q. Did you provide any specific instructions to the Regulatory Affairs Department in preparing this GRC filing?

A. Yes. In recognition of the broader economic conditions and concern for the impact of any rate increase on Idaho Power’s customers, I instructed Mr. Tatum, Vice President of Regulatory Affairs, to identify areas where the Company could forego requesting an increase at this time. Mr. Tatum and his department identified the following areas where the Company is not asking for incremental increases:

- Reduce ROE from the recommended level of 10.6 percent to 10.4 percent;
- Hold test year non-labor O&M to the 2022 level with the exception of a limited number of known and measurable adjustments;
- Maintain Valmy and Bridger cost recovery at current levels with the exception of collection related to previously deferred revenue requirement amounts;
- Minimize the current revenue increase related to wildfire mitigation and pension costs by leveraging existing cost recovery mechanisms; and
- Delay recovery of the revenue requirement associated the 120 megawatts of battery storage resources to be online in 2023, with interim earnings support from the associated federal investment tax credit generated from the battery storage resources.

Mr. Tatum describes the rationale and quantification of each of these adjustments in his testimony.

Q. What options are available to customers to help them manage their energy costs?

A. There are a number of options available to customers who need assistance in managing their energy costs. Project Share is a year-round bill pay assistance program started by Idaho Power in 1982 and administered by the Salvation Army. Funding is provided by Idaho Power's customers and shareholders, other utilities, and private donations, with 100 percent of Idaho Power customers' donations going to Project Share recipients.

The Company also offers several energy efficiency programs targeting low-income customers - Weatherization Assistance for Qualified Customers ("WAQC"), Weatherization Solutions for Eligible Customers ("Solutions"), and Easy Savings, a low-income energy efficiency educational program.

Idaho Power provides just over $1,212,000 annually, funded by base rates, to the Idaho Weatherization Assistance Program to weatherize additional electrically heated customer homes under the WAQC program. Idaho Power also provides a "Near Low Income" weatherization program called Solutions. This program provides weatherization assistance to customers just under or just over the income limit for WAQC. Most of the Solutions customers are seniors who are barely over the federal cutoff, as well as Idaho

Power customers on the waiting list for the longest time to receive weatherization services. Finally, the Easy Savings program provides $125,000 annually to five Community Action Partnership ("CAP") Agencies in the Idaho Power service area and develops and runs the program with a planning committee consisting of CAP Agency, Commission Staff, and Idaho Department of Health and Welfare representatives.

Q. How much do Idaho Power shareowners contribute to Project Share annually?

A. Idaho Power shareowners contribute 10 percent of monthly customer donations to support the Salvation Army's program administration costs. In addition, shareowners make an annual Project Share donation of approximately $25,000 to directly fund customer bill assistance. In recognition of the current cost pressures on customers' bills, in 2023, Idaho Power shareowners elected to contribute an additional $100,000 to support Project Share for a total of $125,000 of shareowner-funded customer bill assistance.

V. CONCLUSION

Q. Can you summarize the Company's requested rate increase and explain why it is important not only to Idaho Power but in the best interest of customers?

A. This general rate request reflects a revenue requirement increase of approximately $111.3 million, or an

8.61 percent increase and includes a requested ROE of 10.4 percent. This increase is important for Idaho Power to achieve fair and timely recovery of its prudently incurred expenses and a reasonable return on the Company's investment in its electrical system, which today's rates will not fully provide. Continued growth in demand for electricity, aging infrastructure, and higher compliance and reliability requirements are driving the need to invest large amounts of capital to expand and improve electricity supply, delivery, and reliability.

Timely and fair recovery of the Company's prudently incurred expenses and investments is critically important to helping it attract capital investment and manage financing costs. A low cost of capital ultimately has a beneficial impact on customers' rates. By providing for fair and timely recovery of the Company's expenses it incurs on behalf of customers and investments in the systems and activities that serve its customers, this rate increase is in the best interests of the Company, its shareholders, and the people and communities it serves.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF LISA A. GROW

I, Lisa A. Grow, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Lisa A. Grow. I am employed by Idaho Power Company as the President and Chief Executive Officer.

2. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: Lisa Grow

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Lisa A. Grow

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

TIMOTHY E. TATUM

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Timothy E. Tatum. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as Vice President of Regulatory Affairs.

Q. Please describe your educational background.

A. I earned a Bachelor of Business Administration degree in Economics and a Master of Business Administration degree from Boise State University. I have also attended electric utility ratemaking courses, including "Practical Skills for The Changing Electric Industry," a course offered through the New Mexico State University's Center for Public Utilities, "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Edison Electric Utilities Consultants, Inc., and Edison Electric Institute's "Electric Rates Advanced Course." In 2012, I attended the Utility Executive Course ("UEC") at the University of Idaho.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1996 in the Company's Customer Service Center where I handled customer phone calls, customer-related transactions, and general customer account maintenance in the areas of billing and metering.

In June of 2003, I began working as an Economic Analyst on the Energy Efficiency Team. As an Economic Analyst, I was responsible for ensuring that the demand-side management ("DSM") expenses were accounted for properly, preparing and reporting DSM program costs and activities to management and various external stakeholders, conducting cost-benefit analyses of DSM programs, and providing DSM analysis support for the Company's Integrated Resource Plan.

In August 2004, I accepted a position as a Regulatory Analyst and in August of 2006, I was promoted to Senior Regulatory Analyst. As a Senior Regulatory Analyst, my responsibilities included the development of complex financial studies to determine revenue recovery and pricing strategies, including preparation of the Company's cost-of-service studies.

In September of 2008, I was promoted to Manager of Cost of Service, and in 2011, I was promoted to Senior Manager of Cost of Service and oversaw the Company's cost-of-service activities, such as power supply modeling, jurisdictional separation studies, class cost-of-service studies, and marginal cost studies.

In March 2016, I was promoted to Vice President of Regulatory Affairs. As Vice President of Regulatory Affairs, I am responsible for the overall coordination and direction of the Regulatory Affairs Department, including development of jurisdictional revenue requirements and class cost-of-service studies, preparation of rate design analyses, and administration of tariffs and customer contracts.

I. CASE OVERVIEW

Q. What role did you play in the preparation of the general rate case ("GRC")?

A. My role in the preparation of the GRC was to oversee, manage, and coordinate the filing and to make the policy decisions related to regulatory matters in consultation with Ms. Lisa Grow, our Company's President and Chief Executive Officer, along with other senior officers within Idaho Power.

Q. What is Idaho Power's requested revenue increase this case?

A. The Company is requesting rate relief of approximately $111.3 million, which is net of a corresponding proposed Power Cost Adjustment ("PCA") decrease of $173.4 million and a reduction to annual Energy Efficiency Rider collection of $3.5 million. If approved, this request would result in an overall increase to adjusted base revenue of 8.61 percent effective January 1, 2024. The Company's request is based on a proposed rate of return of 7.702 percent, with a capital structure comprised of 51 percent equity and 49 percent debt, a 4.895 percent cost of debt, and a 10.40 percent return on equity ("ROE").

Q. What is the Company's test year?

A. The test year is the 12 months ending December 31, 2023.

Q. Why is Idaho Power requesting a corresponding PCA decrease of $173.4 million in this case?

A. Idaho Power's current Idaho base rates collect approximately $300 million annually to fund normalized or "base level" net power supply expense ("NPSE"). This level of NPSE collection authorized by Order No. 33000 in Case No. IPC-E-13-20 became effective June 1, 2014, based on a 2013 calendar year. Since that time, the Company's normalized NPSE has increased largely because of load growth and changes in fuel costs, market energy prices, and increased power purchase agreement costs. Currently, incremental NPSE over the base level NPSE established in 2014 are collected annually through the PCA forecast component. Because the Company's requested Idaho-jurisdictional revenue requirement in this case reflects updated base level NPSE based on the 2023 test year, the Company is requesting a corresponding decrease in annual

PCA collection to ensure customers do not pay twice for the same NPSE. Simply put, this necessary PCA reduction will facilitate the transfer of base level NPSE collection from the PCA into base rates.

Q. How is energy efficiency currently funded at Idaho Power?

A. The Company's energy efficiency activities, also referred to as DSM, are primarily funded through the Energy Efficiency Rider, Schedule 91 ("Rider"), which is applied as a fixed percentage of each customer's billed base revenue. Idaho Power is currently authorized to collect 3.1 percent of base revenue annually through the Rider.

Q. What is the Company's proposal regarding annual Rider collection?

A. Idaho Power is proposing to transfer approximately $3.5 million in ongoing Rider-funded labor costs into base rates, while otherwise maintaining the same level of annual DSM funding as measured in dollars that exists today. To achieve this goal, the Company is proposing a decrease in Rider collection from the current 3.1 percent to 2.25 percent.

Q. Why is the Company proposing to transfer approximately $3.5 million in ongoing DSM labor costs in this rate filing?

A. There are two reasons for this proposal. First, energy efficiency has been a core business activity at Idaho Power for over 20 years, since the Rider was established in 2002. At the time the Rider was established, the Company identified all incremental costs associated with implementing and managing new DSM programs, including incremental labor-related costs, to be funded through that mechanism. Over time, DSM program management and administration staffing has reached a relatively steady state, both from a cost and head-count perspective. For these reasons, it is appropriate to treat DSM labor the same as any other Company labor costs for ratemaking purposes.

Secondly, DSM labor costs have been a point of concern for the Commission Staff ("Staff") in past prudence review cases. My understanding of Staff's concern is that Rider-funded labor, under the annual prudence review process, has allowed for recovery of labor-related costs annually without the rigorous, comprehensive review applied in general rate cases. By treating DSM labor the same as all other labor costs for cost recovery purposes, Idaho Power believes this will address Staff's concern.

Q. What is the implication of this proposal for energy efficiency activities going forward?

A. The proposed reduction in energy efficiency

Rider funding will have no impact on the Company’s pursuit of cost-effective energy efficiency activities. This adjustment is only intended to transfer the collection of energy efficiency labor costs to base rates and to ensure that the increase to base rate revenue requested in this case does not result in an increase to the annual revenue collected under the Rider. As always, Idaho Power will monitor the need for energy efficiency funding and will propose adjustments to funding levels as warranted to allow for the Company’s continued pursuit of all cost-effective energy efficiency.

Q. Is Company seeking any specific regulatory treatment related to wildfire mitigation and insurance costs as part of this case?

A. Yes. Idaho Power requests the Commission continue to authorize the Company to defer incremental wildfire mitigation and insurance costs as measured from a new base level of costs established in this case. This proposed treatment is consistent with the authority granted by the Commission in Case Nos. IPC-E-21-02 and IPC-E-22-27, with certain limited modifications.

In this case, the Company is only requesting authority to defer incremental costs associated with two previously authorized cost deferral categories of vegetation management and insurance.

Q. Why is Idaho Power requesting ongoing deferral authority for incremental vegetation management and insurance expenses above the baseline levels set in this case?

A. As discussed in the Direct Testimony of Company Witness Mr. Brian Buckham, insurance costs have increased in recent years and continue to rise. Further, insurance costs are increasingly difficult to forecast due to price volatility. While Idaho Power undertakes significant efforts to ensure it receives the greatest insurance value possible for its customers, the Company is largely a price-taker in the insurance market and must absorb price increases as insurers raise premiums due to losses. Therefore, the Company believes it is appropriate to request a new baseline level of insurance in rates and also to establish a new deferral to capture incremental insurance premium costs above the new baseline.

Similarly, as addressed in detail in the Direct Testimony of Company Witness Mr. Mitch Colburn, vegetation management costs continue to rise. These costs constitute the largest single expense associated with the Company's wildfire mitigation efforts. As such, the Company requests the authority to continue to defer incremental vegetation management above the new baseline established in this case until such a time that these costs stabilize.

Q. Is the Company requesting new deferral authority for wildfire-mitigation related capital items?

A. No. Because the Company has already made the majority of necessary incremental capital investments related to the implementation of its Wildfire Mitigation Plan, there is no longer a need to defer related depreciation expense amounts.

Q. Is the Company requesting any other specific regulatory treatment as part of this case?

A. Yes. The Company has several requests for specific regulatory treatment and necessary regulatory accounting as part of this case that I will cover in detail later in my testimony. At the end of my testimony, I will provide a summary listing each of those requests for clarity and transparency.

II. <u>TEST YEAR</u>

Q. How did the Company prepare its test year in this proceeding?

A. Idaho Power prepared its 2023 test year in this case using the same general forecast methodology used in the Company's last two general rate cases, IPC-E-08-10 and IPC-E-11-08. The Company's test year methodology starts with actual 12-month financial results adjusted to include typical and traditional ratemaking adjustments consistent with a historical test year. The adjusted 2022 actual financial information was then further adjusted to reflect 2023 results through the use of known and measurable adjustments appropriate for the particular revenue, expense, or asset classification.

Q. What attributes should be considered when selecting a test year?

A. In practice, in every rate case, a test year must be selected. Whether the test year selected is historical, future, or some hybrid, the most important attribute of the selected test year should be that it accurately reflects the best expectation of the cost of service.

Regardless of which test year is adopted, the ratemaking process is inherently prospective and requires reliance upon projections. Whether the test year is completely historical or based totally on future results, the ratemaking process requires an informed determination of what conditions will prevail in the future. As of the date of filing, Idaho Power has used its best financial and operational information to construct its forecast test year.

Utility commissions and policy makers throughout the country, and particularly in the West, are increasingly recognizing that in times of high inflation and heavy construction, future test years are necessary to allow utilities a reasonable opportunity to earn their authorized rate of return. Utilities that operate in a period of rapid expansion and rate base growth will chronically under-earn if test years are historical in nature and fail to synchronize the matching of expenses and revenues.

Ultimately, Idaho Power must apply a test year approach that is both timely and reflective of the costs that the Company can reasonably expect to incur going forward. A historical test year is by definition not timely and may not be a reflection of costs going forward. Similarly, a test year based on a reasonable forecast may be more indicative of the costs the Company will be experiencing during the time rates are in place, thereby reducing the effects of “regulatory lag”.

Q. Why is regulatory lag such a critical issue to Idaho Power at this time?

A. During periods of escalating costs where marginal costs are higher than average costs, new rates are already inadequate by the time they go into place. If this situation continues for a prolonged period of time, the Company will be denied a reasonable opportunity to earn its authorized rate of return. The effects of regulatory lag are particularly pronounced in periods where the Company is engaged in capital-intensive projects and where interest rates to finance capital projects are rising.

Q. Is regulatory lag always harmful to a utility?

A. No. The impact of regulatory lag is dependent upon the situation – if overall revenue growth is keeping pace with cost escalation, and the Company is not engaged in capital-intensive projects and procuring debt and equity financing for those projects, then the Company is not typically harmed by regulatory lag. Unfortunately, Idaho Power is not in that situation currently, and will not likely be for the foreseeable future.

III. REVENUE REQUIREMENT MITIGATION ADJUSTMENTS

Q. Did you receive any specific instructions from Ms. Grow in preparing this general rate case filing?

A. Yes. In recognition of the broader economic conditions and concern for the impact that any rate increase has on customers, Ms. Grow asked me to identify specific areas where the Company could reduce the requested increase at this time. As a result, I identified the following areas where the Company is not asking for incremental increases or has otherwise taken action to minimize the overall requested revenue increase:

- Reduce return on equity ("ROE") from the recommended level of 10.60 percent to 10.40 percent;
- Hold test year non-labor operations and maintenance ("O&M") expenses to the 2022 actual level with

the exception of a limited number of known and measurable adjustments;

- Maintain the North Valmy Power Plant ("Valmy") and the Jim Bridger Power Plant ("Bridger") non-fuel coal-related cost recovery at current levels, with the exception of collection related to previously deferred revenue requirement amounts;
- Minimize the current revenue increase related to wildfire mitigation and pension costs by leveraging the existing cost recovery mechanisms; and
- Delay recovery of the revenue requirement associated with the 120 megawatts ("MW") of battery storage resources to be online in 2023 with interim earnings support from the associated investment tax credits generated from the battery storage resources.

Q. How did the Company arrive at its recommended mitigated ROE of 10.4 percent?

A. After discussions with Mr. Buckham, Senior Vice President and Chief Financial Officer, regarding Ms. Grow's directive to mitigate our rate relief request, the Company decided to apply an ROE that is at the lower end of the range provided by our outside ROE expert. Mr. Buckham believes this recommendation represents the minimum required ROE necessary to not weaken the Company's ability to attract capital at favorable and customer-beneficial rates in the current uncertain and volatile financial markets.

Q. What steps did the Company take to minimize the level of non-labor O&M included in the test year and what were the results?

A. The Company chose to hold test year non-labor O&M expense to the 2022 actual level, with the exception of a limited number of known and measurable adjustments. As discussed by Ms. Grow in her testimony, the Company has a strong track record of managing its O&M expenses, and as a result has achieved an average annual O&M growth rate of <u>only one percent between 2012 and 2022</u>. After applying all known and measurable adjustments to the 2022 actual financial results, Idaho Power's proposed test year non-labor O&M is within approximately $340 thousand of the 2022 expense level.

Q. What is the Company's recommendation regarding the recovery of non-fuel coal-related revenue requirements associated with the Valmy and Jim Bridger power plants?

A. Because the Commission has previously established separate cost recovery mechanisms for these components of the Valmy and Bridger plants in Order Nos. 33771 and 35423, respectively, the Company is proposing to maintain the current level of recovery as previously authorized by the Commission with one exception. In addition to maintaining recovery of the amounts already included in customer rates, the Company is proposing to increase collections only related to the Bridger plant to include revenue requirement amounts that the Commission chose to defer for later recovery in Order No. 35423.

Q. What incremental Bridger-related cost recovery is the Company requesting in this case?

A. Idaho Power is requesting recovery of the full annual levelized revenue requirement approved in Case No. IPC-E-21-17 and amortization of previously deferred levelized revenue requirement amounts. The total incremental annual Bridger-related cost recovery included in this case is approximately $10.7 million.

Q. What is the Company's recommendation regarding the test year level of wildfire mitigation costs?

A. Idaho Power is proposing to hold test year levels of wildfire mitigation costs to 2022 actual cost. Further, the Company is requesting amortization into rates of previously deferred wildfire mitigation costs, excluding deferred vegetation management costs, over a seven-year amortization period.

Q. Why is the Company requesting to exclude deferred vegetation management costs as part of its amortization request in this case?

A. As introduced earlier, vegetation management costs represent the largest single cost component of the Company’s overall wildfire mitigation costs. As a rate mitigation measure, the Company chose to postpone the recovery of deferred vegetation management costs and instead continue to utilize the deferral account authorized by the Commission in Order Nos. 35077 and 35717 issued in Case Nos. IPC-E-21-02 and IPC-E-22-27, respectively. By setting cost recovery at the 2022 level, the Company anticipates that the need to defer incremental amounts over time may diminish.

Further, the Company is hopeful that advances in new vegetation monitoring technology may eventually reduce annual vegetation management costs, allowing for deferred amounts to be offset by future cost reductions, thereby reducing the deferral balance. The Company will continue to closely monitor its vegetation management costs and will report back to the Commission in a future proceeding if an adjustment to related cost recovery is warranted.

Q. How did the Company arrive at its recommended test year pension cost recovery amount?

A. To arrive at its proposed test year pension cost recovery amount, the Company considered several factors, including its expected ongoing annual cash contributions to the pension plan and the cost recovery mechanism and balancing account approved by Commission

Order No. 31003 issued in Case No. IPC-E-09-29. In recent years, the Company has been contributing approximately $40 million annually to fund its pension plan. While the annual minimum required funding level fluctuates, this annual level of funding has represented a levelized or normal level of required funding. The Company's current rates include recovery of approximately $17 million a year. Annual differences between the $40 million in annual cash contributions to the pension plan and the $17 million of recovery through rates have been deferred as authorized by Order No. 31003. Rather than request recovery of the full $40 million of annual pension funding, as a rate mitigation measure, the Company is proposing to increase the current $17 million in annual pension cost recovery to approximately $35 million, and to continue to defer any differences between collection and plan contributions through the pension balancing account. If interest rates continue to stay at current elevated levels or higher, the associated discount rates used to determine annual pension funding requirements are more likely to drive required plan contributions down. While not known at this time, the Company is hopeful that the $35 million in annual pension cost recovery may ultimately provide sufficient revenue to cover the ongoing required cash contributions to the plan while also serving to reduce the regulatory asset in the balancing account.

Q. What is the Company’s proposal regarding deferred recovery of the 120 MW battery storage project to be online in 2023?

A. As an additional rate increase mitigation measure, the Company is proposing to delay recovery of the revenue requirement associated with the 120 MW of battery storage resources to be online in 2023, with interim earnings support from the associated federal investment tax credit (“ITC”) generated from the battery storage resources. More specifically, the Company is requesting authorization to 1) move to the Accumulated Deferred Investment Tax Credits ("ADITC")/Revenue Sharing Mechanism an additional amount of ITC equal to the incremental ITC generated from the Company’s investment in the 2023 battery storage projects, and 2) increase to the maximum allowed annual accelerated amortization amount by a level of ADITC equal to the actual revenue requirement of the battery storage projects in any applicable year plus the current annual $25 million cap authorized by Order No. 30978 issued in Case No. IPC-E-09-30.

Q. Is the Company proposing to exclude the 120-MW battery storage projects from rate base as part of this proposal?

A. No. The Company is requesting a full prudence review of the 120-MW battery storage projects as part of this case, with the goal of receiving Commission approval to include the Idaho jurisdictional portion of the investment in its Idaho rate base. As part of this rate impact mitigation measure, the Company is proposing to include in the final Idaho jurisdictional revenue requirement a temporary credit adjustment equal to the Idaho-jurisdictional share of the 120-MW battery revenue requirement. This credit would remain in place until the Company is authorized to recover the associated revenue requirement in a future general rate case or other applicable revenue requirement proceeding.

Q. Please provide an overview of the ADITC/Revenue Sharing Mechanism.

A. Since 2009, the Company has been subject to an ADITC/Revenue Sharing Mechanism that includes provisions for the accelerated amortization of ADITC to help achieve a minimum specified percent Idaho-jurisdiction return on year-end equity ("Idaho ROE"), currently set at 9.4 percent. The mechanism also provides for the potential sharing between Idaho Power and Idaho customers of Idaho-jurisdictional earnings in excess of a 10.0 percent Idaho ROE. Under the current mechanism, the ADITC and sharing thresholds are to be reset at a general rate case to align the sharing threshold with the then-authorized ROE and the use of accelerated amortization of ADITC at 95 percent of the authorized ROE.

Q. What is the expected dollar value of the ITC generated by the 120-MW battery storage investment?

A. The Company expects the 120 MW of battery storage projects will generate approximately $45 million of new federal ITC based on an assumption that the ITC will be equal to 30 percent of total project cost under Section 48 of the Internal Revenue Code.

Q. What is the annual revenue requirement associated with the 120 MW battery storage projects?

A. The test year revenue requirement associated with the 120 MW battery storage projects is $21,149,854. When considering the approximately $45 million of new federal ITC associated with the investment, the ITC represents approximately two years of the annual revenue requirements for the batteries.

Q. Under the Company’s proposal, what will happen to the ITC generated from the 120-MW battery projects, if they have not been amortized prior to the time the Company is allowed to recover the cost of the batteries in customer rates?

A. The Company proposes that the ITC remain available for accelerated amortization under the provisions of the ADITC/Revenue Sharing Mechanism until fully amortized - either on an accelerated basis or according to the standard amortization schedule tied to the depreciable life of the associated asset. Both maintain the Company’s long-standing compliance with federal and state ITC normalization rules.

Q.   Does the $21,149,854 test year revenue requirement include an offsetting annual benefit of the amortization of associated ITC?

A.   Yes. The $21,149,854 test year revenue requirement includes the impacts of ITC using the standard amortization schedule that ties to the depreciable life of the associated asset. An ITC amortization benefit would remain in future associated revenue requirement calculations until the ITC are fully amortized.

Q.   Aside from deferring the rate impact of the battery projects, what other benefits will customers receive?

A.   Aside from deferring the rate impact of the battery projects, customers will continue to receive the benefits of the ITC for ratemaking purposes until the ITC has been fully amortized as I previously described. As has been the case since the ADITC/Revenue Sharing Mechanism was first implemented, customer rates have continued to reflect the offsetting benefit of ITC amortization and, as of December 31, 2022, the Company has not utilized any of the currently available ADITC for accelerated amortization. In this instance, customers are guaranteed to get the benefits of service from the 120 MW of batteries at no cost in the near-term, while preserving an opportunity to still benefit from that ITC in future ratemaking proceedings.

IV. WITNESS LIST

Q. What was your level of involvement with the preparation of the testimony and exhibits presented by the other Company witnesses?

A. I discussed the content and preparation of the witnesses' testimony and exhibits with Ms. Connie Aschenbrenner (Rate Design Senior Manager), Mr. Matthew Larkin (Revenue Requirement Senior Manager), and Mr. Donovan Walker (Lead Counsel), as well as Ms. Lisa Nordstrom (Lead Counsel) and Ms. Megan Goicoechea Allen (Corporate Counsel).

Q. Please provide an overview of the Company's general rate case filing.

A. The Company begins the presentation of its case with Ms. Grow's testimony, who provides a general overview of the Company and addresses Idaho Power's current financial and operating situation and need for general rate relief. My testimony is next and covers the regulatory policy matters related to the development of the general rate case.

Mr. Eric Hackett, Projects and Design Senior Manager, discusses the growth in the Company's generation-related rate base since the completion of the Company's last general rate case, up to and including major projects expected to be completed during the 2023 test year. He presents the prudent nature of these investments, detailing why they are needed to ensure Idaho Power's generation fleet is robust and well-positioned to provide continued safe, reliable service to customers. Mr. Hackett is also the witness who presents the costs associated with, and an operation overview of, the 120-MW battery projects placed into service in 2023.

Ms. Lindsay Barretto, 500 kV and Joint Projects Senior Manager, discusses the prudent nature of investments made at Bridger and Valmy since the Company's last prudence determinations before the Commission.

Mr. Mitch Colburn, Vice President of Planning, Engineering and Construction, discusses investments the Company has made in the electrical grid to ensure the provision of safe, reliable service to customers. Specifically, Mr. Colburn details Idaho Power's recent history of reliability and system performance that demonstrates a thoughtful approach to grid construction and maintenance. He also presents specific investments included in the Company's 2023 test year that demonstrate the

Company’s prudent investment in the electrical grid at the transmission and distribution levels. Finally, Mr. Colburn reviews the Company’s wildfire mitigation efforts and associated capital and O&M expenditures.

Mr. James “Bo” Hanchey, Vice President of Customer Operations and Chief Safety Officer, describes the Company’s Safety First culture and ongoing efforts to enhance our customers’ overall experience with the Company. Mr. Hanchey also describes the Company’s advancements in energy efficiency as well as customer relations activities and related technology upgrades.

Ms. Sarah Griffin, Vice President of Human Resources, provides justification for the labor and total compensation costs included in the Company’s test year. Ms. Griffin also describes the Company’s overall compensation philosophy and explains why the level of compensation requested in this case is necessary to provide safe, reliable, affordable electricity to customers. As part of this discussion, she also provides the justification for the requested increase in cost recovery related to the Company’s pension plan, which serves as a key component of Idaho Power’s overall compensation package.

The next witness is Mr. Adrien McKenzie, who has been retained by the Company as its ROE expert. Mr. McKenzie discusses risk factors relevant to Idaho Power, performs calculations of ROE appropriate for the Company using standard financial methodologies, and recommends a reasonable ROE range appropriate for Idaho Power. In this proceeding, Mr. McKenzie’s ROE range is from 10.10 to 11.10 percent.

Mr. Brian Buckham, Idaho Power Company’s Senior Vice President and Chief Financial Officer, builds on Mr. McKenzie’s recommendations by more specifically addressing the relevant risk factors impacting the Company. Mr. Buckham selects a 10.40 percent ROE point estimate as the appropriate cost of equity, supports the cost of Idaho Power’s long-term debt, and includes the long-term debt and the 10.40 percent ROE in the test year capital structure to derive the Company’s proposed overall rate of return.

Ms. Paula Jeppsen, the Company’s Forecasting and Planning Director, next testifies to the actual 2022 financial results with standard ratemaking adjustments. Ms. Jeppsen describes the development and application of the methodologies used to prepare the 2022 base financial information and the adjustments to those data associated with deductions to certain expenses not allowed in rates, certain adjustments to expenses and rate base, and other adjustments to revenues, expenses, and rate base related primarily to past Commission orders.

Mr. Matthew Larkin, Revenue Requirement Senior

Manager, describes how the Company utilized the 2022 financial data as presented by Ms. Jeppsen as a starting point from which he made conservative adjustments to derive similar data corresponding to the 2023 test year. Mr. Larkin prepared an exhibit that details the method and rationale for each adjustment he utilized in developing the 2023 test year data. Once he determined the 2023 test year system-level data, Mr. Larkin supervised the preparation of the jurisdictional separation study utilized to determine the Idaho jurisdictional revenue requirement.

Ms. Jessica Brady, Regulatory Analyst, provides the normalized net power supply expenses for the test year and addresses the requisite changes to the Company’s PCA as a result of changing the normalized net power supply expenses in Idaho Power Company’s base rates.

Ms. Kelley Noe, Regulatory Consultant, incorporates Ms. Jeppsen’s financial data, Mr. Larkin’s test year adjustments, Mr. Buckham’s overall rate of return recommendation, and Ms. Brady’s normalized net power supply expenses, along with other necessary inputs, and prepares the jurisdictional separation study (“JSS”). The JSS, as its name states, separates system values for rate base, revenues, and expenses for each state jurisdiction through an assignment and allocation process that is described in detail in Ms. Noe’s testimony. One result of the JSS is the

Idaho retail jurisdictional revenue requirement, which is the Company’s best representation of its expected annual cost to serve its Idaho retail customers. The 2023 Idaho jurisdictional revenue requirement is $1,404,314,821. In order to obtain this amount, Idaho’s annual retail revenues will need to increase by $111,304,981 or 8.61 percent.

Ms. Connie Aschenbrenner, Rate Design Senior Manager, describes the Company’s approach to rate design strategy as well as the policy basis for the rate design proposals being made in this case. Ms. Aschenbrenner also presents an overview of the Company’s approach to developing pricing for its on-site generation customers, specifically considering interdependencies between this case and Case No. IPC-E-23-14, which is currently pending before the Commission.

Mr. Pawel Goralski, Regulatory Consultant, uses the Idaho retail jurisdictional output from the JSS as developed by Ms. Noe and further separates costs by customer class and special contract in preparing the Company’s class cost-of-service study (“CCOS”). The study prepared by Mr. Goralski in this case presents an approach most similar to that used by the Company in its last general rate case, with certain modifications and additions. In the Company’s 2008 general rate case, IPC-E-08-10, the Commission approved a cost-of-service methodology termed “3CP/12CP” and the Company subsequently used a similar methodology in its 2011 general rate case, IPC-E-11-08, which was ultimately settled without a Commission decision regarding the filed CCOS. Mr. Goralski used that same CCOS method as the starting point for his CCOS in this case and then applied modifications to the seasonal definition for peak capacity allocation, the classification of baseload resources between demand and energy, and other changes described in his testimony. Mr. Goralski recommends that his CCOS be used as the appropriate starting point for rate spread (the process of spreading the Idaho jurisdictional revenue requirement to the customer classes and special contract customers) and rate design (the ultimate calculation of rates for customers). Mr. Goralski also presents the Company’s rate recommendations for its special contract customers and Schedule 20, Speculative High-Density Load as well as the proposed Fixed Cost Adjustment rates and the corresponding modifications to Schedule 54.

Mr. Grant Anderson, Regulatory Consultant, presents the Company’s proposed rate design and resulting prices for the residential classes, including standard service (Schedule 1), time-of-use (Schedule 5), and residential on-site generation (Schedule 6) and explains the Company’s Residential Price Modernization Plan. Mr. Anderson also presents the rate design proposals for Small General Service On-Site Generation (Schedule 8), Large General Service – Primary and Transmission (Schedule 9P/T) and Large Power customers (Schedule 19).

Mr. Zack Thompson, Regulatory Analyst, presents the rate design proposals for Small General Service (Schedule 7), Large General Service – Secondary (Schedule 9S), Agricultural Irrigation Service (Schedule 24), Dusk to Dawn Customer Lighting (Schedule 15), Street Lighting Service (Schedule 41), Traffic Control Signal Lighting Service (Schedule 42), and Non-Metered General Service (Schedule 40).

Finally, Riley Maloney describes the recommendation for the Company's Standby Service schedules (Schedules 31 and 45) and Alternate Distribution Service schedule (Schedule 46). Mr. Maloney also presents several proposed modifications to the Company's tariff.

V. RATE SPREAD AND RATE DESIGN

Q. What has been Idaho Power's policy with regard to rate spread and rate design proposals?

A. Idaho Power has consistently advocated for the principle that rate spread among the customer classes, and for component pricing within the customer classes, should be primarily cost-based. Accordingly, the Company's ratemaking proposals have traditionally advocated movement toward cost-of-service results that assign costs to those customers that cause the Company to incur the costs. The Company is also committed to providing customers cost-based price signals, which encourage the wise and efficient use of energy. As such, I have directed Ms. Aschenbrenner to design cost-based rate proposals that also encourage increased energy efficiency among the Company's Residential Service, Large General Service, Large Power Service and Irrigation customer groups.

Q. Do the Company's proposals in this case strictly adhere to that objective?

A. No. The Company realizes that there are often other ratemaking objectives, such as rate stability, ability to pay, and mitigating rate shock, that the Commission may consider in making its determination. However, the Company believes that the best starting point for Commission deliberations is an economic one. Nevertheless, because some ratemaking situations may cause abrupt change, Idaho Power has traditionally proposed some limits to the movement toward cost-of-service. The specifics of the Company's proposed rate spread and an exhibit delineating the target revenue requirement for each customer class are contained in Mr. Goralski's testimony.

Q. What guidance did you provide Mr. Goralski regarding cost-of-service constraints applied to the rate spread ultimately recommended?

A. First, I discussed the CCOS prepared for this case with Mr. Goralski and agreed that his recommended CCOS methodology represented the preferred starting point in this proceeding to develop the recommended rate spread. However, this method when applied without constraints, does show a larger impact to a number of customer classes (relative to the overall average increase), most notably Agricultural Irrigation, Schedule 24. Given recent rate pressures and the somewhat subjective nature of cost allocation and year-to-year cost components, I asked Mr. Goralski to run several rate mitigation scenarios to look at the impacts of constraining the rate increase at different levels.

After this review, the Company chose to impose a cap of one and a half times the average revenue change for any customer class or special contract customer exceeding the overall average increase. This level allowed for a reasonable level of revenue movement, while not dramatically impacting the remaining classes that had to make up the shortfall.

Q. How has Idaho Power addressed the cost-based objective in its rate design proposals?

A. This objective has been met by the implementation of seasonal rates for all metered service schedules, and the implementation of rate structures that reflect a greater emphasis on the demand and customer components. The Company also proposes the continuation of mandatory time-of-use pricing for Large Commercial customers taking service at primary and transmission voltages and all Large Power Service customers. In addition, this objective has been met by offering optional time-of-use pricing for Residential and Large General service customers taking service at the secondary voltage level.

Q. Please summarize the Company’s requested Price Modernization Plan.

A. I directed Ms. Aschenbrenner to evaluate and recommend a proposal that would move fixed cost collection from volumetric rates into fixed charges, while mitigating the bill impact to customers. In this case, the Company is proposing the Commission authorize Idaho Power to implement revenue neutral rate changes on January 1, 2025, and January 1, 2026, to achieve this goal. The proposed three-year Price Modernization Plan appropriately mitigates customer bill impacts while reducing reliance on the FCA.

VI. CONCLUSION

Q. Please summarize Idaho Power’s requested revenue increase this case?

A. The Company is requesting rate relief of approximately $111.3 million, which is net of a corresponding proposed PCA decrease of $173.4 million and a reduction to annual Rider collection of $3.5 million. If approved, this request would result in an overall increase to adjusted base revenue of 8.61 percent effective January 1, 2024. The Company's request is based on a proposed rate of return of 7.702 percent, with a capital structure comprised of 51 percent equity and 49 percent debt, a 4.895 percent cost of debt, and a 10.40 percent ROE. This request was developed using a test year of 12 months ending December 31, 2023.

Q. Will you please summarize the Company's other requests for specific regulatory treatment and/or necessary accounting authority proposed in this case?

A. In addition to approval of the base revenue increase presented in this case and each of the affected tariff schedules, the Company requests the Commission issue an order that includes the following:

1. Approval of a revised Schedule 55, Power Cost Adjustment, reflecting the transfer of certain base level NPSE from the PCA to base rates.
2. Approval of a revised Schedule 91, Energy Efficiency Rider, reflecting the transfer of DSM labor-related cost collection from the Rider into base rates.

3. Approval of a revised Schedule 54, Fixed Cost Adjustment, reflecting the modifications necessary to support the Company’s proposed rate designs.
4. Authorization of the continued deferral of incremental vegetation management and insurance costs in 2024 and beyond as measured from a new base level of costs established in this case.
5. In association with the rate increase mitigation measure proposed in this case, authorization to 1) move to the ADITC/Revenue Sharing Mechanism an additional amount of ITC equal to the incremental ITC generated from the Company’s investment in the 2023 battery storage projects and 2) increase the maximum allowed annual accelerated amortization amount by a level of ITC equal to the actual revenue requirement of the battery storage projects in any applicable year plus the current $25 million cap.
6. Authorization to defer and amortize annual differences between certain periodic maintenance costs at the Langley Gulch and Bennett Mountain natural gas-fired power plants (as described in Mr. Larkin’s testimony).

7. Approval of the Company’s request for its proposed Residential Price Modernization Plan.

Q. Is it your opinion that the granting of the rate relief proposed by the Company is in the public interest?

A. Yes. The proposed rates will allow Idaho Power to continue providing safe, reliable service at reasonable rates while maintaining its financial health.

Q. Does this conclude your testimony?

A. Yes, it does.

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DECLARATION OF TIMOTHY E. TATUM

I, Timothy E. Tatum, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Timothy E. Tatum. I am employed by Idaho Power Company as the Vice President of Regulatory Affairs.

2. On behalf of Idaho Power, I present this pre-filed direct testimony.

3. To the best of my knowledge, my pre-filed direct testimony is true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: Tim Tatum ____________________
Timothy E. Tatum

REDACTED

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

ERIC HACKETT

Q. Please state your name, business address, and present position with Idaho Power Company (“Idaho Power” or “Company”).

A. My name is Eric Hackett. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Projects and Design Senior Manager.

Q. Please describe your educational background.

A. I graduated in 2003 from Boise State University in Boise, Idaho, receiving a Bachelor of Science degree in Civil Engineering. I am a registered professional engineer in the state of Idaho. In 2010, I earned a Master of Business Administration from Boise State University.

Q. Please describe your work experience with Idaho Power.

A. From 2005 to 2007, I was employed as an engineer in Idaho Power’s Transmission Engineering group. In 2007, I became a Project Manager leading transmission and distribution line and station infrastructure projects. In 2012, I was promoted to Engineering Leader where I managed the Cost and Controls group supporting project management. In 2015, I changed leadership roles and managed the Stations Engineering and Design group as an Engineering Leader. In 2018, I was promoted to Senior Manager of Projects overseeing Project

Management and Cost and Controls, which later became my current role of Senior Manager of Projects and Design in 2021, adding Power Production Design and Project Management. In addition, I am currently leading a team of internal employees and consultants in development and evaluation of Idaho Power's Request for Proposals for Peak Capacity and Energy Resources.

Q. What is the purpose of your testimony in this matter?

A. The purpose of my testimony is to discuss the growth in the Company's generation-related rate base since the completion of the Company's last general rate case ("GRC"), up to and including major projects expected to be complete in the 2023 test year. In my testimony I will discuss the prudent nature of these investments, detailing why they are needed to ensure Idaho Power's generation fleet is robust and well-positioned to provide continued safe, reliable service to customers.

Q. How is your testimony organized?

A. My testimony begins with a background of the Company's generation fleet and the factors that have led to generation-related investment since the conclusion of the Company's last GRC in 2011, Case No. IPC-E-11-08. I will then provide a discussion of proactive investments in Idaho Power's aging hydro fleet to ensure these facilities are well-equipped to continue to provide safe, clean and reliable energy to customers. My testimony will conclude with detail on Idaho Power's investment associated with the addition of utility-scale battery projects included in the 2023 test year, and explain why the Company's investment in these facilities reflects the least-cost, least-risk option to ensure sufficient capacity to meet customer demand in 2023 and beyond.

I. BACKGROUND

Q. Please describe Idaho Power's current generation fleet.

A. The backbone of Idaho Power's current generation fleet consists of the Company's 17 hydroelectric projects on the Snake River and its tributaries. Together, these projects comprise the Company's largest generation source at approximately 1,800 megawatts ("MW") of nameplate capacity. Additionally, the Company is the sole owner of three gas-fired generation facilities: the Danskin and Bennett Mountain simple-cycle power plants located near Mountain Home, Idaho, and the Langley Gulch combined-cycle power plant located near New Plymouth, Idaho, which provide approximately 762 MW of combined capacity. The Company also holds a 33 percent ownership share in the coal-fired Jim Bridger power plant ("Bridger"), which is expected to undergo conversion to natural gas generation at two of four units in the first half of 2024. Idaho Power’s share of current coal-fired operations at Bridger provides approximately 706 MW of combined net dependable capacity. The Company also has access to 134 MW of net dependable capacity at the coal-fired North Valmy power plant, reflecting 50 percent of the nameplate capacity at Unit 2 of that facility. Lastly, the Company owns and operates a 5 MW diesel facility near Salmon, Idaho.

Q. How has Idaho Power’s generation-related rate base grown since the last GRC in 2011?

A. As discussed in the Direct Testimony of Company Witness Ms. Lisa Grow, over the last decade Idaho Power has placed in service over $3.3 billion in infrastructure. Of this $3.3 billion, approximately $1.3 billion reflects investment in the Company’s generation facilities. This investment was largely driven by growth on the Company’s system and a proactive approach to addressing aging infrastructure. Because the Langley Gulch plant has already been approved for recovery in customer rates, the remainder of my discussion will focus on investments after Langley Gulch came online in 2012.[1]

Q. How has growth driven investment in Idaho Power’s generation fleet since Langley Gulch came online in 2012?

[1] Order No. 32585

A. For the first time since Langley Gulch came into service in 2012, Idaho Power is adding new Company-owned resources to its generation fleet in the 2023 test year. As discussed in Ms. Grow's testimony, the Company has experienced unprecedented growth over the past decade, adding approximately 117,000 new customers between 2012 and 2022. Over that same time period, normalized energy sales have grown from 14,010,319 megawatt-hours ("MWh") in 2012 to over 15,358,562 MWh in 2022. From a peak load perspective, Idaho Power's system peak load (approximately 95 percent of which is attributable to the state of Idaho) has grown from 3,245 MW in 2012 to 3,568 MW in 2022. As I will detail in the next section of my testimony, this growing load resulted in the Company experiencing a resource deficiency in 2023, thus necessitating the addition of new resources.

Q. How has the age of the Company's existing generation fleet driven investment over the last decade?

A. In addition to growth, Ms. Grow also describes how much of the Company's infrastructure is aging to the extent that replacement or refurbishment is required to maintain safe, reliable operation of the electrical grid. Much of the Company's hydro facilities are decades old, such as the Shoshone Falls power plant, which is over 100 years old, and the Hells Canyon Complex ("HCC"), which was constructed in the 1950s and 1960s. To ensure the Company’s generation fleet can continue to provide safe, reliable service, the Company takes a proactive approach to ensuring a robust and reliable generation fleet, resulting in significant investment over the last decade.

II. HYDRO FACILITIES INVESTMENTS

Q. Please describe the major investments related to the Company’s hydro fleet since the conclusion of the 2011 GRC.

A. Since the Company’s last GRC, Idaho Power has made several major investments in its hydro fleet, notably the refurbishment of all four turbines at the Brownlee hydrogeneration facility (“Brownlee”), upgrades and improvements at Shoshone Falls, and refurbishment of the Lower Salmon Falls hydrogeneration facility (“LSF”).

Brownlee

Q. Please describe the Brownlee hydrogeneration facility.

A. Brownlee is the most upriver dam in the HCC, which is comprised of the largest and most operationally flexible facilities in the Company’s hydro fleet. The HCC consists of three dams: Brownlee, Oxbow, and Hells Canyon, which, prior to the upgrades I will discuss, provided over 1,166.9 MW of nameplate generation capacity. Brownlee consists of five turbines, four with a generating capacity prior to refurbishment of 90.1 MW, for a total of 360.4 MW and one (Unit 5) with a generating capacity of 225 MW.

Q. What drove the need for the turbine refurbishment project at Brownlee?

A. At the time the refurbishment commenced, the four turbines at Brownlee had been in service for over 57 years. The turbines were nearing the end of their useful lives, cavitation damage had accumulated and deterioration was observed on the turbines and wicket gates. To ensure the reliable operation of the plant and the continued availability of this source of low-cost, clean hydropower, refurbishment of the turbines was absolutely necessary.

Q. Did Idaho Power gain any additional benefits from the turbine refurbishment project in addition to reliability?

A. Yes. In addition to improving reliability at the plant, the refurbishment project increased the nameplate capacity of Brownlee, resulting in an increase of 22.4 MW for each of units 1 through 4, or a cumulative increase of 89.6 MW for the entire facility, elevating the total nameplate capacity from 585.4 MW to 675 MW. Additionally, the existing turbine runners were replaced with new aerating runners, which added the ability to aerate the water to meet expected dissolved oxygen requirements associated with the Federal Energy Regulatory Commission ("FERC") license for the HCC.

Q. When was the Brownlee refurbishment project completed?

A. Refurbished Units 1, 3, 2, and 4 went into service in 2016, 2017, 2018, and 2019, respectively.

Shoshone Falls

Q. Please describe Shoshone Falls.

A. Shoshone Falls is a hydroelectric facility outside Twin Falls, Idaho. Prior to the upgrade of this facility, it consisted of three units at a combined nameplate capacity of 12.5 MW.

Q. Please describe the scope of work Idaho Power performed at Shoshone Falls since its last GRC.

A. Between 2018 and 2020, Idaho Power replaced Units 1 and 2, replaced the exterior equipment conveyer, made improvements to the intake structure, and completed significant work to ensure the safe, reliable operation of the plant.

Q. What drove the need for the replacement of these units?

A. Prior to their replacement, both units were over 85 years old. Unit 2 had become inoperable due to cavitation damage and cracking of the turbine runner, while Unit 1 was shut down in 2017 due to a thrust bearing failure. Further, under the existing setup, both units could only be operated manually from the powerhouse, limiting the ability for dynamic dispatch.

Q. Please describe the work Idaho Power performed at Shoshone Falls related to the generating units.

A. Idaho Power replaced Units 1 and 2 with a single horizontal new turbine and generator with a nameplate capacity of 3.2 MW, increasing the plant's overall nameplate capacity to 14.7 MW. New unit ancillary equipment including a turbine inlet valve and turbine unit controls were also installed.

Lower Salmon Falls

Q. Has Idaho Power performed any other major upgrades or refurbishments at any of its other hydro facilities over the last decade?

A. Yes. For the last eight years, Idaho Power has been upgrading and refurbishing the hydrogeneration facility at Lower Salmon Falls to ensure the safe and reliable production of energy and to enhance the generation capability of this aging plant.

Q. Please describe LSF.

A. LSF was first constructed in 1910 by the Greater Shoshone and Twin Falls Power Company, then acquired by Idaho Power in 1916 and rebuilt in 1946. LSF consists of four generating units that provide a combined 60 MW of clean, reliable hydropower.

Q. What drove the need for investment in LSF?

A. Many components at LSF were aging and in need of replacement. Annual condition-based testing of the coils showed them to be deteriorated and in need of replacement. Various components of the facility were aging and in need of replacement, such as the coils (32 years), core (70 years), and turbine and mechanical components (70 years).

Q. Please describe the scope of work for the LSF refurbishment project.

A. Idaho Power replaced the turbine runners for Units 1, 2 and 3, and the Unit 2 Kaplan runner received new blades and refurbished inner mechanical components. The turbine unit was completely disassembled and mechanical components of the units were refurbished or replaced as necessary. The head cover was replaced on Units 1 and 3 due to cracking. Generator work included a new stator core and new coils for all units.

Q. What benefits will the LSF refurbishment provide?

A. This project is expected to increase unit efficiency by 2 to 5 percent and is anticipated to increase unit operational flexibility. In addition to incremental generation and flexibility, this project should reduce long-term maintenance costs as well. As an added benefit, the increased generation from the project is expected to qualify for tax credits and renewable energy credits (“REC”), which will be sold in accordance with the Company’s REC Management Plan to offset net power supply expenses for all customers.

Q. When is the LSF project expected to be completed?

A. Refurbished Units 1, 2, and 4 went into service in 2022, 2020, and 2015, respectively. Refurbished Unit 3 is scheduled to go into service December 2023.

Q. Do the examples discussed in your testimony reflect a prudent and proactive approach to managing the Company’s hydro fleet?

A. Yes. Over the last decade Idaho Power has completed numerous projects at its hydro facilities to ensure they are able to provide safe, clean, and reliable service to customers.

REDACTED

III. 2023 BATTERIES

Q. What drove the need for the addition of the utility-scale battery projects for which the Company is seeking a prudence determination in this case?

A. As discussed earlier in my testimony, Idaho Power has experienced and expects sustained load growth and transmission import constraints, thereby requiring the addition of new dispatchable resources to meet peak summer demand. As a result of this growth and import constraints, in May 2021, the Company identified a near-term capacity deficit in summer 2023. To meet its obligation to reliably serve customer load and fill this capacity deficiency, in June 2021, the Company issued a competitive solicitation through a request for proposals ("RFP") seeking to acquire dispatchable resources to be online by June 2023. This robust competitive bidding process resulted in the procurement of 120 MW of dispatchable four-hour duration battery energy storage as well as execution of a 20-year Power Purchase Agreement ("PPA") for 40 MW of photovoltaic ("PV") solar, all of which was necessary to adequately address 2023 capacity deficits.

Q. Did the Company file a request for a Certificate of Public Convenience and Necessity ("CPCN") for the 2023 resource procurement?

A. Yes. Idaho Power's request for a CPCN associated with a total of 120 MW of Company-owned battery storage, the Hemingway 80-MW four-hour duration battery energy storage system ("BESS") and the Black Mesa 40-MW four-hour duration BESS, was presented in Case No. IPC-E-22-13. At the conclusion of this case, the Commission granted a CPCN with Order No. 35643, stating that "...the evidence and the record ... demonstrates that the public convenience and necessity requires the Company to acquire 120 MW of dispatchable energy storage." The request for approval of the 20-year PPA for 40 MW of solar was filed in Case No. IPC-E-22-06, which was approved by the Commission in Order No. 35482.

Q. Did the Company request binding ratemaking treatment for the investments in the 120 MW of Company-owned battery storage facilities?

A. No. Due to the urgency of the 2023 capacity deficiency and the issuance of the resulting RFP, Idaho Power was still in the process of negotiating a number of agreements necessary for the construction, installation, and maintenance of the projects and, therefore, binding ratemaking treatment was not requested. The Company's request was that the Commission find Idaho Power had met the requirements of *Idaho Code* § 61-526 and issue a CPCN, which was ultimately granted in Order No. 35643.

Q. Did Order No. 35643 impose any conditions on recovery of costs associated with the procurement of the 120 MW of Company-owned battery storage?

A. Yes. Order No. 35643 approved the acquisition of the 120 MW of energy storage resources but found that "implementing a soft cap of up to $50,228,329 and $100,456,659, for the 40 MW BESS and 80 MW BESS, respectively, is reasonable."[2] This equates to a total soft cap of $150,684,988.

Q. Why did the Commission impose a soft cap on the 2023 battery storage investments?

A. In its Order, the Commission adopted Commission Staff's ("Staff") recommendation to implement the soft cap due to concerns regarding whether the selected resources were least-cost. In comments, Staff expressed concerns about the lead time and certain restrictions associated with the resource procurement process, resulting in its recommendation regarding the soft cap.[3] The soft cap did not foreclose future requests by Idaho Power for recovery of costs above the soft cap, but rather indicated the Company would have to provide justification for any costs above the soft cap when requesting rate recovery.

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[2] Order No. 35643 pg. 12.
[3] Order No. 35643 pg. 13.

Q. Was the procurement of the 120-MW Company-owned battery storage facilities least-cost?

A. Yes. The Company's competitive solicitation process was initiated as soon as feasibly possible once the 2023 capacity deficiency was identified, and the project that was ultimately selected was the direct result of this process.

Q. What led to the rapid change in the 2023 capacity deficiency?

A. The Company's rapid change in the 2023 capacity deficiency was the result of several dynamic and evolving factors including: transmission availability, planning reserve margin determinations and reliability methodology modernization, an increasing population, new large customers in the service area and associated emergent load demands on the Company's system, and the ability of demand response programs and variable energy resources to meet load during the Company's highest-risk hours. The updated load and resource balance analysis prepared in May 2021 first identified a 2023 capacity deficit, and the Company immediately began to prepare an RFP, which was issued on June 30, 2021, roughly one month after the load and resource balance was updated.

Q. Was the RFP solicitation as expedient and robust as possible given the urgency of the capacity need in 2023?

A. Yes. Due to the urgency, the RFP solicitation focused on the importance of having a project in service by June 2023; given resource-specific permitting and construction timelines, the RFP solicited energy storage projects, solar PV projects, solar PV plus storage projects, wind projects, and wind plus storage projects. There was only one economic project bid into the RFP that was able to meet the required commercial operation date of June 2023 — the 20-year PPA associated with a 40-MW solar PV facility - which was selected through the RFP process.

The initial proposal also envisioned a build-transfer agreement associated with a 40-MW battery storage facility. However, during negotiations associated with the PPA, the developer indicated they were no longer interested in pursuing a build-transfer agreement and instead coordinated on the Idaho Power-owned battery storage project located at the developer’s solar PV site, ultimately resulting in a self-build option that was lower cost for customers.

Q. Aside from being the only economic project able to meet the required commercial operation date of June 2023, does the Company have any additional support to indicate the 120 MW of Company-owned battery storage facilities were least-cost?

A. Yes. At the time, Idaho Power was performing a parallel investigation into different configurations of Company-owned and constructed BESS, and the indicative pricing received was comparable to the lowest-cost proposals for similar battery storage projects submitted through the RFP process. In fact, pricing on the proposed 40-MW battery storage was based on a BESS from Powin Energy Corporation (“Powin”), one of the suppliers for which the indicative pricing was based. Procuring the BESS from Powin directly resulted in lower BESS costs, further supporting the acquisition of the least-cost, least-risk resource necessary to fill the 2023 capacity deficiency.

Q. Does the Company believe the RFP process was robust and that the resources procured were least-cost resources?

A. Yes. The 40-MW solar facility plus 40 MW of battery storage was identified through the RFP, resulting in a PPA for the solar facility. The decision for Idaho Power to procure the 40-MW battery storage facility directly from Powin was the result of conversations with the solar developer and Powin, ultimately resulting in a self-build option that was lower cost for customers. The remaining 80-MW project was identified through the

Company’s extensive analysis of other configurations to complement the RFP process, ensuring the resulting projects were least cost and least risk.

The lack of sufficient viable projects resulting from the RFP was not an indication that the RFP was inadequate, but rather the result of the requirement for a commercial operation date of June 1, 2023, which other bidding entities would not commit to achieving. During this time, the United States and the rest of the world were also experiencing significant supply chain disruptions and constraints, which impacted in-service dates and costs. The RFP was robust and sufficient, indicating prudent action based on information known at the time.

Q. Did Idaho Power agree with Staff’s quantification of the soft cap?

A. No. In Case No. IPC-E-22-13, the Company expressed concern that the quantification of the soft cap, presented in Staff’s Comments in that case, was flawed. Because Idaho Power did not receive multiple bids through the RFP process, Staff performed a benchmark analysis on which the quantification of the soft cap was based. The analysis, however, was based on a National Renewable Energy Laboratory (“NREL”) study that is intended for long-term planning purposes and ignores current market realities and supply chain disruptions that impact the costs of lithium-ion battery systems, resulting in a flawed analysis. In fact, the NREL study states in its disclaimer: the NREL data is “prepared for reference purposes only,” “based upon expectations of current and future conditions,” and “subject to change without notice.”[4]

While NREL data may be valuable in developing long-term integrated resource plan (“IRP”) forecast cost assumptions over a 20-year time horizon, market realities can vary significantly when contracting near-term resources. This was certainly the case between 2020 and 2022, as the COVID-19 pandemic, inflation, and other factors disrupted markets across the world. As evidenced by actual lithium-ion battery system costs, the downward pricing trend anticipated by NREL reversed into an upward trend starting in late 2021 and continued into 2022. This increasing price trend is well documented by industry reporting firms and will likely be incorporated into upcoming NREL forecasts.

Q. Are there any additional factors that would suggest the NREL study used by Staff is not appropriate for use in a benchmark analysis?

A. Yes. In addition to not factoring in current market realities, which include current real-world supply chain constraints, pricing, and above-normal inflation, the

[4] https://atb.nrel.gov/electricity/2022/disclaimer

NREL study referenced used 2020 as its base year or last historical year, which, at the time, anticipated a decline of 27 percent in costs from 2020 to 2023, as can be seen in the table below.

Table 1
NREL Forecasted Utility-Scale Battery Storage – 4Hr – Moderate

	2020	2021	2022	2023	2024	2025
$/kW	$1,727	$1,475	$1,371	$1,256	$1,167	$1,104
Annual Change		($252)	($104)	($115)	($89)	($63)
Annual Percent Change		-15%	-7%	-8%	-7%	-5%
Change from 2020		($252)	($356)	($471)	($560)	($623)
Percent Ch. From 2020		-15%	-21%	-27%	-32%	-36%

This stale NREL data did not consider recent market realities and should not have been used as a basis for Staff's soft cap recommendation. Further, in the *Annual Technology Baseline: The 2022 Electricity Update*,[5] NREL notes that it does not track near-term cost variability, and further notes that the baseline is to help in conducting scenario analysis for 5 to 30-year futures.

Q. Did the Company see a decline in battery storage costs as indicated in the NREL study?

A. No, the opposite occurred. Demand for utility-scale BESS projects in the second half of 2021 and into 2022, coupled with supply chain constraints and above-normal inflation, resulted in an *increase* in pricing of

[5] https://www.nrel.gov/docs/fy22osti/83064.pdf, slide 54.

battery storage. Industry information suggested a 10 to 20 percent increase or more from 2020 levels, driven by this high demand, input prices for lithium carbonate, and inflationary pressures on other materials and labor.[6] Utility Dive noted in April 2022 that battery storage costs rose more than 20 percent as compared to 2020 and 2021 installs, stating “crimped supply chains, rising demand for batteries and higher costs of lithium used in ubiquitous lithium-ion batteries make for a steep climb ahead ...”[7] Nearly all battery material costs had increased over the prior year and some major battery module inputs increased significantly.

> The index for nearly every commodity that is required to manufacture lithium-ion batteries, including aluminum, copper, and nickel, has risen across the board. The price of lithium-carbonate has increased 500 percent in the last 12 months. Bloomberg New Energy Finance calculates that each 20 percent increase in the price of lithium-carbonate results in a three percent increase in the total cost of battery modules.[8]

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[6] *IHS Markit:* “Multiple factors halt downward trajectory of Li-ion battery costs, with higher prices for energy storage systems set to continue throughout 2022 and 2023” January 6th, 2022.

[7] *Utility Dive:* “Battery storage costs rise more than 20% in New York as state forges ahead with 6 GW goal”, April 12th, 2022.

[8] *Utility Dive:* “Navigating the evolving state of the storage industry,” April 4th, 2022.

Q. Does Idaho Power have an alternative source of data that it believes would have been a more appropriate basis for a benchmark analysis of battery storage costs?

A. Yes. The most appropriate market guide is actual RFP responses. However, if a benchmark is desired, as part of the IRP process, the Company utilizes Wood Mackenzie, a global research and consultancy business that provides quality data, analytics, and insights for energy, chemicals, metals, mining, and the power and renewables industries, as a data source for battery storage prices. In *Wood Mackenzie's U.S. Energy Storage Monitor – 2021 Year in Review Full Report*, dated March 2022, average utility-scale four-hour battery prices averaged [redacted] per kilowatt ("kW") for the same time period, as compared to the NREL data utilized by Staff that suggested battery storage costs in 2021 would have been $1,475 per kW.

Q. How did the total estimated cost of the battery storage projects compare?

A. Using the Company's estimated project costs at the time Case No. IPC-E-22-13 was filed, the total cost of the 120 MW of battery storage projects, excluding interconnection and transmission upgrade costs analogous to the NREL and Wood Mackenzie cost estimates, was approximately $1,650 per kW. Staff used the outdated NREL data to benchmark Idaho Power's battery storage costs, suggesting that, based on the forecasted 2023 NREL battery storage costs, the Company could have procured the BESS for as little as $1,256 per kW, and therefore Idaho Power's selection of the products was not least cost. Yet, when current market conditions and industry trends are factored into battery storage costs, average costs for procurement in 2022 would range from $1,966 per kW to as high as $2,144 per kW, evidence that the soft cap was inherently flawed and punitive and should not have been imposed on Idaho Power.

Q. Assuming the low range of Idaho Power's estimate of the average cost for procurement of battery storage developed in 2022, what is the Company's quantification of a reasonable benchmark estimate?

A. Using the low end of the range, $1,966 per kW, for average battery storage costs developed in 2022 would suggest that a battery project costing $235.9 million represents a more reasonable benchmark estimate, which is $85.2 million greater than the soft cap imposed by the Commission.

Q. Your discussion of the average battery storage costs focuses on data available during the processing of Case No. IPC-E-22-13, the point at which Staff presented the benchmark analysis. Does Idaho Power have an updated estimate of the average cost of battery storage?

A. Yes. As part of the modeling for the 2023 IRP, Idaho Power is estimating average four-hour duration battery storage costs of $1,600 per kW.

Q. What is the total investment in the 120 MW of Company-owned battery storage included in the Company's 2023 test year?

A. The Company is requesting in this case to include $146.8 million for 120 MW of battery capacity plus an additional $28 million investment to account for performance degradation over time that will ensure the batteries maintain the 120 MW of capacity.

Q. Does the Company's request in this case reflect a cost that is below an appropriately calculated benchmark estimate?

A. Yes. The Company's total request for $174.8 million in rate base for the 120 MW of batteries reflects a cost of $1,457 per kW. Relative to available cost data at the time Case No. IPC-E-22-13 was being processed, the 2023 test year amounts are well below the range of $1,966 per kW to $2,144 per kW based on average costs for procurement in 2022. Further, the Company's 2023 test year costs are nearly 10 percent lower than current battery storage costs based on the Company's forthcoming IRP analysis.

Q. Does the information presented in your testimony support the Company's assertion that the 120 MW of batteries procured by Idaho Power were the least-cost option to meet the 2023 capacity deficiency?

A. Yes. Idaho Power identified a 2023 capacity deficiency in May 2021 and issued an RFP as soon as feasibly possible in June 2021. This robust competitive process ultimately resulted in the procurement of the 120 MW of batteries included in the Company's 2023 test year. The final cost of these batteries is lower than Wood Mackenzie-based pricing available at the time the 2023 CPCN case was being processed and was even less than costs available today. For all these reasons, the 120 MW of batteries included in this case represent the least-cost, least-risk option for customers.

IV. CONCLUSION

Q. Please summarize your testimony.

A. As mentioned in Ms. Grow's testimony, Idaho Power experienced unprecedented growth over the past decade, resulting in the need for the Company to procure its first utility-scale resources since Langley Gulch was placed in service in 2012. The Company's proactive approach to refurbishing and upgrading its existing resource fleet reflects a prudent approach to ensuring the continued provision of safe, clean, and reliable energy to meet the needs of Idaho Power's customers. Idaho Power's investment in the 2023 batteries reflects the least-cost, least-risk option to meet the Company’s resource need, as identified in the 2023 CPCN case and affirmed in Commission Order No. 35643.

Q. Do you believe the inclusion in rates of the generation-related rate base in the Company’s 2023 test year would result in fair, just, and reasonable rates?

A. Yes.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF ERIC HACKETT

I, Eric Hackett, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Eric Hackett. I am employed by Idaho Power Company as the Projects and Design Senior Manager.

2. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Eric Hackett

Signed: ____________________
ERIC HACKETT

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

LINDSAY BARRETTO

Q. Please state your name, business address, and present position with Idaho Power Company (“Idaho Power” or “Company”).

A. My name is Lindsay Barretto. My business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Civil Engineering from Purdue University, West Lafayette, Indiana in 2005. In 2007, I earned a Master of Science degree in Civil Engineering from Purdue University. I am a registered professional engineer in the state of Idaho.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 2010 as an engineer in Power Production’s Civil Engineering department. As an engineer I worked on hydroelectric and hatchery projects and regulatory compliance. In 2015, I moved to Transmission and Distribution Engineering and Construction as a project manager leading power line and substation projects. In 2018, I became an Engineering Leader, responsible for the Stations Engineering and Design department. In 2020, I was promoted to my current position, Senior Manager of 500kV and Joint Projects, where my responsibilities include supervision over Idaho Power’s 500kV and Joint Projects.

Q. What is the purpose of your testimony in this matter?

A. My testimony discusses the prudent nature of investments made at the North Valmy Power Plant (“Valmy”) and the Jim Bridger Power Plant (“Bridger”) since the Company’s last prudence determinations before the Idaho Public Utilities Commission (“Commission”), including a discussion of Idaho Power’s compliance with Order No. 34349, issued in Case No. IPC-E-22-05, as modified with Order No. 35774.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibit Nos. 1, 2 and 3.

I. BACKGROUND

Q. Please describe the Bridger and Valmy plants.

A. Valmy is a coal-fired power plant that consists of two units and is located near Winnemucca, Nevada. Unit 1 went into service in 1981 and Unit 2 followed in 1985. Idaho Power owns 50 percent of Valmy. NV Energy is the co-owner of the plant with the remaining 50 percent ownership and operates the Valmy facility. Idaho Power and NV Energy (collectively, the “Valmy Co-Owners”) work jointly to make decisions regarding Valmy. The Company exited coal-fired operations of Unit 1 December 31, 2019, as accepted by the Commission in Order No. 33983 as part of Idaho Power’s 2017 Integrated Resource Plan. The Preferred

Portfolio identified in the 2021 IRP, filed in Case No. IPC-E-21-43, concluded an exit from Valmy Unit 2 in 2025 provides a more favorable economic outcome when compared to an earlier exit.

The Bridger plant, located near Rock Springs, Wyoming, consists of four generating units. PacifiCorp has two-thirds ownership and is the operator of the facility and Idaho Power owns one-third of Bridger. Unit 1 began commercial operation in 1974, Unit 2 in 1975, Unit 3 in 1976 and Unit 4 in 1979. The Company and PacifiCorp (collectively, the “Bridger Co-Owners”) work jointly to make decisions regarding the plant, including required investments and the retirement of the plant. Idaho Power’s Second Amended 2019 IRP acknowledged in Case No. IPC-E-19-19 identified a preferred portfolio that included early Bridger unit exits in 2022, 2026, 2028, and 2030. Subsequently, the 2021 IRP Preferred Portfolio, filed in Case No. IPC-E-21-43, includes the conversion of Units 1 and 2 from coal to natural gas by the summer of 2024, and the exit of coal-fired operations in Units 3 and 4 by year-end 2025 and 2028, respectively.

Q. What are the current agreements under which the Valmy Co-Owners own and operate the plant?

A. The ownership and operation of Valmy is governed by three agreements: the Agreement for the

Ownership of the North Valmy Power Plant Project and the Agreement for the Operation of the North Valmy Power Plant Project, both of which are dated December 12, 1978, and the North Valmy Station Operating Procedures Criteria, dated as of February 11, 1993, between Idaho Power Company and Sierra Pacific Power Company,[1] as amended by Amendment No. 1 to the Operating Procedure Criteria for Valmy Coal Diversion Procedures and Usage, dated as of January 1, 2012. Additionally, the Valmy Co-Owners entered into the North Valmy Project Framework Agreement between NV Energy and Idaho Power dated as of February 22, 2019, memorializing the terms and conditions under which either partner may elect exit of participation of Valmy.

Q. What agreements govern the ownership and operation of the Bridger plant?

A. Currently, the ownership and operation of Bridger is dictated by three agreements: the Agreement for the Ownership of the Jim Bridger Project between Idaho Power Company and Pacific Power & Light Company, the Agreement for the Construction of the Jim Bridger Project between Idaho Power Company and Pacific Power & Light Company, and the Agreement for the Operation of the Jim Bridger Project between Idaho Power Company and Pacific

[1] Sierra Pacific Power Company has conducted business as NV Energy since 2008.

Power & Light Company, all of which are dated September 22, 1969, as amended by Amendments 1 through 9 (collectively, “Bridger Agreements”). The Bridger Agreements set forth the respective obligations of the Bridger Co-Owners with respect to the ownership, construction and operation of Bridger.

II. RATEMAKING TREATMENT OF VALMY AND BRIDGER

Q. Has the Company requested from the Commission any ratemaking treatment associated with the coal investments in Valmy and Bridger based on the early exit of coal-fired operations?

A. Yes. In Case No. IPC-E-16-24 and updated in Case No. IPC-E-19-08, Idaho Power requested approval of a balancing account mechanism designed to smooth revenue requirement impacts associated with the shutdown of Valmy and allow for full recovery of Valmy-related costs near the plant’s end-of-life. In addition, this mechanism more closely aligns the cost recovery period with the remaining operating life of the plant, resulting in a better matching of cost recovery from customers who benefit from the plant’s operations while mitigating the risk of future customers bearing the costs of a plant that will no longer be providing service. The Commission approved the Company’s request with Order Nos. 33771 and 34349, respectively. Similarly, in Case No. IPC-E-21-17, Idaho Power requested approval of a balancing account mechanism for the Bridger coal-related investments, which was approved by the Commission with Order No. 35423.

Q. Did approval of the balancing account mechanisms for both plants include a prudence determination of the investments at the time?

A. Yes. With the issuance of Order No. 34349, it was determined that all Valmy investments through December 31, 2018, had been prudently incurred. Further, in Case No. IPC-E-22-05, the Company requested the Commission find that all actual Valmy investments made during the January 1, 2019, through December 31, 2021, time period were prudently incurred. However, Order No. 34349, issued in Case No. IPC-E-22-05 delayed a prudence determination of Valmy investments. With respect to Bridger, Order No. 35423 found that all Bridger coal-related investments through December 31, 2020, were prudently incurred.

Q. Why did the Commission delay a prudence determination on the Valmy investments made during the January 1, 2019, through December 31, 2021, time period?

A. In their review of Idaho Power's request, Commission Staff ("Staff") analyzed two types of prudence, decisional prudence, which is based on need, and operational prudence, which is based on whether or not the Company implemented the investment in the least-cost manner. Commission Staff concluded that the investments were needed to continue safe and reliable operation of the facility, or decisional prudence, but indicated they could not “recommend that the investments were operationally prudent due to lack of sufficient evidence documenting that the projects were done in a least-cost way.”[2] As such, Staff recommended Idaho Power work with them to develop the documentation necessary for Commission Staff’s audit and prudence review and provide Commission Staff with the additional information via a compliance filing within six months of the Commission’s order to determine prudence.[3] With Order No. 35494, the Commission indicated it was “fair just and reasonable for the Company to file additional documentation to support a prudence determination as part of the 2022 Annual Review” after working with Commission Staff to expand the documentation process.[4]

Q. Did Idaho Power file additional documentation to support a prudence determination as part of the Valmy 2022 Annual Review?

A. No. On March 31, 2023, after discussing with Staff, Idaho Power filed a Motion for an Extension of Time to Comply with Order No. 35494 because Commission Staff and the Company were still working to memorialize and finalize

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[2] Case No. IPC-E-22-05, Staff Comments, p. 4.
[3] *Id.* At 8.
[4] Order No. 34594 at 6.

the information and documentation necessary for Commission Staff’s prudence review. As part of this Motion, Idaho Power proposed to include the request for a prudence determination and the associated documentation, as part of this general rate case proceeding. The Motion requested the Commission acknowledge the Company will include its 2022 Annual Review, as required by Order No. 34349, as part of the general rate case filing as well. The Commission issued Order No. 35774 on May 8, 2023, granting the Motion.

Q. Have Idaho Power and Staff come to an agreement regarding an expanded documentation process for investments made at the Company’s jointly-owned generating facilities?

A. Yes, in principle. However, Staff and Idaho Power are still working to finalize a Memorandum of Understanding (“MOU”) that will govern Idaho Power’s demonstration of oversight of its jointly-owned generating facilities, and will represent a mutual agreement on the types of information the Company will file to support its request for a prudence determination of expenditures made at the Valmy and Bridger plants. Staff and Idaho Power are finalizing a Major Projects Checklist that is intended to detail the review timing and documentation to accompany capital project expenditures over a certain dollar threshold, and an Oversight Meeting Checklist that will document Idaho Power's ongoing and continual participation in the capital budget reviews of each plant throughout the year, encompassing the entirety of the capital budget regardless of the dollar amount of individual projects. A summary of the key provisions envisioned to be contained in an MOU is provided as Exhibit No. 1 to my testimony.

Q. Based on the Company's request for a prudence determination of the Valmy and Bridger investments in this proceeding, has the Company prepared the documentation necessary to support the investments?

A. Yes, Idaho Power has the documentation necessary to support a prudence determination of the Valmy and Bridger investments. However, the Company cannot retroactively complete checklists for meetings that have already occurred, but Idaho Power stands ready to provide all available information for the Valmy and Bridger capital projects in support of a prudence determination.

III. VALMY INVESTMENTS SINCE 2018

Q. As a 50-percent owner in the plant, is Idaho Power involved in the decision-making process related to capital investments at Valmy?

A. Yes. As the plant operator, NV Energy manages the capital budget for Valmy. However, Idaho Power has established guidelines at Valmy to allow NV Energy to manage the capital budget as needed and directed by the plant manager, without exceeding the yearly budget, or adding large projects without authorization by the Valmy Co-Owners. These guidelines provide the appropriate level of oversight while allowing the plant operator to practically manage the plant and any variances that may occur throughout the budget year.

Q. What guidelines are in place to monitor capital expenditures at Valmy?

A. First, if Idaho Power's share of the capital forecast is greater than the capital budget by more than $100,000, the Company will review and may authorize the budget change. In addition, all new or unbudgeted Unit 2 or common facility capital projects larger than $1 million, at the plant level, require a review and authorization in writing by each Valmy Co-Owner prior to starting the project. Finally, any time an individual Unit 2 or common facility capital project with a value greater than $1 million, at the plant level, is forecast to exceed the current year original budget by 20 percent, each Valmy Co-Owner must review and authorize it in writing prior to starting or continuing the project.

Q. Aside from the guidelines, are there any other ways the Company participates in the capital budget process?

A. Yes. Individual capital project variances are discussed during Ownership Meetings and other meetings as directed by the Valmy Co-Owners. In addition, NV Energy produces an Authorization for Expenditures (“AFE”) request for all capital projects. AFEs include the project title, date, project manager, description and purpose of the expenditure, cost and budget information, along with various other information to provide support for the project. If the project is expected to exceed the AFE amount by either 10 percent, for variances greater than $10,000, or $100,000, a supplemental AFE is required.

Currently, Idaho Power provides authorization to NV Energy of all AFEs and supplemental AFEs for each project. The Company has requested that no projects begin, and the total annual budget may not be exceeded, unless the AFE is approved by both NV Energy and Idaho Power. Lastly, in addition to the plant-specific guidelines detailed above, Idaho Power performs holistic budget reviews on a monthly and quarterly basis. This includes capital expenditures at all of the Company’s facilities, including Valmy, and therefore provides an additional review process through which the Company monitors its capital spend at Valmy.

Q. What is the time period for which Idaho Power is requesting a prudence determination of Valmy investments?

A. Because Order No. 34349 delayed a prudence determination on the Valmy investments made during the January 1, 2019, through December 31, 2021, time period, the Company is requesting a prudence determination of Valmy investments made during the January 1, 2019, through December 31, 2022, time period. There have been a number of investments required to operate the plant in a safe, efficient, and reliable manner, including investments required to ensure environmental compliance as well as a number of investments for routine asset replacement.

Exhibit No. 2 presents Idaho Power's share of the investments made at Valmy between January 1, 2019, and December 31, 2022, detailing 92 different capital projects totaling $8.19 million. In addition, for those projects for which Idaho Power's ownership share is over $50,000, and all investments associated with Unit 1, the Company has included a project description and investment purpose classification as to whether the investment was for environmental compliance, safety, and/or reliability. Of the 44 projects for which a detailed project description and investment purpose classification was provided, 26 were for continued reliable plant operations, three were required for environmental compliance, and 15 were for a combination of either reliability, environmental compliance, or safety.

Q. Why did the Company include a project description and investment purpose classification for all investments associated with Unit 1, even if they were less than $50,000?

A. Idaho Power included a project description and investment purpose classification for all investments associated with Unit 1 to highlight that although the Company exited operations of Unit 1 on December 31, 2019, there were investments required to ensure reliable operations of Unit 1 until the Company’s exited participation in coal-fired operations.

Q. Were all the projects comprising the $8.19 million in investments that occurred between January 1, 2019, and December 31, 2022, necessary for either environmental compliance, the safe and economic operation of the plant, or for reliability purposes?

A. Yes.

Plant Reliability Investments

Q. You indicated there were 26 investments greater than $50,000 or associated with Unit 1 that were required for the reliable operation of the plant. What was the largest investment made to maintain reliability?

A. While not the largest investment made during the January 1, 2019, through December 31, 2022, time period, the largest investment made solely for reliability purposes was for approximately $630,000 for an update to the Distributed Control System ("DCS") of Unit 2.

Q. Why was an update to the DCS required?

A. The existing DCS was installed in 2015 and was operating both servers and human machine interfaces of Unit 2. A typical life-cycle of the DCS is 10 years, with a five-year mid-cycle human machine interface and operating system update required. The existing DCS was operating beyond the original equipment manufacturer ("OEM") support and security patches were no longer being created for the systems. In addition, the control servers were operating on Windows Server 2008, which Microsoft ceased supporting as of January 1, 2020, and the human machine interfaces were operating on Windows 7, which Microsoft stopped supporting as of January 14, 2020. Operating without the OEM supported cybersecurity patches put these servers and human machine interfaces at an elevated security risk.

Q. What did the upgrade entail?

A. The upgrade replaced the human machine interfaced hardware and upgraded the operating system to Windows 10. In addition, the following control equipment was upgraded: (1) new virtualized Windows 2019 control servers host, (2) Emerson Ovation software, and (3) new ethernet switches and routers. All of the upgrades enabled implementation of the latest critical security controls for cyber defense and detection tools.

Q. Were there any additional factors that influenced the decision to update the DCS when the plant did?

A. Yes. An additional concern existed with the scheduled retirement of Unit 1. Several common plant systems were controlled by the DCS on Unit 1 and required code changes to move these controls to the DCS on Unit 2. Therefore, the decision was made to upgrade Unit 2’s DCS prior to the retirement of Unit 1 and coincident to other cybersecurity project upgrades.

Q. What additional investments were made at Valmy solely for reliability purposes?

A. The majority of the investments made to maintain reliable operations of Valmy were associated with normal wear and tear of existing investments which I will discuss first, including (1) the replacement of the pulverizer gear box, (2) the purchase of pulverizer spare parts, (3) the Unit 2 pin mixer replacement, and (4) Unit 2 generator bushing gasket replacements.

Q. What is the purpose of a pulverizer?

A. Pulverizers are utilized to grind coal to fine dust via roll wheel assemblies and table grinding segments before being transported to burner fronts. Each Valmy unit requires four pulverizers to reach full load status each year in order to perform annual testing and certification of the cold reheat safety valves in compliance with the Annual State of Nevada Boiler Operating Permit. The plant maintains a spare pulverizer for Unit 2 in the event of a failure of one pulverizer to maintain reliability.

Q. What occurred to require the replacement of a pulverizer gear box?

A. One of the pulverizers on Unit 2 tripped, compromising the reliability of the unit. Plant personnel opened the gearbox inspection port and discovered the gearbox had failed. Approximately $588,000 was invested in pulverizer repairs to ensure Unit 2 maintained reliability.

Q. Why does the plant purchase spare parts for the pulverizers?

A. The grinding of coal to a fine dust wears out the roll wheel assemblies, table grinding segments, and the interior of pulverizer equipment. As a result, the normal operating life cycle of a Unit 2 pulverizer is roughly 18 to 24 months until a major rebuild of the pulverizer is required. Routine inspections are typically performed at 3,000 hours and maintenance performed to ensure the maximum life of the pulverizer rebuild. However, with an upcoming end-of-life of Unit 2 in 2025, upon routine inspection, it was determined the pulverizers were not in need of a major overhaul. Rather a more cost-effective approach would be to purchase a full set of grinding table segments and three roll wheel assemblies, to expedite repair once excessive wear occurred, while also avoiding long lead times for replacement equipment. In addition, during routine maintenance of a pulverizer at a different time, three refurbished trunnion wheel assemblies were purchased as capital spares, totaling $456,000 and $166,000, respectively, as opposed to performing a major overhaul. The capital spares will allow the capital maintenance outages to be completed on an as needed basis, as opposed to during the routine inspection, when the pulverizers' hours of operation and level of wear justifies the overhauls.

Support of the need for spare pulverizer parts occurred when the Unit 2B pulverizer failed due to a seized roll wheel assembly, compromising reliability. A spare roll wheel assembly was installed at the time, for approximately $231,000, ensuring Unit 2 was in compliance with the State of Nevada testing requirements. Further, in 2019, on the Unit 1D pulverizer, three of the roll wheel assemblies failed, one in April, and two in September requiring replacement, for investments totaling approximately $160,000 and $47,000, respectively. The Unit 1D pulverizer had exceeded 20,000 hours of operation with significant wear and parts deteriorated beyond the service life expectations. Upon inspection, it was found that one of the three wheel assemblies in the pulverizer was cracked and not rotating freely due to a bearing failure.

Q. Why was the replacement necessary in 2019 if the Company was exiting the unit that year?

A. The plant was coming up on its annual testing and certification of the cold reheat safety valves, a compliance requirement of the annual State of Nevada Boiler Operating Permit as I mentioned earlier, and needed to reach full load status, requiring all four pulverizers. Due to the wear, there were sizing differences of the three roll wheels' diameters, requiring the replacement of three of the roll wheel assemblies on the Unit 1D pulverizer.

Q. What was the purpose of the last two projects resulting from the normal wear and tear of existing investments, the Unit 2 pin mixer replacement and the Unit 2 generator bushing gasket replacements?

A. The Unit 2 pin mixer, which unloads the wet fly ash, required replacement and was rebuilt prior to the summer run to avoid the potential of a serious failure due to the lack of non-redundant equipment. This project totaled approximately $225,000. In addition, approximately $107,000 was spent to replace bushing gaskets and for the regasketing of the bushing terminal plant.

Q. Why must bushing gaskets be replaced?

A. The terminal plate gaskets for the high voltage bushings of the generator were worn out and there was indication of bushing gaskets leaking as the viscasil lubricant was seeping through the bushing gaskets, indicating possible failure of the bushing. Bushing gasket leakage could lead to catastrophic failure of the generator.

Q. When was this issue first identified?

A. The issue was first identified in 2010 and temporary repairs were made. In 2017, it was noticed that the leak had become significant and one more temporary repair was made and annual inspections conducted. However, the 2018 annual inspection discovered more leakage so the replacement of the bushings and regasketing of the bushing terminal plate was performed.

Q. What additional investments were made at Valmy to maintain reliability?

A. The following investments greater than $50,000 or associated with Unit 1 that were required for the reliable operation of the plant include the (1) installation of freeze protection heaters, (2) repair of the generator exciter power supply system, (3) replacement of the underground equipment wash piping, and (4) recoating of the condenser inlet tube sheet.

Q. What necessitated installation of freeze protection heaters?

A. In 2018, because the Valmy operating schedule shifted to running the units in only the summer months and to be in long-term layup during the remaining months of the year, it was determined that with both units offline there was no auxiliary steam to provide heat to the turbines, boilers and buildings to keep them dry and above the dew point, per the long-term layup plan.

Q. How was Valmy heated at the time?

A. The plant was renting portable electric space heaters to sufficiently heat the plant buildings and equipment during the layup period. However, it was determined that the purchase of the heaters for approximately $541,000 was more cost-effective than renting. In addition, the purchase and installation included four water-to-air dry finned coolers which cool the component cooling system on each unit and exhaust warm dry air into the lower level of the turbine building, reducing the number of electric heaters required to be purchased. Heating of the turbines and buildings helps ensure the units can be operational when needed.

Q. What occurred that required the replacement of the generator current transformers?

A. The Unit 2 exciter power supply transformers had failed, preventing the unit from returning to service.

One of the three saturable current transformers that supply power to the generator exciter, one linear reactor transformer, and the exciter control card module were damaged. This project, which totaled approximately $468,000, replaced two saturable current transformers that had compromised integrity due to oil and heat damage as well as one of the remaining linear reactor transformers that had degraded while running at an elevated temperature.

Q. What was the replacement of the underground equipment wash piping necessary to maintain reliability of Valmy?

A. A section of the boiler equipment wash piping, which is used to fill both circulating water systems prior to start-up, failed. The underground piping was the original piping put in during construction in 1979. Using alternative means to fill the circulating water systems is very time consuming and results in start-up delays, thus requiring the replacement of the underground equipment wash piping. The replacement of the boiler equipment wash piping in 2021 was approximately $151,000.

Q. Why was recoating of the condenser inlet tube sheet necessary to maintain reliability at Valmy?

A. In 2019, the recoating of the condenser inlet tube sheet was required contributing to approximately $108,000 of the Valmy investments. The condenser inlet tube sheet of a unit is exposed to erosion from particles and turbulence in the circulating water. It is coated with a wear resistant coating to protect the metal tube sheet and condenser tube ends. The coating on Unit 2 had worn to the point that significant portions of bare tube and tube ends were exposed.

Q. What happens if the metal tube sheet and condenser tub ends are left exposed?

A. When exposed, the tube ends will erode and can result in tube failure and leakage of circulated water into the steam side of the condenser, contaminating the boiler water. Recoating of the tube sheet was required. However, when the recoating began, the plant was able to repair some of the existing waterbox coating resulting in project costs lower than initially estimated.

Q. What additional investments were made solely for reliability purposes?

A. The remaining 13 projects associated with investments for reliable operations of Valmy made between the January 1, 2019, through December 31, 2022, time period that I have not discussed yet were all between $50,000 and $100,000. They included: (1) the refurbishment of the Unit 2 boiler feed pump, (2) the replacement of the coal handling conveyor following sustained run time failure, (3) the replacement of the pumps on production wells 13 and 14,

(4) the purchase and installation of two redundant 1000 kilovolt-amp transformers that power the coal handling system following failure beyond economic repair, (5 and 6) two projects associated with the motor of the Unit 1 circulating water pump that failed following a ground fault, one investment associated with the replacement of the motor and the second with the rewind of the failed motor for use as a capital spare, (7) the use of a capital spare to replace the failed Unit 2A pulverizer, (8) the replacement of three generator current transformers following failure, (9) the installation of the spare Unit 1A primary air fan motor due to damage, (10) a new fly ash blower to convey ash in order to prevent the baghouse hoppers from overflowing due to internal wear and damage, (11) an upgrade of the revenue meter required when Idaho Power exited participation in operations of Unit 1, (12) refurbishment of the block valve that supplies extraction steam to the Unit 1 first point feedwater heater, and (13) the Unit 1B pulverizer rebuild. Exhibit No. 2 provides additional information for each project including the total investment amount and a detailed project description and justification.

Q. How have these 26 investments required for the continued reliable operations of Valmy contributed to the additions at the plant since January 1, 2019?

A. At $4.50 million, the investments for reliability purposes are the largest expenditures made at Valmy since 2018, making up 55 percent of the total projects.

Q. You mentioned some of the investments over $50,000 or associated with Unit 1 were made for a combination of either reliability, environmental compliance, or safety purposes. Were there any additional investments for which the purpose included a reliability component?

A. Yes. There were eight projects required for a combination of reliability and safety purposes.

Plant Reliability and Safety Investments

Q. Please describe those projects greater than $50,000 or associated with Unit 1 that have been identified as required for reliability and safety purposes.

A. The largest investment made at Valmy during the January 1, 2019, through December 31, 2022, time period was for a combination of reliability and safety purposes. In 2021, $1.24 million was spent to fix the Unit 2 turbine high pressure/intermediate pressure ("HP/IP") section shell steam leaks.

Q. What caused the HP/IP section shell steam leaks on the Unit 2 turbine?

A. Beginning in 2015, the Unit 2 steam turbine

HP/IP shell experienced five steam leaks from the mating surfaces of the steam turbine HP/IP upper and lower shells. Each steam leak damaged the two turbine shells by eroding the mating surfaces material and providing further paths for the superheated steam to escape from the turbine HP/IP shells. At the time, previous repairs did not fix the eroded mating surfaces or the compromised connection hardware that compresses the two shell halves together to form the mating surfaces seal.

Q. What happens when the mating surfaces and connection hardware is not repaired?

A. Connecting hardware eventually wears out, only enduring a limited number of tightening and loosening cycles before the connecting hardware loses its strength and the ability to provide the compressive forces necessary to form the mating surfaces seal of the two shell halves. This loss of connecting hardware strength is also compounded by the high temperature during operations causing the plastic deformation of the steel. This process is known as creep.

Q. How did the creeping compound the issues with the HP/IP shells?

A. The plastic deformation, in conjunction with applied stresses, can also warp and distort both the connecting hardware and the HP/IP shells themselves. A ‘tapped stud’ threads into the lower shell half and a large nut is installed on the upper portion of the tapped stud and tightened to apply the compressive force to the two shell mating surfaces.

Q. Were the tapped studs of the HP/IP shells affected?

A. Yes. A minimum of six tapped connecting studs are known to have been compromised in some fashion, mostly warpage.

Q. What was the extent of the investments necessary to repair and prevent future HP/IP section shell steam leaks?

A. This project replaced the connecting hardware, which was no longer providing sufficient consistent compressive force, with new hardware and refurbished the mating surfaces of the two HP/IP shells. The two turbine HP/IP turbine shells were separated, and the mating surfaces were refurbished with a combination of welding and machining. In addition, ten tapped connecting studs and nuts on each side of the HP/IP turbine section in the areas of the five steam leaks were replaced with new tapped connecting studs and nuts. The tapped stud threads in the lower half shell were also repaired as necessary. The tapped studs replacement, lower half thread repairs and HP/IP shell mating surfaces refurbishment were made after the two HP/IP shells were separated. These repairs corrected the known root causes and corrected for the turbine HP/IP section shell steam leaks.

Q. What additional investments required for both safety and reliability purposes were made?

A. In November 2017 an evaluation of the fire protection systems was performed that determined the refurbishment or replacement of the systems was required due to degradation of the existing system, through a combination of worn out and/or outdated components and systems. As a result, the refurbishment of the Early Warning Smoke Detection system was performed, the Unit 1 and Unit 2 stand-pipe booster pipes were replaced, the fire alarm control panels and associated controls and alarms were replaced, the deluge valves were replaced, and the required flow testing of the electric fire pump and the diesel fuel tank system was performed. Total project costs were approximately $263,000.

In addition, Unit 2 was experiencing erratic control valve movement that resulted in unit trips due to the resulting load and drum level swings. The primary cause of the erratic valve movement was leakage in the upper and lower positioners. To operate as reliably as possible and limit the erratic valve movements, the control valves were kept wide open. Replacement of the upper and lower turbine control valve hydraulic cylinder positioners, for approximately $119,000, was necessary to restore stable operation of the turbine and improve plant reliability.

Q. Please describe the additional investments made between January 1, 2019, and December 31, 2022, classified as required for reliability and safety purposes.

A. The next set of investments over $50,000 or associated with Unit 1 made for reliable and safe operation of the plant were required because of the age of the existing investment and the associated wear and tear, including the replacement of the Unit 2 stack elevator and transportation fleet at the plant. The stack elevator was installed with Unit 2 in 1984 and replacement parts had become obsolete. On several occasions the elevator stopped operating properly during the installation of environmental compliance equipment and prior to scheduled emission testing, causing delayed installation timelines. A total of approximately $107,000 was invested to complete the elevator replacement including the car, brake assembly, drive motor and gearbox, electrical system replacement and call system replacement.

In 2020 and 2022, approximately $88,000 and $78,000, respectively, was spent to replace some of the van transportation fleet due to concern with safety and reliability. The Valmy fleet was aging and reaching high mileage, traveling approximately 1,750 miles for maintenance and 5,200 miles for operations/fuels per month by 2022. The vans transport employees to and from the remote plant site, 24 hours a day, seven days a week, which is a standard in northern Nevada set by local mining companies. Three of the existing nine vans were replaced in both 2020 and again in 2022 as each van was over ten years old with between 190,000 to 256,000 miles.

Q. What were the two remaining investments made for reliability and safety purposes between January 1, 2019, and December 31, 2022?

A. The remaining investments identified as necessary for reliable and safe operations of Valmy include the (1) refurbishment of the trisector air heater expansion joint following damage from thermal expansion, rust, acid condensation and erosion, and (2) refurbishment of the first point feedwater inlet valve on Unit 1.

Q. How have these projects, necessary for the continued reliable and safe operations of Valmy, contributed to the additions at the plant since January 1, 2019?

A. The investments made at Valmy for reliability and safety purposes during the January 1, 2019, through December 31, 2022, time period total $1.97 million, or 24 percent of the total projects.

Q. Were there any additional investments made at Valmy between January 1, 2019, and December 31, 2022, that included a purpose classification for continued reliable operations of the plant?

A. Yes. There were five projects associated with continued reliable operations of Valmy as well as required for environmental compliance.

Plant Reliability and Environmental Compliance Investments

Q. What were the Valmy investments required for continued reliable operations and environmental compliance purposes?

A. Four of the investments made at Valmy between January 1, 2019, and December 31, 2022, and identified as required for both continued reliable operations and environmental compliance were associated with the scrubber atomizer wheels on Unit 2, while the largest investment made was associated with the scrubber spray machine gearbox that drives the atomizer wheels. The dry scrubber on Unit 2 utilizes nine atomizing spray machines, three atomizers per scrubber vessel, to atomize a lime/recycled fly ash mixed slurry that reacts with the sulfur dioxide in the flue gas to produce calcium sulfate. The solid calcium sulfate particles are then collected along with fly ash in the baghouse.

To accomplish this, the atomizer wheel rotates via the gearbox at approximately 13,000 revolutions per minute and centrifugal force shears the lime/recycled ash slurry into very small droplets for intimate liquid/gas contact. The force of the shearing slurry slowly erodes the atomizer wheels which require routine replacement. An atomizer wheel can be expected to last for 10,000 to 12,000 hours in service. In 2019 the procurement of six new atomizer wheels was required. Five of the atomizer wheels that were at the end of their service life were replaced in 2020 and 2021, and eight were replaced in 2022. In addition, the gearbox, which requires precision balancing and tight tolerance on gear clearances could not be repaired and required replacement. The five projects totaling approximately $683,000 were required to ensure the continued reliable operations of Valmy.

Environmental Compliance Investments

Q. What investments were made at Valmy solely for environmental compliance?

A. There were three investments over $50,000 or associated with Unit 1 made at Valmy between January 1, 2019, and December 31, 2022, for which the purpose was environmental compliance. The first, for approximately $220,000, included the installation of nine new ground water monitoring wells.

Q. Why were the new ground water monitoring wells required?

A. Ground water elevation at Valmy had risen noticeably over the last six to eight years, presumably due to cessation of dewatering activities at the nearby Lone Tree Mine. As a result, the screened interval intake of several wells was nearly fully submerged.

Q. Are there guidelines in place for appropriate groundwater levels?

A. Yes. According to Nevada Division of Environmental Protection ("NDEP") monitoring well guidelines, the groundwater level should be within the screened interval level to obtain an accurate water level reading. Any reported ground water levels above the top screen level are considered invalid. At the time, of the Valmy plant's 14 ground water monitoring wells, five were reading above the top screen level and four were close.

Q. What would happen if the groundwater levels were not addressed?

A. If the wells were not redrilled, plugged, abandoned or replaced, the existing wells may have become non-compliant with the regulatory intent of monitoring the potential impacts of operating the facilities' landfill and evaporation ponds. In addition, if not in compliance, the NDEP can order similar action. As a result, the plant installed nine new ground water monitoring wells.

Q. Please describe the remaining investments made at Valmy for environmental compliance.

A. Approximately $13,000 was associated with the replacement of the low nitrogen-oxide burner nozzles of Unit 1 to remain compliant with the Mercury and Air Toxics Standards, and finally $1,000 of costs were associated with the replacement of the existing sorbent trap mercury monitoring equipment closed in 2019.

Q. Were there any additional investments made at Valmy between January 1, 2019, and December 31, 2022, that included a purpose classification for environmental compliance?

A. Yes. There were two projects over $50,000 or associated with Unit 1 that were required for both environmental compliance and the continued safe operations of Valmy.

Environmental Compliance and Safety Investments

Q. Please describe the first required investment for environmental compliance and safety.

A. The three dry scrubber vessels on Unit 2 often suffer severe scaling and/or debris material buildup as scale is dislodged from the scrubber vessel walls. The scale and buildup can be severe enough that several times per year the unit is curtailed by 70 MWs while the scale and buildup are removed from the vessel walls and the outlet duct via the existing debris chute and from the outlet duct door. The debris material is then collected and transported to the ash landfill. The removal of the debris is required under the Mercury and Air Toxic Standards regulations.

In 2020, approximately $127,000 in project costs were incurred to enlarge the existing Unit 2 scrubber vessel debris chute and install three 24-inch diameter hydraulically actuated knife gate valves. The purpose was to allow for the faster and safer removal and collection of the scale, sludge and debris for disposal in the ash landfill. The investment reduced the duration of forced outages by 50 percent. In addition, automation of the valves to open the scrubber vessel, which previously required personnel to perform via a ladder, rectified a safety concern.

Q.   What additional investment was made for environmental compliance and safety of Valmy?

A.   The primary and backup scrubber computer room air conditioning units were aging equipment and required frequent maintenance. Operating failures of the system had resulted in unit trips due to overheating of the baghouse pollution control device that is located in the scrubber computer room. Baghouse pollution control device components and the HVAC units were repaired and returned to service, but overheating was a recurring problem. Replacement of both the primary and backup scrubber computer room air conditioning units totaling approximately $65,000 was necessary to ensure reliable operation of Unit 2 while also maintaining safety of the plant personnel.

Q. Please summarize the investments that were made at Valmy over $50,000 or were specific to Unit 1 that make up the $8.19 million for which Idaho Power is requesting a prudence determination.

A. Of the 44 projects for which a detailed project description and investment purpose classification was provided, 26 were for the continued reliable plant operations totaling $4.50 million, another $234,000 was associated with the three projects required for environmental compliance, and the remaining 15, which were for the combination of either reliability, environmental compliance, or safety, contributed to $2.85 million of the total investments made at Valmy between January 1, 2019, through December 31, 2022.

IV. BRIDGER INVESTMENTS SINCE 2020

Q. As a one-third owner in the plant, is Idaho Power involved in the decision-making process related to capital investments at Bridger?

A. Yes. As the plant operator, PacifiCorp manages the capital budget for Bridger. However, the

Company is and always has been actively involved in the decision-making process in all matters associated with Bridger capital investments as a co-owner. While PacifiCorp, as the operator, vets and analyzes the need for specific capital replacements as they arise to continue reliable and safe operation of the plant, Idaho Power regularly participates in discussions of the capital investment forecast prepared by PacifiCorp, influencing the investments ultimately made.

Q. What documentation does the Company review as the one-third owner and non-operating partner?

A. Idaho Power receives from PacifiCorp a monthly billing invoice, invoice support documentation, and monthly invoice reconciliation. Appropriation Requests are available for every project, which include a project description, investment reason, project number, and projected expenditures for the project, by year. During the quarterly Ownership Meetings, Idaho Power reviews the current year operations and maintenance (“O&M”) expense and capital budgets and forecasts. As noted in the Exhibit No. 1, Idaho Power plans to implement an Oversight Meeting Checklist to document its participation in these quarterly meetings at Bridger, including the budget overview document provided at and discussed during these meetings.

Q. Does Idaho Power have any contractual rights to approve items such as capital spend?

A. Yes. Under Section 5.4 of the Operation Agreement, each October PacifiCorp will submit a forecast of its estimate of operating expenses for the following calendar year, including capital projects, to Idaho Power. The budget will include items of expenditures for replacement and repair of facilities and will include a contingency for emergency repairs and replacements. The forecast is subject to approval by the Company. Under the agreement, if the forecast for projects changes by 10 percent or more during the calendar year, PacifiCorp will notify Idaho Power. In addition, under compliance with the Sarbanes-Oxley Act, forecasts for projects over $1 million that change by 10 percent or more during the calendar year must be approved by both Bridger Co-Owners.

Q. Please describe the Company’s participation in the Bridger capital investment discussions that meet the contractual rights described above.

A. Mid-year, the Co-Owners hold a capital budget review where the forecasted capital projects expected to occur over the next three calendar years over $50,000 are discussed in detail. In addition, large capital projects expected over the next decade are reviewed, unit overhauls, and the scope and need of projects are discussed. Following the meeting, plant personnel consolidates and finalizes the list of all projects, including the scope, need and consequence for each.

Following the quarterly Ownership Meeting that occurs in September, the plant personnel present a formal capital and O&M expense budget for the following year as well as a high level 10-year forecast. The intent of the meeting is for the Bridger Co-Owners to ask questions of the plant personnel, most often the subject matter experts, about any details surrounding the forecasted capital investments and O&M expense.

Q. How does the Company monitor the budget?

A. During each quarterly Ownership Meeting, a standing agenda item is to review the current year capital and O&M expense budget, routinely providing Idaho Power the opportunity to raise any questions necessary about upcoming projects. Additionally, on a monthly basis, forecasts for capital and O&M expense are provided for review by the Company.

Q. What is the time period for which Idaho Power is requesting a prudence determination of Bridger investments?

A. Order No. 35423 found that investments made at

Bridger through December 31, 2020, had been prudently incurred therefore the Company is requesting a prudence determination on the Bridger investments made during the January 1, 2021, through December 31, 2022, time period. There have been a number of investments required to operate the plant in a safe, efficient, and reliable manner, including investments required to ensure environmental compliance as well as a number of investments for routine asset replacement.

Exhibit No. 3 presents Idaho Power's share of the investments made at Bridger between January 1, 2021, and December 31, 2022, detailing 216 different projects totaling $19.33 million. In addition, for those projects for which Idaho Power's ownership share is over $100,000, the Company has included a project description and investment purpose classification as to whether the investment was for environmental compliance, safety, and/or reliability. Of the 61 projects for which a detailed project description and investment purpose classification was provided, 31 were for continued reliable plant operations, 17 were required for environmental compliance, one was for safety, and 12 were for a combination of either reliability, environmental compliance, or safety.

Q. Were all the projects comprising the $19.33 million in investments that occurred between January 1, 2021, and December 31, 2022, necessary for either environmental compliance, the safe and economic operation of the plant, or for reliability purposes?

A. Yes.

Plant Reliability Investments

Q. You indicated there were 31 investments greater than $100,000 that were required for the reliable operation of the plant. What was the largest investment made to maintain reliability?

A. The largest investments in both 2021 and 2022 required for continued reliable operations of Bridger, as well as 12 others, were associated with the normal wear and tear of existing plant equipment. The two largest projects as well as two other projects, were the result of the accumulation of failures of either pumps, valves or gearboxes during the year, for a total of $1.34 million. These failures and subsequent replacements were unplanned and not budgeted but resulted in capital improvements required to maintain reliability of the plant.

In addition, $2.04 million in investments were made (1) for the overhaul of two pulverizers per year, (2) the repair of the primary air ducts that had developed leaks over the years of operation, (3) the replacement of the hot end and cold end seals in both air pre-heaters during an overhaul of Units 2 and 4, (4) the replacement of warped sector plates on both Units 2 and 4, (5) new boiler side wall tubes required due to increased ash erosion on Units 2 and 4, (6) restoration of turning vanes that had been worn through by fly ash on both Units 2 and 4, (7) replacement of high pressure turbine packing on Unit 2, and (8) installation of new mill discharge valves on the units to isolate the supply of fuel to the boiler.

Q. How would you categorize the next set of Bridger investments made for continued reliable operations of the plant?

A. There were 7 projects totaling approximately $1.38 million associated with the replacement of obsolete equipment that was no longer supported and the repair or replacement parts were costly. This included the upgrade of the electro-hydraulic pumps on Unit 2 and Unit 4, a new continuous vibration monitoring system for the Green River pump station, a digital front end excitation system retrofit, the replacement of both Unit 2 and Unit 4’s DCS, and the replacement of flame scanners on Unit 4.

Q. What were the remaining investments required for the reliable operation of Bridger?

A. Neural network combustion controls and a soot blowing optimizer were installed on Unit 4 to lower emissions and improve heat rates for a total of approximately $218,000. To assure proper alignment with both the rotating element and the pump to the turbine, the boiler feed pump was rebuilt, and the casing replaced for $199,000. Approximately $184,000 was associated with the re-build of a failed boiler circulating pump for future re-use. Pulverizer journals were replaced as it was more cost-effective than repairing, totaling approximately $160,000. Radio communications were upgraded increasing bandwidth in and around the plant for $131,000. On Unit 4, retracts and water injection penetration equipment was installed for $122,000 to help burn the existing coal. The existing feedwater heaters were replaced to drain the system more efficiently and return the water to the condensate system for reuse as opposed to dumping, for a total investment of $245,000. Finally, a new acoustic leak detection was installed in the boiler of Unit 4 for approximately $177,000.

Q. Please summarize the investments made at Bridger during the January 1, 2021, through December 31, 2022, time period that were necessary for continued reliable operations of the plant.

A. In summary, there were 31 projects greater than $100,000 that were required for the reliable operation of the plant in 2021 and 2022 for a total of $6.19 million, or 32 percent of the total investments.

Q. You mentioned some of the investments over

$100,000 were made for a combination of either reliability, environmental compliance, or safety purposes. Were there any additional investments for which the purpose included a reliability component?

A. Yes. There were eight projects for a combination of reliability and safety purposes and three projects for a combination of reliability and environmental compliance.

Plant Reliability and Safety Investments

Q. Please describe those projects greater than $100,000 that have been identified as required for reliability and safety purposes.

A. The largest investment required for reliability and safety purposes, totaling $308,000, replaced the electromechanical trip system and eliminated the mechanical over speed bolt on the boiler feed pump turbines because the existing system was over 30 years old and maintenance issues had been increasing. Two projects involved the installation parts on Unit 4: new wear plates for the submerged drag chain conveyor and an automatic sprinkler system, for approximately $287,000. The remaining five projects were associated with the replacement of existing investments.

Q. What investments were replaced and necessary to ensure reliable and safe operations of Bridger?

A. The feeder breaker relays on Unit 4 were replaced because the existing relays were obsolete. Also, Unit 4 required the replacement of the coal pipes from the pulverizers to the boiler due to high wear from the abrasiveness of the coal. A dozer with the highest operating hours and requiring the most maintenance was rebuilt. A failed epoxy liner and the stator leak monitor system were both replaced on Unit 2. The remaining five projects totaled approximately $971,000.

Plant Reliability and Environmental Compliance Investments

Q. What three investments were required for the combination of reliability and environmental compliance?

A. Both Unit 2 and Unit 4 required the replacement or repair of the burner components due to damage or warped hardware for a total of $406,000 and $648,000, respectively. In addition, new secondary air flow monitors were required on Unit 4 for approximately $175,000.

Environmental Compliance Investments

Q. What investments were made at Bridger solely for environmental compliance?

A. There were 17 projects necessary for environmental compliance. The largest of the investments made at Bridger since 2020 was for environmental compliance and required the replacement of two levels of Selective

Catalytic Reduction ("SCR") catalyst. The Bridger catalyst management plan requires the replacement of catalysts on a set cycle of every four years or coincident with major outages. The extent of catalyst replacements depends on an evaluation of the condition of the catalyst which will determine how many layers must be replaced to ensure a fully functioning SCR for compliance with environmental regulations. Two layers of the catalyst on Unit 4 were replaced totaling approximately $1.41 million. An additional 12 more projects necessary for environmental compliance were associated with investments in Unit 4, totaling $3.76 million. These included: (1) the extension of the pin block liner to the mid-level of the stack, (2) the replacement of discharge electrode wires in the precipitator, (3) the repair and recoat of the scrubber ductwork, (4) installation of online catalyst cleaning equipment to reduce ash pluggage, (5) installation of a new large particle ash screen to maintain optimal catalyst performance, (6) upgrade of the transformer-rectifiers and current limiting reactors in the precipitator, (7) repair and recoat of the precipitator ductwork, (8) installation of turning vanes and flow straightening devices, (9) replacement of Nuva feeder piping (10) the overhaul of the mini drag-chains that transport ash from the SCR large particle ash hopper to the drag chain hopper, (11) the purchase and install of Limitorque drivers on the precipitator inlet and outlet dampers, and (12) the replacement of six discharge electrode rappers.

Q. What were the remaining four projects necessary for environmental compliance?

A. Similar to Unit 4, the repair and recoat of the scrubber and precipitator ductwork on Unit 2 was required as was the replacement of the rapper shaft, bearings, and hammers of the precipitator rapping systems. Finally, a redundant soda liquor supply line was installed. In total, there were 17 projects necessary for environmental compliance, totaling $5.73 million, or 30 percent of the total investments.

Environmental Compliance and Safety Investments

Q. Please describe the investments required for environmental compliance and safety of Bridger.

A. There was just one project necessary for both environmental compliance and safety of the plant personnel, totaling $139,000. The coating in the ducts from the scrubbers into the stack was worn so it was replaced. This is a high wear area and if not repaired or replaced will lead to excessive leaking and ultimately environmental violations. In addition, the leaking flue gas could be a hazard to plant employees.

Safety Investments

Q. Were there any investments at Bridger made solely for safety purposes?

A. Yes. One investment, for approximately $127,000, was made for safety purposes. The existing outdated station breaker relays were a safety concern due to arc flash hazards and were upgraded. The plant has been replacing the old relays with arc flash compliant relays that will significantly reduce the hazard or arc flash incidents to plant personnel.

Q. Please summarize the investments that were made at Bridger over $100,000 that make up the $19.33 million for which Idaho Power is requesting a prudence determination.

A. Of the 61 projects for which a detailed project description and investment purpose classification was provided, 31 were for the continued reliable plant operations totaling $6.19 million, another $5.73 million was associated with the 17 projects required for environmental compliance, one project at $127,000 was required for safety purposes, and the remaining 12, which were for the combination of either reliability, environmental compliance, or safety, contributed to $2.93 million of the total investments made at Bridger between January 1, 2021, through December 31, 2022.

V. **CONCLUSION**

Q. Please summarize your testimony.

A. The Preferred Portfolio in the 2021 IRP reflects an early exit of coal-fired operations from both Valmy and Bridger as a more favorable economic outcome. The Company has been required to make investments at Valmy and has been actively involved in the capital spend decision making process at the plant. Of the 44 projects for which a detailed project description and investment purpose classification was provided, 26 were for the continued reliable plant operations totaling $4.50 million, another $234,000 was associated with the three projects required for environmental compliance, and the remaining 15, which were for the combination of either reliability, environmental compliance, or safety, contributed to $2.85 million of the total investments made at Valmy between January 1, 2019, through December 31, 2022.

With respect to Bridger, the Company has been required to make investments and remains actively involved in the capital spend decision making process at the plant. Of the 61 projects for which a detailed project description and investment purpose classification was provided, 31 were for the continued reliable plant operations totaling $6.19 million, another $5.73 million was associated with the 17 projects required for environmental compliance, one project at $127,000 was required for safety purposes, and the remaining 12, which were for the combination of either reliability, environmental compliance, or safety, contributed to $2.93 million of the total investments made at Bridger between January 1, 2021, through December 31, 2022. While Idaho Power is cognizant of the approaching cessation of coal-fired operations at both Valmy and Bridger, the investments made were prudent and required to ensure the plants remain operational in a safe, efficient, and reliable matter.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF LINDSAY BARRETTO

I, Lindsay Barretto, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Lindsay Barretto. I am employed by Idaho Power Company as the Senior Manager of 500kV and Joint Projects.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 1 through 3 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: ______________________

LINDSAY BARRETTO

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BARRETTO, DI TESTIMONY

EXHIBIT NO. 1

Memorandum of Understanding Concepts
for Joint Projects Documentation
May 2023

The following summarizes Company's and Staff's agreement in principle, that will ultimately be contained in a Memorandum of Understanding ("MOU"), on the types and presentment of information Idaho Power will file to support its requests for a prudence determination of expenditures made at its jointly-owned generating facilities. This document reflects Idaho Power's current understanding of the primary components that will be contained in the MOU and corresponding checklists, but is subject to change as the MOU is finalized with Staff.

1) Major Projects Checklist

   This checklist is envisioned to detail review timing and documentation that will be provided for all projects over a certain threshold. Idaho Power will provide the Appropriations Request (for Bridger) or Authorization for Expenditure (for Valmy), along with a list of project characteristics and areas that Joint Projects will review as prescribed in the checklist. The checklist will also prescribe specific documentation that will occur if costs exceed budget by a certain amount. Lastly, the checklist will prescribe the review that will occur, and the associated documentation that will be provided, with regard to project bidding and / or in-house completion of projects if expenditures exceed a certain level.

2) Valmy-Bridger Oversight Meeting Checklist

   In addition to the Major Projects Checklist, Joint Projects will complete a Valmy-Bridger Oversight Meeting Checklist for each regularly scheduled budget discussion with the Company's operating partners. These meetings currently occur monthly for Valmy and quarterly for Bridger. This checklist is envisioned to include the time, date, location, and attendees of these meetings, as well as any meeting notes taken by Joint Projects, either written directly on the checklist or attached. In addition, the Company will retain with the capital budget review worksheets that list all capital projects at the facility, including ancillary information such as budget variances and project notes.

3) Maintenance of Documentation for Commission Staff Review

   Idaho Power will agree to maintain documentation associated with the processes outlined in the MOU to support its prudence requests for expenditures at Bridger and Valmy.

4) Staff Review, Sufficiency of Documentation

   The Company will provide the checklists and associated documentation to Staff either upon filing or at Staff's request, depending on Staff's preference and the volume of information related to the period for which prudence is being requested.

5) Term and Termination.

   The MOU will become effective on the Effective Date and will continue until the Company does not have ownership of a jointly-owned facility, unless terminated earlier by one or more Parties with written notice to the other Party.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BARRETTO, DI TESTIMONY

EXHIBIT NO. 2

VALMY PLANT ADDITIONS: Jan 1, 2019 - Dec 31, 2022

Project	Descr	V1	V2	VC	Total	Purpose	Project Description/Justification
27574743	VALMY 98482392 V2 REPLACE TURBINE HP/IP SECTION		1,240,965		1,240,965	Reliability/Safety	The Unit 2 steam turbine high pressure/intermediate pressure (HP/IP) shell experienced five steam leaks from the mating surfaces of the steam turbine HP/IP upper and lower shells, beginning in 2015. Each steam leak damaged the two turbine shells by eroding the mating surfaces material and providing further paths for the superheated steam to escape from the turbine HP/IP shells. At the time, previous repairs did not fix the eroded mating surfaces or the compromised connection hardware that compresses the two shell halves together to form the mating surfaces seal. Connecting hardware wears it out, only enduring a limited number of tightening and loosening cycles before the connecting hardware loses its strength and the ability to provide the compressive forces necessary to form the mating surfaces seal of the two shell halves. This loss of connecting hardware strength is also compounded by the high temperature during operations causing the plastic deformation of the steel in a process known as creep. This plastic deformation in conjunction with applied stresses can also warp and distort both the connecting hardware and the HP/IP shells themselves. A 'tapped stud' threads into the lower shell half and a large nut is installed on the upper portion of the tapped stud and tightened to apply the compressive force to the two shell mating surfaces. A minimum of six tapped connecting studs are known to have been compromised in some fashion, mostly warpage. This project replaced the connecting hardware, which was no longer providing sufficient consistent compressive force, with new hardware and refurbished the mating surfaces of the two HP/IP shell mating surfaces. The two turbine HP/IP turbine shells were separated and the mating surfaces were refurbished with a combination of welding and machining. In addition, ten tapped connecting studs and nuts on each side of the HP/IP turbine section in the areas of the five steam leaks were replaced with new tapped connecting studs and nuts. The tapped stud threads in the lower half shell were also repaired as necessary. The tapped studs replacement, lower half thread repairs and HP/IP shell refurbishment were made after the two HP/IP shells were separated. These repairs corrected the known root causes, compromised mating surfaces and compromised connecting hardware, that were causing the turbine HP/IP section shell steam leaks.
27574748	VALMY 98483985 V2 OVATION HMI AND SERVER UPDATE		629,538		629,538	Reliability	The Valmy U2 Emerson Ovation Distributed Control System ("DCS") was operating both the servers and Human Machine Interfaces ("HMI") beyond the Original Equipment Manufacturer ("OEM") support and security patches are no longer created for these systems. The existing U2 DCS equipment was installed in 2015. The control servers were operating on Windows Server 2008 and Microsoft ceased mainstream supporting as of January 1, 2020. The HMIs were operating on Windows 7 originally released in 2009 with a service pack update in 2016, which Microsoft stopped supporting as of January 14, 2020. Operating without the OEM supported cybersecurity patches put these servers and HMIs at elevated risk. It also violated NV Energy's Information Technology ("IT") mandate to keep all critical systems patched and secured (vulnerability management). The upgrade replaced the HMI hardware and upgrade the operating system to Windows 10. In addition to the HMI and operating system upgrades, the following control equipment was upgraded: new virtualized Windows 2019 control servers host, Emerson Ovation software upgraded from 3.5.1 to 3.8 level, new ethernet switches and routers. All of the upgrades enabled implementation of latest Top 20 Critical Security Controls ("CSC") SANS guidelines for cyber defense and detection tools. Although there is no specific standard, full control system upgrade life-cycle is about 10 years, with a 5-year mid-cycle HMI and operating system updates. These timelines are general guidelines and can vary slightly to align with plant outage cycles and cybersecurity risk concerns. Additionally, the operating system version update cycle and vendor application refresh cycle variabilities can sometimes cause shorter or longer cycles than the typical 5 and 10 year time span. Given the Valmy U2 existing control system was commissioned in 2015, it had reached the mid-cycle HMI and operating system upgrade requirement. The project was executed in fall 2021 to align with other cybersecurity project upgrades, the operating schedule and to maximize the project benefits given the unit retirement date. An additional concern existed with the scheduled 2021 retirement of Valmy U1. A number of common plant systems are currently controlled from U1's DCS and required code changes to move these controls to U2's DCS.
27590306	VALMY 98493081 V2 PULVERIZER C GEARBOX FAILURE		587,457		587,457	Reliability	Four pulverizers are needed on U2 to reach full load status each year to perform annual testing and certification of the cold reheat safety valves. This testing is a compliance requirement needed to maintain Valmy's Annual State of Nevada Boiler Operating Permit. Reliability is also increased by the availability of having a spare pulverizer when needed in the event of failure of another pulverizer. After pulverizer 2C tripped off, the gearbox inspection port was opened by maintenance personnel and discovered the gearbox had failed. U2's reliability was compromised at this time as well as compliance with the state testing requirements with 2C pulverizer not being ready for service.
27514784	VALMY 98438396 VC FREEZE PROTECTION HEATERS,			541,325	541,325	Reliability	When the Valmy operating schedule shifted to running the units in only the summer months, and to be in long-term layup during the remaining months of the year, it was determined that with both units offline there was no auxiliary steam to provide heat to the turbines, boilers and buildings to keep them dry and above the dew point, per the long-term layup plan. The plant was renting portable electric space heaters to sufficiently heat the plant buildings and equipment during the layup period. It was determined that the purchase of the heaters was more cost effective than renting. In addition, the purchase and installation included four water-to-air dry finned coolers which cool the component cooling system on each unit and exhaust warm dry air into the lower level of the turbine building, reducing the number of electric heaters required to be purchased.
27585672	VALMY 98490890 V2 EXCITER POWER SUPPLY TRANSF		468,110		468,110	Reliability	Two of the U2 exciter power supply transformers had failed, preventing the return to service of the U2 generator. Following a loss of phase generator protection trip caused by the A phase, U2 was not able to return to service due to damage that was discovered in the generator exciter power supply system. An exciter representative was required to aide in troubleshooting the issues. One of the three saturable current transformers ("SCT") that supply power to the generator exciter, one linear reactor (transformer), and the exciter control card module were damaged during the unit trip. The emergency repairs were completed to restore the U2 generator back to service. Following recommendations to avoid future failures requires replacement of the two SCTs that had compromised integrity due to oil and heat damage, as well as one of the remaining linear reactor transformers that had degraded and was running at an elevated temperature of 350 degrees compared to the other two that were 200 degrees.
27582989	VALMY 98489340 V2 PULVERIZER CAPITAL SPARE RO		456,113		456,113	Reliability	U2 is scheduled for retirement at the end of 2025. Based on inspections, the pulverizers were not in immediate need of major overhauls. To be prepared for unexpected failures and reduce the capital investment required to operate reliably through 2025, the plant purchased a full set of grinding table segments and three roll wheel assemblies. This purchase will expedite repairs in the event of a pulverizer damage or excessive wear that could occur during the remainder of plant operation. Long lead times for replacement equipment would cause extended forced outages or derates while waiting for replacements.
27517151	VALMY 98438233 VC FIRE PROTECTION SYSTEM, REF			262,492	262,492	Reliability/Safety	In November 2017, an evaluation of the fire protection systems was performed that determined the refurbishment or replacement of the systems was required due to degradation of the existing system, through a combination of worn out and/or outdated components and systems. This project included the refurbishment of the Early Warning Smoke Detection system, the replacement of the Unit 1 and Unit 2 stand-pipe booster pipes, the replacement of the fire alarm control panels and associated controls and alarms, replacement of deluge valves, the electric fire pump and the required flow testing on the diesel fuel tank system.
27596251	VALMY 98496301 V2 PULVERIZER B ROLL WHEEL REPLACEMENT VA		230,734		230,734	Reliability	Four pulverizers are needed on U2 to reach full load status each year to perform annual testing and certification of the cold reheat safety valves. This testing is a compliance requirement needed to maintain Valmy's Annual State of Nevada Boiler Operating Permit. Reliability is also increased by the availability of having a spare pulverizer when needed in the event of failure to another pulverizer. Inspection of pulverizer 2B by maintenance personnel discovered a seized roll wheel assembly. U2 reliability was compromised at this time as well as compliance with the state testing requirements with 2B pulverizer not being ready for service.
27528897	VALMY 98455128 V2 PIN MIXER/UNLOADER, REBUILD		224,787		224,787	Reliability	The existing original Unit 2 pin mixer (wet fly ash unloader) required replacement due to normal wear and tear. In addition, in 2018 an ash hauling dump truck damaged the Unit 2 wet fly ash unloader, further impacting the reliability of the pin mixer. The pin mixer/unloader was rebuilt prior to the summer run to avoid the potential of serious failure of the non-redundant equipment.
27555279	VALMY 98455852 VC GROUND WATER MONITORING WEL			219,799	219,799	Environmental	Ground water elevation at Valmy had risen noticeably over the last 6-8 years, presumably due to cessation of dewatering activities at the nearby Lone Tree Mine, resulting in the screened interval intake of several wells becoming fully submerged. According to Nevada Division of Environmental Protection (NDEP) monitoring well guidelines, the groundwater level should be within the screened interval level to obtain an accurate water level reading. Any reported ground water levels above the top screen level are considered invalid. Valmy has 14 total ground water monitoring wells, of which five were reading above the top screen level and four were close. If the wells were not redrilled, plugged, abandoned or replaced, the existing wells may have become non-compliant with the regulatory intent of monitoring the potential impacts of operating the facilities landfill and evaporation ponds. In addition, if not in compliance, the NDEP can order similar action. These costs are associated with the installation of nine new ground water monitoring wells.
27596247	VALMY 98494653 V02 SCRUBBER SPRAY MACHINE GEARBOX REPLACEMEN		180,709		180,709	Environmental/Reliability	The scrubber spray machine gearbox drives atomizer wheels at 12,000 rpm for sulfur dioxide removal. The high speed components require precision balancing and tight tolerance on gear clearances. This project replaced a gearbox that was no longer repairable. The spray machine gearbox is necessary to ensure the plant's reliability and environmental compliance for the summer peak season, for both the Title V SO2 removal and Sulfur emissions as well as the MATS SO2 emissions.

VALMY PLANT ADDITIONS: Jan 1, 2019 - Dec 31, 2022

Project	Descr	V1	V2	VC	Total	Purpose	Project Description/Justification
27604610	VALMY 10086049 V2 SCRUBBER ATOMIZER WHEELS REPLACEMENT		168,148		168,148	Environmental/Reliability	The scrubber atomizer wheels are exposed to a harsh environment of fly ash laden flue gas, as well as a spray of an abrasive slurry of lime and ash at 12,000 rpm for sulfur dioxide removal. This causes erosion on both the carbide slurry nozzles and the titanium wheel body. With the plant's anticipated load forecast, eight of the existing atomizer wheels were at the end of their service life each year, and were no longer capable of being rebuilt/balanced. The procurement of eight new atomizer wheels was necessary to ensure the plant's reliability and environmental compliance for the summer peak season, for both the Title V SO2 removal and Sulfur emissions as well as the MATS SO2 emissions.
27547460	VALMY 98377358 V2 PULVERIZER "A" MAJOR REBUILD-2016		165,540		165,540	Reliability	Pulverizers are utilized to grind coal to fine dust before being transported to burner fronts. This process wears out roll wheel assemblies, table grinding segments, and the interior of pulverizer equipment. The normal operating life cycle of a Unit 2 pulverizer is roughly 18 to 24 months. Routine inspections are performed at 3,000 hours and required maintenance is performed to ensure the maximum life of the pulverizer rebuild. Typically, major pulverizer overhauls for continued reliable operation of Unit 2 and include replacements of roll wheels, air seals, coal shields, bearings, wear resistant ceramic liners, classifier vanes, coal feeder wear components, spring frame wear plate, and the pyrites plow. A pulverizer overhaul was scheduled for 2019 but due to reduced run times for Unit 2, a full overhaul was not yet needed. Instead, the project consisted of purchasing three refurbished trunnion wheel assemblies as capital spares. The capital spares will allow the capital maintenance outages to be completed on an as needed basis, as opposed to during the routine inspection, when the pulverizers' hours of operation and level of wear justifies the overhauls.
27545751	VALMY 98466935 V1 PULVERIZER D ROLL WHEEL ASS	159,459			159,459	Reliability	In April 2019, one roll wheel assembly failed and was replaced in the Unit 1D pulverizer. Black Butte coal requires all four pulverizers to achieve full load. In September 2019, plant personnel reported high amps on the Unit 1 pulverizers drive motor. Unit 1 had been experiencing much higher than expected availability requirements; the 1D coal pulverizers exceeded 20,000 hours of operation with significant wear and parts deteriorated beyond the service life expectations. The plant was coming up on its annual testing and certification of the cold reheat safety valves, a compliance requirement of the annual State of Nevada Boiler Operating Permit, and needed to reach full load status, requiring all four pulverizers. Due to the wear of the two old assemblies and the replacement of the one roll wheel assembly earlier in the year, there were sizing differences of the three roll wheels' diameters in addition to the failing other two assemblies, requiring the replacement of all three of the roll wheel assemblies.
27591516	VALMY 98494358 VC EQUIPMENT WASH PIPING REPLACEMENT			150,961	150,961	Reliability	A section of boiler equipment wash piping that is used to fill both circulating water systems prior to start up failed. This was the original underground piping from construction in 1979. Using alternative means to fill the circulating water systems is very time consuming and results in start up delays. These costs included the replacement of the underground equipment wash piping.
27549554	VALMY 98467485 V2 SCRUBBER OUTLET DUCT PLUGGA		126,759		126,759	Environmental/Safety	The three dry scrubber vessels on Unit 2 often suffer severe scaling and/or debris material buildup as scale is dislodged from the scrubber vessel walls. The scale and buildup can be severe enough that several times per year the unit is curtailed by 70 MW's while the scale and buildup are removed from the vessel walls and the outlet duct via the existing debris chute and from the outlet duct door. The debris material is then collected and transported to the ash landfill. The removal is also required under the Mercury and Air Toxic Standards regulations. This project enlarged the existing Unit 2 scrubber vessel debris chute and installed three 24-inch diameter hydraulically actuated knife gate valves to allow for the faster and safer removal and collection of the scale, sludge and debris for disposal in the ash landfill. The duration of forced outage was decreased by half and automated the valves to open the scrubber vessel, which previously required personnel to perform via a ladder, improving safety.
27603201	VALMY 10074750 V2 TURBINE CONTROL VALVE POSITIONER REPLACEME		119,399		119,399	Reliability/Safety	U2 was experiencing erratic control valve movement that resulted in unit trips due to the resulting load and drum level swings. Troubleshooting included replacement of the position feedback and tuning. The primary cause of the erratic valve movement was leakage in the upper and lower positioners. In order to operate as reliably as possible, an abnormal operating practice of keeping the control valves wide open was implemented to limit the erratic valve movements. Replacement of the upper and lower turbine control valve hydraulic cylinder positioners was necessary to restore stable operation of the turbine and improve plant reliability.
27533137	VALMY 98455854 V2 ATOMIZER WHEELS, REPL		115,962		115,962	Environmental/Reliability	A dry scrubber utilizes nine atomizing spray machines to atomize a lime/recycled fly ash mixed slurry that reacts with the sulfur dioxide in the flue gas to produce calcium sulfate. In 2018, Valmy was expected to be used as a seasonal facility and to only run during the summer peak months. The plant was utilized more than anticipated and stayed on through the winter of 2018 and into the spring of 2019, primarily due to the impacts of the Enbridge pipeline explosion that occurred in October 2018. The extended run time amounted to many more hours on the wheels than originally anticipated requiring the procurement of six new atomizer wheels. The replacement of the wheels ensured the plant's reliability for the 2019 summer peak season.
27579441	VALMY 98485333 V2 SCRUBBER ATOMIZER WHEELS, R		109,728		109,728	Environmental/Reliability	The dry scrubber on Unit 2 utilizes nine atomizing spray machines (three atomizers per scrubber vessel) to atomize a lime/recycled fly ash mixed slurry that reacts with the sulfur dioxide in the flue gas to produce calcium sulfate. The solid calcium sulfate particles are then collected along with fly ash in the baghouse. To accomplish this the atomizer wheel rotates at approximately 13,000 revolutions per minute and centrifugal force shears the lime/recycled ash slurry into very small droplets for intimate liquid/gas contact. The force of the shearing slurry slowly erodes the atomizer wheels which require routine replacement. An atomizer wheel can be expected to last for 10,000 – 12,000 hours in service. This project replaced five of the atomizer wheels that were at the end of their service life and was necessary to ensure the plant's reliability for the 2021 summer peak season.
27557530	VALMY 98473784 V2 SCRUBBER ATOMIZER WHEELS, R		108,817		108,817	Environmental/Reliability	The dry scrubber on Unit 2 utilizes nine atomizing spray machines (three atomizers per scrubber vessel) to atomize a lime/recycled fly ash mixed slurry that reacts with the sulfur dioxide in the flue gas to produce calcium sulfate. The solid calcium sulfate particles are then collected along with fly ash in the baghouse. To accomplish this the atomizer wheel rotates at approximately 13,000 revolutions per minute and centrifugal force shears the lime/recycled ash slurry into very small droplets for intimate liquid/gas contact. The force of the shearing slurry slowly erodes the atomizer wheels which require routine replacement. An atomizer wheel can be expected to last for 10,000 – 12,000 hours in service. This project replaced five of the atomizer wheels that were at the end of their service life and was necessary to ensure the plant's reliability for the 2020 summer peak season.
27528895	VALMY 98455127 V2 CONDENSER INLET WATERBOX, R		108,028		108,028	Reliability	The condenser inlet tube sheet of a unit is exposed to erosion from particles and turbulence in the circulating water so it is coated with a wear resistant coating to protect the metal tube sheet and condenser tube ends. The coating on Unit 2 had worn to the point that significant portions of bare tube and tube ends were exposed. When exposed, the tube ends will erode and can result in tube failure and leakage of circulated water into the steam side of the condenser, contaminating the boiler water. The scope of the project included the recoating of the tube sheet. When the recoating began, the plant was able to repair some of the waterbox coating resulting in project costs lower than initially estimated.
27539687	VALMY 98462057 V2 STACK ELEVATOR, REPLACE		107,341		107,341	Reliability/Safety	The Unit 2 stack elevator reliability and safety was compromised due to the age of the elevator and replacement parts had become obsolete. The elevator installed with Unit 2 was constructed in 1984. On several occasions the elevator stopped operating properly during the installation of environmental compliance equipment and prior to scheduled emission testing, causing delayed installation timelines. The project included a complete elevator replacement including the car, brake assembly, drive motor and gearbox, electrical system replacement and call system replacement.
27527353	VALMY 98438400 V2 GENERATOR BUSHINGS, REPLACE		106,641		106,641	Reliability	The terminal plate gaskets for the high voltage bushings of the generator were worn out and there was indication of bushing gaskets leaking as the viscasil was seeping through the bushing gaskets. Bushing gasket leakage could lead to catastrophic failure of the generator. The issue was first identified in 2010 and temporary repairs were made. In 2017, it was noticed that the leak had become significant and one more temporary repair was made and annual inspections conducted. The 2018 annual inspection discovered more leakage so the replacement of the bushings and regasketing of the bushing terminal plate was performed.
27609108	VALMY 10108935 V2 BOILER FEED PUMP, REFURBISH		93,383		93,383	Reliability	U2 is equipped with a single turbine driven boiler feed pump. The high pressure and high flow produced by the boiler feed pump resulting in wear as well as deposits on the rotating elements make it necessary to refurbish the rotating element periodically. The U2 Boiler Feed Pump was last overhauled in 2007. This refurbishment was required to maintain a high level of plant reliability.
27570622	VALMY 98481652 VC 5B COAL UNLOAD CONVEYER BELT, REPLACE VA			88,583	88,583	Reliability	Coal handling conveyor 5B sustained a run time failure resulting in severe damage to the conveyor belting, bend pulleys and to the bend pulley support framing. Permanent repairs were made to the bend pulleys and bend pulley support framing. Temporary repairs were made to the damaged 5B building in order to make the 5B belt train available for emergency use only if needed. Because Valmy was relying on only conveyors 5A and 6A for full delivery of coal (two conveyors used in tandem are required), conveyor 5B was replaced in the event 5A or 6A became damaged or inoperable. Upon inspection of the drive gearbox, it was determined a replacement was necessary. Quotes were received for a rebuild of the gearbox but it was determined a replacement was more cost-effective.

VALMY PLANT ADDITIONS: Jan 1, 2019 - Dec 31, 2022

Project	Descr	V1	V2	VC	Total	Purpose	Project Description/Justification
27555276	VALMY 98466597 VC VANS, REPLACE (3) VA			87,965	87,965	Reliability/Safety	The plant was concerned with the safety and reliability of the van transportation fleet. The Valmy fleet was aging and reaching high mileage, traveling approximately 1,650 miles for maintenance and 4,575 miles for operations/fuels per month. The vans transport employees to and from the remote plant site, 24 hours a day, seven days a week, which is a standard in northern Nevada set by local mining companies. The cost of the vans is partially offset by a payroll deduction from each employee riding in the van. This project replaced three of the existing nine vans, each van is over ten years old with between 190,000 to 256,000 miles.
27596244	VALMY 98494647 VC PRODUCTION WELL 13 & 14 REPLACEMENT VA			81,191	81,191	Reliability	Production well 13 & 14 experienced damage to the pump. Production well 13 & 14 produce 300-400 gallons per minute each of raw water to supply the cooling tower basins on both units or the Fire and Raw Water Tanks. Replacement of Production Well 13 & 14 helped ensure adequate make up water supply to the cooling tower basins during summer peak operation.
27582985	VALMY 98485334 VC VANS, REPLACE (3) VA			78,206	78,206	Reliability/Safety	This project was driven by safety and reliability concerns regarding the van transportation fleet. The Valmy fleet is aging and vans are reaching high mileage. Valmy replaced three vans out of the fleet of nine vans. Traditionally Valmy has leased the vans through Fleet. Each Valmy van travels between 1,750 miles for maintenance/administration and 5,200 miles for operations/fuels per month. The plant purchased the three replacement vans rather than lease through fleet, and discontinued the lease of the high mileage stated vans. The vans are needed for the transportation of the employees to and from the remote plant site. Company transportation is a standard in Northern Nevada set by local mining companies. The three vehicles replaced were the highest mileage vehicles, and had between 200,000 to 250,000 miles on each vehicle. By replacing these three vans the safety risk to employees from running high mileage vans was reduced. These vans are used in the 24x7 operation of the plant in transporting employees.
27604612	VALMY 10087092 V2 SCRUBBER REPLACEMENT OF HVAC UNITS		65,043		65,043	Environmental/Safety	The primary and backup scrubber computer room air conditioning units were aging equipment and required frequent maintenance. Operating failures of the system had resulted in unit trips due to overheating of the baghouse pollution control device that is located in the scrubber computer room. Baghouse pollution control device components and the HVAC units were repaired and returned to service, but overheating issue was a recurring problem. Replacement of both the primary and backup scrubber computer room air conditioning units was necessary to ensure reliable operation of U2.
27506993	VALMY 98437320 VC UNIT SUB 5A 5B 1000 KVA DRY TRANSORMER RPL			64,961	64,961	Reliability	The coal handling system is powered by two redundant 1000 KVA transformers. Both of the transformers have failed and were beyond economic repair so the system was being run on a temporary transformer that is close enough in design to be used for temporary purposes only. Two redundant transformers are necessary for reliable operation. If not remedied and the temporary transformer were to fail, the coal handling system would go down until a new or rewound transformer is installed. The lead time for a new transformer is 8 to 10 weeks. This would result in a 100 percent derate on the units because there would be no coal delivery to the plant. These costs were associated with the purchase and install of two new transformers.
27568576	VALMY 98478100 V2 TRISECTOR AIR HEATER EXPANSION JOINT REFUR		61,203		61,203	Reliability/Safety	The trisector air heater expansion joint suffered damage from thermal expansion, rust, acid condensation and erosion and failure was imminent. The expansion joint was torn and leaking on the outlet side of the trisector air heater. Valmy's cycling operation compounds the fatigue and wear exposure from thermal stress from cooling to ambient conditions when the unit is in reserve shutdown followed by heating back to operating temperatures in excess of 700 degrees Fahrenheit. Continued operation would likely cause deterioration, which would have resulted in an outage or derate, as well as a potential safety concern and heat rate impact due to the hot air leakage. This repair was critical for reliability and safety.
27533144	VALMY 98459394 V1 CIRCULATION WATER PUMP 1A MOTOR, REPL	58,576			58,576	Reliability	In April 2019, the Unit 1 circulating water pump failed due to a motor ground fault. Absent a circulating water pump in service, Unit 1 would be de-rated to approximately 125 net MW output, or half its normal load. The motor was sent to a contract repair shop for evaluation where it was determined that a complete motor rewind was required. At the request of the Western Electricity Coordinating Council, and because of the four to six-week lead time associated with the repairs, a new replacement motor was purchased so that the plant could meet reliability and availability needs. The rewind was performed and used as a capital spare and a replacement motor was procured.
27598663	VALMY 10037777 V2 PULVERIZER 600 HP ELECTRIC		57,779		57,779	Reliability	The 2A Pulverizer motor failed due to an electrical short circuit to ground. The maintenance team installed the capital spare motor. This project replaced the U2 capital spare motor to ensure unit availability for full load in the event of another pulverizer motor failure, because all 4 pulverizers are required to achieve full load. The failed motor was sent out to be rewound to serve as the new capital spare motor for all the U2 pulverizers.
27617793	VALMY 10146694 V2 GENERATOR CURRENT TRANSFORMER REPLACEMENT		51,317		51,317	Reliability	U2 was forced offline by failure of the Generator Current Transformers. Replacement of the three Generator Current Transformers was necessary to be able to return the unit to operation.
27533145	VALMY 98459395 V1 D1 PULVERIZER ROLL WHEEL ASSEMBLY, REPL	46,984			46,984	Reliability	In April 2019, one the Unit 1D pulverizer roll wheel assembly failed (each pulverizer has three roll wheel assemblies). Black Butte coal requires all four pulverizers to achieve full load. At that time, one roll wheel assembly was replaced to bring the unit back online and available for full load. The other two roll wheel assemblies were identified as in poor condition, but due to the timing of replacement parts not available and the need to gete the unit online for summer load, it was decide to replace just the one roll wheel assembly.
27534969	VALMY 98455853 V2 PULVERIZER MOTOR 2D, REBUILD		44,287		44,287		
27611233	VALMY 10115633 V2 RECYCLED ASH AGITATOR GEARBOX FOR LOOP 1		43,832		43,832		
27609106	VALMY 10111518 V2 WATER LAB INSTRUMENTATION REPLACEMENT		42,056		42,056		
27587933	VALMY 98492604 V2 CONDENSATE PUMP CAPITAL SPARE INSTALLATION		40,991		40,991		
27556791	VALMLY 98473462 VAL DMZ SERVER CLUSTER VA			37,130	37,130		
27539686	VALMY 98459449 V1 1A CIRCULATING WATER PUMP M	35,960			35,960	Reliability	In April 2019, the Unit 1 circulating water pump failed due to a motor ground fault. Absent a circulating water pump in service, Unit 1 would be de-rated to approximately 125 net MW output, or half its normal load. The motor was sent to a contract repair shop for evaluation where it was determined that a complete motor rewind was required. At the request of the Western Electricity Coordinating Council, and because of the four to six-week lead time associated with the repairs, a new replacement motor was purchased so that the plant could meet reliability and availability needs. The rewind was performed and used as a capital spare and a replacement motor was procured.
27534970	VALMY 98458824 V2 AUXILIARY STEAM DESUPERHEAT		34,947		34,947		
27603167	VALMY 10074741 VC RO MEMBRANE REPLACEMENT 68/32			34,141	34,141		
27547697	VALMY 98468760 V1 PRIMARY AIR FAN A MOTOR, RE	33,880			33,880	Reliability	On October 31, 2019, the Unit 1 A Primary Air Fan motor inboard bearing overheated and failed while in service. The motor inboard bearing alarm sounded and upon inspection of the motor, plant personnel discovered a large amount of smoke coming from the motor inboard bearing housing. The motor was shut down and replaced with the existing spare motor. The damaged motor was refurbished to become a spare Primary Air Fan motor. Unit 1 Primary Air Fans are used to convey fluidized coal from the pulverizers to the boiler burner through attached coal conduit piping. Without both Primary Air Fans, Unit 1 could not reach stable operation and would have been curtailed until late December 2019 while the damaged motor was repaired. While the costs appear as 2020 plant additions, the work was performed on Unit 1 in 2019 but final costs did not close to the project until early 2020.

VALMY PLANT ADDITIONS: Jan 1, 2019 - Dec 31, 2022

Project	Descr	V1	V2	VC	Total	Purpose	Project Description/Justification
27551304	VALMY 98453212 V2 SKY CLIMBER ATTACHMENT PLATFORM, INSTALL		33,051		33,051		
27531065	VALMY 98454279 VALMY TECHNOLOGY SECURITY UPDA			30,781	30,781		
27587123	VALMY 98490976 VC CONVEYOR 2 GEARBOX			28,940	28,940		
27579435	VALMY 98486141 VC SYSTEM1 UPDATE			27,363	27,363		
27543734	VALMY 98464825 V1 FLY ASH BLOWER 1B, REPLACE	25,802			25,802	Reliability	A fly ash blower is needed to convey ash in order to keep the baghouse hoppers from overflowing which would lead to an eventual unit shutdown. Inspection of the fly ash blower 1B after it began making unusual noises determined that the blower was not reliable for dependable service and failure was imminent due to internal wear and damage. Plant reliability is increased as replacing the 1B fly ash blower ensures that there is a redundant blower to convey ash and fluidize when needed to do so.
27609114	VALMY 10107331 V2 PULVERIZER 600 HP ELECTRIC MOTOR REPLACEME		25,779		25,779		
27603199	VALMY 10069417 V2 LIME TRANSFER BLOWER 2A REPLACEMENT		24,057		24,057		
27566786	VALMY 98475628 VC RO MEMBRANES, REPLACE 68/32			21,496	21,496		
27539690	VALMY 98463011 V2 LIME TRANSFER BLOWER 2B, RE		20,983		20,983		
27570624	VALMY 98478541 V2 BOILER DRUM MERLI REPL		20,359		20,359		
27577136	VALMY 98485331 VC EDI MODULES, REPLACE 2			18,853	18,853		
27533141	VALMY 98459392 V2 1ST POINT HEATER DRAIN VALVE, REPL		18,078		18,078		
27566788	VALMY 98478101 VC DIGITAL ALIGNMENT TOOL			16,892	16,892		
27596241	VALMY 98494646 VC STACKER CONTROL PLC REPLACEMENT VA			16,652	16,652		
27590308	VALMY 98493304 V2 CONDENSATE PUMP B MOTOR REPLACEMENT		15,158		15,158		
27539683	VALMY 98455129 VC DATA LOGGERS, REPLACE			14,967	14,967		
27533139	VALMY 98457380 VA HMI REPLACEMENT			14,622	14,622		
27533143	VALMY 98459393 V1 1ST POINT FEEDWATER INLET VALVE, REFUR	14,564			14,564	Reliability/Safety	In August 2018 a steam leak to atmosphere from the pressure seal surface of the valve on Unit 1 was discovered. Disassembly and refurbishment was the only way repairs could be made to the valve to avoid the burn hazard of leaking steam to plant personnel and ensure continued reliability of the unit's operation.
27537126	VALMY 98459140 V2 REVENUE METER, UPGRADE		14,443		14,443		
27502697	VALMY 98434354 V1 LOW NOX BURNER NOZZLES, REP	13,148			13,148	Environmental	Mercury and Air Toxics Standards ("MATS") Rule 40 CFR 63.10021 require a burner and combustion control inspection, and combustion tuning every thirty-six months. During the inspection, completed in December 2017, significant degradations were noted on 22 thermocouples, 15 coal burner assemblies, and refractory around all burners. This scope of work was identified as required to be completed to meet regulations and allow continued boiler operation.
27557532	VALMY 98473888 VC ONSITE BACKUP HOST SERVER			12,989	12,989		
27537123	VALMY 98459139 V1 REVENUE METER, UPGRADE	12,709			12,709	Reliability	Given Idaho Power's impending exit from Unit 1 operations, it is important to have in place a sufficient measurement infrastructure to properly account for both owners' utilization of each unit. Based upon NV Energy's review of the net megawatt ("MW") billing infrastructure, it was determined that Valmy lacked sufficiently accurate meters, totalizers, and communication infrastructure to reliably account for MW generation including transformer losses. At the time the Company joined the Energy Imbalance Market, the Valmy metering infrastructure had not been upgraded and instead relied on a mix of local readings from different meters and systems that did not always match. This project consolidates and standardizes Valmy net MW reporting by sending the data to the plant's distributed controls system, which then consolidates the information and reports it in a single, consistent value to each owner.
27568580	VALMY 98480883 V2 PULVERIZER 600HP ELECTRIC MOTOR, CAP SPARE		11,641		11,641		
27599865	VALMY 98493576 V2 TURBINE REHEAT DRAIN VALVE		10,300		10,300		
27603169	VALMY 10074744 VC AUTOMATED COMPRESSION DEVICE			10,102	10,102		
27579439	VALMY 98486138 V2 DCS NETWORK GPS TIME SERVER		10,088		10,088		
27587933	VALMY 98492604 V2 CONDENSATE PUMP CAPITAL SPARE INSTALLATION		9,643		9,643		
27533147	VALMY 98459448 V1 1ST POINT HEATER EXTRACTION STEAM BLOCK VA	9,119			9,119	Reliability	The block valve that supplies extraction steam to the Unit 1 1st point feedwater heater failed in the closed position in July 2018. This valve serves to isolate the 1st point feedwater heater from turbine fed extraction steam and also protects the turbine from backflow/water induction by going to closed position when called on. The failure required the bypass of the 1st point feedwater heater affecting the plant reliability and diminishing the heat rate. This project refurbished the block valve.
27591520	VALMY 98494614 VC WEST 1ST PASS RO MEMBRANE R			8,916	8,916		
27596255	VALMY 98496604 V2 FORCED DRAFT FAN B MOTOR REPLACEMENT VA		6,926		6,926		
27501116	VALMY 98427786 V1 PULVERIZER "B" MAJOR REBUILD	6,732			6,732	Reliability	Pulverizers are utilized to grind coal to fine dust before being transported to burner fronts. This process wears out roll wheel assemblies, table grinding segments, and interior of pulverizer equipment. The normal operating life cycle of a Unit 1 pulverizer is roughly 18 to 24 months. Routine inspections are performed at 3,000 hours and required maintenance is performed to ensure the maximum life of the pulverizer rebuild. Major overhaul includes replacements of roll wheels, air seals, coal shields, bearings, wear resistant ceramic liners, classifier vanes, coal feeder wear components, spring frame wear plate, and the pyrites plow. In addition, the gearbox and lubrication system was refurbished and other associated welding and re-building was performed due to erosions to the pulverizer housing and associated equipment. The purpose of this project is for the continued reliable operation of Unit 1.
27545750	VALMY 98466598 VC UTILITY CARTS, REPLACE			6,268	6,268		
27591516	VALMY 98494358 VC EQUIPMENT WASH PIPING REPLACEMENT			5,915	5,915		
27570624	VALMY 98478541 V2 BOILER DRUM MERLI REPL		2,582		2,582		
27517150	VALMY 98442216 ACOUSTIC MONITORING SECU			2,051	2,051		
27545747	VALMY 98454282 OT PLANT TECHNICIAN TOOLS NORT			988	988		
27502692	VALMY 98434198 V1 SORBENT TRAP MERCURY MONITO	929			929	Environmental	A mercury monitoring system is required for environmental compliance. The monitoring provisions apply to the measurement of total vapor phase mercury in emissions from sorbent trap monitoring systems that must be capable of measuring mercury in units of the applicable emissions standards. The existing monitoring system suffered failures requiring parts to be replaced and exhausted warehouse stock. While attempting to replenish the stock, it was determined that replacement parts were no longer available. This project replaced the existing sorbent trap mercury monitoring equipment with units which meet compliance requirements and have parts readily available to maintain compliance. The majority of the project costs closed in 2018, with some remaining dollars closing in 2019.
27502694	VALMY 98434199 V2 SORBENT TRAP MERCURY MONITO		627		627		
27587123	VALMY 98490976 VC CONVEYOR 2 GEARBOX			521	521		
27568635	VALMY 98476439 VC FPS DIESEL FIRE PUMP A ENGINE REBUILD			413	413		
27619674	VALMY 10152570 VC ANNEX OFFICE BUILDING FLOOR REPL			295	295		
27603164	VALMY 10074746 VC UTILITY CARTS REPLACEMENT			263	263		
27603165	VALMY 10065457 VC CRUSHER FEEDER MOTOR AND GEARBOX REPLACEME			229	229		
27509175	VALMY 98437316 VC RO MEMBRANES, REPLACE			92	92		
27556791	VALMLY 98473462 VAL DMZ SERVER CLUSTER VA			(28)	(28)		
27514789	VALMY 98443689 V1 ID FAN MOTOR 1B, REBUILD	(1,002)			(1,002)		
27570622	VALMY 98481652 VC 5B COAL UNLOAD CONVEYER BELT, REPLACE VA			(15,589)	(15,589)		
27440893	VALMY 98376800 VC PRODUCTION WELL #10 REPLACE			(109,095)	(109,095)		
Grand Total		**416,860**	**6,013,329**	**1,761,649**	**8,191,837**		

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BARRETTO, DI TESTIMONY

EXHIBIT NO. 3

BRIDGER PLANT ADDITIONS: Jan 1, 2021 - Dec 31, 2022

Accounting Year	Project	Description	U1	U2	U3	U4	Common	Total	Purpose	Project Description/Justification
2021	27541813	BRIDGER 2019C091 U4 SCR CATALYST REPLACEMENT 20				1,413,556		1,413,556	Environmental	Replaced two levels of Selective Catalytic Reduction ("SCR") catalyst as defined in the catalyst management plan. Current SCR design requires replacement of catalyst on a set cycle corresponding to major outages.
2021	27549354	BRIDGER 2020C010 U4 STACK LINER (PHASE 2) 20				897,531		897,531	Environmental	This project extended the pin block liner to the mid level of the stack and was a continuation of the project to complete the line replacement. The project will prevent deterioration of acid brick lining and compression bands.
2021	27547308	BRIDGER 2020C009 U4 BURNERS - MAJOR 20				648,381		648,381	Reliability / Environmental	Replaced burner (nozzle tip) components and repair other damaged/warped hardware. Most burner front components have a 4-year life. Warpage causes less-than-optimal combustion.
2021	27503065	BRIDGER 2018C011 U4 PRECIPITATOR WIRE REPLACEMENT 20				575,461		575,461	Environmental	This project replaced discharge electrode wires in the precipitator. Without replacement, electrode wires will begin breaking at an increasing rate adversely impacting precipitator performance.
2021	27553266	BRIDGER 2020C016 BLANKET - PUMPS, VALVES, GEARBOXES 20					456,375	456,375	Reliability	These costs are associated with miscellaneous pumps, valves and gearboxes associated with several capital mechanical projects performed throughout the year.
2021	27553276	BRIDGER 2020C011 U4 SCRUBBER DUCTWORK 20				407,605		407,605	Environmental	Recoated scrubber ductwork and completed repairs as required. The project was required to maintain the integrity of the ductwork.
2021	27551439	BRIDGER 2020C035 U4 SCR AIR CANNONS 20				315,713		315,713	Environmental	Installed online catalyst cleaning equipment to reduce ash pluggage. During several catalyst inspections on U4, ash buildup was observed on the front wall of the bottom two layers of the catalyst. This project installed air cannons/ash sweepers on the front wall and turning valves to eliminate this ash buildup.
2021	27545744	BRIDGER 2020C004 U4 BFPT TRIP SYSTEM 20				308,162		308,162	Reliability/Safety	This project replace the electro mechanical trip system as well as eliminate the mechanical over speed bolt on the boiler feed pump turbines. This is a triple redundant system. The existing system was over 30 years old and maintenance issues increased over the years. This was the first set of boiler feed pump turbines slated for the upgrade.
2021	27533268	BRIDGER 2020C001 U4 LPA SCREEN REPLACEMENT 20				291,847		291,847	Environmental	Installed a new large particle ash ("LPA") screen to maintain the optimal catalyst performance and service life. The LPA screens prevent the SCR catalyst from plugging. The catalyst is costly hardware that is used to produce the operating permit NOx value. The LPA screen typically has a 5 year life expectancy. U4 LPA screens have experienced higher than expected failure in parts of the screen and this project is part of a warranty agreement.
2021	27549348	BRIDGER 2020C006 U4 PRECIPITATOR TR & CLR REPLACEMENT 20				274,230		274,230	Environmental	Upgraded 18 transformer-rectifiers ("TR") and 18 Current Limiting Reactors ("CLR") in the precipitator. Existing TRs and CLRs were reaching the end of their service life and had become unreliable. TR and CLR malfunctions can significantly impact precipitator performance.
2021	27551426	BRIDGER 2020C022 U4 WATERWALL COUTANT SLOPE INTERFACE PHA				252,486		252,486	Reliability	This project replaced boiler side wall tubes at the interface with the coutant slope. Tube in this area experiences increased ash erosion as compared to other areas of the boiler. Tubes had previously been pad welded numerous times and required replacement.
2021	27553282	BRIDGER 2020C052 U4 PRECIPITATOR DUCT WORK 20				229,106		229,106	Environmental	The project was required to maintain the integrity of the ductwork. If the ductwork is not repaired and recoated, the steel will be impacted by fly ash erosion. This impacts the structural integrity of the duct work.
2021	27575653	BRIDGER 2021C012 BLANKET - MILLS, PULVERIZER VERTICAL SHA					226,258	226,258	Reliability	This work order allocates funds for major pulverizer overhauls. Approximately two pulverizers require major overhauls each year therefore these costs are associated with the replacement parts that were ordered in advance to provide a quick turn-around time of the mills.
2021	27545655	BRIDGER 2019C094 U4 EHC PUMPS SKID UPGRADE 20				218,633		218,633	Reliability	This project improved Electro-Hydraulic pump performance by upgrading the pumps from the existing obsolete equipment. It was difficult and costly to find service shops that could rebuild the pumps. Having contemporary pumps will also increase reliability and serviceability.
2021	27493693	BRIDGER 2017C110 U4 BOILER OPTIMIZATION SYSTEM 17				217,915		217,915	Reliability	This project implemented neural network combustion controls and soot blowing optimizer on the unit. The optimizer seeks to lower emissions (NOx and CO) while minimizing heat rate. Other targets such as steam temperatures, oxygen controls, and Regional Haze requirement emission restriction profiles can also be set. Results achieved on U2 are a 65 BTU/kWh reduction in the net unit heat rate with the combustion optimizer alone; other power plants have experienced an additional 0.5% improvement in heat rates as a result of the soot blowing optimizer.
2021	27547299	BRIDGER 2019C095 U4 ABS INLET TURNING VANES 20				202,986		202,986	Environmental	The project involved the installation of turning vanes and flow straightening devices to ensure uniform flow profile across the absorber inlet and equal distribution of flow in all absorbers. These devices will also reduce flow recirculation at the absorber inlet hence reducing slurry to flow back into absorber inlet plenum.
2021	27549359	BRIDGER 2020C015 U4 #42 BOILER FEED PUMP REBUILD 20				199,417		199,417	Reliability	This project rebuilt the boiler feed pump and replaced the pump casing. It was required to assure proper alignment with both the rotating element and the pump to the turbine.
2021	27549360	BRIDGER 2020C021 U4 NUVA FEEDER PIPING REPLACEMENT 20				197,957		197,957	Environmental	Replacement of the Nuva feeder piping. The existing piping was reaching the end of its life and was starting to deteriorate. The piping replacement maintains the integrity of the system.
2021	27575652	BRIDGER 2021C003 BLANKET - PUMPS, VALVES, GEARBOXES 21					195,757	195,757	Reliability	These costs are associated with miscellaneous pumps, valves and gearboxes associated with several capital mechanical projects performed throughout the year.
2021	27573809	BRIDGER 2020C074 U4 ECONOMIZER OUTLET TURNING VANE 20				189,477		189,477	Reliability	This area is subject to fly ash erosion to structural supports and duct work. This project restored turning vanes that had been worn through by fly ash. The support structure and turn vanes are directly over the air pre-heater. This material can fall onto the air pre-heater and stop the rotor which will cause a unit trip.
2021	27583201	BRIDGER 2021C021 U0 BCP MOTOR REWINDS & COOLERS 21					184,447	184,447	Reliability	This work order includes costs associated with the rebuild of a failed boiler circulating pump for future re-use. Absent the spare boiler circulating pump, a typical rebuild time is at least 2 months which would impact unit generation for the time period that one of the boiler circulating pump is out of service.
2021	27547293	BRIDGER 2019C082 U4 REPLACE 7200 VAC BUS RELAYS 20				182,230		182,230	Reliability/Safety	This project replaced existing motor and Load Control Center transformer feeder breaker relays with new solid state relays on U4 because the existing relays are obsolete. The new relays provide enhanced diagnostic and monitoring capability.
2021	27551428	BRIDGER 2020C025 U4 PA DUCT INSPECT AND REPAIR 20				182,137		182,137	Reliability	Inspected and repaired the primary air duct, including the required scaffolding and insulation work. The primary air ducts had developed leaks over years of operation. The cracks and holes that were visible were repaired during unit outages; however, the insulation on the hot air duct and the height of the vertical duct continue to limit the inspection view. This project enabled a more complete inspection and repair to restore the ductworks ability to supply adequate primary air pressure for full load.
2021	27507255	BRIDGER 2018C088 GREEN RIVER 3500 VIBRATION MONITORING SY					180,430	180,430	Reliability	The existing Emerson 4500 was obsolete and no longer supported by Emerson. A new Bently Nevada 3500 was installed on the green river pump station. The Continuous Vibration Monitoring System provides real time vibration shutdown protection for the six Green River pumps. This upgrade was necessary in order to have OEM support, and to standardize this system with the rest of Bridger's on-line monitoring systems. This system will also be tied into the plant network, using the latest critical security control upgrades and will provide real time vibration data for trending, alarming, and advanced analysis at the plant.

BRIDGER PLANT ADDITIONS: Jan 1, 2021 - Dec 31, 2022

Accounting Year	Project	Description	U1	U2	U3	U4	Common	Total	Purpose	Project Description/Justification
2021	27551444	BRIDGER 2020C046 U4 INSTALL NEW AIR FLOW PROBES 20				174,584		174,584	Reliability / Environmental	Installed new secondary air flow monitors. Unit operation at low load requires increased accuracy of boiler air load.
2021	27549363	BRIDGER 2020C024 U4 SDCC WEAR PLATE LOAD SIDE 20				165,783		165,783	Reliability/Safety	Purchased and installed AR500 wear plates for the U4 submerged drag chain conveyor, which removes ash from the bottom of the boiler. The original wear plates were installed in 2012 and had reached the end of their 8 year design life.
2021	27559516	BRIDGER 2020C075 REPLACE PULVERIZER JOURNALS					160,334	160,334	Reliability	The project replaced pulverizer journals which were beyond economical repair. The purchase of journals help to maintain pulverizer availability. Underground coal has proven to be more abrasive which leads to increased journal wear.
2021	27549352	BRIDGER 2020C008 U4 LPA SCR COLLECTION/TRANSFER CNVYR 20				139,597		139,597	Environmental	This project overhauled the mini drag-chains that transport ash from the SCR large particle ash hopper to the drag chain hopper. Replacement of components are required to operate the equipment reliably for the next four years.
2021	27475574	BRIDGER CITC2017C207 BACKUP BANDWIDTH UPGRADES 2017					130,809	130,809	Reliability	This project upgraded the radio communications at the plant. Contact with personnel including technicians and maintenance needed improvement by adding some off the circuits and increasing the bandwidth in and around the plant.
2021	27549367	BRIDGER 2020C045 U4 APH SEAL REPLACEMENT 20				130,390		130,390	Reliability	Replaced all hot end and cold end seals in both air pre-heaters during major overhaul. Air pre-heater seals have to be set with an interference fit to reduce air leakage at operating temperatures. The interference fit will cause additional wear during shutdowns and startups, leading to excessive air leakage.
2021	27551441	BRIDGER 2020C041 U4 EX-2100E CONTROL UPGRADE & PARTS 20				129,263		129,263	Reliability	Upgraded the EX2100 control system with an EX2100e digital front end excitation system retrofit. The U4 system was installed 12 years ago and the hardware, circuit board, and control interface had become obsolete. In addition, the manufacturer had stopped supporting the old hardware and recommended an upgrade to the new EX2100e control system.
2021	27553281	BRIDGER 2020C050 U4 DCS MINOR 20				123,134		123,134	Reliability	Replaced failed Distributed Control Systems ("DCS") component. The plant has moved from a 4 year major DCS component Evergreen cycle to an 8 year cycle. Work stations and monitors have a 4 year life.
2021	27551452	BRIDGER 2020C057 U4 RETRACTS & WATER INJECTION PENETRATIO				122,268		122,268	Reliability	Installed equipment to help burn a better coal quality. Bridger Coal Company is delivering fuel that contains higher sodium, calcium and iron. Coal with these constituents result in accumulations of fouling and plugging of the boiler. This results in load reductions and forced outages. The plant installed hardware that will burn the supplied coal without negatively impacting the boiler.
2021	27545743	BRIDGER 2019C101 U4 TURBINE BEARING FIRE DETECTION/SUP 20				121,474		121,474	Reliability/Safety	Install of an automatic pre-action closed-head sprinkler system to protect the turbine generator bearings on the unit and mitigate the risk of fire damage to the turbine generator and the plant. This project will help reduce the risk of turbine bearing fire damage and was identified through a risk audit.
2021	27549361	BRIDGER 2020C023 U4 PRECIP DAMPER LIMITORQUE REPLACE 20				112,405		112,405	Environmental	This project included the purchase and install new Limitorque drives on the precipitator inlet and outlet dampers and was needed to maintain reliable operation of the precipitator and allow maintenance repairs to be completed with the unit on-line. High availability of network systems used to communicate with customers is critical to maintaining efficient and effective business operations as well as meeting customer expectations.
2021	27580827	BRIDGER 2021C023 U4 PRECIP CE/DE RAPPER REPLACEMENT 21				111,888		111,888	Environmental	This project replaced 6 discharge electrode rappers in A fields, 5 collector electrode rappers in A Fields and 4 CE rappers in B fields. Electrostatic precipitator removes fly ash from the gas. Opacity is used to quantify the effectiveness of precipitator. Precipitator consists of highly charged electrodes and collecting electrodes to collect fly ash.
2021	27551448	BRIDGER 2020C055 U4 APH SECTOR PLATES 20				110,624		110,624	Reliability	Replaced the two worst sector plates on each unit. Sector plates have reached their effective life after 35 years of use. Warped sector plates result in excessive air pre-heater leakage.
2021	27549357	BRIDGER 2020C012 U4 FLAME SCANNER 20				102,853		102,853	Reliability	Replaced the 12 flame scanners on U4. The supplier was no longer manufacturing spare parts for the existing scanners. The scanners are integral in the boiler operation.
2021	27575902	BRIDGER 2020C040 U4 COAL PIPE REPLACEMENT 20				100,188		100,188	Reliability/Safety	This project replaced the coal pipes from the pulverizers to the boiler that had high wear due to the abrasiveness of the coal. Over time the coal flowing through the pipes will develop high wear areas and thinning of the steel coal pipes, mostly at the elbow. If the pipes are not replaced, the high wear areas will wear through and pulverized coal and air from the primary air fans will be blowing into the power plant causing a hazard to employees and lost efficiency in the boiler.
2021 Total			**-**	**-**	**-**	**8,849,280**	**1,534,411**	**10,383,691**		

BRIDGER PLANT ADDITIONS: Jan 1, 2021 - Dec 31, 2022

Accounting Year	Project	Description	U1	U2	U3	U4	Common	Total	Purpose	Project Description/Justification
2022	27602389	BRIDGER 2022C016 U0 BLANKET- PUMPS, VALVES, GEARBOXES 22					555,832	555,832	Reliability	These costs are associated with miscellaneous pumps, valves and gearboxes associated with several capital mechanical projects performed throughout the year.
2022	27595046	BRIDGER 2021C042 U2 BURNERS MAJOR 22		405,663				405,663	Reliability / Environmental	Replaced burner (nozzle tip) components and repaired other damaged/warped hardware. Most burner front components have a 4-year life. Warpage causes less-than-optimal combustion.
2022	27597944	BRIDGER 2022C001 U2 DCS MAJOR 22		400,965				400,965	Reliability	This project upgraded the DCS software and select power supplies and controllers. DCS software is upgraded on an eight year cycle and hardware is replaced as necessary to be compatible with the software.
2022	27613523	BRIDGER 2022C045 U0 REBUILD FRAME UP D-10T DOZER 22					313,469	313,469	Reliability/Safety	This project rebuilt the D-10T Dozer with the highest operating hours/in the worst condition to maintain fleet reliability. D-10Ts are required for coal delivery to the plant. Equipment operating hours reached OEM recommended limits for major rebuilds. Maintenance costs and downtime had been increasing.
2022	27575650	BRIDGER 2020C076 U2 REPLACE 25 FEEDWATER HEATER 21		245,336				245,336	Reliability	This project replaced the existing 25 feedwater heater. The system was taking 8 hours to drain to the floor resulting in a delay before repairs to the feedwater system could begin. The new drains will drain the system in half the time and return the water to the condensate system for reuse rather than dumping the hot water to the floor.
2022	27483895	BRIDGER 2017C035 U2 REPLACE EPOXY LINER IN CW TUNNELS 17		244,537				244,537	Reliability/Safety	The epoxy liner installed in the circulating water pipelines beneath the power building floor had partially failed, requiring replacement. This project replaced the failed epoxy liner.
2022	27597953	BRIDGER 2022C015 U2 EHC PUMPS REPLACEMENT 22		223,574				223,574	Reliability	Replaced obsolete electro-hydraulic controlled pumps with a supported pump. Pumps were obsolete and were difficult to maintain.
2022	27597951	BRIDGER 2022C012 U2 WATERWALL COUTANT SLOPE INTERFACE PHASE		222,866				222,866	Reliability	This project replaced boiler side wall tubes at the interface with the coutant slope. Tubing in this area experienced increased ash erosion as compared to other areas of the boiler. Tubes had been pad welded numerous times and need to be replaced.
2022	27602391	BRIDGER 2022C030 U2 REPLACE ECON OUTLET TURNING VANES 22		204,776				204,776	Reliability	This area is subject to fly ash erosion to structural supports and duct work. This project restored turning vanes that have been worn through by fly ash. The support structure and turn vanes are directly over the air pre-heater. This material can fall onto the air pre-heater and stop the rotor which will cause a unit trip.
2022	27551450	BRIDGER 2020C056 U4 ACOUSTIC LEAK DETECTION SYSTEM 20				176,915		176,915	Reliability	Installed acoustic leak detection in boiler for detection and monitoring of tube leaks. Provides early detection and scheduling of tube leak repairs.
2022	27602387	BRIDGER 2022C008 U2 SCRUBBER DUCTWORK 22		166,210				166,210	Environmental	Recoat scrubber ductwork and completed repairs as required. If the ductwork is not repaired and recoated, the steel will continue to corrode. This impacts the structural integrity of the duct work.
2022	27602388	BRIDGER 2022C009 U2 PRECIPITATOR DUCTWORK 22		154,319				154,319	Environmental	The project was required to maintain the integrity of the ductwork. If the ductwork is not repaired and recoated, the steel will be impacted by fly ash erosion. This impacts the structural integrity of the duct work.
2022	27597961	BRIDGER 2022C017 U2 HP TURBINE PACKING 22		151,812				151,812	Reliability	This project replaced the U2 high pressure turbine packing with new packing to restore efficiency. With the new packing, it is expected that the heat rate will improve by 27 BTU/kWh.
2022	27602384	BRIDGER 2022C003 U2 STACK BREECH COATING 22		138,797				138,797	Environmental / Safety	This project replaced the worn coating in the ducts from the scrubbers into the stack (stack breach). This is a high wear area and if not repaired and/or replaced will lead to excessive leaking and could lead to environmental violations. This could also be a hazard to employees if there is leaking flue gas where employees might be working.
2022	27559555	BRIDGER 2020C086 U0 REDUNDANT SODA LIQUOR SUPPLY LINE					134,591	134,591	Environmental	Installed redundant soda liquor supply line, in case repairs are required on the existing soda liquor supply line to prevent unit derates or outages.
2022	27575652	BRIDGER 2021C003 BLANKET - PUMPS, VALVES, GEARBOXES 21					130,908	130,908	Reliability	These costs are associated with miscellaneous pumps, valves and gearboxes associated with several capital mechanical projects performed throughout the year.
2022	27597946	BRIDGER 2022C004 U2 SLMS HP UPGRADE 22		130,829				130,829	Reliability/Safety	This project replaced the Stator Leak Monitor System ("SLMS") on U2. The components on the U2 SLMS were approaching end of life. The monitoring of hydrogen leakage into the stator water cooling system is a good indicator on the overall health of the machine's insulation system.
2022	27607052	BRIDGER 2022C031 U2 APH SECTOR PLATES 22		130,526				130,526	Reliability	Replaced the two worst sector plates on each unit. Sector plates have reached their effective life after 35 years of use. Warped sector plates result in excessive air pre-heater leakage.
2022	27600043	BRIDGER 2022C019 U2 7200 LCC RELAY ARC FLASH UPGRADE 22		126,971				126,971	Safety	This project upgraded the existing outdated station breaker relays that were a safety concern due to arc flash hazards. The plant has been replacing the old relays with arc flash compliant relays that will significantly reduce the hazard or arc flash incidents to plant personnel.
2022	27566689	BRIDGER 2020C088 U0 MILL DISCHARGE VALVE REPLACE 21					126,415	126,415	Reliability	This project replaced mill discharge valves on the units to isolate the supply of fuel to the boiler and will maintain National Fire Protection Association compliance for coal pipe isolation valves. The existing valves wear out as they remain in the abrasive coal flow, but the replacement valves are be designed with longer life.
2022	27604648	BRIDGER 2022C033 U2 APH SEAL REPLACEMENT 22		110,702				110,702	Reliability	Replaced all hot end and cold end seals in both air pre-heaters during major overhaul. Air pre-heater seals have to be set with an interference fit to reduce air leakage at operating temperatures. The interference fit will cause additional wear during shutdowns and startups, leading to excessive air leakage.
2022	27595047	BRIDGER 2022C011 U2 PRECIPITATOR RAPPERS 22		100,969				100,969	Environmental	Complete replacement of rapper shaft, bearings and hammers as the precipitator rapping systems were reaching their end of life.
2022 Total			**-**	**3,158,849**	**-**	**176,915**	**1,261,215**	**4,596,979**		
Grand Total - Projects Over $100k			**-**	**3,158,849**	**-**	**9,026,195**	**2,795,626**	**14,980,670**		

BRIDGER PLANT ADDITIONS: Jan 1, 2021 - Dec 31, 2022

Accounting Year	Project	Description	U1	U2	U3	U4	Common	Total	Purpose	Project Description/Justification
2021	27569520	BRIDGER 2020C093 REPLACE PLANT VEHICLES 20					99,571	99,571		
2021	27559520	BRIDGER 2020C082 U4 LOADOUT CONVEYOR PLATFORM				98,763		98,763		
2021	27551442	BRIDGER 2020C044 U4 ECONOMIZER HARMONIC BAFFLES 20				93,701		93,701		
2021	27569745	BRIDGER 2020C103 U4 SCR ADD AIR NOZZLES @ TURN VANES 21				91,162		91,162		
2021	27549345	BRIDGER 2019C103 U4 AMMONIA MONITOR				91,000		91,000		
2021	27583200	BRIDGER 2021C002 BLANKET - MOTORS 21					87,265	87,265		
2021	27569735	BRIDGER 2020C102 REPAVE PLANT ROADS 20					79,203	79,203		
2021	27545653	BRIDGER 2019C068 03A & 03B BUS RELAY UPGRADES 19					75,607	75,607		
2021	27566691	BRIDGER 2020C053 U0 PLANT LIGHTING IMPROVEMENTS 20					75,351	75,351		
2021	27578625	BRIDGER 2021C006 U4 BLANKET UPGRADE 7.2 KV MAGNEBLAST BREAKE				73,680		73,680		
2021	27549344	BRIDGER 2016C031 U4 MERCURY DEVICE REPLACEMENT 20				71,261		71,261		
2021	27555273	BRIDGER 2020C072 REBUILD 777 ASH HAULER FRAME UP (A) 20					69,663	69,663		
2021	27575648	BRIDGER 2020C065 U4 SDCC LINER/SHELL REPLACEMENT 2020				67,491		67,491		
2021	27545746	BRIDGER 2020C014 U4 BFPT AC/DC OIL PUMPS 20				67,173		67,173		
2021	27553278	BRIDGER 2020C027 U4 SDCC TU/SUB IDLER REPLACEMENT 20				63,910		63,910		
2021	27553272	BRIDGER 2020C002 U4 UPGRADE COOLING TOWER VFDS 20				63,874		63,874		
2021	27549347	BRIDGER 2020C005 REPLACE EX-2100 HMI COMPUTERS 20					63,627	63,627		
2021	27561649	BRIDGER 2020C092 U0 CONTRACTOR PARKING GATE 2 CONCRETE WORK					61,391	61,391		
2021	27551431	BRIDGER 2020C031 BLANKET - ELECTRICAL/INSTRUMENTATION 20					59,620	59,620		
2021	27551430	BRIDGER 2020C026 U4 COVER ECONOMIZER HOPPERS 20				56,811		56,811		
2021	27555268	BRIDGER 2020C030 HEAT TRACE SYSTEM UPGRADES 20					56,699	56,699		
2021	27549365	BRIDGER 2020C029 BLANKET UPGRADE 7.2 KV MAGNEBLAST BREAKE					55,825	55,825		
2021	27560921	PAC-SPONS JOOA: JIM BRIDGER REPLACE EPU					53,296	53,296		
2021	27553280	BRIDGER 2020C034 U2 COOLING TOWER FAN BRAKE SYSTEMS 20		52,711				52,711		
2021	27591387	BRIDGER 2019C034 U0 REPLACE ROOFING SYSTEM 21					51,456	51,456		
2021	27547309	BRIDGER 2020C013 U4 FEEDWATER SYSTEM DRAINS TO COND 20				47,882		47,882		
2021	27569857	BRIDGER 2020C073SEWER SEWER PIPES LINERS- JIM BRIDGER PLANT					46,346	46,346		
2021	27553351	BRIDGER 2020C036 U4 COOLING TOWER FAN BRAKE SYSTEMS 20				45,882		45,882		
2021	27580817	BRIDGER 2020C058 U4 SDCC REPLACE DEWATERING SLOPE 20				44,550		44,550		
2021	27547327	BRIDGER 2019C083 U3 STACK OPACITY MONITOR HEATING 19			43,546			43,546		
2021	27580822	BRIDGER 2021C007 BLANKET - ELECTRICAL/INSTRUMENTATION 21					42,360	42,360		
2021	27580826	BRIDGER 2021C022 BLANKET LCC SWITCHGEAR & XFMR UPGRADES 21					39,990	39,990		
2021	27575904	BRIDGER 2020C104 U2 PRECIP INTERLOCK PANEL REPLACEMENT 20		36,934				36,934		
2021	27551347	BRIDGER 2020C017 BLANKET - SMALL TOOLS 20					36,830	36,830		
2021	27553353	BRIDGER 2020C043 U4 SO3 NOZZLE REPLACEMENT 20				36,038		36,038		
2021	27580825	BRIDGER 2021C020 U4 SDCC REFRACTORY REPLACEMENT 21				34,442		34,442		
2021	27573808	BRIDGER 2021C004 U0 BLANKET - SMALL TOOLS 21					33,829	33,829		
2021	27571833	BRIDGER 2020C070 BLANKET MCC UPGRADES 20					30,155	30,155		
2021	27578675	BRIDGER CITC2021C202 2021 CONSOLIDATED PC TOM					30,038	30,038		
2021	27568634	BRIDGER 2020C071 U4 LCC OV/UV RELAY UPGRADE				28,479		28,479		
2021	27560845	PAC-SPONS JOOA: NERC PRC-002 AND MOD-033					28,016	28,016		
2021	27587057	BRIDGER 2021/C/032 CONVEYOR BELTS 21					26,556	26,556		
2021	27524343	BRIDGER 2018C132 U4 MAIN TURBINE OVERSPEED UPGRADE.				25,761		25,761		
2021	27553279	BRIDGER 2020C032 U4 ERV MODIFICATION 20				25,012		25,012		
2021	27505201	BRIDGER CITC2018C250 BOUNDARY DEFENCE IMPROVEMENT					24,301	24,301		
2021	27578626	BRIDGER 2021C013 U0 CH LINER PLATES 21					22,987	22,987		
2021	27585690	BRIDGER CITC2021C018 DRAGOS -JIM BRIDGER					22,110	22,110		
2021	27549350	BRIDGER 2020C007 U4 REPLACE DOGBONE EXPANSION JOINT 20				18,733		18,733		
2021	27524338	BRIDGER 2018C130 U2 MAIN TURBINE OVERSPEED UPGRADE.		17,191				17,191		
2021	27501256	BRIDGER 2018C064 U1 FLAME SCANNER 18	15,358					15,358		
2021	27564797	BRIDGER U0 2020/C/081 DUST COLLECTOR DUCTWORK REPLACEMENTS					15,008	15,008		
2021	27571832	BRIDGER 2020C083 U0 REPLACE RO MEMBRANES 20					15,003	15,003		
2021	27551437	BRIDGER 2020C033 U4 REPLACE 42 MOISTURE SEPARATOR 20				14,660		14,660		
2021	27559496	BRIDGER 2020C038 REPLACE FORKLIFT					12,199	12,199		
2021	27525030	BRIDGER 2019C032 BLANKET - PUMPS, VALVES, GEARBOXES 19					12,151	12,151		
2021	27578627	BRIDGER 2021C015 U0 BLANKET - UNDERGROUND IPS / HYDRANTS 21					11,421	11,421		

BRIDGER PLANT ADDITIONS: Jan 1, 2021 - Dec 31, 2022

Accounting Year	Project	Description	U1	U2	U3	U4	Common	Total	Purpose	Project Description/Justification
2021	27580823	BRIDGER 2021C014 U4 COOLING TOWER COMPONENT COATING 21				7,049		7,049		
2021	27578672	BRIDGER 2020C068 U1 SHOWER FOOM FLOOR COATING	6,207					6,207		
2021	27585109	BRIDGER 2021C011 U0 DAHS SERVER CHANGE OUT 21					6,054	6,054		
2021	27569728	BRIDGER 2020C100 REPLACE FIRE EXTINGUISHERS 20					6,038	6,038		
2021	27580818	BRIDGER 2020C060 U4 SDCC & TRANSFERCHUTES 20				5,795		5,795		
2021	27527161	BRIDGER 2019C039 BLANKET - ELECTRICAL / INSTRUMENTATION 1					4,949	4,949		
2021	27591375	BRIDGER 2021C005 U0 BLANKET - OFFICE EQUIPMENT 21					3,803	3,803		
2021	27527167	BRIDGER 2019C066 U0 MERCURY DEVICE REPLACEMENT 19					3,584	3,584		
2021	27551348	BRIDGER 2020C019 BLANKET - OFFICE EQUIPMENT 20					3,398	3,398		
2021	27551447	BRIDGER 202C051 DCS SECURITY SERVER UPGRADES 20					3,260	3,260		
2021	27517680	BRIDGER 2018C117 INSTALL EFFLUENT TO MINE WATER PIPING					3,155	3,155		
2021	27557169	BRIDGER 2020C078 U1 REPLACE PYRITE HOPPERS 20	3,107					3,107		
2021	27589304	BRIDGER 2021C008 U0 BLANKET - SHOP MACHINERY REPLACEMENT 21					2,844	2,844		
2021	27541805	BRIDGER 2019C040 BLANKET UPGRADE 7.2 KV MAGNEBLAST BREAKE					2,228	2,228		
2021	27578781	BRIDGER CITC2020C308 CONTROL NETWORK ROUTER/SWITCH TOM 2020					1,976	1,976		
2021	27564795	BRIDGER U0 2020C080 REPLACE CATHODIC PROTECTION ANODE BED					1,348	1,348		
2021	27569752	BRIDGER 2020C095 REPLACE 35 TON CRANE 20					775	775		
2021	27553270	BRIDGER 2020C067 U4 ULTRASONIC FEEDWATER FLOW METER				46		46		
2021	27524351	BRIDGER 2018C135 U2 ELEVATOR UPGRADES		1				1		
2021	Various	CORRECTIONS ASSOCIATED WITH INVESTMENTS PRIOR TO 2021	(8,969)	(4,287)	(29,024)	(3,066)	(72,606)	(117,951)		
2021 Total			**15,704**	**102,550**	**14,522**	**1,170,089**	**1,308,676**	**2,611,541**		
2022	27587065	BRIDGER 2021C016 GAS CEMS CHANGEOUT 21					94,645	94,645		
2022	27600046	BRIDGER 2022C024 U0 BLANKET - MOTORS 22					91,390	91,390		
2022	27607057	BRIDGER 2022C041 U2 WATERWALL SOOTBLOWER PANELS AND TUBES		89,972				89,972		
2022	27568632	BRIDGER 2018C125 U0 RADIO COMMUNICATIONS TOWER					88,802	88,802		
2022	27595041	BRIDGER 2021C017 U0 GAS UMBILICAL 21					83,831	83,831		
2022	27560916	PAC-SPONS JOOA: TPL 2017 BACKUP BUS DIFF RLY- JIM BRIDGER 34					80,873	80,873		
2022	27597954	BRIDGER 2022C018 U2 SDCC REPLACE CHAIN 22		80,035				80,035		
2022	27593467	BRIDGER 2021C039 U3 REPLACE PULVERIZER JOURNALS 21			78,942			78,942		
2022	27608979	BRIDGER 2022C044 U2 STACK LINING REPAIRS 22		73,341				73,341		
2022	27604649	BRIDGER 2021C046 U0 REPLACE TRUCK SCALE 21/22					71,420	71,420		
2022	27580822	BRIDGER 2021C007 BLANKET - ELECTRICAL/INSTRUMENTATION 21					70,351	70,351		
2022	27587061	BRIDGER 2021C028 U2 SDCC TU/SUB IDLER REPLACEMENT 21		70,268				70,268		
2022	27549365	BRIDGER 2020C029 BLANKET UPGRADE 7.2 KV MAGNEBLAST BREAKE					66,506	66,506		
2022	27600040	BRIDGER 2022C006 U2 REPLACE PRECIP/SCRUB EXPANSION JOINT		65,394				65,394		
2022	27607055	BRIDGER 2022C038 U2 SDCC LINER / SHELL REPLACEMENT 22		63,141				63,141		
2022	27589306	BRIDGER 2021C010 U0 BLANKET - PLANT LIGHTING IMPROVEMENTS 21					59,719	59,719		
2022	27607054	BRIDGER 2022C038 U2 SDCC INSTALL LINER AT CHAIN GUARD 22		59,698				59,698		
2022	27615665	BRIDGER 2022C054 U0 RPLC LARGE SECONDARY CRUSHER ROTOR 22					49,677	49,677		
2022	27597950	BRIDGER 2022C007 U2 REPLACE DOGBONE EXPANSION JOINTS 22		48,066				48,066		
2022	27600042	BRIDGER 2022C010 U2 SDCC REPLACE DEWATERING SLOPE 22		47,534				47,534		
2022	27615669	BRIDGER 2022C060 U1 REPLACE SDCC DRIVE SHAFT 22	47,001					47,001		
2022	27566763	BRIDGER 2020C096 U2 STACK OPACITY MONITOR HEATING		46,005				46,005		
2022	27578627	BRIDGER 2021C015 U0 BLANKET - UNDERGROUND IPS / HYDRANTS 21					42,973	42,973		
2022	27578625	BRIDGER 2021C006 U4 BLANKET UPGRADE 7.2 KV MAGNEBLAST BREAKE				42,838		42,838		
2022	27583200	BRIDGER 2021C002 BLANKET - MOTORS 21					41,186	41,186		
2022	27587062	BRIDGER 2021C027 U3 SDCC TU/SUB IDLER REPLACEMENT 21			39,601			39,601		
2022	27587057	BRIDGER 2021/C/032 CONVEYOR BELTS 21					39,461	39,461		
2022	27597941	BRIDGER 2021C048 U0 01 CLARIFIER COATING REPAIRS 21					35,038	35,038		
2022	27602396	BRIDGER 2022C039 U2 COAL PIPE REPLACEMENT 22		32,401				32,401		
2022	27607056	BRIDGER 2022C040 U2 PA DUCT INSPECT AND REPAIR 22		31,947				31,947		
2022	27600048	BRIDGER 2022C025 U0 BLANKET - ELECTRICAL / INSTRUMENTATION 2					31,694	31,694		
2022	27595024	BRIDGER 2021C043 U4 LAB PANEL INSTRUMENTATION 21				31,485		31,485		
2022	27617945	BRIDGER 2022/C/050 U0 BIRD LASER HAZING SYSTEM INSTALLATION					30,542	30,542		
2022	27597943	BRIDGER 2021C049 U4 #43 SCRUBBER OUTLET DUCT RECOAT 21				29,713		29,713		
2022	27600049	BRIDGER 2022/C/032 U0 CONVEYOR BELTS 22					29,076	29,076		
2022	27589308	BRIDGER 2021C033 U4 TURBINE BUILDING WINDOWS				28,712		28,712		
2022	27597939	BRIDGER 2021C047 U0 BLANKET SCR LPA SCREENS 21					28,314	28,314		
2022	27597932	BRIDGER 2021C041 U0 DCS SIMULATOR UPDATES 21					23,560	23,560		
2022	27507255	BRIDGER 2018C088 GREEN RIVER 3500 VIBRATION MONITORING SY					17,142	17,142		
2022	27503087	BRIDGER 2018C060 BLANKET UPGRADE 7.2 KV MAGNEBLAST BREAKE					16,893	16,893		
2022	27589304	BRIDGER 2021C008 U0 BLANKET - SHOP MACHINERY REPLACEMENT 21					15,065	15,065		

BRIDGER PLANT ADDITIONS: Jan 1, 2021 - Dec 31, 2022

Accounting Year	Project	Description	U1	U2	U3	U4	Common	Total	Purpose	Project Description/Justification
2022	27600045	BRIDGER 2022C020 U0 BLANKET - SMALL TOOLS 22					15,026	15,026		
2022	27602394	BRIDGER 2022C036 U2 REPLACE 22 MOISTURE SEPERATOR 22		14,799				14,799		
2022	27597938	BRIDGER 2021C045 U0 REPLACE MILL BOWL HEATER 21					13,466	13,466		
2022	27553266	BRIDGER 2020C016 BLANKET - PUMPS, VALVES, GEARBOXES 20					10,664	10,664		
2022	27615664	BRIDGER 2022/C/049 U0 REPLACE POST 1 TURNSTILES 22					10,277	10,277		
2022	27615841	BRIDGER CITC2019C603 WIRELESS BRIDGE REPLACEMENT					9,789	9,789		
2022	27597962	BRIDGER 2022C021 U0 ADD LOOP 3440-C CHANNEL BANK 22					9,498	9,498		
2022	27591387	BRIDGER 2019C034 U0 REPLACE ROOFING SYSTEM 21					9,124	9,124		
2022	27573808	BRIDGER 2021C004 U0 BLANKET - SMALL TOOLS 21					8,750	8,750		
2022	27589307	BRIDGER 2021C029 U0 BLANKET MCC UPGRADES 21					8,061	8,061		
2022	27617947	BRIDGER 2022/C/052 U0 REPLACE CATHODIC PROTECTION ANODE BED					8,023	8,023		
2022	27583202	BRIDGER 2021C018 U0 GAS PROBE CHANGEOUT 21					7,881	7,881		
2022	27602390	BRIDGER 2022C029 U0 BLANKET - OFFICE EQUIPMENT 22					7,378	7,378		
2022	27597935	BRIDGER 2021C044 U0 REPLACE BOTH CONTROL ROOM CARPET 21					7,143	7,143		
2022	27553272	BRIDGER 2020C002 U4 UPGRADE COOLING TOWER VFDS 20				5,974		5,974		
2022	27575653	BRIDGER 2021C012 BLANKET - MILLS, PULVERIZER VERTICAL SHA					5,744	5,744		
2022	27566691	BRIDGER 2020C053 U0 PLANT LIGHTING IMPROVEMENTS 20					5,540	5,540		
2022	27501256	BRIDGER 2018C064 U1 FLAME SCANNER 18	5,456					5,456		
2022	27615666	BRIDGER 2022C055 U4 REPLACE SHOP DOOR 22				5,281		5,281		
2022	27580826	BRIDGER 2021C022 BLANKET LCC SWITCHGEAR & XFMR UPGRADES 21					3,749	3,749		
2022	27524338	BRIDGER 2018C130 U2 MAIN TURBINE OVERSPEED UPGRADE.		2,868				2,868		
2022	27527164	BRIDGER 2019C057 BLANKET - REPLACE SUPPORT EQUIPMENT 19					2,320	2,320		
2022	27549348	BRIDGER 2020C006 U4 PRECIPITATOR TR & CLR REPLACEMENT 20				2,277		2,277		
2022	27541813	BRIDGER 2019C091 U4 SCR CATALYST REPLACEMENT 20				2,085		2,085		
2022	27551447	BRIDGER 202C051 DCS SECURITY SERVER UPGRADES 20					1,744	1,744		
2022	27479282	BRIDGER 2017C029 U2 BFPT TRIP SYSTEM 17		1,618				1,618		
2022	27559520	BRIDGER 2020C082 U4 LOADOUT CONVEYOR PLATFORM				1,054		1,054		
2022	27597929	BRIDGER 2021C025 U2 SDCC REPLACE FLIGHTS 21		997				997		
2022	27578675	BRIDGER CITC2021C202 2021 CONSOLIDATED PC TOM					790	790		
2022	27483924	BRIDGER 2017C068 SCRAPER REBUILD 17					724	724		
2022	27549359	BRIDGER 2020C015 U4 #42 BOILER FEED PUMP REBUILD 20				611		611		
2022	27604694	BRIDGER CITC2020C305 U0 UPS TOM 2020					527	527		
2022	27559765	BRIDGER TSYS/2017/C/864 NERC PRC-002/MOD-033 SYS UPGRADE					498	498		
2022	27475628	BRIDGER 2017C017 U2 REPLACE SCRUBBER DUCT DRAIN/SEAL POTS		409				409		
2022	27487476	BRIDGER 2017C031 COMMON ANNUNCIATORS TO DCS 17					258	258		
2022	27483897	BRIDGER 2017C047 U2 CIRC WTR PMPS CONTINUOUS VIBRATION 1		225				225		
2022	27483894	BRIDGER 2017C034 U2 NETWORK HARDWARE UPGRADE 17		44				44		
2022	27587059	BRIDGER 2021C031 U4 SCR OUTLET NEMS PLATFORMS				15		15		
2022	27517677	BRIDGER 2018C055 REPLACE FIRE EXTINGUISHERS 18					11	11		
2022	Various	CORRECTIONS ASSOCIATED WITH INVESTMENTS PRIOR TO 2021	(13,114)	(51,420)	(30,577)	(244,470)	(229,270)	(568,851)		
2022 Total			**39,342**	**677,342**	**87,965**	**(94,425)**	**1,025,873**	**1,736,097**		
Grand Total - Projects Under $100k			**55,046**	**779,892**	**102,487**	**1,075,664**	**2,334,549**	**4,347,638**		
Total Projects (2021 - 2022)			**55,046**	**3,938,741**	**102,487**	**10,101,859**	**5,130,175**	**19,328,308**		

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MITCH COLBURN

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Mitch Colburn. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Vice President of Planning, Engineering, and Construction.

Q. Please describe your educational and professional experience.

A. I graduated from the University of Idaho in 2006 with a Bachelor of Science degree in Electrical Engineering, Summa Cum Laude. Thereafter, I obtained a Master of Engineering degree in Electrical Engineering from the University of Idaho in 2010 and a Master of Business Administration from Boise State University in 2015. I am a licensed Professional Engineer in the State of Idaho.

I have worked at Idaho Power since 2007. Prior to my current role, I served as Director of Engineering and Construction, Director of Resource Planning and Operations, Senior Manager of Transmission & Distribution Strategic Projects, Engineering Leader over 500 kilovolt ("kV") and Joint Projects. I held several engineering roles prior to these leadership roles.

Q. What are your duties as Vice President of Planning, Engineering, and Construction?

A. I am responsible for an organization of more than 380 employees focused on multiple areas:

1) Identifying future electric grid infrastructure requirements,

2) Operating and maintaining the electric grid, including the wildfire mitigation program and vegetation management, and

3) Designing, engineering, and constructing grid infrastructure projects.

Q. What is the purpose of your testimony in this matter?

A. The purpose of my testimony is to discuss the investments the Company has made in the electrical grid to ensure the provision of safe, reliable service to customers. My testimony will begin with a discussion of Idaho Power's recent history of reliability and performance that demonstrates a thoughtful approach to grid construction and maintenance. Next, I will detail specific investments included in the Company's 2023 test year that demonstrate the Company's prudent investment in the electrical grid at the transmission and distribution ("T&D") levels. Finally, my testimony will review the Company's wildfire mitigation efforts and associated capital and operation and maintenance ("O&M") expenditures proposed for recovery in this case.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibit Nos. 4 and 5.

I. **Reliability and Performance**

Q. How is reliability typically measured on the Company's system?

A. As discussed in the Direct Testimony of Company Witness Ms. Lisa Grow, Idaho Power primarily uses four indices to measure reliability of the system. To summarize the information provided by Ms. Grow, these four measurements are:

SAIFI: System Average Interruption Frequency Index

SAIDI: System Average Interruption Duration Index

CEMI: Customers Experiencing Multiple Interruptions

MAIFI: Momentary Average Interruption Frequency Index

Q. Please provide a brief description of each of these measures.

A. SAIFI, SAIDI, and CEMI are indices that measure sustained outages. A sustained outage is defined as customers out of power for five minutes or longer. CEMI is typically referred to as "CEMI-1" through "CEMI-6," where CEMI-1 indicates the percentage of customers who had one or more outage, CEMI-2 indicates the percentage of customers who had two or more outages, and so on. MAIFI is an index that measures momentary interruptions. Momentary interruptions are when customers are out of power for fewer than five minutes.

Q. Based on these metrics, has Idaho Power demonstrated prudent and reliable operation of the electrical grid?

A. Yes. As detailed in Ms. Grow's testimony, Idaho Power's SAIFI metric has improved substantially since 2007. On a relative basis, a comparison of Idaho Power's rolling five-year average SAIFI compared to a peer utility group demonstrates that the Company outperformed its peers in each year since 2017.

Q. Has Idaho Power shown similar improvement in MAIFI, SAIDI, and CEMI?

A. Yes. Each of these metrics has improved across Idaho Power's system for the prior 10-year period, as demonstrated in Figures 1 through 3.

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FIGURE 1
SAIDI, 2007 THROUGH 2022

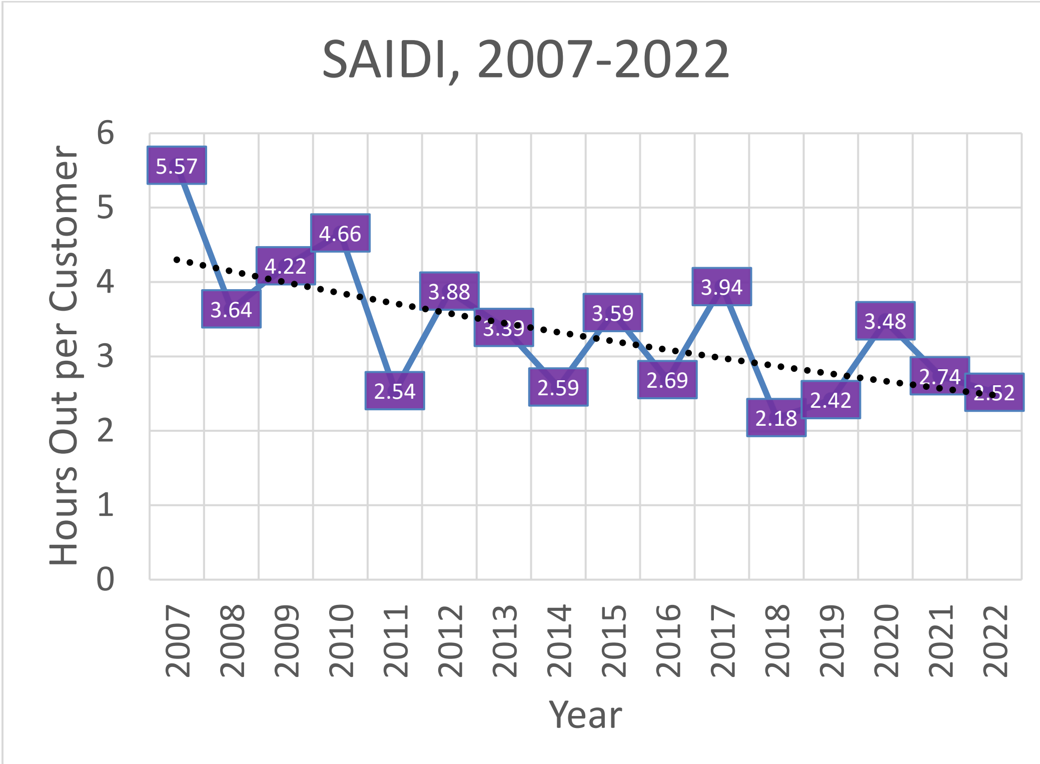


FIGURE 2
MAIFI, 2007 THROUGH 2022

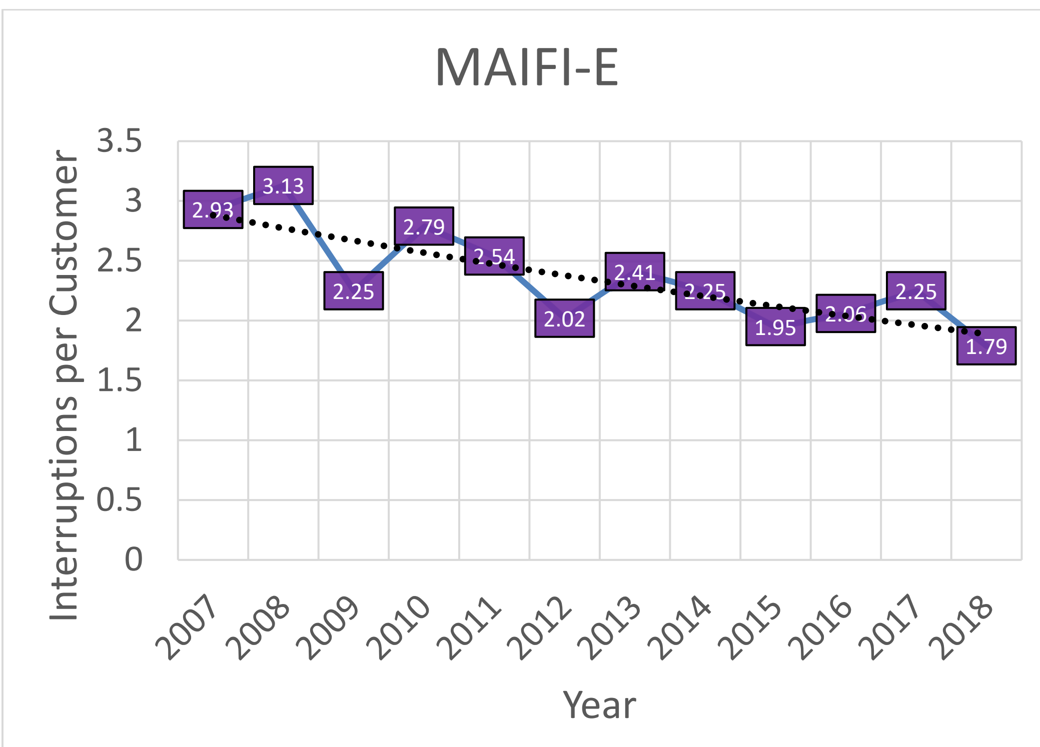


FIGURE 3

CEMI 3 AND CEMI 6, 2007 THROUGH 2022

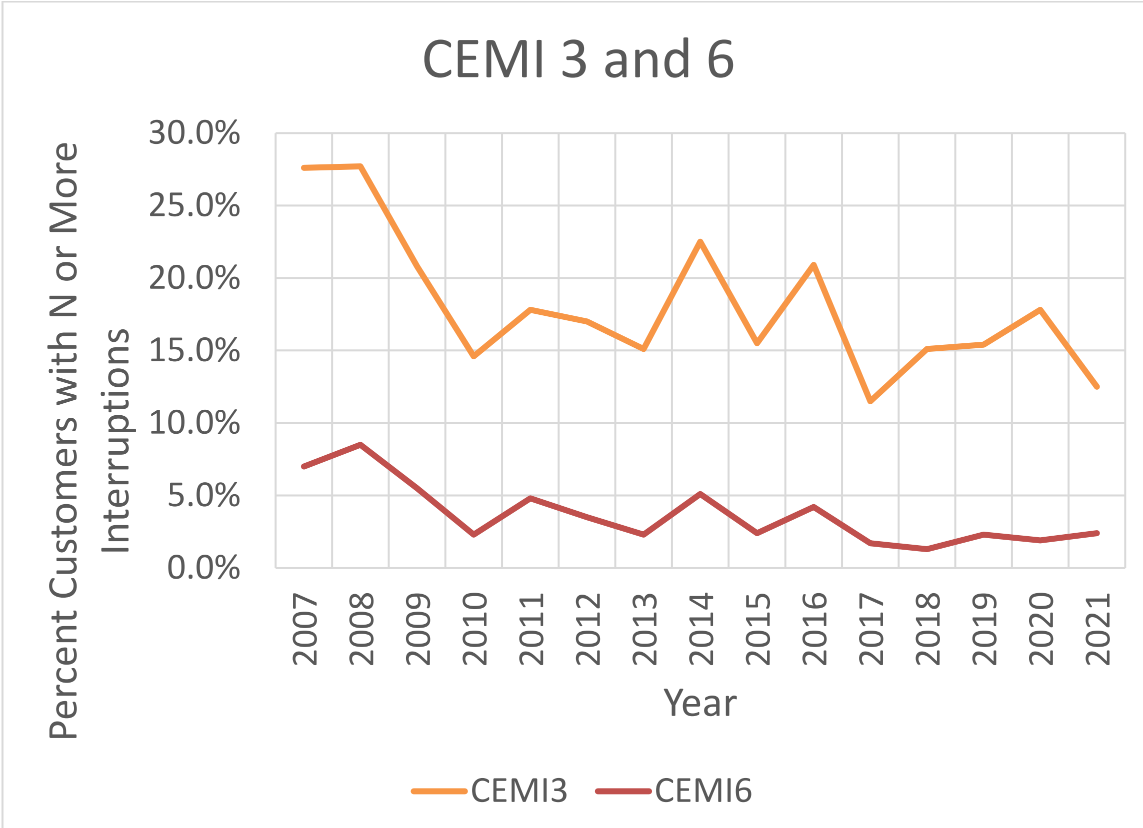
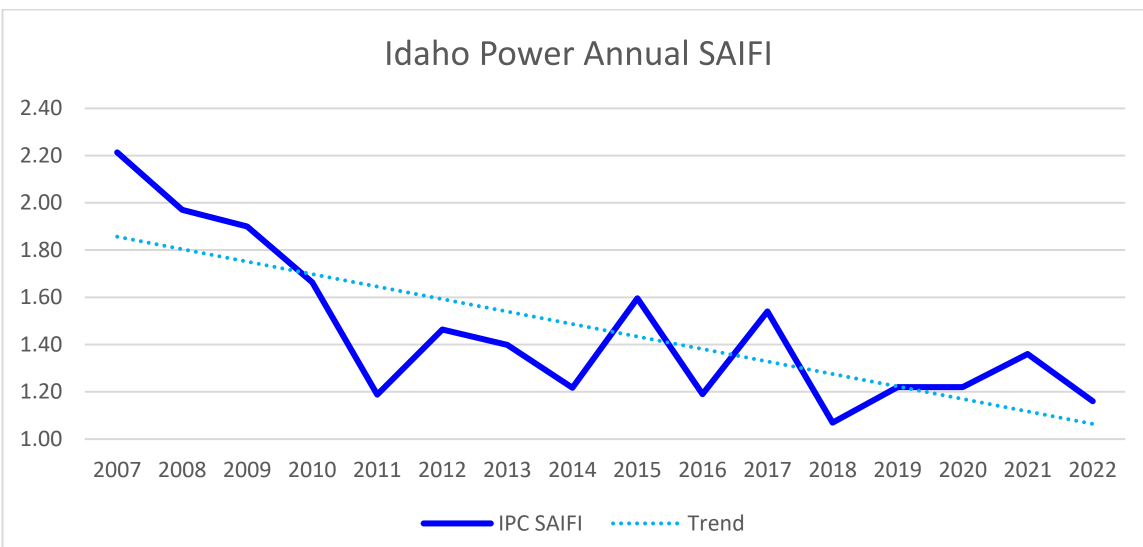


FIGURE 4

SAIFI, 2007 THROUGH 2022



Q. Do these metrics indicate prudent construction and maintenance of the Company's distribution and transmission systems?

A. Yes. Idaho Power's reliability metrics reflect a thoughtful approach to construction and maintenance of its T&D systems. Since the completion of the Company's last general rate case ("GRC") in 2011 in Case No. IPC-E-11-08, the Company has placed in service over $3.3 billion in infrastructure. As I will discuss in my testimony, approximately $1.6 billion of this total reflects prudent investment in the T&D systems. The corresponding improvement in the Company's reliability metrics over this same period indicates that this investment was prudent to ensure the safe, reliable provision of electric service.

II. Transmission Investments

Q. Please describe how the Company defines the transmission-related portion of the electrical grid.

A. Transmission generally describes the bulk or high voltage components of the electrical grid, including stations and high voltage lines typically utilized to transmit large volumes of electricity closer to load centers. On Idaho Power's system, transmission equipment is considered to be facilities at or above 138 kV, with an additional sub-transmission component comprised of facilities at 46 kV and 69 kV.

Q. How has transmission-related investment grown since the completion of the 2011 GRC?

A. Of the $3.3 billion in infrastructure placed in service over this period, approximately $553 million reflects investment in the Company's transmission system.

Q. What drives investment in the transmission system?

A. Growth and reliability are the primary drivers of the transmission investments reflected in the Company's 2023 test year. Growth-related projects typically include either the construction of new transmission facilities or the expanded capacity of existing facilities. Reliability projects typically include the proactive reconstruction or replacement of aging facilities.

Q. Please provide examples of growth and reliability needs driving investment in the Company's transmission system between 2012 and 2022.

Q. Based on the growth experienced by Idaho Power over this period, investment has been required to ensure reliability on the Company's transmission system. Two projects that demonstrate how growth drives transmission investment are the rebuild of the 59-mile transmission line between the King Substation and the Wood River Substation in the Wood River Valley ("King-Wood River Rebuild") and the upgrade of the 6.8-mile transmission line between the Cloverdale Substation and the Hubbard Substation in the Treasure Valley ("Cloverdale Line Rebuild").

Q. What factors led to the King-Wood River Rebuild?

A. Growth in the Wood River Valley was causing strain on the regional grid. Specifically, transmission planning studies required[1] by the North American Electric Reliability Corporation ("NERC") and dating back to 2009 demonstrated the need for transmission system upgrades to maintain adequate system voltage in the future and avoid needing to shed load for certain system conditions. To comply with NERC standards and to ensure the Company's reliability metrics provided earlier in my testimony did not degrade, investment in the local area transmission system was necessary.

Q. What actions did Idaho Power take to ensure the reliability of its transmission system?

A. In response to the identified need, Idaho Power rebuilt the line between the King and Wood River substations, upgrading the capacity of the line. Additionally, for enhanced reliability the Company replaced

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[1] NERC TPL-001 Reliability Standard (Table 1 – Steady State & Stability Performance).

the existing wood structures with steel components. This investment was required to ensure that system reliability was maintained while accommodating growth in the area.

Q. Did similar factors lead to the Cloverdale Line Rebuild in the Treasure Valley?

A. Yes. Similar factors led to the Cloverdale Line Rebuild, further exemplifying how growth drives the need for investment to maintain a robust, reliable transmission system. In 2015, NERC-required transmission planning studies demonstrated the need for a 230-kV connection between the Hubbard and Cloverdale substations, whereas the existing line was 138 kV. The study showed that growth in the area had resulted in expected loads under certain conditions exceeding emergency equipment rating limits.

Q. What actions did Idaho Power take to address the reliability needs identified by this study?

A. In response to the growth-driven reliability requirements in the area, Idaho Power upgraded the local-area capacity by replacing the existing 138-kV line with a 230-kV circuit, as well as constructing distribution circuits located on the same structures as the 230-kV transmission line. This upgrade reflected a cost-effective solution to meet the requirements of growing load in the

Treasure Valley, enhancing and maintaining reliability of the local transmission system.

Q. Can you provide an example of transmission investment driven by the Company's proactive approach to aging infrastructure?

A. Yes. The Company's work on the Midpoint-to-Borah 345-kV transmission line demonstrates the need to invest in maturing longer-lived assets to ensure ongoing safe and reliable operation of the grid.

Q. Please describe the Midpoint-to-Borah transmission line.

A. The Midpoint-to-Borah 345-kV transmission line serves as a major component of the Company's bulk transmission system. This line was originally constructed in 1948 and operated at 138 kV, and over the next several decades was modified and improved to its current operating capacity of 345kV. Enhancements to the line over this period included an increase in capacity due to the addition of the Jim Bridger Power Plant, which included the addition of a second conductor, conductor re-configuration on the structures, and adding additional insulation to operate at a higher voltage. However, as the transmission line aged, issues began to arise related to ground clearance and leaning structures.

Q. What action was required to address this aging and important component of the Company's bulk transmission system?

A. The age and importance of this line warranted complete replacement of the structures from the Midpoint Substation to the Borah Substation. The existing wood-pole structures were replaced with steel-pole structures, remedying the potential structural issues by installing resilient, long-life steel poles.

Q. Do the projects you have discussed demonstrate a prudent approach to investment in the Company's transmission system over the last decade, and support the Company's transmission-related rate base included in this case?

A. Yes. Over the last decade Idaho Power has invested over $553 million in its transmission system. As evidenced by the King-Wood River Rebuild and Cloverdale Line Rebuild projects, Idaho Power is constantly evaluating the capacity needs and reliability of its transmission systems, ensuring that the electrical grid is stable and in compliance with NERC standards. As further evidenced by the Midpoint-to-Borah Rebuild, Idaho Power's investments in the transmission system over the last decade reflect a thoughtful, proactive approach to ensuring bulk system reliability. As evidenced by the improving reliability metrics experienced over this same period, these investments were prudently made and in the public interest.

III. Distribution Investments

Q. Please describe how the Company defines the distribution-related portion of the electrical grid.

A. Distribution refers to equipment at 34.5 kV and below, including lower voltage lines, substations, and transformers that are typically utilized to provide electricity at the lower voltages required by the majority of end-use customers.

Q. How much has distribution-related investment grown since the completion of the 2011 GRC?

A. Of the $3.3 billion in plant placed in service referenced previously in my testimony, approximately $1.0 billion is comprised of investments in the distribution system.

Q. What factors contributed to investment in Idaho Power's distribution system over this period?

A. Growth in the distribution system can be directly tied to the addition of new customers, as every new customer, regardless of service level, requires some form of additional equipment. In addition, similar to certain components of the Company's generation and transmission systems, Idaho Power has also undertaken a number of key projects to proactively harden its distribution system to maintain and improve reliability in light of aging infrastructure. These investments not only include the proactive replacement of aging infrastructure, but also the improvement of the distribution system through the installation of modern technology.

Q. How does growth impact the need for investment on the distribution system?

A. Growth impacts the distribution system in several ways. First, the addition of new customers requires new investment – from new service transformers and service drops for every new customer to, once demand reaches certain levels, new substations and lines. Additionally, construction and growth within the Company's service area also result in the need for investment related to facility relocations for road construction and other civil projects.

Q. What were the primary growth-related components of distribution investment made over the last decade?

A. Growth-related investment in the Company's distribution system consisted primarily of meters, transformers, and other distribution infrastructure in each of the Company's operating regions. In addition to new facilities, Idaho Power spent approximately $25 million related to the relocation of facilities as the result of road projects in the Company's service area.

Q. In addition to serving growth, has Idaho Power undertaken any major initiatives to maintain or improve the reliability of its distribution system?

A. Yes. There are two notable initiatives Idaho Power has undertaken to improve the reliability of its distribution system: 1) the replacement of direct-buried underground cable and 2) a grid modernization initiative that encompasses multiple projects.

Q. Please describe what is meant by "direct-buried cable."

A. Direct-buried cable describes underground distribution cable that was directly buried in the soil with no conduit. The use of direct-buried cable was standard practice in the industry and for Idaho Power up until the mid-1990s.

Q. What are the benefits of replacing direct-buried cable with new cable in conduit?

A. Replacing the existing direct-buried cable with new cable in conduit improves reliability and lowers future expenses when the cable needs to be replaced.

Q. How does the installation of cable with conduit improve reliability?

A. Cable in conduit is better protected from impacts related to direct contact with soil and moisture.

Consequently, faults are less frequent and cable in conduit is expected to last longer than direct-buried cable.

Q. How does the installation of cable in conduit help to lower future expenses when the cable needs to be replaced?

A. The installation of conduit allows the Company to replace the cable within the conduit more effectively and cheaply. With conduit in place, the cable can be removed from the conduit and new cable can be installed more efficiently. This will help to eliminate fees and expenses associated with permitting, flagging, landscaping and repaving roads and sidewalks.

Q. How far has Idaho Power's underground cable replacement project progressed?

A. The underground cable replacement program began in 2012 with completion forecasted for 2035, targeting the replacement of approximately 350,000 feet of direct-buried cable each year until all 7 million feet of direct-buried cable have been replaced. To date, the Company has completed approximately 4 million feet of cable replacement.

Q. Please describe the grid modernization initiative.

A. The grid modernization initiative is a set of multi-year projects designed to maintain and improve reliability on the Company's electrical grid. This suite of projects replaces and modernizes equipment nearing its end of life and updates the Company's distribution system with modern technology to enhance reliability while keeping costs low.

Q. What notable projects comprise grid modernization efforts included in the 2023 test year?

A. Two notable projects under the Company's grid modernization initiative are the implementation of a new 700-megahertz ("MHz") Field Area Network ("FAN") and replacement of an Automated Capacitor Control ("ACC") system with the development of a new integrated volt-var control ("IVVC") system. The IVVC system and FAN became operational in 2019 and were built out across Idaho Power's service area by 2022.

Q. What are the FAN and the IVVC system, and how do they interrelate?

A. The 700-MHz FAN serves as the communication backbone for the IVVC system. The 700-MHz FAN is utilized to send and receive secure, reliable wireless communications to and from line devices on Idaho Power's distribution system. This communication supports the gathering of data and control of distribution system devices within the IVVC.

Q. How does the IVVC system benefit customers?

A. The IVVC system replaced a 22-year-old DOS-based system that was nearing its end of life and was unable to provide for direct and coordinated voltage control offered by more modern systems such as the IVVC system. Replacing the ACC with the IVVC provides the Company with the ability to better control devices and gather data in real-time, allowing the Company to improve power quality and voltage levels, optimize efficiency, and provide visibility and control to engineers and operators to better manage the distribution system.

At a high level, the IVVC system provides direct feedback on the status of devices through two-way communication, which reduces the need for seasonal inspections, instead allowing for inspections to focus on alarmed devices. This system is also the foundation for a future fault location, isolation, and service restoration ("FLISR") system. Idaho Power is in the process of installing fault location devices on the distribution system, which is prevalent in the industry.

Q. Do these projects demonstrate a prudent approach to investment in the Company's distribution system over the last decade and support the Company's distribution-related rate base included in this case?

A. Yes. Idaho Power's thoughtful and proactive approach to investing in its distribution system has resulted in improved reliability metrics over the past decade as detailed earlier in my testimony. In addition to investing to accommodate growth within the Company's service area, Idaho Power invested in initiatives such as underground cable replacement and grid modernization that ensure the distribution system is equipped to provide safe, reliable service to customers now and in the future.

IV. **Idaho Power's Wildfire Mitigation Efforts**

Q. What total system costs did the Company incur related to wildfire mitigation in 2022?

A. As outlined below in Table 1 of my testimony, Idaho Power incurred a systemwide total of $26,408,743 in wildfire mitigation-related O&M costs in 2022. This amount excludes insurance, which is discussed in the Direct Testimony of Company Witness Mr. Brian Buckham.

Regarding capital expenditure, Idaho Power placed in service $12,059,451 in capital projects to support wildfire mitigation in 2021 and 2022. This amount does not include capital depreciation, which is addressed in the Direct Testimony of Company Witness Mr. Matthew Larkin.

Capital placed in service for 2021 and 2022 and O&M expenditure for 2022 is detailed in Exhibit No. 4 to my testimony.

Q. Are the Company’s actual 2022 costs related to wildfire mitigation reflected in the Company’s revenue requirement in this case?

A. Yes. The costs identified in my testimony are factored into the Company’s 2023 test year revenue requirement, as addressed in Mr. Larkin’s testimony. Additionally, the treatment and accounting of the Commission’s authorized wildfire deferrals are addressed in the Direct Testimony of Company Witness Ms. Paula Jeppsen.

The remainder of my testimony in this section will present the Company’s implementation of its Wildfire Mitigation Plan (“WMP”) and will demonstrate the prudence of the associated costs proposed for recovery in this case. I will focus on costs incurred during 2022, as those costs represent previously deferred amounts proposed for amortization into rates in this case and form the basis for the test year values addressed by Mr. Larkin.

Q. Why did Idaho Power develop a WMP?

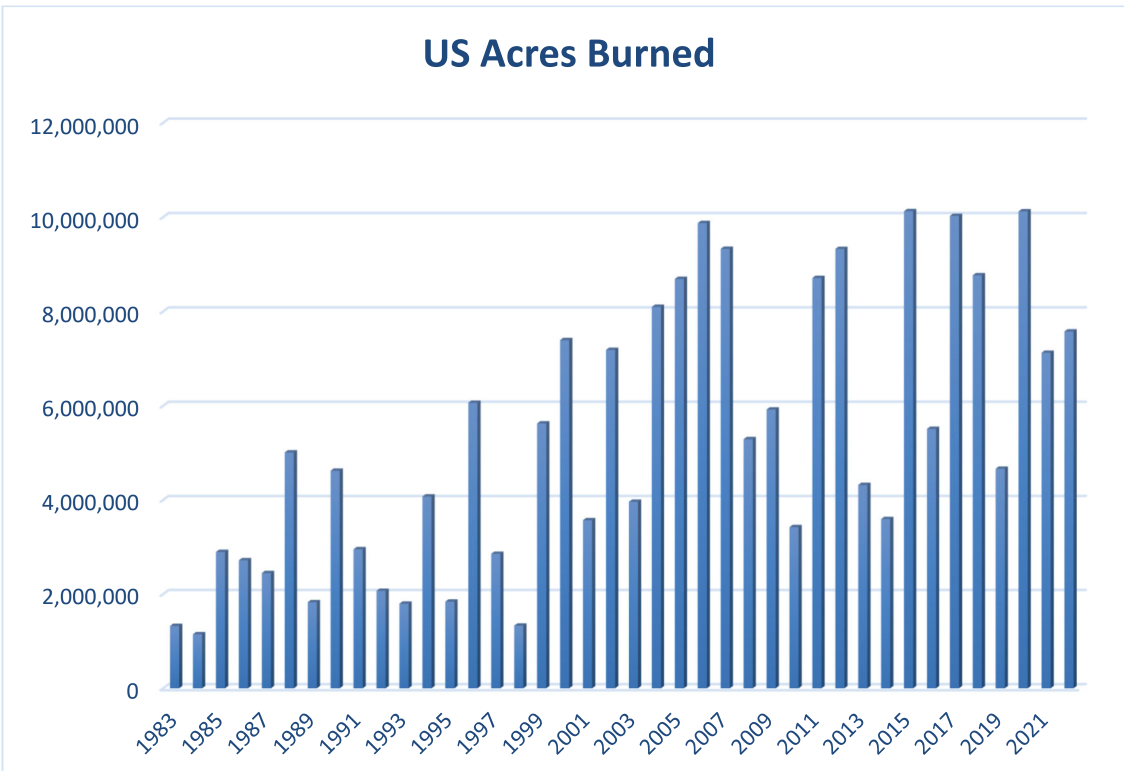
A. Idaho Power is dedicated to safely delivering reliable, affordable energy to its customers. In pursuit of that mission, the Company developed a WMP in response to the increase in frequency and intensity of wildfires seen across the western United States (“US”) in recent years.

Q. To what extent has wildfire activity increased in the West?

A. Since the 1980s, wildfire activity in the US, as measured by acres burned, has more than tripled and, according to the National Interagency Fire Center, western states account for upwards of 95 percent of the acres burned in recent years.[2] Since 1983, the 10 years with the largest acreage burned have all occurred in the period of 2004 through 2022.[3]

FIGURE 5

TOTAL US ACRES BURNED (1983-2002)



Q. What has contributed to the growth of western wildfires in recent years?

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[2] Based on the National Interagency Fire Center historical year-end fire statistics by state. https://www.nifc.gov/fire-information/statistics

[3] Based on the National Interagency Fire Center total wildland fires and acres (1983-2022). https://www.nifc.gov/fire-information/statistics https://www.nifc.gov/fire-information/statistics/wildfires

A. A variety of factors have contributed to a greater number of destructive wildfires, including climate change, increased human encroachment in wildland areas, historical land management practices, and changes in wildland and forest health, among other factors.

Q. How has Idaho Power been affected by the increase of wildfires in the West?

A. While Idaho Power has not experienced catastrophic wildfires within its service area at the same level experienced in other western states, such as California and Oregon, millions of acres of rangeland and southern Idaho forests have burned in the last 30 years.[4]

In 2022, Idaho had fewer wildfires and acres burned during wildfire season than the previous 20-year average.[5] However, 436,733 acres burned in Idaho during the 2022 fire season, a larger amount than the combined acres burned in Arizona, Colorado, Montana, Nevada, Utah, and Wyoming in 2022.[6]

Q. What impacts could Idaho Power face because of wildfire?

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[4] Rocky Barker, *70% of S. Idaho's Forests Burned in the Last 30 Years. Think That Will Change? Think Again.*, Idaho Statesman, Oct 4, 2020.
[5] Based on the National Interagency Fire Center historical year-end fire statistics by state. https://www.nifc.gov/fire-information/statistics
[6] National Interagency Coordination Center Wildland Fire Summary and Statistics Annual Report, 2022. https://www.predictiveservices.nifc.gov/intelligence/2022_statssumm/annual_report_2022.pdf

A. Wildfire can create myriad and costly environmental, social, and economic impacts. The magnitude and duration of these impacts depends on a fire's size, severity, and location. Generally, though, wildfire impacts are considered in terms of lives threatened, structures or homes lost or damaged, and damage to natural resources.

Specific to Idaho Power, wildfires have the potential to damage or destroy the Company's facilities, impact personnel, and cause significant harm to Idaho Power's customers and the communities in which the Company serves.

Q. How has Idaho Power responded to growing wildfire risk?

A. As a result of growing and more frequent wildfires in the West, Idaho Power began a proactive effort in 2019 to develop a guiding wildfire mitigation document — the WMP — that would use robust risk analysis to identify areas within the Company's service area exposed to higher levels of wildfire risk. As an action plan for Company operations, the WMP includes best practices for mitigating wildfire risk that guide operational, personnel, and communication practices before, during, and after wildfire season.

Q. What are the objectives of the WMP?

A. Idaho Power developed the WMP to accomplish two critical objectives: (1) reduce wildfire risk associated with Idaho Power's T&D facilities and associated field operations and (2) improve the resiliency of the Company's T&D system impacted by wildfire events.

Q. How many WMPs has the Company developed?

A. In December 2022, the Company published its 2023 WMP (Exhibit No. 5), the Company’s fifth version of the WMP since 2021.

Q. Please describe the prior versions of the WMP.

A. Version 1 of the WMP was filed with the Commission in January 2021 in Idaho Power’s initial wildfire-related cost deferral Application in Case No. IPC-E-21-02. Version 2, dated December 21, 2021, included an expanded cost-benefit analysis discussion, WMP progress and updates, and an introduction to the Company’s newly developed Public Safety Power Shutoff (“PSPS”) program. Version 3, dated June 28, 2022, included information added to comply with the Public Utility Commission of Oregon’s conditions of approval of the Company’s 2022 WMP. Version 4, filed with the Company’s cost deferral Application in Case No. IPC-E-22-27, added Idaho and Oregon specific information and state-specific forecasts of incremental mitigation expenditure. Version 5, the current WMP for the 2023 fire season, includes a new executive summary, a review of the 2022 fire season with lessons learned, a forecast of condition for the upcoming fire season, and provides a detailed discussion of 2023 fire season mitigation measures.

Q. How will the WMP change from year to year?

A. Each year, the Company strives to improve upon previous versions by incorporating new learnings, methods, and feedback from stakeholders, customers, communities, fire experts, and the Company's regulators. Going forward, the Company will file its annual WMP with the Commission, as specified in Order No. 35717.[7] Moving forward and to reduce confusion, the Company will endeavor to avoid multiple versions of the WMP and, instead, release one plan in advance of each fire season.

Q. Please summarize the key elements of the WMP that help meet the Company's wildfire mitigation objectives.

A. Idaho Power's WMP includes comprehensive and multi-faceted strategies that are effective at reducing wildfire risk. Key elements of the plan include:

- <u>Risk analysis and mapping:</u> Utilizing a risk-based approach for decision making and quantifying wildfire risk throughout the Company's service area.

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[7] Case No. IPC-E-22-27, Order No. 35717, pp. 8-9 (Mar 23, 2023).

- Situational awareness: Informing Company operations and practices by incorporating new methods of visual, geographical, and contextual awareness of the environments in which Idaho Power operates, specifically during wildfire season.
- Mitigation activities: Expanding and/or enhancing many of the same programs that the Company has carried out over the course of its operating history to mitigate wildfire risk, decrease the likelihood of ignition events, and protect infrastructure from wildfire regardless of where it starts.
- Communication: Communicating with and educating customers and the public about wildfire and outage preparedness.
- Monitoring and tracking performance: Routine analysis of wildfire mitigation activities to gauge their effectiveness and build continuous improvement and risk reduction over time.

Q. How does Idaho Power ensure its WMP is informed by industry best practices?

A. Idaho Power recognizes the importance of engaging with federal, state, and local governments as an integral part of deciding on and implementing wildfire mitigation measures. The WMP documents specific activities and forums to engage with key stakeholders to share information, gain feedback, and incorporate lessons learned.

Much of Idaho Power’s service area extends over land managed by the US Bureau of Land Management (“BLM”) and the US Forest Service. As such, the Company engaged with these agencies in the development of the WMP and continues to hold meetings and workshops with them to share information and identify geographic areas and specific mitigation activities that are mutually beneficial.

Idaho Power is also a member of the Idaho Fire Board, which was initiated by the US Forest Service. Membership is voluntary and currently includes the Forest Service, BLM, the Federal Emergency Management Agency, Idaho State Lands Department, Idaho Department of Insurance, Idaho Military Division, City of Lewiston, the Nature Conservancy of Idaho, and Idaho Power. This group, like the efforts listed above, is also focused on sharing Idaho wildfire knowledge and best practices for wildfire mitigation.

Q. Did Idaho Power consult with other utilities to develop and inform its WMP?

A. Yes. Peer utility engagement was crucial in developing the WMP to ensure the Company’s efforts are consistent with best practices and aligned with its peers in the region. To inform the initial development of the

WMP, Idaho Power participated in multiple workshops with San Diego Gas and Electric, Southern California Edison, Pacific Gas and Electric, Sacramento Municipal Utility District, and PacifiCorp. The Company continues to engage with these utilities to learn about California's evolving practices.

In the Pacific Northwest, many utilities work collaboratively to understand and ensure commonality of their respective wildfire plans, while also accounting for the variation in each utility's unique service area. These utilities include Idaho Power, Avista Utilities, Portland General Electric, Rocky Mountain Power, Pacific Power, Chelan County Public Utility District, Puget Sound Energy, NV Energy, Bonneville Power Administration, and NorthWestern Energy.

Q. Does Idaho Power participate in any other collaborative efforts to inform and evolve its WMP?

A. Yes. Idaho Power is a member of both the Edison Electric Institute ("EEI") and the Western Electric Institute, both of which host workshops and conferences to help members discuss and compare their wildfire plans and mitigation efforts.

Additionally, Idaho Power's President and Chief Executive Officer Lisa Grow is an active member of EEI's Electricity Subsector Coordinating Council Wildfire Working

Group. This working group partners with the US Department of Energy and other government agencies to collectively minimize wildfire threats and potential impacts nationwide.

These industry collaboratives continue to prove valuable for sharing wildfire mitigation best practices and discussing new and existing technology related to wildfire mitigation.

Wildfire Risk Analysis & Selection of Mitigation Practices

Q. Was a risk-based approach used to determine the type and level of wildfire mitigation needed for Idaho Power's service area?

A. Yes. The Company followed a risk-based approach in identifying, analyzing, and selecting wildfire mitigation measures. The Company has integrated the practices and principles detailed in the International Standard ISO 31000, Risk Management Guidelines, to manage wildfire risk and meet the goals and objectives of the WMP.

Wildfire risk mitigation is an enterprise-wide effort, and risk reduction practices are integrated into normal business activities and decision making across the Company - from field personnel to executive officers.

Q. Please describe the Company's wildfire-based risk framework.

A. The Company takes a structured and effective approach to managing wildfire-related risk that includes the following:

- <u>Identify risk</u> – Recognize new and evolving threats and associated risk;
- <u>Analyze</u> – Understand new and evolving risk, including likelihood and consequence and any existing controls;
- <u>Evaluate</u> – Determine whether risk levels can be accepted or should have additional controls in place;
- <u>Mitigate</u> – Select appropriate risk treatment;
- <u>Monitor</u> – Continually check and review to determine effectiveness of mitigation practices and protocols; and
- <u>Communicate and consult</u>- Communicate, educate, and engage with stakeholders, customers, communities, and regulators about the Company's risk-based wildfire mitigation work.

Q. What methodology was used to quantify wildfire risk?

A. Idaho Power leveraged an external consultant — Reax Engineering — that specializes in assessing and quantifying wildfire risk to determine where wildfire risk is elevated within the Company's service area. The consultant used a risk-based methodology that incorporates weather modeling, wildfire spread modeling, and Monte Carlo simulations, among other modeling techniques.

This approach to modeling wildfire risk is not unique to Idaho Power. The California Public Utilities Commission("CPUC”) used the same modeling approach — and the same consultant — as part of its development of the CPUC Fire Threat Map. Other utilities in Oregon, Idaho, Nevada, and Utah have utilized similar modeling approaches to identify and quantify wildfire risk.

Q. What calculation does the Company use to determine elevated risk areas?

A. The Company’s wildfire consultant modeled wildfire risk considering a wildfire event's probability multiplied by its potential negative consequences or impacts, should that event occur. Expressed as a formula:

Wildfire Risk = Fire Probability x Consequence

The first term, Fire Probability, is based on fire volume (i.e., spatial integral of fire area and flame length) because rapidly spreading fires are more likely to escape initial containment efforts and become extended fires rather than slowly developing fires. The second term, Consequence, reflects the number of structures (i.e., homes, businesses, and other man-made structures) that could be impacted by a wildfire.

Q. How does this equation translate to elevated risk areas?

A. Using the formula noted above, areas of highest wildfire risk will be those in which both Fire Probability and Consequence are elevated. Conversely, combinations of low Fire Probability and elevated Consequence (or elevated Fire Probability but low Consequence) will not typically be areas with highest risk.

Detailed discussion of the risk formula, including modeling and model inputs, is provided in Exhibit No. 5.

Q. What are the results of the wildfire risk modeling?

A. Using the above methodology and risk formula, Idaho Power and its consultant identified specific geographic areas across its service area and transmission corridors. The Company then sorted these areas into tiers — Yellow Risk Zones, reflecting increased risk, and Red Risk Zones, reflecting highest risk. Red Risk Zones — such as those in the Boise foothills and around Payette Lake in McCall — were determined to have the greatest wildfire risk based on the combination of Fire Probability and Consequence, while Yellow Risk Zones have elevated risk but may have reduced Fire Probability and/or Consequence relative to Red Risk Zones.

These risk zones are the foundation of Idaho Power's wildfire risk mitigation strategies and are used to prioritize targeted investments, vegetation management work, inspection activities, and situational awareness.

Q. How much of the Company's service area is in elevated wildfire risk zones?

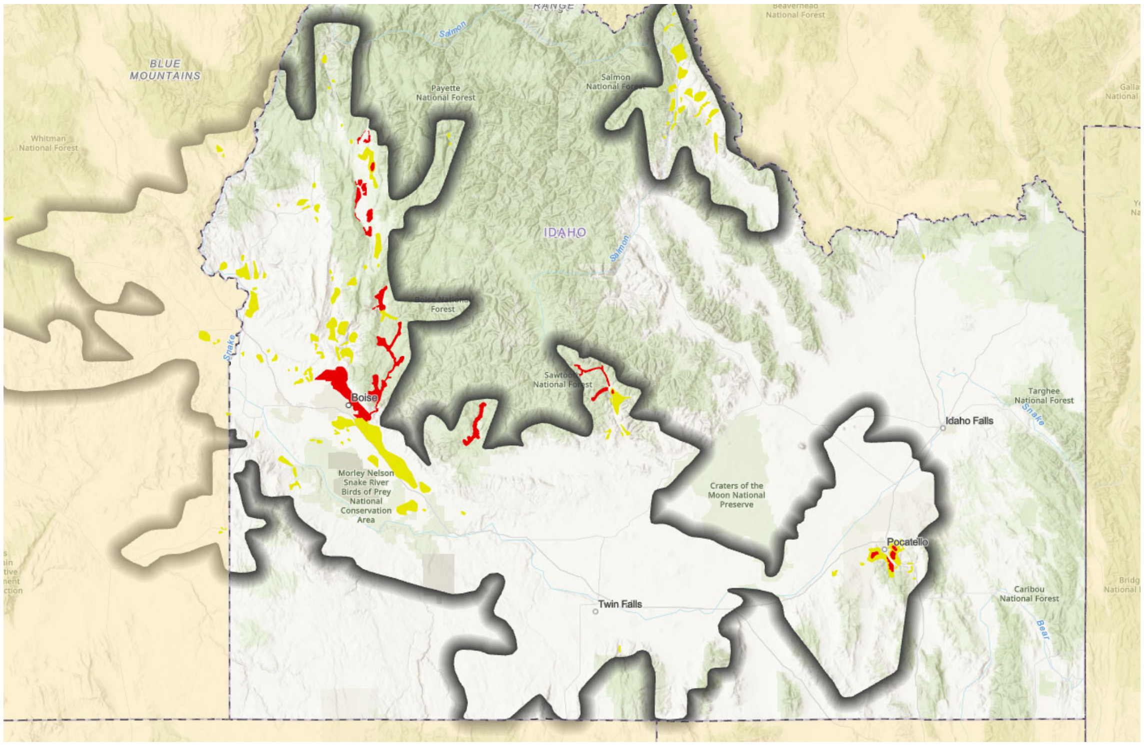
A. Approximately 7 percent of the Company's overhead distribution and 11 percent of transmission lines are located within wildfire risk zones. These geographical areas include approximately 47,000 customers.

Q. Does the Company visualize its elevated risk areas?

A. Yes. Based on the wildfire risk analysis, Idaho Power developed a risk map, shown below, that reflects the two tiers of increased wildfire risk within the Company's service area. The map — provided on Idaho Power's website — is available publicly and accessible to Public Safety Partners to educate and inform them about the Company's elevated risk areas.

FIGURE 6

IDAHO POWER WILDFIRE RISK MAP



Q. How have these wildfire risk zones informed the Company’s wildfire mitigation projects?

A. The Company’s wildfire mitigation activities are specifically targeted at reducing wildfire risk in elevated risk areas, with Red Risk Zones given priority due to the increased level of risk associated with higher fire probability and potential impact to structures.

Q. What types of mitigation activities is the Company pursuing?

A. Based on the risk identified in the Company’s risk assessment, Idaho Power developed and grouped its wildfire mitigation work into the following categories: A) quantifying wildland fire risk; B) situational awareness; C) mitigation associated with field personnel practices; D) mitigation activities within Idaho Power's T&D programs; E) enhanced vegetation management; F) communication; and G) information technology. Idaho Power's specific activities in these categories, as well as actual 2022 O&M and capital expenditures, are described in the sections below.

Wildfire Mitigation O&M Expense

Q. Please describe Idaho Power's system O&M expenses for wildfire mitigation in 2022.

A. The table below summarizes Idaho Power's total systemwide O&M expenses by wildfire mitigation category for 2022:

TABLE 1

WILDFIRE MITIGATION O&M IN 2022

Wildfire Mitigation Category	Program Activity	2022 Actuals
Quantifying Wildland Fire Risk	Risk Analysis and Map Updates	$4,125
Situational Awareness	Weather Forecasting - System Development, Support, and Personnel	$156,201
Mitigation - Field Personnel Practices	Tools/Equipment	$10,720

Mitigation - Transmission & Distribution Programs	O&M Component of Capital Work	$898,966
	Annual O&M T&D Patrol Maintenance Repairs	
	Environmental Management Practices	
	T&D Thermography Inspection Mitigation & Personnel	
	Transmission Wood Pole Fire Resistant Wraps - Red Risk Zone	
	Transmission Wood Pole Fire Resistant Wraps - Yellow Risk Zone	
	Wildfire Mitigation Program Manager	
	Covered Wire Evaluation - Pilot Program in PSPS Zones	
Enhanced Vegetation Management	Transition to/Maintain 3-Year Vegetation Management Cycle	$25,151,422
	Enhanced Practices for Distribution Red & Yellow Risk Zones (Pre-Season Patrols/Mitigation, Pole Clearing, Removals, Work, QA)	
	Line Clearing Personnel	
	Vegetation Management Satellite and Aerial Patrols	
Communications	Wildfire/Wildfire Mitigation Communications - Advertisements/Meetings/Other	$106,779
	PSPS Customer Education/Communication - Advertisements, Bill Inserts/Other	
Information Technology	Communication/Alert Tool development (System set up, outage maps, critical facilities identification)	$80,531

O&M: Quantifying Wildfire Risk

Q. Why did the Company choose to use a consultant to quantify wildfire risk in its service area?

A. The Company selected Reax Engineering for its recognized expertise in wildfire risk modeling and fire science. Hiring an outside consultant helped ensure Idaho Power's risk analysis would be developed in a manner consistent with and comparable to peer utilities.

Q. Was it prudent for the Company to hire an external consultant to develop the wildfire risk analysis?

A. Yes. Hiring an external consultant was a prudent Company decision for two reasons. First, it was more cost effective than hiring additional internal resources with specialized experience in wildland fire behavioral modeling. Second, hiring a nationally recognized consultant provides confidence that the Company's risk areas — the basis for all its wildfire mitigation work—were determined using the best and latest wildfire modeling techniques.

Q. How much did the Company spend to quantify wildfire risk in 2022?

A. The Company's wildfire risk analysis was first conducted in 2020. Every two years the Company intends to work with Reax Engineering to refine the risk analysis, adjust as warranted, and update its risk maps. In 2022, the Company spent $4,125 on external consultant activities to update and refine its wildfire risk map.

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O&M: Situational Awareness

Q. What efforts and activities did the Company conduct in 2022 to enhance situational awareness during wildfire season?

A. The Company's situational awareness activities in 2022 included refining its weather forecasting tools, installing weather stations, training new personnel to assist in the development and analysis of fire-season weather forecasts, and initial efforts to install wildfire detection cameras. Each of these activities is described in more detail below.

Q. How much did Idaho Power's situational awareness efforts cost in 2022?

A. The Company spent $156,201 on situational awareness in 2022.

Q. What is the Fire Potential Index ("FPI") and how does it reduce wildfire risk?

A. An essential component of Idaho Power's fire season work involves enhancing situational awareness by forecasting the FPI. This tool, which forecasts a wildfire risk level on a daily basis during fire season, supports operational decision-making to reduce wildfire threats and risks. For example, on days with a high FPI, automatic reclosing device settings are adjusted and field personnel modify work activities in Red Risk Zones.

The FPI tool accounts for weather, prevalence of fuel (i.e., trees, shrubs, grasses), and topography, and converts that data into an easily understood forecast of the short-term fire threat for different geographic regions in Idaho Power's service area. Additionally, the tool is used to help determine when a PSPS may be necessary in Idaho Power's service area.

The benefits of developing the FPI and enhancing the Company's meteorological forecasting capabilities is greater situational awareness of Idaho Power's system during critical peak summer months.

Q. How has Idaho Power enhanced its ability to forecast weather and fire conditions during wildfire season?

A. The Company has expanded and enhanced situational awareness by incorporating a new weather forecasting system that leverages an ensemble of weather models to improve accuracy and reduce forecast-to-forecast variability. The ensemble approach also provides a measure of certainty to better inform up-to-the-minute decision-making for the FPI and PSPS events. As such, the new system provides greater confidence in severe weather conditions and will allow Idaho Power to provide early PSPS notification to Public Safety Partners, operators of critical facilities, and affected customers. Additional personnel were leveraged to assist in the development and launch of this ensemble tool.

O&M: Field Personnel Practices

Q. Please describe the Company's wildfire mitigation efforts related to field personnel and associated spending in 2022.

A. In 2022, the Company trained its personnel in fire season conditions, practices, and operational modifications. The Company equipped its field crews with fire prevention tools and leveraged field observers to assess on-the-ground conditions.

In total, the Company spent $10,720 on mitigation efforts related to field personnel in 2022.

Q. Why are field personnel practices vital to wildfire risk reduction?

A. Idaho Power's field personnel and contractors work across the Company's service area, including in elevated risk areas. During wildfire season, the basic work, routines, preparatory activities, and preparedness of employees and contractors is paramount to minimizing the risk of ignition events.

Q. What field practices did Idaho Power establish for its employees and contractors during wildfire season?

A. Idaho Power developed a Wildland Fire Preparedness and Prevention Plan to provide guidance to

Idaho Power employees and contractors specifically for operating during wildfire season. The plan includes information regarding fire season tools and equipment available on the job site; daily situational awareness relative to areas with heightened fire conditions; expected actions and mechanisms for reducing on-the-job wildfire risk as well as reporting requirements in the event of an ignition; and training and compliance requirements.

All Idaho Power crews, and certain field personnel and contractors, performing work on or near Company facilities are required to operate in accordance with the provisions of the Wildland Fire Preparedness and Prevention Plan and expected to conduct themselves in a fire-safe manner. They are also equipped for potential wildfire events by carrying specific tools, including, but not limited to, shovels, Pulaskis, and water for initial suppression.

Q. What is the role of field observers during wildfire season?

A. In its benchmarking with other utilities, Idaho Power found that most utilities use field observers in some capacity as part of the de-energization decision-making process. The Company currently has 24 trained field observers made up of Line Operations Technicians, Distribution Designers, Patrolmen, and other technician roles. In 2022, a PSPS event in Pocatello, Idaho was not executed due to reports from field observers that rain had preceded high winds. This information was not immediately evident through weather stations nor available radar at the time. This situation highlighted the importance of having field observers equipped with mobile weather kits to inform de-energization decision making.

O&M: Mitigation Efforts in the Company's T&D Programs

Q. Please summarize Idaho Power's mitigation activities within its T&D programs and associated O&M spending in 2022.

A. Executing the Company's WMP relies on leveraging its asset management programs to maintain safe and reliable operation of T&D facilities. Specific to wildfire mitigation, these efforts include: performing visual and infrared thermography inspections, performing maintenance based on the findings of those inspections, and utilizing innovative and cost-effective approaches to reduce wildfire risk, such as wrapping wood poles with a fire-resistant mesh and evaluating the cost effectiveness of covered conductor for potential future implementation.

In 2022, the Company spent $898,966 on T&D program-related wildfire mitigation efforts.

Q. What are the notable wildfire mitigation expenses associated with Idaho Power's T&D programs?

A. The largest wildfire mitigation expense in the Company's T&D mitigation programs is the installation of fire-resistant mesh wraps. In 2022, Idaho Power spent $364,075 – or 40 percent of the total system actuals in the T&D mitigation category – on fire-resistant mesh wraps. The mesh, which is applied to wood transmission poles in Red and Yellow Risk Zones, is an effective and widely used tool to increase the resilience of the pole and improve reliability for customers.

Q. What other T&D program activities did the Company pursue in 2022 to reduce wildfire risk?

A. In addition to the installation of fire-resistant mesh wraps, the Company conducted work associated with a new Program Manager function, conducted more annual inspections of its facilities in elevated risk zones, expanded the use of infrared thermography inspections in Red Risk Zones, launched a covered conductor pilot program, and performed a variety of capital projects for which there was an O&M component. Specific capital projects are described in detail in the section below.

Q. Please describe the value and purpose of thermography inspections with respect to wildfire mitigation.

A. Infrared thermography inspections are conducted using hand-held and drone-mounted cameras with thermal-sensing technology and can help identify defects associated with the overheating of equipment, connections, splices, or conductors.

Thermography inspections are uniquely valuable in that they can uncover problems undetectable to the naked eye. From the Company's perspective, there is not a viable alternative to this practice. The technology enables more proactive identification of potential issues than would otherwise be possible.

In 2022, the Company used additional personnel to evaluate the annual use of thermography inspections in Red Risk Zones, as opposed to the Company's historical approach of periodic use of the technology across its system.

Q. Please explain the purpose of the covered conductor pilot program.

A. In 2022, Idaho Power began a pilot of covered conductor that will run through 2024 to explore the benefits, tooling requirements for field personnel, and design parameters associated with this potential mitigation practice. While covered conductor may reduce the risk of wildfire, the Company will analyze any other potential concerns or co-benefits, including improved reliability outside of wildfire season, other safety considerations, and reduced outage restoration costs. Upon completion of the pilot, the Company will determine whether installation of covered conductor is a cost-effective risk mitigation practice.

O&M: Enhanced Vegetation Management

Q. What is vegetation management?

A. Vegetation management is the practice of trimming or pruning vegetation away from the Company's facilities to reduce the likelihood of vegetation coming into contact with T&D lines and causing damage or an outage.

Idaho Power has more than 400,000 trees within its system that are inspected and pruned on an ongoing basis. The lines are inspected periodically, and trees and vegetation are cleared from the line while other trees are removed entirely.

Q. Why is vegetation management a key part of the Company's wildfire mitigation efforts?

A. In terms of time, expense, and overall risk reduction, enhanced vegetation management is the most critical aspect of executing Idaho Power's WMP. If vegetation comes in contact with energized powerlines there is potential that it could result in an outage or ignition. Historical outage data from across Idaho Power's service area shows that vegetation contact is one of the most likely sources of faults and possible ignition on the power system.

Q. What strategies has the Company employed to reduce wildfire risk associated with vegetation?

A. Idaho Power employs an enhanced vegetation management strategy in wildfire risk zones that includes transitioning to a sustainable three-year pruning cycle for all distribution circuits and transmission lines in valley locations. In addition to achieving a three-year pruning cycle, the Company conducts mid-cycle patrols and pruning in the second year of the cycle to address "cycle buster" trees and annual "hotspot" patrols to address any new hazard trees or unexpected vegetative growth that poses an immediate threat of contact with energized facilities.

Additionally, the Company strives to complete audits for all pruning work performed in wildfire risk zones, regardless of reason for the pruning. The audits confirm that pruning cuts meet the specification and that the proper clearance (i.e., the distance between vegetation and the Company's T&D lines) was obtained.

Q. When developing the WMP, did the Company consider different pruning cycle lengths?

A. Yes. The Company considered other vegetation management cycle alternatives, including shorter trimming cycles, longer trimming cycles, and strategies that evaluate each tree individually and only trim it once it has nearly grown back to the power line (known as "just-in-time trimming"). Each alternative presented challenges or resulted in negative impacts that undermined any potential benefits. While shorter trimming cycles result in less vegetation being removed during each trimming cycle, this practice costs more due to the need for more resources and more frequent trimming of trees near the power lines.

In contrast, longer cycles result in less frequent trimming of each tree but larger amounts of vegetation that must be removed to maintain larger clearance envelopes around the power lines to accommodate additional years of vegetative growth. Further, longer trimming cycles create logistical challenges that are exacerbated by tree biology. Some trees simply grow faster than a given trimming cycle and the longer the trimming cycle, the more pervasive this issue becomes. Longer cycles that call for heavy pruning also lead to hormonal imbalances between a tree's canopy and its root system. To correct this imbalance, the tree aggressively re-grows new sprouts to quickly replace its lost canopy. In this regard, heavier pruning results in a faster rate of tree regrowth than normal, making it even more difficult to consistently maintain longer trimming cycles.

Finally, "just-in-time trimming" is primarily a reactive strategy that ultimately leads to challenges associated with securing qualified tree-trimming crews, as this ad hoc approach involves hiring crews on an as-needed basis rather than on a consistent schedule.

After evaluating these alternative approaches, Idaho Power concluded that maintaining a three-year trimming cycle is the most cost-effective and sustainable strategy to keep vegetation away from power lines in a proactive manner.

Q. How has shifting to a three-year cycle and implementing other enhanced vegetation management activities affected costs?

A. Moving to a three-year vegetation management cycle and performing enhanced vegetation activities — including pre-season patrols, additional inspections, pole clearing, tree and shrub removal, and quality assurance in Red and Yellow Risk Zones — has resulted in a sizeable increase in O&M expenditure. In 2022, Idaho Power spent $25,151,422 on vegetation management — more than double the $10.7 million of vegetation management expense in 2019 — and representing the single largest source of the Company’s wildfire-related expenditure. The Company’s second largest source of wildfire-related expenditure is insurance, which is addressed in Mr. Buckham’s testimony.

Q. Why has the Company experienced such substantial growth in the cost of vegetation management?

A. A variety of factors help explain the cost increases Idaho Power has experienced to perform vegetation management. Most notably, the availability of qualified labor has diminished while demand for vegetation management services has grown across the western US among other utilities, other industries, and government agencies that also recognize vegetation management is a critical component of wildfire risk mitigation.

Importantly, the vegetation management companies hired by Idaho Power and other utilities are not simple arborists or landscapers. Rather, vegetation management companies qualified to work near electrical lines and equipment require special certifications and training. The limited number of companies offering such qualified services are in high demand in many western states and especially in California, where labor rates are higher for the work itself and the labor that provides it. Idaho Power has felt the effect of out-of-state competition in the form of double-digit cost increases and qualified labor shortages.

Another exacerbating factor of vegetation management cost is Idaho's growth. Greater population density and expansion of homes into more vegetation-dense areas has made it harder to maintain a consistent vegetation management cycle. New development is routinely built with frontage trees and other vegetation. The growth in newly planted trees certainly leads to more work, but an associated problem is that these trees are often inappropriate for their location and environment. Trees that grow wide and tall and/or mature quickly are poor candidates for planting near or beneath electrical lines, and yet tree selection is more often made based on aesthetics rather than safety. This problem persists despite Idaho Power making significant efforts to communicate and educate on appropriate tree selection in several ways, including the "Right Tree, Right Place" tree planting guide, which offers detailed information on selecting appropriate trees and planting them at safe distances from power lines.

Finally, climate change is a factor contributing to escalating vegetation management costs. ln recent years, Idaho has experienced wetter springs followed by more temperate summers and falls, leading to longer vegetation growing seasons.

Another climate-related issue is the spread of pests such as the bark beetle that leave dead trees in their wake. Failure to remove dead or dying vegetation - a problem felt most acutely on government land - complicates vegetation management work and makes adhering to a routine clearing cycle more challenging, time consuming, and, thereby, more costly.

Q. Has the Company explored any alternatives to vegetation management?

A. Yes. The primary alternative to vegetation management is converting overhead distribution circuits to underground. However, undergrounding is consistently more expensive than enhanced vegetation management. The Company continues to evaluate and implement underground solutions, as appropriate and cost-effective based on risk, as part of its WMP hardening efforts, as described in the section below.

Q. Has the Company identified benefits other than risk reduction from enhanced vegetation management practices?

A. Yes. Although vegetation management is a sizeable increased wildfire mitigation expense, performing this work is expected to have notable co-benefits, including reduced vegetation-caused outages, thereby enhanced reliability, in Red and Yellow Risk Zones. Idaho Power plans to monitor performance and outage metrics to confirm the success of the enhanced program. Decreasing vegetation outages was considered one of the most important, cost-effective measures Idaho Power could take to reduce the likelihood of an ignition event and protect utility infrastructure.

Q. Is Idaho Power's enhanced vegetation management program prudent and in customers' best interest?

A. Yes. Shifting to enhanced vegetation management practices, including the move to a three-year pruning cycle, was deemed a prudent course of action based on the reduction of risk in wildfire risk zones and the number of potential outages or ignition sources that may be eliminated. A vegetation management-focused wildfire mitigation program is also the approach adopted by many of Idaho Power's peer utilities.

Q. Has the Company evaluated new technology to help in vegetation management efforts and reduce vegetation-related risks?

A. Yes. Vegetation monitoring tools have come to market in recent years that have the potential to help Idaho Power apply a more targeted approach to vegetation management. The Company conducted a pilot effort in 2022 that involved combining artificial intelligence ("AI") with satellite and aerial imagery surveys of overhead powerlines to detect vegetation encroachment and hazard trees.

The surveys have the potential to identify problem areas more quickly than conventional methods and provide less reliance on "eyes on the ground" to identify areas at risk of vegetation contact or trees in poor health that may fall into powerlines. In addition, the technology has the potential to allow Idaho Power to invest resources where they will be the most effective in mitigating the impact of wildfires.

Q. What were the results of the pilot?

A. Initial results of the pilot did not demonstrate sufficient accuracy needed to make risk-informed decisions for vegetation encroachment.

Q. Will the pilot shift Idaho Power's approach to vegetation management?

A. Perhaps. The Company plans to reassess the technology in 3 to 5 years as improvements in machine learning and AI are made.

Q. What is Idaho Power's assessment of the need for ongoing enhanced vegetation management?

A. Based on comparison to underground conversions and the insufficiency of current technology to allow a more targeted approach to vegetation management, Idaho Power considers its strategy of achieving and maintaining a three-year pruning cycling, along with enhanced practices in Red and Yellow Risk Zones, the most prudent approach for reducing wildfire risk associated with vegetation.

Considering the challenges noted above, the Company expects vegetation management expense may continue to rise.

A discussion of this concern, and the associated justification for ongoing vegetation management cost deferral at a new baseline level, is provided in the Direct Testimony of Company Witness Mr. Timothy Tatum.

O&M: Communications & Information Technology

Q. Please explain the Company's communication and information technology-related strategies in the WMP.

A. The Company conducts several education campaigns around wildfire each year, including promoting the Company's wildfire mitigation activities and work within communities, providing awareness and education on how to prepare for wildfire season. The following core messages are the foundation for all wildfire-related communications each year:

- How customers can prepare for wildfire-related outages, including where to find outage and PSPS information and how to sign up for alerts and update contact information;
- Ways customers can reduce wildfire risk; and
- Idaho Power's work to protect the grid from wildfire and reduce wildfire risk.

Idaho Power communicates with customers and the public before and throughout wildfire season to inform them of steps the Company is taking to reduce wildfire risk and ways they can help prevent wildfires and prepare for outages. Various communication mediums used to accomplish this include: newsletters, news media, website content and videos, social media, postcards, and paid advertising.

The Company also promotes ways that the public can reduce the potential to ignite fires. Customers in PSPS zones are targeted for expanded communication to promote an awareness of PSPS and outage preparation. PSPS-focused communication comes in the form of advertisements, bill inserts, postcards, and other awareness raising and educational campaigns.

Q. What efforts has the Company made to directly contact customers about emergency events and outages?

A. To help provide timely communication of emergency events — specifically, PSPS — to customers, the Company has implemented a communication tool called the Enterprise Omnichannel Notification System ("EONS"). Having advanced alerts prior to and during a PSPS is an important aspect of Idaho Power's PSPS program. A large component of the EONS tool is identifying critical customers and facilities that will automatically be contacted leading up to, during, and after a PSPS event.

Q. What did the Company spend in 2022 on customer communication and related information technology?

A. In 2022, Idaho Power spent $106,779 on communications to customers and communities before, during, and after wildfire season. This amount includes postcards sent to all customers in PSPS zones to educate them about the purpose of PSPS and how they can stay connected to the Company to learn about PSPS events.

Implementing the EONS system, a critical tool for more timely communication with customers, cost $80,531 in 2022.

Wildfire Mitigation Capital Investments

Q. In what capital projects has the Company invested related to wildfire mitigation?

A. The table below summarizes wildfire mitigation investments by mitigation program:

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TABLE 2

CAPITAL INVESTMENT BASED ON PLANT CLOSINGS IN 2021 AND 2022

Mitigation Program	Description of the Program	Risk Reduction Benefit	Plant Closings in 2021 and 2022
Overhead Primary Hardening Program	Systematic replacement of hardware, equipment, and materials, 113-line miles in Red Risk Zones	Reduced potential of equipment failure, utilizing material and equipment with less energy release and potential of ignition, increased resiliency	$9,869,070
Strategic Undergrounding	Select conversion of overhead to underground conversion in Red Risk Zones, 1.85 miles completed in 2022	Reduce exposure and potential of ignition by locating power lines underground	$1,822,482
Red Risk Zone Overcurrent Protection Segmentation	Installation, relocation, and expanded communication for Automatic Reclosing overcurrent protection devices	Isolate circuit segments and improve reliability for enhanced Fire Potential Index settings and PSPS	$367,899

Q. What is included in the Overhead Primary Hardening Program?

A. The Overhead Distribution Hardening program involves systematic replacement of hardware, equipment, and materials to improve safety and reliability and reduce ignition risk. The program is targeted for Red Risk Zones. Enhanced measures to mitigate wildfire are:

Wood Pole Replacement—The Company will replace wood poles if field evaluations determine that significant deterioration or damage has occurred since the last inspection or treatment. Furthermore, poles having wood stubs/structural reinforcements are changed out pursuant to current practices.

Spark Prevention Units—Porcelain arresters used for overvoltage protection will be changed out with arresters utilizing Spark Prevention Units ("SPU"). The SPU acts to eliminate the potential of catastrophic failure during arrester operation.

Fiberglass Crossarms—Replacing wood tangent and dead-end crossarms with fiberglass. Fiberglass crossarms provide decrease the likelihood of heating through a crossarms and cross-functional benefits of lower cost, ease of installation, strength, and supply availability.

Small Conductor—Replace copper conductor and conductor smaller than #4 Aluminum Conductor Steel Reinforced.

Porcelain Switches—All porcelain switches installed in Red Risk Zones will be changed out with cutouts featuring Ethylene Propylene Diene Monomer Rubber.

Avian Protection Coverings—Idaho Power employs several different protection measures to protect wildlife on existing structures, including but not limited to covers, insulated conductor, diverters, perches, nesting platforms, and structural modifications.

In addition to the enhanced hardening measures mentioned above, each location is inspected to ensure structures and equipment are brought up to current construction standards. All existing hardware that will remain in place is re-tightened, loose conductors are re-tensioned, and third-party pole attachments are checked for proper clearances.

Q. Does hardening work occur on the transmission system?

A. Yes. On the transmission side, the Company evaluates upcoming transmission line construction projects-such as new line construction and line rebuilds with the plan to use steel construction for all lines of 138 kV and above. For existing wood poles, a fire-resistant mesh wrap is applied to existing wood poles in designated wildfire risk zones, as discussed earlier in my testimony. The mesh wrap improves the resiliency of the pole and keeps it from catching fire if exposed to a surface fire.

Q. What steps did the Company take to determine what mitigation measures should be included in the hardening program?

A. Idaho Power researched historical faults on the T&D system to determine outage causes that may result in potential ignition. That analysis determined that tree/vegetation contact, equipment failure, loose hardware, corrosion, and animal contact are among the top causes of faults throughout the service area. Specific risk drivers were established and identified as part of the risk evaluation process.

In addition, the Company used the Cal Fire Powerline Fire Prevention Guide to help identify equipment and materials that may contribute or cause an ignition on the power system. This guide, combined with the Company's past root cause analysis and feedback from employees with line construction and maintenance experience, helped identify expulsion fuses, porcelain switches, deteriorated wood crossarms, expulsion arresters, and small conductor as being potential ignition sources.

Q. Does the hardening program offer any co-benefits for customers?

A. Yes. The Overhead Distribution Hardening program includes infrastructure upgrades and the replacement of several materials or equipment to reduce the likelihood of ignition on the distribution system. Each material or equipment selected was analyzed to determine its effectiveness at reducing risk, estimated near-term cost, potential co-benefits of the activity to Idaho Power and its customers, and costs between alternatives. At a foundational level, the program offers the co-benefit of improved reliability for customers and a decrease of ignition potential.

Q. Can reliability indices be used to measure the effectiveness of the hardening program?

A. Yes. Prior to developing the WMP, Idaho Power successfully implemented distribution hardening measures and, through outage data and analytics over that period (2010 through 2019), learned that customer outages were reduced by approximately 38 percent in areas where reliability hardening projects were carried out. This initial success of reducing outages for reliability purposes resulted in the Company selecting similar activities in the WMP to further increase reliability and help reduce ignition potential in Red Risk Zones. Idaho Power is tracking reliability performance in wildfire risk zones over time to assess effectiveness.

Q. What is the Strategic Undergrounding Program?

A. As part of Idaho Power's effort to reduce wildfire risk and impacts associated with outages and PSPS, Idaho Power evaluates the cost-effectiveness of overhead-to-underground conversion of distribution lines on a case-by-case basis.

Areas selected for conversion will have increased reliability and resiliency to wildfire, and customers in the area will no longer be exposed to the potential of long outages associated with operational protection settings on high fire potential days or PSPS. Strategic Undergrounding, one effort of many the Company is taking to reduce wildfire risk, is selected in highest-risk areas when the cost-benefit analysis shows that underground construction is prudent.

Q. Has the Company completed any underground conversion projects for wildfire mitigation?

A. Yes. In 2022, overhead-to-underground conversion was performed on 1.85 miles of distribution lines in Idaho. The projects included four line segments on the Boise Bench and Cartwright feeders in Boise, Idaho. These were the first underground conversion projects that the Company has undertaken to reduce wildfire risk.

Q. Why were the locations selected for underground conversion?

A. The areas were chosen for underground conversion due to the results of risk quantification and work, summarized later in my testimony. That work identified the areas having a combination of high wildfire probability and impacts to structures.

Field assessments and feedback from local fire officials confirmed that the topography and surface fuels in the areas were conducive to rapid fire spread, which could lead to structure and human safety impacts.

Fire history was another factor considered for the project near Idaho Power's Boise Bench Substation, located off Amity Road in East Boise. Another consideration was that the undergrounding of these line segments would decrease the overall risk profile of each feeder due to most of the feeders already having underground distribution.

Q. What criteria did the Company use to select the underground conversion projects?

A. The Overhead Distribution Hardening program is the primary program used to decrease the likelihood of ignition on the distribution system. Underground conversion projects are undertaken for locations where outage data and risk assessments show the need for increased risk reduction beyond what the hardening program provides.

Idaho Power's approach to selecting underground conversion projects involves the ISO 31000 risk management framework. Established criteria used in the assessment for optimal underground conversion locations is as follows:

- Wildfire risk modeling scores, having high wildfire probability and impacts to structures;
- Fire history where distribution overhead circuits may be susceptible to repeat wildfire events over their lifetime;
- Areas having a high likelihood of ignition due to risk drivers such as vegetation contact, contact from objects, lightning, and equipment failure;
- PSPS zones having high likelihood of proactive de-energization due to historic weather patterns, vegetation, or ignition risk;
- Areas of high wildfire risk that present challenges to patrol due to access issues, terrain, or inability to perform aerial inspections after a PSPS or outages on days with high FPI; and
- Areas where PSPS and enhanced protection settings may impact critical infrastructure.

The underground conversion projects in 2022 were analyzed by their expected risk-reduction benefit to overall project cost. And, for the projects in question, underground conversion was deemed cost-effective based on the level of risk reduction and type of risk driver that was mitigated.

Q. How do the costs of overhead distribution hardening compare to underground conversions?

A. The cost of converting overhead distribution lines to underground can vary significantly based on the voltage level, equipment, and terrain to be worked. The 2022 underground conversion projects cost $1,822,482 – or an average cost of $985,125 per line mile. The benefit of the projects are increased wildfire resiliency and decreased potential of ignition. Based on wildfire modeling and property values[8] in the area, Idaho Power estimates that the project is protecting structures that could cost upwards of $45 million to replace in the event of a destructive wildfire.

Q. What is the Overcurrent Protection Segmentation program?

A. The Overcurrent Protection Segmentation program involves the installation of automatic reclosing equipment ("reclosers") at the edge of Red Risk and PSPS zones. By strategically locating reclosers at the edge of a zone, the Company can limit the impact on customers outside of those zones from increased outages due to enhanced protection settings on days with high fire potential and PSPS. The program also includes adding communication capabilities to recloser so they can be remotely operated through the Company's dispatch group. The remote operation

[8] 2022 median home prices as reported by the Ada County Assessor's Office.

provides the benefit of being able to change protection settings remotely on days when the FPI is high. It also gives Reliability Engineers the ability to assess waveforms and fault characteristics immediately after a fault occurs, eliminating the need for a technician to travel and download the event record.

2022 WMP Performance

Q. What metrics is the Company tracking to gauge the effectiveness of the WMP?

A. Idaho Power tracks several metrics to measure the performance of the WMP and its effectiveness over time. Each year, work plans are established at the beginning of the year and items are tracked throughout the year to identify areas needing corrective action or attention. This includes monitoring vegetation management activities, inspections, and circuit hardening. Idaho Power's goal is to complete 100 percent of the work plan each year; however, emergencies or other unplanned events can occur and disrupt the annual work plan.

Q. How did Idaho Power perform on its WMP wildfire mitigation objectives in 2022?

A. As is demonstrated in the table below, the Company met or exceeded its wildfire mitigation objectives in 2022, in all but two instances.

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TABLE 3

2022 WMP PERFORMANCE METRICS

Plan Area	Wildfire Mitigation Plan Activities	2022 Goal	Completed	% Complete	2023 Goal
System Hardening	**Distribution System Hardening**				
	System Hardening Line Miles	48	48.91*	102%	69
	Overhead Line Miles Converted to Underground	1.85	1.85	100%	1
	Expulsion Fuse Replacement	930	942	101%	1319
	Surge Arrester Replacement	830	839	101%	1175
Feeder Segmentation	**Segmentation Devices**				
	Installation or Relocation of Automatic Reclosing Devices	17	17	100%	8
Fire Mesh Installation	**Transmission Fire Mesh Installation**				
	Red Risk Zone Poles	492	492	100%	-
	Yellow Risk Zone Poles	406	585	144%	870
Asset Inspections	**Transmission Inspections**				
	Wildfire Pre-Season Patrol - Red Risk Zones (Structures)	923	923	100%	923
	Infrared Thermography Patrol (Structures)	923	923	100%	923
	Distribution Inspections				
	Wildfire Pre-Season Patrol - Red Risk Zones (Structures)	20,192	20,192	100%	20,192
	Infrared Thermography Patrol - Red Risk Zones (Structures)	3,000	3,800	127%	4,000
Vegetation Management	**Pruning Cycle**				
	Transition to a 3-Year Pruning Cycle (circuits)	282	173	70%**	320
	Enhanced Vegetation Management				
	Annual Patrol - Red & Yellow Risk Zones (circuits)	65	65	100%	65
	Annual Mitigation - Red & Yellow Risk Zones (circuits)	65	65	100%	65
	Mid-Cycle Patrols - Red & Yellow Risk Zones (circuits)	47	47	100%	1
	Mid-Cycle Pruning - Red & Yellow Risk Zones (circuits)	47	47	100%	1
	Hazard Trees Identified and Pruned	-	77	100%	100% of All Identified
	Hazard Trees Identified and Removed	-	49	100%	100% of All Identified
	Audits of Pruning Activities - Red & Yellow Risk Zones (worksites)	6,324	977	15%**	100% of All Identified
Meteorology	**Idaho Power Weather Stations**				
	Weather Station Installations	5	5	100%	5

*Excludes hardening work outside of wildfire risk zones

**Estimated year end completion

The Company did not fully achieve its 2022 vegetation management production goal in the transition to a three-year vegetation management cycle and, similarly, fell below the goal with respect to pruning audits in high-risk zones. Both of these outcomes are the direct result of the vegetation management challenges discussed earlier in my testimony — namely, labor shortages that have made it difficult to hire enough qualified crews to perform the Company's needed vegetation management work.

Q. Please summarize your testimony in this case.

A. As evidenced by the Company’s ongoing improvement in reliability metrics, Idaho Power has taken a thoughtful and prudent approach to construction and maintenance of its T&D systems.

Regarding wildfire mitigation, the Company made substantial and prudent 2022 investments in programs, personnel, infrastructure, system hardening, and vegetation management to ensure that Idaho Power can continue to safely and reliably serve customers and continue to make great strides to mitigate wildfire risk.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF MITCH COLBURN

I, Mitch Colburn, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Mitch Colburn. I am employed by Idaho Power Company as the Vice President of Planning, Engineering, and Construction.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 4 through 5 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed Mitchell D. Colburn

MITCH COLBURN

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

COLBURN, DI TESTIMONY

EXHIBIT NO. 4

Wildfire Mitigation Category	Program Activity	2022 Actuals
Quantifying Wildland Fire Risk	Risk Analysis and Map Updates	$4,125
Situational Awareness	Weather Forecasting - System Development, Aupport, and Personnel	$156,201
Mitigation - Field Personnel Practices	Tools/Equipment	$10,720
Mitigation - Transmission & Distribution Programs	O&M Component of Capital Work	$160,123
	Annual O&M T&D Patrol Maintenance Repairs	$100,461
	Environmental Management Practices	$9,225
	T&D Thermography Inspection Mitigation & Personnel	$97,888
	Transmission Wood Pole Fire Resistant Wraps - Red Risk Zone	$127,258
	Transmission Wood Pole Fire Resistant Wraps - Yellow Risk Zone	$236,817
	Wildfire Mitigation Program Manager Function	$135,006
	Covered Wire Evaluation - Pilot Program in PSPS Zones	$32,189
Enhanced Vegetation Management	Transition to/Maintain 3-Year Vegetation Management Cycle	$24,848,875
	Enhanced Practices for Distribution Red & Yellow Risk Zones (Pre-Season Patrols/Mitigation, Pole Clearing, Removals, Work, QA)	
	Line Clearing Personnel	$150,927
	Vegetation Mgmt Satellite and Aerial Patrols	$151,620
Communications	Wildfire/Wildfire Mitigation Communications - Advertisements/Meetings/Other	$106,779
	PSPS Customer Education/Communication - Advertisements, Bill Inserts/Other	
Information Technology	Communication/Alert Tool development (System set up, outage maps, critical facilities identification)	$80,531
TOTAL O&M		**$26,408,745**

Mitigation Program	Description of the Program	Risk Reduction Benefit	Plant Closings in 2021 and 2022
Overhead Primary Hardening Program	Systematic replacement of hardware, equipment, and materials, 113-line miles in Red Risk Zones	Reduced potential of equipment failure, utilizing material and equipment with less energy release and potential of ignition, increased resiliency	$9,869,070
Strategic Undergrounding	Select conversion of overhead to underground conversion in Red Risk Zones, 1.85 miles completed in 2022	Reduce exposure and potential of ignition by locating power lines underground	$1,822,482
Red Risk Zone Overcurrent Protection Segmentation	Installation, relocation, and expanded communication for Automatic Reclosing overcurrent protection devices	Isolate circuit segments and improve reliability for enhanced Fire Potential Index settings and PSPS	$367,899
TOTAL CAPITAL			**$ 12,059,451**

BEFORE THE

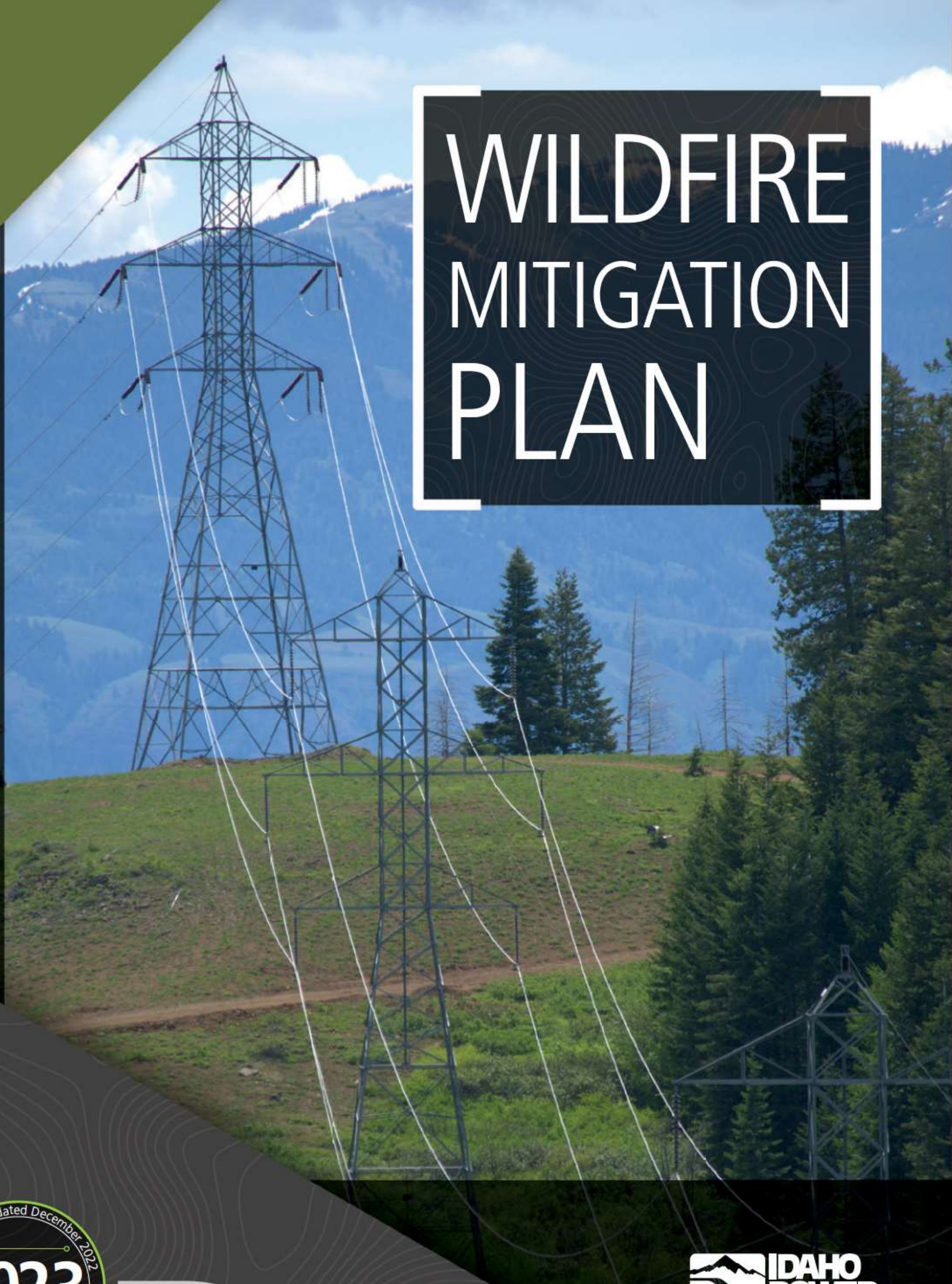
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

COLBURN, DI TESTIMONY

EXHIBIT NO. 5



WILDFIRE MITIGATION PLAN

Version 5 – Updated December 2022

2023

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC
Page 1 of 158

TABLE OF CONTENTS

LIST OF TABLES

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC
Page 7 of 158

LIST OF FIGURES

LIST OF APPENDICES

Review/Revision History

This document has been approved and revised according to the revision history recorded below.

Review Date	Revisions
Jan. 22, 2021	WMP Version 1 was filed with the Idaho Public Utilities Commission and posted to the Idaho Power website.
Dec. 29, 2021	Modifications including expanded cost-benefit discussion, plan progress and updates, and inclusion of Idaho Power's Public Safety Power Shutoff plan.
March 18, 2022	Added Appendix C.
June 28, 2022	Added information to comply with the Public Utility Commission of Oregon's conditions of approval of Idaho Power's 2022 Wildfire Mitigation Plan.
Oct. 19, 2022	Updated cost table within the WMP and filed with the Idaho Public Utilities Commission.
Dec. 29, 2022	WMP Version 5.0, including 2022 season in review, changes for 2023 season, and addition of Appendix C—Oregon Wildfire Requirements and Recommendations.

EXECUTIVE SUMMARY

Idaho Power is dedicated to the safety of our customers and communities, and to delivering reliable, affordable energy. In pursuit of that mission, we built off our existing Wildfire Mitigation Plan (WMP) and took major steps in 2022 to enhance our situational awareness in the field, enhance vegetation management, further harden the electrical system, and expand and better the ways in which we communicate and alert customers and communities about wildfire and wildfire risk. As the company enters its third year with a WMP, this new edition (Version 5.0) has been improved to reflect key learnings, feedback from stakeholders, and a focus on new technology. The WMP also provides supporting information on wildfire requirements and actions specific to our Idaho and Oregon regulators, but the document remains—first and foremost—an evolving guide that provides holistic and prudent strategies for reducing wildfire risk.

This Executive Summary—a new introduction in the 2023 WMP—provides a comprehensive summary of the 2022 wildfire season and the company's lessons learned and progress toward our wildfire mitigation objectives. Additionally, the Executive Summary previews changes to the company's risk management framework and lessons learned that will inform 2023 wildfire mitigation efforts and beyond.

2022 Weather and Fire Potential

The spring of 2022 brought above normal precipitation and below normal temperatures. As an example, parts of southern Idaho—including the Boise area—experienced heavy snowfall in the second week of May 2022.[1] This led to an abundance of fuels across the region. The summer months saw record high temperatures and below normal relative humidity that increased wildfire potential. Idaho Power atmospheric scientists conducted regular forecasts during wildfire season to determine a daily Fire Potential Index (FPI) value across the company's service area. The FPI is used to inform Idaho Power's on-the-ground, operational strategies when the fire potential is high.

A combination of record heat and low humidity led to a dramatic increase in FPI levels throughout the summer of 2022. There were nearly three times as many high-fire-potential days as in 2021. Despite the seasonal challenges, the company fulfilled and executed the WMP as planned for 2022.

[1] Carolyn Komatsoulis. 2022. Idaho Press. It's Pretty Unusual: Half-Inch of Snow, Power Outages Make for Manic Monday in Boise. May 2, 2022.

Figure 1
A field team installs a mesh wrap on a wood pole in 2022

Idaho Power continues to monitor climate variability and changing conditions to determine how wildfire risk is shifting season to season and in the longer term. Historical data shows temperature has increased over the past 80 years in southern Idaho and eastern Oregon. Studies show a connection between higher temperatures and increased wildfire activity, both in intensity and size of wildfires.[2] Further, extreme fire weather days are increasing, and fire season is getting longer.[3]

As climate conditions change, the company is committed to monitoring increased wildfire risk and enhancing the WMP to keep customers and communities safe.

Impacts of Wildfires in 2022

This year, both Idaho and Oregon had fewer wildfires and acres burned during wildfire season than the previous 20-year average.[4] However, wildfires did affect Idaho Power equipment both

[2] Idaho reviewed academic, scientific, and governmental climate change studies, including those from the Center for Climate and Energy Solutions, the US Environmental Protection Agency, the National Aeronautics and Space Administration, the National Oceanic and Atmospheric Administration, North Carolina State University, and National Geographic.

[3] In late 2022, Idaho Power analyzed temperatures over the last 80 years in the Idaho Power service area to assess changing climate conditions. The analysis showed that daily high temperatures and extreme weather events are increasing.

[4] Interagency Fire Center. Current National Statistics. www.nifc.gov/fire-information/statistics.

inside and outside of our service area. Three major wildfires threatened or burned wood structures. In some cases, we de-energized lines to keep firefighters safe.

Table 1
Wildfires impacting Idaho Power operations and facilities in 2022

Incident Name	Location	Fire Discovery Date	Containment Date	Acres	Cause	Facilities Impacted
Moose	17 Miles North of Salmon, ID	7/17/2022	11/9/2022	130,144	Unattended Campfire	Transmission
Four Corners	6 Miles west of the City of Cascade, ID	8/13/2022	10/20/2022	13,702	Lightning	Distribution
Double Creek	10 miles SE of Imnaha, OR	8/30/2022	10/25/2022	175,937	Lightning	Transmission

Idaho Power's mapping applications include geographic information system (GIS) data for active wildfires to inform operational planning and provide insight into areas that could be threatened throughout the fire season. The company monitored fire activity throughout the season to compare fire behavior to modeling. We expect to learn more about how real-time fire analytics can inform risk-based decision-making in coming fire seasons.

Key Objectives of 2022 WMP

Idaho Power met the 2022 WMP's key objectives, including the completion of major projects to ensure the WMP could be effectively carried out. A new Public Safety Power Shutoff (PSPS) program was implemented and all processes and procedures guiding customer communication, weather forecasting, switching plans and de-energization criteria were completed before fire season. This includes the installation and commissioning of a new communication system used to expedite notifications of PSPS events via voice, text messaging, and e-mail. We also installed 17 protective devices to isolate line segments and provide a means of remote de-energization.

Figure 2
A line worker installs a spark prevention unit near Eagle, Idaho

Overview of 2022 WMP Progress

By almost all measures, Idaho Power met or exceeded its WMP goals in 2022. Work plans are established at the beginning of the year and these items are tracked throughout the year to identify areas needing corrective action or attention. As some wildfire mitigation work is on a rotating cycle based on wildfire season (and not the calendar year), some of the items listed are still in progress at the time of writing this 2023 WMP.

Idaho Power's Progress Toward 2022 Wildfire Mitigation Goals

Table 2
2022 WMP activity summary and results

Plan Area	Wildfire Mitigation Plan Activities	2022 Goal	Completed	% Complete	2023 Goal
System Hardening	**Distribution System Hardening**				
	System Hardening Line Miles	48	48.91*	102%	69
	Overhead Line Miles Converted to Underground	1.85	1.85	100%	1
	Expulsion Fuse Replacement	930	942	101%	1319
	Surge Arrester Replacement	830	839	101%	1175
Feeder Segmentation	**Segmentation Devices**				
	Installation or Relocation of Automatic Reclosing Devices	17	17	100%	8
Fire Mesh Installation	**Transmission Fire Mesh Installation**				
	Red Risk Zone Poles	492	492	100%	-
	Yellow Risk Zone Poles	406	585	144%	870
Asset Inspections	**Transmission Inspections**				
	Wildfire Pre-Season Patrol - Red Risk Zones (Structures)	923	923	100%	923
	Infrared Thermography Patrol (Structures)	923	923	100%	923
	Distribution Inspections				
	Wildfire Pre-Season Patrol - Red Risk Zones (Structures)	20,192	20,192	100%	20,192
	Infrared Thermography Patrol - Red Risk Zones (Structures)	3,000	3,800	127%	4,000
Vegetation Management	**Pruning Cycle**				
	Transition to a 3-Year Pruning Cycle (circuits)	282	173	70%**	320
	Enhanced Vegetation Management				
	Annual Patrol - Red & Yellow Risk Zones (circuits)	65	65	100%	65
	Annual Mitigation - Red & Yellow Risk Zones (circuits)	65	65	100%	65
	Mid-Cycle Patrols - Red & Yellow Risk Zones (circuits)	47	47	100%	1
	Mid-Cycle Pruning - Red & Yellow Risk Zones (circuits)	47	47	100%	1
	Hazard Trees Identified and Pruned	-	77	100%	100% of All Identified
	Hazard Trees Identified and Removed	-	49	100%	100% of All Identified
	Audits of Pruning Activities - Red & Yellow Risk Zones (worksites)	6,324	977	15%**	100% of All Identified
Meteorology	**Idaho Power Weather Stations**				
	Weather Station Installations	5	5	100%	5

*Excludes hardening work outside of wildfire risk zones
**Estimated year end completion

As can be observed from the numbers above, vegetation management is a challenging area. Much of the delay in reaching 2022 goals is attributable to broader challenges in the workforce. Idaho Power uses contractors to perform vegetation management and audit work. The company witnessed labor shortages, more inexperienced contract workers than in the past, and increased turnover that led to lower vegetation management production levels throughout the year. Vegetation management production was also lower than anticipated because more climbing work was required than originally expected. Climbing to prune or remove vegetation requires contractors with more skill and takes more time. Despite these challenges, Idaho Power continues to work with contractors to push toward its goals and estimates that, by the end of the calendar year, the production level will be near 70% of target.

Audits were also impacted by resource availability, as contractors did not reach full staff levels until December 2022. Because of this, random sampling was used in lieu of auditing all vegetation management work in wildfire risk zones. Idaho Power will work with contractors at the end of 2022 to develop corrective action plans and make necessary adjustments to meet targeted performance levels in 2023.

Regarding customer communication in 2022, Idaho Power used several methods to inform customers throughout the year of our WMP and PSPS plan. These included social media, radio, customer newsletters, postcards, and voice and text messaging. Before the 2022 wildfire season, the company focused on asking customers—especially those in PSPS potential zones—to update their contact information and prepare for potential PSPS events. Additionally, the company conducted over 20 in-person and virtual meetings to engage with customers, counties, and fire and other public agencies to discuss and seek feedback on the WMP and PSPS efforts.

Figure 3
[Idaho Power developed an educational video to explain PSPS]

Fortunately, the company did not need to fully implement a PSPS in 2022. However, the company's planning and communication apparatuses were tested in one instance in Pocatello, Idaho, where the company anticipated a PSPS event due to high winds and extremely high fire potential. The company took the steps to inform public safety partners, critical facilities, and customers in the area that a PSPS was imminent. Rain showers preceded high winds in the area and the PSPS event was canceled before de-energization took place.

Looking Ahead—Expanded Mitigation Activities

As detailed in the WMP, Idaho Power deploys a comprehensive and multi-faceted strategy to reduce wildfire risk. The company plans to implement new activities and expand existing ones in 2023. The list below summarizes new or expanded activities.

Infrastructure Hardening
In 2022, we hardened approximately 49 line miles to decrease the risk of wildfire in Red Risk Zones—areas with the highest wildfire risk based on wildfire probability and potential impacts. The hardening program is 26% complete, with Red Risk Zones given the highest priority at this time. This work will increase in 2023 by 40% and include hardening to 69 line miles.

Strategic Undergrounding
In 2022, Idaho Power buried approximately 1.85 miles of overhead distribution line in areas of highest wildfire risk. This work primarily targeted the main trunk of distribution feeders. In 2023, we will target a smaller line segment in an area that includes residences.

The company's goal is to work through the complexities and costs associated with burying primary overhead powerlines, overhead services, and converting customer-owned service-entrance equipment. This work will take place in a PSPS zone in Idaho with high fire probability and potential impact. The projects in 2022 and upcoming work in 2023 will inform future underground conversion strategies by helping us weigh costs and risk-reduction benefits against those of traditional feeder hardening and covered conductor conversions.

Vegetation Management

Idaho Power's effort to achieve a three-year pruning cycle will continue in 2023. It is a critical aspect of meeting our objective to reduce wildfire risk. We will expand brush clearing and applying ground sterilant around wood poles to reduce fuels. We are also exploring an opportunity to partner with the National Forest Foundation, Boise National Forest, Bureau of Land Management, and local fire districts on a shared stewardship program in the Boise Front. This work is expected to provide a means for Idaho Power to participate in fuel reduction activities outside of the right of way, which will reduce wildfire risk by decreasing surface fuels and the potential of tree contact.

Figure 4
A contractor trims trees in a bucket truck

Risk Modeling

Risk modeling of Idaho Power's service area is used to prioritize mitigation activities. In 2023, we will re-evaluate our risk modeling by incorporating new structure information based on 2020 Census data and explore new areas of consequence based on the feedback received in the past year from fire agencies and customers.

Situational Awareness
The FPI is forecasted daily during fire season and provides critical information that informs operational changes during days with high fire potential. In 2023, we will work to improve the communication and calculation of the FPI by creating more clear and concise messaging to stakeholders.

PSPS
While the company did not proactively de-energize any customers as part of its PSPS program in 2022, engagement with communities and customers this year highlighted their concerns—specifically the inability to communicate or suppress fire via electric wells and water pumps without power. This feedback highlights the need for the company to find ways to limit the impact and frequency of future PSPS events. Many of the activities being pursued here, such as strategic undergrounding and utilizing covered conductor, will decrease the likelihood of PSPS. However, PSPS will remain a tool available to the company to mitigate wildfire risk during extreme fire weather conditions.

Figure 5
Idaho Power uses visual graphics to illustrate the conditions that could require a PSPS event

Segmentation
We completed the installation of 17 automatic reclosing devices (reclosers) in Red Risk Zones as part of an effort to isolate circuit segments and improve reliability for customers outside of those zones. In 2023, we will continue this work and install an additional eight reclosers in Red Risk Zones.

New Technology and Innovations
New technology and innovative programs were explored in 2022 to find new ways to reduce the risk and impacts of wildfire. In 2023, we will conduct pilots based on our findings with the goal of learning more about their implementation complexities and to analyze costs and risk reduction benefits prior to fully integrating into the WMP. These pilots or trials include the following:

- Satellite Imagery—Using satellite imagery to detect vegetation encroachment and hazard trees.

- Covered Conductor—Covered conductor is a solution used throughout the industry to decrease the potential of ignition if an object contacts powerlines. A trial of covered conductor will be carried out in our training yard to determine overall costs, tooling requirements, work methods, and construction standards and specifications.

- Structural Resilience of Wood Poles—We will increase situational awareness in Red Risk Zones by performing a survey of distribution poles using Light Detection and Ranging (LiDAR) technology to identify structural loading capacity of existing wood poles.

- Shared Stewardship—We will partner with federal agencies on a shared stewardship fuel reduction program in forested areas and evaluate the benefits in terms of reduced surface fuels and fire spread potential. The collaboration will also provide the company with the opportunity to work with land managers and owners to expand vegetation management and reduce the potential of ignition from vegetation contact.

- Fire Detection Cameras—In 2022, we explored the benefits that cameras can have in early fire detection and became part of the Wildfire Detection Camera Strategy Work Group in Oregon. We are working to identify optimal locations and developing partnerships with state and federal agencies and will expand our knowledge of cameras that utilize artificial intelligence for fire detection. We plan on piloting cameras in 2023 to further understand the complexities of installations, permitting, systems used for notification, and overall accuracy. The pilot will be critical in determining a long-term strategy for the use of cameras to reduce wildfire risk.

Lessons Learned

Idaho Power has conducted its own assessment of lessons from the 2022 wildfire season and the company's wildfire mitigation practices. The following lessons learned were developed by supplementing this analysis with feedback heard from stakeholders, customers, public safety partners, peer utilities, and through wildfire-related forums, research, and education.

Pre-Wildfire Season Patrols

Idaho Power strives to complete wildfire patrols prior to the start of each wildfire season to identify issues that may pose a risk of ignition if left unchecked. Above-normal precipitation and below-normal temperatures in the spring months of 2022 created access issues in mountain areas where snow levels were several feet deep. Late, heavy snow delayed completion of these patrols until mid-June, which, while later than target, was still prior to the onset of conditions conducive for wildfire.

Situational Awareness

The FPI is an essential tool to support operational decision making. It includes detailed forecasts of 148 different geographical areas or zones throughout the service area and is used to determine when a PSPS is necessary. The preparation for a PSPS event in August 2022 highlighted an opportunity to improve the communication and precision of the forecasts. In that case, a line segment subject to the potential PSPS was included in two different FPI zones that had different fire potential across their geographical areas. Initially, this created confusion as to which forecast to use for decision-making purposes. In 2023, we will review areas that have overlapped FPI zones and refine mapping and forecasted boundaries to eliminate the potential of this situation occurring again.

Vegetation Management
Pruning levels in 2022 did not meet the target established for the year largely due to labor issues. We added outsourced crews from throughout the country to assist in conducting vegetation management activities and expect to reach approximately 70% of targeted vegetation management pruning by the end of 2022. In 2023, we will conduct a thorough review of all activities and assess means of working with contractors to drive towards 2023 production goals.

Expansion of the Wildland Urban Interface
As the population in Idaho Power's service area continues to grow, we've seen an expansion of new construction in the wildland urban interface (WUI). This expansion creates challenges for wildfire mitigation as new wildfire risks emerge. In 2023, we will analyze the growth of the WUI and create new strategies to address new risks.

Functional Exercises
Two functional exercises were conducted in the spring of 2022 to test processes and procedures needed to fully execute the PSPS program. The exercises were beneficial and ensured that the company was prepared to effectively carry out a PSPS prior to the onset of severe fire weather. Forty action items were identified throughout the exercises and consisted of refining and improving communication methods, timing, documentation, and website functionality. We found that PSPS events can be complex and occur within different parts of the company's service area simultaneously. To help ensure expedited and accurate communication for all potential scenarios, templates were developed for communication activities involving customers, Public Safety Partners, Emergency Support Function (ESF-12), and departments within the company. The templates will be reviewed and improved as needed in 2023.

List of Stakeholders
The PSPS functional exercises highlighted the need for accurate and readily available lists of Public Safety Partners and critical facilities. We developed a central repository for all information related to PSPS which includes contacts for Public Safety Partners, operators of critical facilities, and Emergency Support Function ESF-12 personnel.

Estimated Time of Restoration
As with all outages, having accurate estimates for the time or restoration (ETR) is a priority. The PSPS functional exercises highlighted that setting an initial ETR for PSPS events is more challenging than ordinary unplanned or planned outages. The company determined that the ETR for a PSPS should take into consideration the duration of the weather event and the time needed for safety patrols to occur. Internal atmospheric scientists became a crucial part of determining the duration of weather events. Operational plans were developed for each region to guide restoration and switching procedures to expeditiously restore power during a PSPS. These plans include estimated patrol times which are also used for establishing an initial ETR. We plan on reviewing any assumptions in the operational plans each year and

include lessons learned from the previous year into the patrol estimates to ensure we are providing the best information possible.

Field Observer Program
PSPS events are carefully evaluated by an assessment team to balance wildfire risk with potential PSPS impacts on the customers and the communities we serve. In 2022, we expanded the PSPS decision-making process to include real-time on-site conditions from Field Observers (FOBs). FOBs are Idaho Power personnel positioned within pre-defined PSPS zones to monitor system conditions and periodically report observations to help inform the PSPS assessment team. The location of FOBs in PSPS zones was examined to ensure their safety during severe weather conditions and communication templates were developed to ensure accurate and consistent fire weather reporting. We found that, in some areas, cellular and radio communication does not exist and we had to rely on satellite messaging services. The FOB program became more complex than anticipated, and we will work in 2023 to improve the documentation and procedures as well as increase the number of qualified resources to perform FOB duties in situations where multiple areas are at risk of PSPS.

Customer Communication
Notifying customers in PSPS zones was a priority this year and consisted of telephone, text, and e-mail outreach. We found that some of the targeted customers did not have up-to-date contact information associated with their account. Several efforts were made to encourage customers to update their contact information, and additional information was mailed to those customers without current contact information. This will be a continued focus in 2023.

Community Feedback
The company conducted over 20 WMP and PSPS plan presentations throughout the service area, to advise customers of our plans and to solicit feedback to help inform future versions of the WMP. Seven public meetings were held in Oregon at the end of fire season, and we received good feedback from local fire chiefs, emergency managers, and the general public. Feedback and themes from these meetings and others throughout the year will be incorporated into the 2023 WMP and include:

- Adjusting the timing of public meetings in Oregon to coincide with fire season
- Partnering with agencies and other programs, such as Firewise, when conducting public meetings
- Reviewing risk modeling to include additional areas of consequence
- Having more collaboration with fire agencies including the Idaho Bureau of Land Management (BLM), Forest Service, Baker County, and La Grande Rural Fire Protection District

Vulnerable Populations

Idaho Power participated in two mock events, one conducted by Malheur County in Oregon and another as part of the Idaho Office of Emergency Management's Cascade Rising event. These two events highlighted two opportunities to improve our support for vulnerable populations during an outage or PSPS event. First, the Red Cross was added as a Public Safety Partner in Malheur County based on their role in coordinating Community Resource Centers (CRC). Second, the emPower program was identified as a tool to help notify customers on durable medical devices (DME) if a PSPS event is predicted. Targeted outreach to vulnerable populations was also conducted to include outage preparedness flyers sent to Meals on Wheels participants. In 2023, Idaho Power will further the efforts made in identifying and communicating with vulnerable populations.

Risk Management Process

A review of Idaho Power's risk management process used in developing previous versions of the WMP was completed in 2022. The review found opportunities to improve by strategically incorporating a more formalized risk management process into the WMP. The International Standardization Organization (ISO 31000-2018) is a recognized standard for risk management and will be integrated into the 2023 plan. The standard will help position the company to achieve the objectives of the WMP by fostering continuous improvement and ensuring a consistent approach to risk-based decision making.

REGULATORY CONTEXT

As part of Idaho Power Company's (Idaho Power or company) commitment to deliver safe, reliable, and affordable energy, the company developed a comprehensive Wildfire Mitigation Plan (WMP) to reduce wildfire risk associated with its facilities. The WMP has three core objectives:

1. Reducing wildfire risk for the safety of Idaho Power's customers and the communities in which it operates.

2. Ensuring the continued and reliable delivery of electricity to more than 600,000 retail customers in Southern Idaho and Eastern Oregon.

3. Furthering the company's good stewardship of the beautiful and natural lands within Idaho Power's service area and beyond.

Idaho Power released its inaugural WMP in January 2021. The company's WMP is a living document that will evolve over time. Idaho Power will seek to review, modify, and expand the WMP in the coming years to reflect shifts in industry best practices and to ensure the company is following procedures and requirements established by its regulators. Given that Idaho Power operates in both Oregon and Idaho, below is a description of recent wildfire-related regulatory activities by state.

Idaho

On January 22, 2021, Idaho Power proactively filed its first WMP with the Idaho Public Utilities Commission (IPUC). The company's application provided a narrative of Idaho Power's effort to develop the WMP, including discussion of risk analysis across its service area and evaluation of specific wildfire mitigation activities (e.g., enhanced vegetation management and system hardening) the company would undertake in the coming fire season. Idaho Power asked the IPUC for authority to defer the Idaho jurisdictional share of incremental operations and maintenance expenses and capital depreciation expenses related to implementing the measures in the WMP, as well as incremental insurance costs.

On June 17, 2021, the IPUC issued Order No. 35077, granting the company's application and allowing cost deferral of all incremental wildfire mitigation and insurance expenses identified in Idaho Power's application.

On October 20, 2022, the company filed an updated WMP and a new application for deferral of newly identified wildfire mitigation-related costs.

Oregon

In August 2020, the Public Utility Commission of Oregon (OPUC) opened an informal rulemaking related to mitigating wildfire risks to utilities, utility customers, and the public. The scope of this docket (AR 638) shifted following the 2020 wildfire season, splitting into two tracks—a temporary wildfire rulemaking to govern the 2021 wildfire season and a secondary track to establish replacement permanent rules for the 2022 fire season.

On July 19, 2021, Oregon Governor Kate Brown signed into law Senate Bill 762 (SB 762), a wildfire bill that, among other actions, established minimum requirements for utility wildfire protection (or mitigation) plans. The bill required that utilities file inaugural plans no later than December 31, 2021.

In response to the passage of SB 762, the OPUC halted the permanent wildfire rulemaking in AR 638 and opened docket AR 648 to develop interim permanent rules adhering to the requirements and timing of the new law. On September 8, 2022, the OPUC issued Order No. 22-335 in AR 638 finalizing requirements specific to requirements for utility WMPs.

Idaho Power added Appendix C to the WMP to provide Oregon-specific information related to wildfire requirements and recommendations.

1. INTRODUCTION

1.1. Background

In recent years, the Western United States has experienced an increase in the frequency and intensity of wildland fires (wildfires). A variety of factors have contributed in varying degrees to this trend including climate change, increased human encroachment in wildland areas, historical land management practices, and changes in wildland and forest health, among other factors.

While Idaho Power has not experienced catastrophic wildfires within its service area at the same level experienced in other western states, such as California and more recently certain areasin Oregon, millions of acres of rangeland and southern Idaho forests have burned in the last 30 years.[5] In that same time period, the wildfire season in Idaho has expanded by 70 days.[6] Idaho's wildfire season is defined by Idaho Code § 38-115 as extending from May 10 through October 20 each year, or as otherwise extended by the Director of the Idaho Bureau of Land Management (BLM). Oregon's wildfire season is designated by the State Forester each year pursuant to Oregon Revised Statute § 477.505 and typically begins in June. Idaho Power's operational practices account for the differences between Idaho and Oregon's wildfire seasons and requirements.

1.2. Idaho Power Profile and Service Area

Idaho Power is an investor-owned utility headquartered in Boise, Idaho, engaged in the generation, transmission, and distribution of electricity. Idaho Power is regulated by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. Idaho Power serves approximately 600,000 retail customers throughout a 24,000 square mile area in southern Idaho and eastern Oregon (see Figure 6).

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[5] Rocky Barker, *70% of S. Idaho's Forests Burned in the Last 30 Years. Think That Will Change? Think Again.*, Idaho Statesman, October 4, 2020.

[6] Ibid.

Figure 6
Idaho Power service area

Of Idaho Power's 24,000 square mile service area, approximately 4,745 square miles are located in Oregon and 19,255 in Idaho. Approximately 20,000 customers are served in Oregon and 580,000 in Idaho.

1.3. Asset Overview

Idaho Power delivers electricity to its customers via more than 310 substations, 4,800 miles of overhead transmission lines, and 19,300 miles of overhead distribution lines. Table 3 summarizes the overhead powerline asset information by state. Approximately 2,871 pole miles (12%) are in Oregon and 21,042 (87%) are in Idaho.

Table 3
Overhead transmission voltage level and approximate line mileage by state (Dec. 31, 2021)

ASSET	TOTAL	IDAHO		OREGON		MONTANA		NEVADA		WYOMING	
	Pole Miles	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%
46 kV Transmission Lines	383	383	100								
69 kV Transmission Lines	1,136	743	65	344	30	50	4				
115 kV Transmission Lines	3			3	100						
138 kV Transmission Lines	1,448	1,242	86	141	10			65	4		
161 kV Transmission Lines	84	84	100								
230 kV Transmission Lines	1,148	927	81	219	19						
345 kV Transmission Lines	473	364	77							110	23
500 kV Transmission Lines	103	53	51	50	49						
Total OH Transmission Lines	4,778	3,796	80	757	16	50	1	65	1	110	2
Total OH Distribution	19,297	17,183	89	2,114	11						
Total OH Pole Miles	**24,075**	**20,979**	**87**	**2,871**	**12**	**50**	**0.21**	**65**	**0.27**	**110**	**0.46**

1.4. Objectives of this Wildfire Mitigation Plan

The primary objectives of this WMP are to identify and implement strategies to accomplish the following:

1. Reduce wildfire risk associated with Idaho Power's transmission and distribution (T&D) facilities and associated field operations.

2. Improve the resiliency of Idaho Power's T&D system in a wildfire event, independent of the ignition source.

3. Comply with all wildfire mitigation requirements established by its regulators.[7]

Idaho Power's approach to achieving these objectives includes the following actions:

- Engage with government and industry entities and electric utility peers to ensure understanding and commonality of wildfire mitigation plans.

- Utilize a risk-based approach to quantify wildland fire risk that considers *wildfire probability* and *consequence* to identify areas of elevated wildfire risk within Idaho Power's service area. These identified areas are then incorporated in Idaho Power's geographic information system (GIS) mapping.

- Create specific and targeted operations and maintenance practices, system hardening programs, vegetation management, and field personnel practices to mitigate wildfire risk.

[7] The OPUC established docket AR 648, the interim permanent wildfire rulemaking, after the Oregon legislature passed Senate Bill 762. The bill created a requirement for public utilities in Oregon to submit "wildfire protection plans" to the OPUC by December 31, 2021.

- Incorporate information regarding current and forecasted weather and field conditions into operational practices to increase situational awareness.
- Employ public safety power shutoff (PSPS) protocols for Idaho Power's service area and transmission corridors.
- Evaluate the performance and effectiveness of strategies identified in this WMP through metrics and monitoring. The WMP and all its components will be reviewed prior to wildfire season each year.

2. Government, Industry, and Peer Utility Engagement

2.1. Objective

Idaho Power recognizes the importance of engaging with federal, Idaho and Oregon State governments, and local governments as an integral part of mitigating wildfire risk. Idaho Power also recognizes the importance of engagement and outreach with respect to potential future PSPS events to minimize customer impact.

Idaho Power's wildfire mitigation plan and outage preparedness strategy includes specific activities to engage with key stakeholders to share information, gain feedback, and incorporate lessons learned. Peer utility engagement is crucial to ensure the company's efforts are informed by the best practices of its peers in Idaho and Oregon.

2.2. Government Engagement

Much of Idaho Power's service area extends over land managed by the BLM and U.S. Forest Service. Idaho Power engages with both agencies to share information and identify areas and activities that are mutually beneficial. For example, Idaho Power allowed for an extended firebreak along Highway 93 in Jerome County, Idaho, on its property to help with BLM wildfire mitigation initiatives.

Idaho Power is also a member of the Idaho Fire Board, which was initiated by the U.S. Forest Service. Membership is voluntary and currently includes the Forest Service, BLM, Federal Emergency Management Agency (FEMA), Idaho State Lands Department, Idaho Department of Insurance, Idaho Military Division, City of Lewiston, Idaho Power, and The Nature Conservancy in Idaho.

Idaho Power is actively engaged with both the IPUC and the OPUC with respect to wildfire mitigation activities. Idaho Power filed its WMP with the IPUC in 2021 and again in 2022. In Oregon, the company is required to submit an updated WMP by the end of each calendar year. Idaho Power continues to participate in the OPUC's Oregon Wildfire and Electric Collaborative (OWEC) and ongoing rulemaking efforts.

2.3. Industry and Peer Utility Engagement

Although Idaho Power relied on plans developed by several California utilities in drafting its own WMP, modifications were made to account for Idaho Power's considerably different risk profile. Additionally, Idaho Power participated in multiple workshops with San Diego Gas and Electric, Southern California Edison, Pacific Gas and Electric, Sacramento Municipal Utility District, and PacifiCorp. The company continues to engage with these utilities to learn about California's evolving practices.

In the Pacific Northwest, many utilities work collaboratively to understand and ensure commonality of their various wildfire mitigation plans, while accounting for the variation in each utility's unique service area. These utilities include Idaho Power, Avista Utilities, Portland General Electric, Rocky Mountain Power, Pacific Power, Chelan County Public Utility District, Puget Sound Energy, NV Energy, Bonneville Power Administration (BPA), and Northwestern Energy.

Idaho Power is also a member of both the Edison Electric Institute (EEI) and the Western Electric Institute (WEI). The company participated in multiple workshops and conferences with both entities and member utilities to evaluate the strength and effectiveness of Idaho Power's WMP in comparison to other members' plans. Additionally, Idaho Power's CEO and President is an active member of the EEI Electricity Subsector Coordinating Council Wildfire Working Group. This working group has been partnering with the U.S. Department of Energy and other government agencies to collectively minimize wildfire threats and potential impacts.

These workshops continue to prove valuable for sharing wildfire mitigation best practices and discussing new and existing technology related to wildfire mitigation. For example, EEI and WEI workshops, as well as independent investigations, led Idaho Power to expand its use of Unmanned Aircraft Systems ([UAS] also known as drones) during line patrols, replace expulsion fuses with energy limiting fuses, and add mesh wraps to wood poles in wildfire risk zones. Idaho Power has also enlisted a team of employees to focus on wildfire mitigation technologies by identifying opportunities to incorporate new and innovative technologies into Idaho Power's wildfire mitigation efforts.

2022 Industry and Peer Utility Engagement

Idaho Power continues to engage with industry groups and peer utilities to gain knowledge of new mitigation activities, industry best practices, and employing technology to reduce wildfire risk. The following summarizes 2022 activities:

- Technology—Held meetings with over 30 vendors and manufacturers to identify new technology and innovations used to mitigate wildfire risk. The findings were used to develop a roadmap and led to the creation of pilot projects in 2022 and 2023.
- Electric Power Research Institute (EPRI)—Engaged with EPRI to learn more about new technology and the attributes of covered conductor, particularly the UV performance and reliability performance.
- Utility Wildfire Symposium—Attended a symposium hosted by EPRI and Portland General Electric focused on new technology, trends, and ways to mature risk modeling.
- NW Wildfire Group—Attended biennial meetings and shared details of Idaho Power's WMP and PSPS plan with attendees including how new technology and innovative materials are being incorporated.
- WEI—Provided a presentation and details of Idaho Power's documented processes and procedures used in PSPS execution and customer notifications.
- WEI Wildfire Planning and Mitigation Virtual Meeting—Attended a two-day conference to gain insight into mitigation activities and strategies other utilities are pursuing.
- International Wildfire Risk Mitigation Consortium—Held meetings throughout the year with program managers and participated in a risk reduction seminar focused on vegetation management.
- Oregon Wildfire Detection Camera Strategy Group—Became a member of a workgroup focused on the interoperability of different camera platforms to improve fire detection, suppression efficiency, and response time. This group has provided valuable information into the benefits that cameras hold for early fire detection and how partnerships can be utilized to expedite the installation.
- Wildfire Technology Webinar—Attended webinar focused on using artificial intelligence (AI) drones for grid inspections, aerial sensors, and cameras to gain situational awareness.
- National Forest Foundation (NFF)—Attended multiple meetings with the NFF and other agencies to learn more about the benefits of fuel treatments and shared stewardship programs and how utilities have participated in other locations. Lessons learned include details of the success achieved in the Upper Arkansas Forest Fund in the State of Colorado.
- British Standards Institute (BSI) —Attended a two-day course taught by BSI to gain knowledge of the International Organization for Standardization (ISO) 31000 risk management framework and how it can be applied to the company's WMP.

3. Quantifying Wildland Fire Risk

3.1. Objective

Idaho Power's approach to quantifying wildland fire risk is to identify geographic areas of elevated wildfire risk if a wildfire ignites near a power line. Mitigation actions and programs are prioritized in those areas identified as elevated wildfire risk areas.

3.2. Identifying Areas of Elevated Wildfire Risk

Idaho Power hired an external consultant that specializes in assessing and quantifying the threat of wildfire through a risk-based methodology that leverages weather modeling, wildfire spread modeling, and Monte Carlo simulation. This methodology is not unique to Idaho Power's WMP. The California Public Utilities Commission (CPUC) used the same modeling approach (and in fact, the same consultant) in developing its CPUC Fire Threat Map. In addition, other utilities in Oregon, Idaho, Nevada, and Utah have utilized similar modeling to identify and quantify wildfire risk.

This methodology is consistent with conventional definitions of *risk*, which is usually taken as an event's *probability* multiplied by its potential negative *consequences* or impacts should that event occur. For Idaho Power's wildfire risk assessment, this formula is:

Wildfire Risk = Fire Probability x Consequence

The definition of each component is as follows:

Fire Probability. Fire volume (i.e., spatial integral of fire area and flame length) is used as Fire Probability because rapidly spreading fires are more likely to escape initial containment efforts and become extended fires than slowly developing fires. Data inputs used in the fire spread model to determine the fire volume (Fire Probability) include:

- Historical weather (temperature, wind speed/direction, relative humidity)
- Topography
- Fuel types present
- Fuel moisture content (both dead and live fuels)

Consequence. Number of structures (i.e., homes, businesses, other man-made structures) that may be impacted by a wildfire.

Wildfire Risk. Fire Probability multiplied by the Consequence. The highest Wildfire Risk areas are those where both the Fire Probability and Consequence are elevated. Conversely, combinations of low Fire Probability and elevated Consequence, or elevated Fire Probability and low Consequence typically indicate lower Wildfire Risk.

3.2.1. Wildfire Risk Modeling Process

The wildfire risk modeling process incorporated the following major steps:

1. A 20-year (2000–2019) fire weather climatology was developed utilizing the Weather Research and Forecasting (WRF) model to recreate historical days of fire weather significance across Idaho Power's service area. This analysis generated high-resolution hourly gridded fields of relative humidity, temperature, dead fuel moisture, and wind speed/direction that was used as input to a Monte Carlo-based fire modeling analysis.

2. Estimates of seasonal variation in live fuel moisture across Idaho Power's service area were developed. This was accomplished by analyzing historical fuel measurements and/or weather station observations. This step was necessary because live fuel moisture data is needed for fire spread modeling, but the WRF weather model does not provide live fuel moistures.

3. The federal LANDFIRE program was utilized to provide high-resolution (approximately 100 feet) fuel rasters for use in fire spread modeling.[8]

4. The data developed above (WRF climatology, live fuel moisture, and LANDFIRE data) was used to drive a Monte Carlo[9] fire spread modeling analysis. This Monte Carlo simulation was accomplished by randomly selecting an ignition location and a randomly selected day from the fire weather climatology developed in step 1 above. Ignition locations were limited in the model to be within a two-kilometer buffer surrounding Idaho Power's overhead T&D lines (i.e., 1 kilometer on either side). The model used equal ignition probability for all overhead distribution and transmission asset types. Urbanized areas having underground circuitry were not included in the model due to a low probability of wildfire associated with underground electrical equipment. Note that transmission lines jointly owned by Idaho Power and PacifiCorp were included in the analysis. Furthermore, the proposed Boardman to Hemingway (B2H) 500 kilovolt (kV) line route was also included in this analysis. For each combination of ignition location and time of ignition, fire progression was then modeled for 6 hours. For each modeled fire, potential fire impacts to structures were quantified using structure data. This was repeated across Idaho Power's service area for millions of combinations of ignition location and time of ignition.

5. The Monte Carlo results were processed, and GIS based data depicting fine grained wildfire risk was developed. This risk was then visually depicted on GIS based wildfire risk maps.

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[8] Chris Lautenberger, Mapping areas at elevated risk of large-scale structure loss using Monte Carlo simulation and wildland fire modeling. IAFSS 12th Symposium 2017.

[9] Ibid.

2023 Risk Modeling Update

With the help of our consultant in 2023, Idaho Power will strive to improve risk modeling to better understand wildfire risk and estimations of wildfire consequences along electric lines and equipment. Ares of focus include:

- Incorporate structure density information using 2020 Census data
- Incorporate proposed building developments in or near wildfire risk zones
- Explore new available data to potentially incorporate into wildfire probability and consequence. Examples include:
    - Fire history
    - Land use changes

Additionally, Idaho Power's risk modeling update will include assessing feedback from customers and agencies received throughout the year. Enhancements made will provide more understanding and improved methods to better inform operational decision-making and risk treatments.

Idaho Power's broader risk framework is discussed in Section 4.

3.2.2. Wildfire Risk Areas

Based on the previously described modeling, draft risk tiers were generated algorithmically[10] by an automated process. Tiers were established which, if exceeded, would classify an area as Tier 2 (elevated risk) or Tier 3 (high risk). To aid in customer and public understanding, Idaho Power also color-coded the tiers to reflect relative risk—Yellow Risk Zones (YRZ) for Tier 2 and Red Risk Zones (RRZ) for Tier 3. This was accomplished by manually setting threshold values at naturally occurring breaks. Idaho Power held several public workshops wherein tiers were reviewed and adjusted based upon consideration of local and institutional knowledge and potential impacts to communities. This was a similar approach taken by the California Public Utilities Commission in developing a state wildfire risk map. Consequently, the resulting risk tiers reflect risk relative to Idaho Power's service area only and not absolute risk. As set forth later in this plan, Idaho Power's risk profile is significantly lower than utilities serving California.

An integral part of the consultant's mapping process involved reviewing the tiers and making necessary adjustments to account for unique aspects of certain areas, including factors that may increase or decrease risk, which would not be accounted for in the computer modeling. Several factors were considered, including the following:

[10] Ibid.

- Topography and resistance to fire control
- Means of ingress and egress
- Presence/absence of defensible space
- Vulnerable populations
- Cell phone coverage
- Non-burnable land cover such as built-up urban areas

This review helped define overall tier boundaries and, in some cases, expanded Tier 3 areas or moved certain Tier 2 areas into Tier 3. For example, the Charlotte fire was a human-caused fire that occurred in Pocatello in 2012 and burned more than 1,000 acres and destroyed 66 homes and 29 outbuildings. It was a difficult fire to control and highlighted the dangers of juniper trees intermixed within the wildland urban interface (WUI). Local knowledge of this event was used to expand outlying Tier 2 areas in the vicinity of the Charlotte fire into Tier 3. As part of integrating the ISO 31000 risk management processes into the WMP, Idaho Power plans to review tier levels and boundaries as part of continuous improvement and maturing our risk modeling methods.

Table 4 provides a breakdown of pole miles in risk zones on a system-wide basis and by state. Across Idaho Power's service area, 8% of pole miles exist in elevated risk zones (either RRZs or YRZs). In Idaho, 5% of pole miles exist in YRZs and 3% exist in RRZs. In Oregon, less than 1% of pole miles exist in YRZs. The company has no RRZs in Oregon.

Table 4
Idaho Power's transmission and distribution lines by risk zone in Idaho and Oregon*

Asset	Total	Total Pole Miles within Wildfire		Wildfire Risk Zone by State											
				Tier 2 - Idaho		Tier 3 - Idaho		Tier 2 - Oregon		Tier 3 - Oregon		Tier 2 - Nevada		Tier 3 - Nevada	
	Pole Miles	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%
Transmission Lines	4,778	517	11%	376	8%	110	2%	20	0.42%	0	0%	11	0.23%	0	0%
Distribution Lines	19,297	1,447	7%	837	4%	581	3%	29	0.15%	0	0%	0	0%	0	0%
Total Pole Miles	24,075	1,964	8%	1,213	5%	691	3%	49	0.20%	0	0%	11	0.05%	0	0%

*Geospatial analysis was performed in 2022 to reconfirm the pole miles in wildfire risk zones.

The final two-tier risk map reflecting relative increased risk in YRZs and RRZ is shown in Figure 7. The map is the foundation of Idaho Power's wildfire mitigation and risk reduction strategies. It is used to determine and prioritize targeted investments, inspection activities, and increase situational awareness for field personnel.

The risk zone map can be viewed in detail on Idaho Power's website. Individual addresses can be entered on the map to determine proximity to identified risk zones.

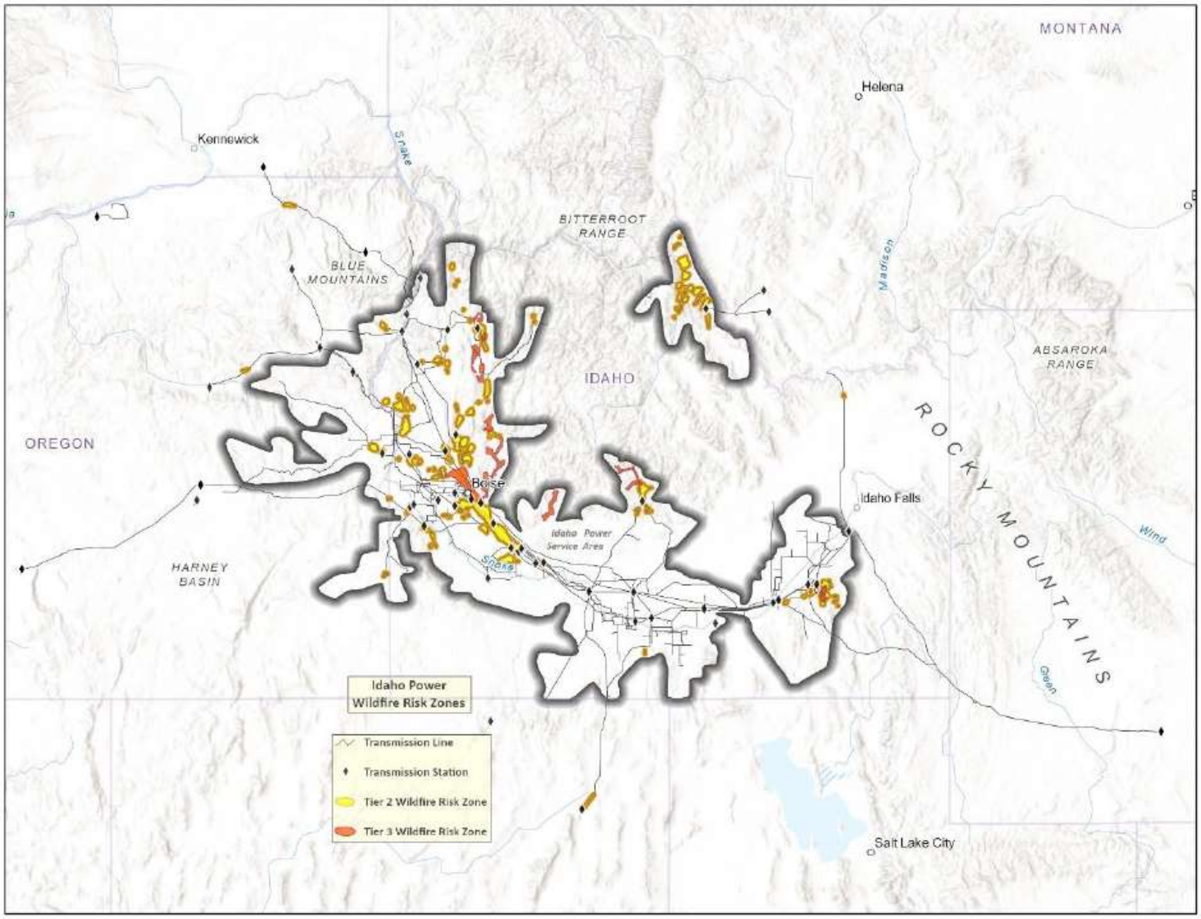


Figure 7
Wildfire Mitigation Plan—Risk Map

Additionally, Figures 8 through 11 delineate risk zones in Idaho and Oregon.

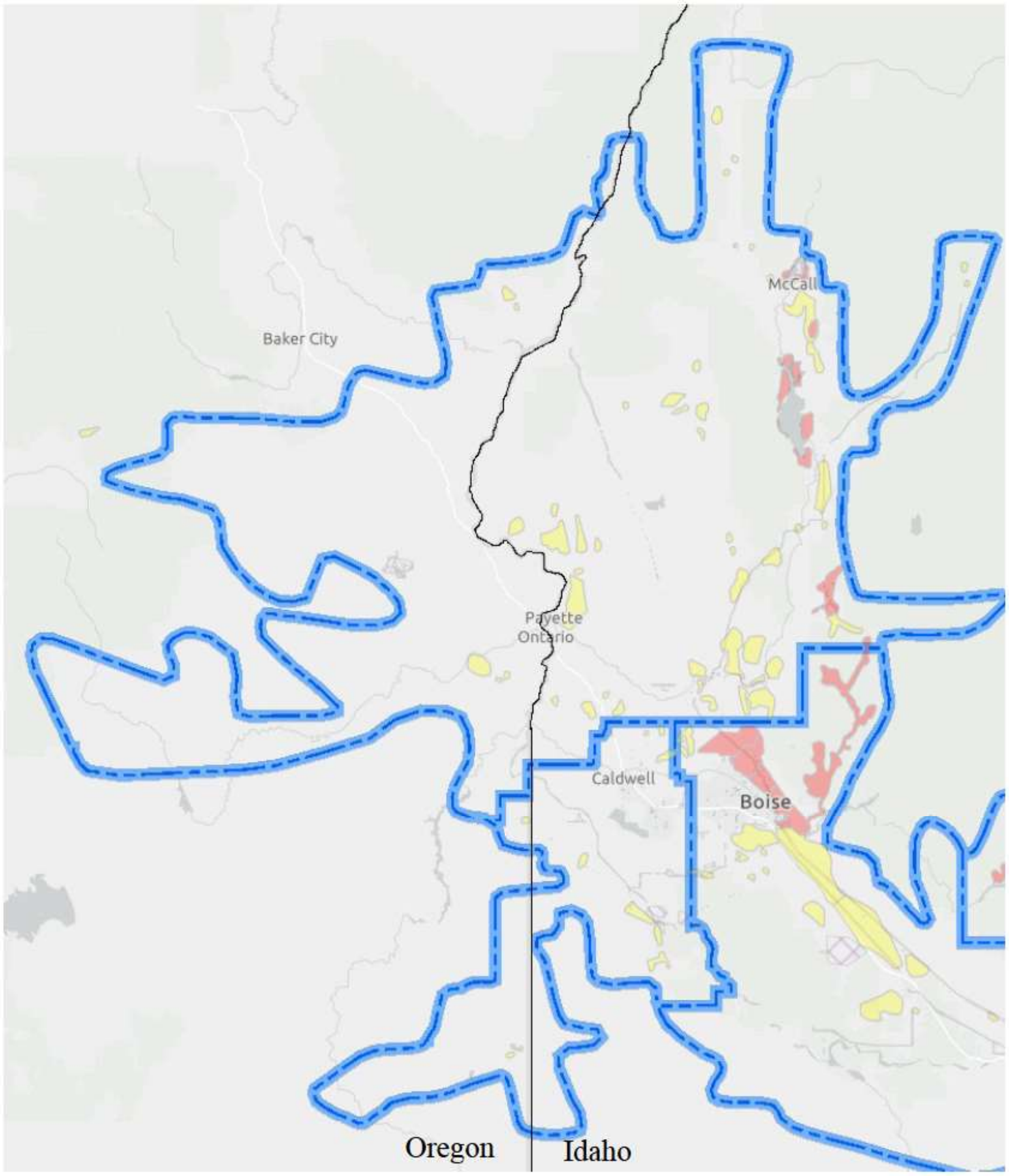
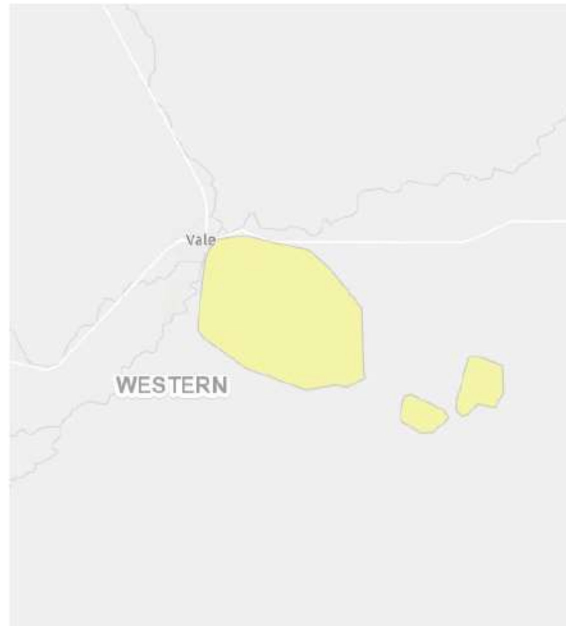


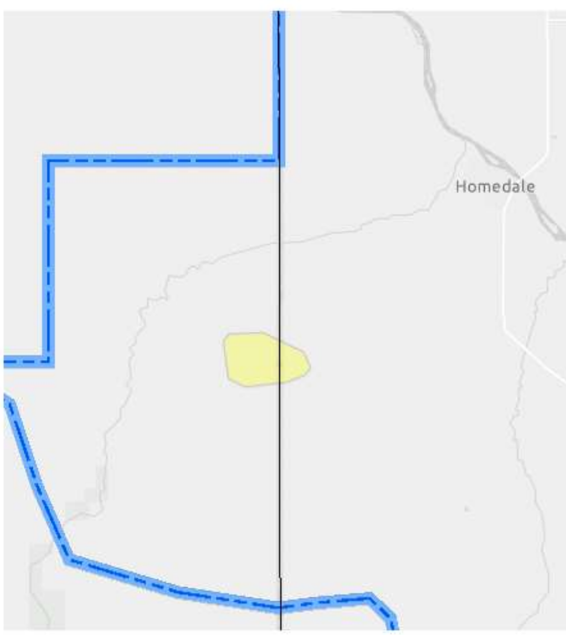
Figure 8
Wildfire Risk Map—western Idaho and eastern Oregon

Halfway

Vale



Idaho-Oregon Boarder



Jordan Valley

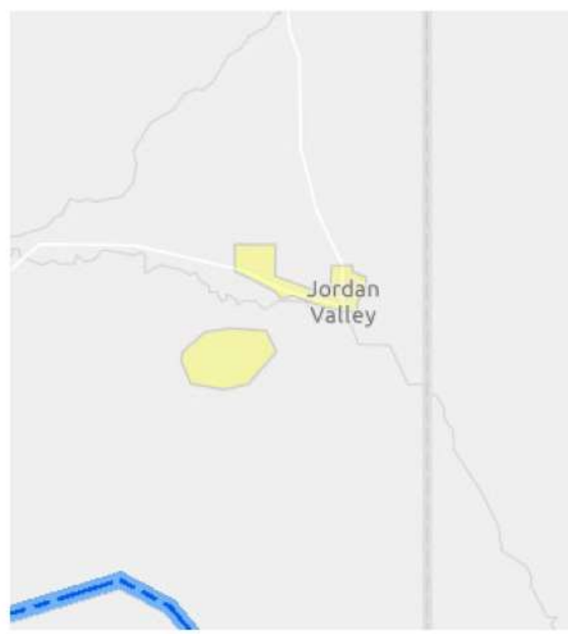


Figure 9
Oregon-specific zones

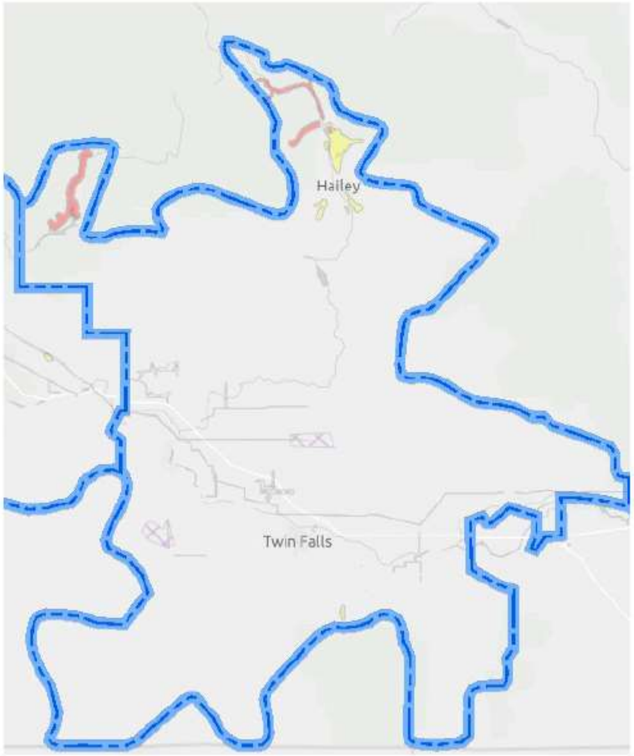
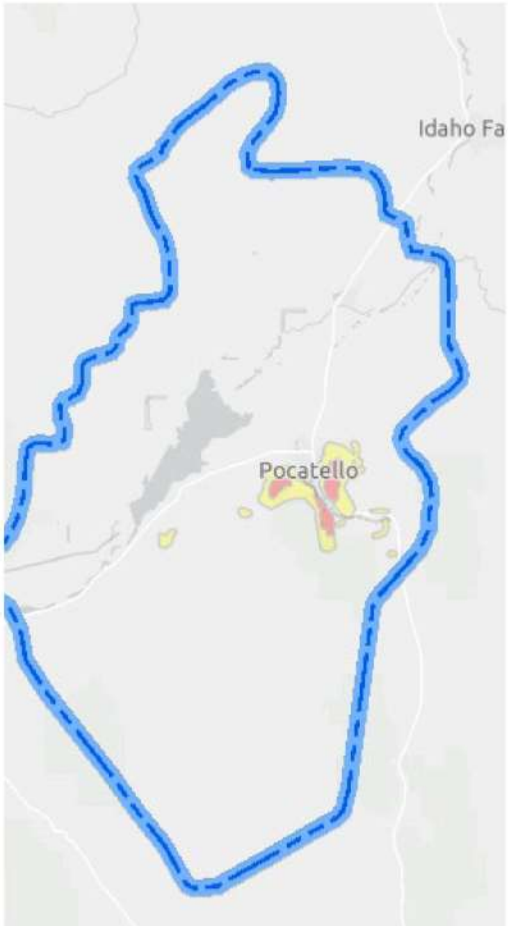


Figure 10
Wildfire Risk Map—southern Idaho

Pocatello



Salmon

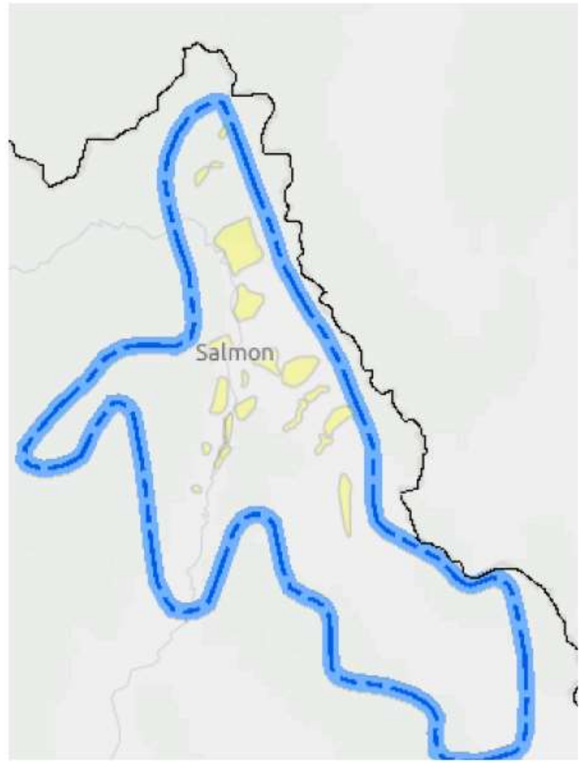


Figure 11
Wildfire Risk Map—eastern Idaho

3.2.2.1. Boardman to Hemingway Proposed Transmission Line

Idaho Power specifically considered the proposed route of the B2H 500 kV transmission line as part of the WMP. The proposed B2H route was included in the wildfire risk assessment and associated map analysis (see Figure 3). Two locations are identified along the route as having increased wildfire risk (YRZs), and there were no areas of higher risk (RRZs). Although the B2H transmission line has not been constructed as of the publication of this 2023 WMP, Idaho Power intends this WMP (as it will be reviewed annually) will apply to B2H. Additionally, Idaho Power will continue to update its fire risk mapping periodically and address the locations with elevated risk consistent with the mitigation strategy for transmission lines as described in sections 5–9 of this WMP.

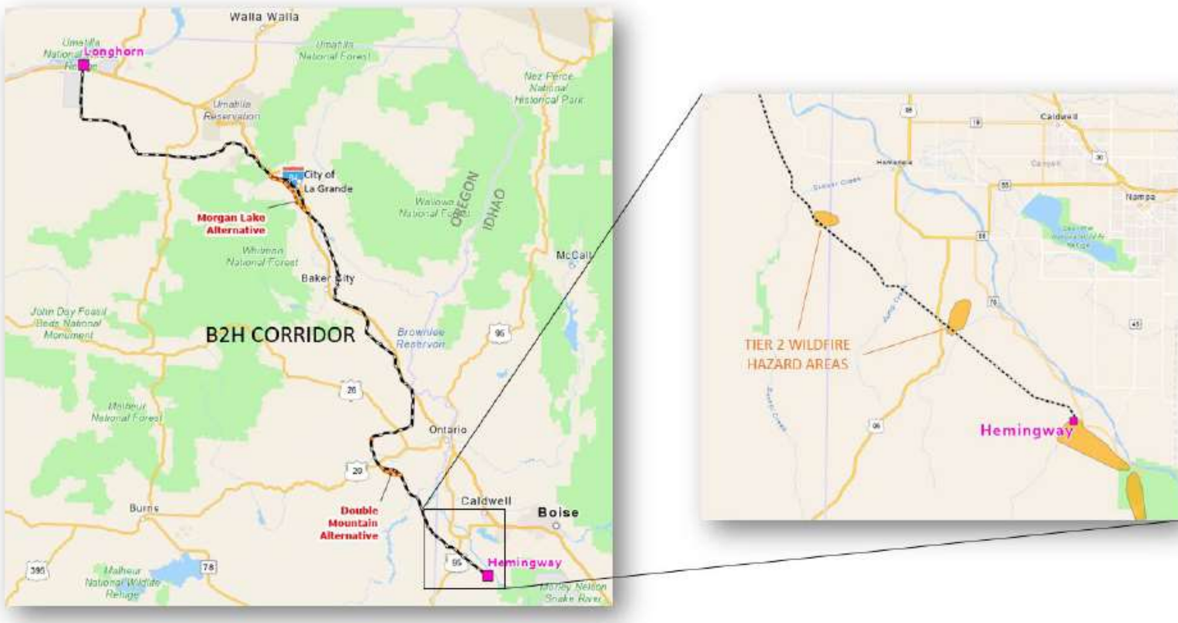


Figure 12
B2H proposed route risk zones

4. Costs and Benefits of Wildfire Mitigation

4.1. Objective

This section details Idaho Power's assessment of high-level risk with respect to undertaking wildfire mitigation activities. This assessment provides a framework for understanding the potential consequences of wildfire damage and the possibility of diminishing those consequences through targeted mitigation activities.

To that end, Section 4.3 identifies selected mitigation activities and the estimated costs of those activities on a system level. In Section 4.4, each mitigation activity is discussed in detail, with an assessment of why it was selected, what alternatives (if any) may be available, and any additional benefits (referred to as "co-benefits") the company believes may result from pursuing it.

4.2. Risk-Based Cost and Benefit Analysis of Wildfire Mitigation

In assessing the probability and consequence of wildfire risk, and to identify benefits of various wildfire mitigation efforts, Idaho Power engaged with its external consultant and considered several sources of empirical data on the costs of major wildfires—both in terms of fires that burn into Idaho Power's facilities or that originate from electric infrastructure. These costs can include replacement costs of the company's property; the cost of fire suppression and environmental damage; third-party claims for property damage; employee and public injuries and fatalities; and other economic losses.

Through its research, Idaho Power found that obtaining a precise calculation of the potential costs of future wildfires is not realistic. The damage that any fire may cause depends on factors such as wind and weather, vegetation, fire risk levels, location, and population and structure density.

Idaho Power's assessment of the potential costs of wildfires—used in developing the WMP and the scope of proposed updates to practices—involved a review of prior major fires in other states, as well as calculations by other western utilities. While this assessment did not yield a precise quantification of potential benefits specific to Idaho Power, it provides a helpful illustration of the potential costs of not taking actions aimed at reducing wildfire risk.

Idaho Power reviewed and considered calculations analyzing the potential reduction in probability of igniting wildfires based on risk-mitigating activities. For instance, in a June 2020 filing before the IPUC, Avista Corporation (Avista) stated that its "analysis indicates a 10-year inherent potential risk exposure of at least $8 billion dollars," though noted the figure should not be interpreted as a precise financial estimate.[11] Avista further noted that the actions it proposes in its own wildfire resiliency plan result in an average percentage of risk mitigation of 89% for the overall plan.[12]

In California, costs and damages associated with wildfires in recent years have exceeded $10 billion per year, with those associated with the 2020 fires alone potentially set to exceed $20 billion.[13] This increase[14] is consistent with the fact that, with few exceptions, the prevalence, intensity, and impact of wildfires continues to escalate year after year as evidenced by information compiled by the California Department of Forestry and Fire Protection (CAL FIRE) and detailed in Table 5.

Table 5
CAL FIRE wildfire data by year

Year	Estimated Acres Burned	No. of Wildfires	No. of Confirmed Fatalities	No. of Structures Damaged or Destroyed
2020	4,197,628	9,279	31	10,488
2019	259,823	7,860	3	732
2018	1,975,086	7,948	100	24,226
2017	1,548,429	9,270	47	10,280
2016	669,534	6,954	6	1,274

The data compiled by peer utilities, historic fire costs, and known damage from prior fires are instructive. Considering peer metrics and analyses on probability and magnitude, as well as Idaho Power's own empirical review of wildfire events such as those in California and Oregon—and the resulting loss of lives—it is reasonable to conclude that the potential human and capital costs and damage from wildfire events vastly exceed any incremental costs of wildfire mitigation efforts identified in this WMP.

[11] *In the Matter of Avista Corporation's Application for an Order Authorizing Accounting and Ratemaking Treatment of Costs Associated with the Company's Wildfire Resiliency Plan,* Case No. AVU-E-20-05, Application at 17.

[12] Ibid.

[13] Jill Cowan, *How Much Will the Wildfires Cost?*, The New York Times, Sept. 16, 2020, at https://www.nytimes.com/2020/09/16/us/california-fires-cost.html.

[14] Idaho Power believes that its system is in notably better condition than some utilities in California. Nevertheless, these figures illustrate the destruction that can occur from vegetation contact if vegetation is not actively managed.

2023 Wildfire Mitigation Analysis Framework

In 2022, Idaho Power reviewed the risk management process used in developing previous versions of the WMP. The review consisted of reexamining existing risk management practices, specifically how risk is analyzed, evaluated, treated, and continuous improvement is applied. We also benchmarked against other western utilities' risk management approaches and consulted with risk management professionals, both internal and external to Idaho Power.

A formalized risk management process will provide greater structure and consistency in decision making, continuous improvement, and maturing our analytical approach to balancing costs and mitigation benefits. As part of this work, the company determined that the international standard ISO 31000 is widely used by other utilities as a guide or foundation for their WMPs and was recommended to be incorporated by risk management professionals. The ISO 31000 is one of several guides to effective risk management and much of the processes used to create previous versions of the WMP align with the recommended practices found in the standard. However, the ISO 31000 provides a more comprehensive approach to risk management than what was being employed prior and will be integrated into the plan in 2023. This effort will start by performing the following:

- Engage Idaho Power stakeholders to participate in risk review processes and activities with the goal that all employees become managers of risk
- Develop a comprehensive picture of all risk management activities associated with the WMP and how they compare to the ISO 31000
- Determine how the ISO 31000 principles can be applied, achieved, measured, and tracked
- Develop a framework based on the ISO 31000 that provides a structured and effective approach to managing wildfire-related risk and includes a process of reviewing and maturing the methods used for risk identification, analysis, evaluation, and treatment

4.3. Wildfire Mitigation Cost Summary

From 2022–2025, Idaho Power estimates investing $46.8 million in incremental operations and maintenance (O&M) expenses to further wildfire mitigation measures. The following table summarizes the company's planned expenditures associated with executing its WMP through 2025. Estimated amounts reflect the company's best estimates and plans as of the 2022 WMP. These estimates will likely change in the future as the company reviews and refines its WMP and associated mitigation activities. For the 2022 WMP, each wildfire mitigation category—and associated estimated expenditures in Oregon and Idaho—is discussed in Section 4.4.

Table 6
Estimated system-wide incremental O&M expenses for wildfire mitigation, $000s (2023–2025)[15]

	2023	2024	2025	Idaho Power System Total 2023 - 2025
A. Quantifying Wildland Fire Risk				
Risk Map Updates	$ 67	$ -	$ 69	$ 136
B. Situational Awareness				
Weather Forecasting - System development and support	$ 47	$ 74	$ 74	$ 195
Weather Forecasting Personnel - Fire Potential Index (FPI) and Public Safety Power Shutoff (PSPS)	$ 178	$ 99	$ 102	$ 379
Weather Forecasting - Weather Station Maintenance	$ 19	$ 24	$ 30	$ 73
Pole Loading Modeling & Assessment (Contract service)	$ 75	$ 75	$ 75	$ 225
Cameras	$ 165	$ 220	$ 220	$ 605
C. Mitigation - Field Personnel Practices				
Tools/Equipment	$ 5	$ 5	$ 5	$ 15
Mobile Weather Kits for Field Observers	$ 10	$ -	$ -	$ 10
International Wildfire Risk Mitigation Consortium	$ 40	$ 40	$ 40	$ 120
D. Mitigation - Transmission & Distribution Programs				
O&M Component of Capital Work	$ 61	$ 60	$ 54	$ 175
Annual O&M T&D Patrol Maintenance Repairs	$ 50	$ 50	$ 50	$ 150
Environmental Management Practices	$ 25	$ 25	$ 25	$ 75
Transmission Thermography Inspection Mitigation - Red Risk Zon	$ 20	$ 20	$ 20	$ 60
Distribution Thermography Inspection Mitigation - Red Risk Zone	$ 30	$ 30	$ 30	$ 90
Thermography Technician Personnel	$ 160	$ 165	$ 170	$ 495
Transmission Wood Pole Fire Resistant Wraps - Red Risk Zone	$ 88	$ -	$ -	$ 88
Transmission Wood Pole Fire Resistant Wraps - Yellow Risk Zone	$ 163	$ 163	$ 163	$ 489
Wildfire Mitigation Program Manager	$ 191	$ 196	$ 202	$ 589
Covered Wire Evaluation - Pilot Program in PSPS Zones	$ 50	$ 50	$ -	$ 100
E. Vegetation Management				
Transition to/Maintain 3-year Vegetation Management Cycle	$ 11,196	$ 13,347	$ 12,172	$ 36,715
Enhanced Practices for Distribution Red & Yellow Risk Zones (Pre-Fire Season Patrols/Mitigation, Pole Clearing, Removals, Work QA)	$ 1,284	$ 1,349	$ 1,416	$ 4,049
Line Clearing Personnel	$ 159	$ 164	$ 169	$ 492
Fuel Reduction Program	$ 75	$ 75	$ 75	$ 225
Vegetation Mgmt Satellite and Aerial patrols	$ 150	$ 300	$ 300	$ 750
F. Communications				
Wildfire/Wildfire Mitigation Education/Communication - Advertisements, Bill Inserts, Meetings, Other	$ 100	$ 100	$ 100	$ 300
PSPS Customer Education/Communication - Advertisements, Bill Inserts, Other	$ 71	$ 71	$ 71	$ 213
G. Information Technology				
Communication/Alert Tool for PSPS Customer Alerts/Extended Use	$ 129	$ 129	$ 129	$ 387
Forecast Incremental O&M Expenditures Total	$ 14,608	$ 16,831	$ 15,761	$ 47,200

[15] As of December 29, 2022.

4.4. Mitigation Activities

Idaho Power selected individual wildfire risk mitigation activities based on a variety of factors, including assessment of industry best practices in wildfire mitigation; discussions with peer utilities; consultation with government entities and agencies; and with consideration of alternatives that could be pursued.

Below is a narrative of each mitigation activity, its purpose, estimated near-term cost, potential co-benefits of the activity to Idaho Power and its customers, and potential alternatives.

With respect to Idaho and Oregon cost estimates, the estimated costs identified below are grounded in cost assignment between the company's Idaho and Oregon service areas and further informed by anticipated work in the two service areas.

4.4.1. Quantifying Wildland Fire Risk

Idaho Power's assessment of wildland fire risk is discussed in Section 3 of this WMP.

The first step in developing Idaho Power's WMP was to conduct a comprehensive assessment of the company's service area and transmission corridors. The company worked with Reax Engineering, a consulting firm that specializes in wildfire risk modeling and fire science, to conduct Idaho Power's wildfire risk analysis. The company determined that hiring an external consultant was beneficial for two reasons: (1) an external consultant was more cost effective than hiring additional resources within Idaho Power to perform the modeling, and (2) an outside consultant helped ensure Idaho Power's risk analysis approach was similar to its peer utilities.

An additional co-benefit of hiring an external consultant is aligning risk analysis with other utilities' practices to create a basis for comparison of risk and also a standard terminology and methodology in discussing risk. Idaho Power deemed Reax Engineering a qualified consultant to perform wildfire risk analysis based on the work it performed for the CPUC in developing the CPUC Fire Threat Map. Other utilities in Oregon, Idaho, Nevada, and Utah have utilized similar modeling approaches to identify and quantify wildfire risk.

Cost Estimate for Quantifying Wildland Fire Risk (2023–2025)

Idaho Power intends to re-evaluate its risk analysis using an external consultant on two more occasions between 2023 and 2025. Idaho Power estimates system-wide expenditure for these services to be approximately is $136,000.

4.4.2. Situational Awareness—Weather Forecasting Activities and Personnel

Idaho Power discusses specific situational awareness practices in Section 5 of this WMP.

In developing the WMP, Idaho Power created a new Fire Potential Index (FPI) tool to support operational decision-making to reduce wildfire threats and risks. The tool takes data on weather,

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC

prevalence of fuel (i.e., trees, shrubs, grasses), and topography, and converts that data into an easily understood forecast of the short-term fire threat for different geographic regions in Idaho Power's service area. Additionally, Idaho Power plans to continue to enhance meteorological and weather forecasting capabilities to further improve FPI forecasting and help determine when a Public Safety Power Shutoff may be necessary in Idaho Power's service area.

The benefits of developing the FPI and enhancing the company's meteorological forecasting capabilities is greater situational awareness of Idaho Power's system during critical peak summer months. To continue to generate useful information and system benefits, Idaho Power's situational awareness activities will be evaluated and updated annually as necessary to support the company's wildfire preparedness.

The company considers the FPI and related efforts an essential part of reducing the risk of ignition from work activities. This provides Idaho Power field personnel would not have a tool to assess the fire potential on a consistent basis. Given the distinct benefits that result from the FPI and enhanced foresting capabilities, Idaho Power did not consider alternatives to the development of these critical tools.

Cost Estimate for Situational Awareness—Weather Forecasting Activities and Personnel (2023–2025)

The estimated expenditure for weather forecasting activities (weather forecasting tools, system development, weather station maintenance, and personnel) is $647,000 between 2023 and 2025.

4.4.3. Situational Awareness—Advanced Technologies

Beginning in 2022, Idaho Power created a Technology Strategy Initiative team aimed at determining how new technologies and innovative practices can be incorporated into the company's wildfire mitigation practices to further decrease wildfire risk. Technology-based practices being considered include—amongst others—strategic use of cameras, satellite, and aerial imagery to detect vegetation hazards, pole loading modeling (to assess the structural integrity of poles), as well as covered conductors. With regard to cameras, the company is evaluating a pilot to test placement of cameras in strategic, high-risk locations to enhance situational awareness. Additionally, the company is learning more about artificial intelligence and how it can be leveraged to detect wildfire ignitions. Multiple camera and analytics companies are being considered to determine potential cost-effective solution(s). The company is also working with local agencies to explore the possibility of partnering on the installation and ongoing use of cameras which may lead to reduced cost.

Cost Estimate for Situational Awareness—Pole Loading Modeling and Assessment (2023–2025)

The estimated system-wide expenditure to conduct pole loading modeling and assessment, which includes LIDAR assessment, is $225,000 for 2023 through 2025. Idaho Power plans to conduct the assessment in its highest risk zones, which are located exclusively in Idaho, as detailed in Table 4.

Cost Estimate for Situational Awareness—Cameras (2023–2025)

The estimated system-wide expenditure for the pilot evaluation installation of cameras in high-risk areas is $605,000 from 2023 through 2025. Idaho Power plans to prioritize the use of cameras in its highest risk zones, which are located exclusively in Idaho as detailed in Table 4.

4.4.4. Field Personnel Practices

Idaho Power discusses its field personnel practices in Section 6 of this WMP.

Idaho Power's wildfire mitigation strategy includes procedural measures to reduce potential ignition and spread of wildfires. Idaho Power developed a *Wildland Fire Preparedness and Prevention Plan* (included as Appendix A to this WMP) to provide guidance to Idaho Power employees and contractors. The plan includes information regarding fire season tools and equipment available on the job site; daily situational awareness relative to areas with heightened fire conditions; expected actions and mechanisms for reducing on-the-job wildfire risk as well as reporting requirements in the event of an ignition; and training and compliance requirements.

All Idaho Power crews, and certain field personnel and contractors performing work on or near Idaho Power's facilities are required to operate in accordance with the provisions of the *Wildland Fire Preparedness and Prevention Plan* and expected to conduct themselves in a fire-safe manner. They should be prepared for wildfire by carrying specific tools, including but not limited to, shovels, Pulaskis,[16] and water for initial suppression. Additionally, Idaho Power's PSPS program (included as Appendix B to this WMP) includes employees acting as Field Observers to report on site conditions as part of the de-energization process. Field Observers are equipped with mobile weather kits that include wind meters, compasses, and satellite communication devices to report real-time conditions.

The preparedness of Idaho Power crews and contractors is critical to comprehensive wildfire risk reduction practices. The incremental investment in field personnel equipment is focused on additional tools carried by employees working in elevated risk zones. Additionally, Idaho Power will join the International Wildfire Risk Mitigation Consortium (IWRMC), a group whose mission is to share lessons learned, best practices, and innovation in the area of wildfire mitigation. Many of Idaho Power's utility peers are part of the consortium. The company is not aware of any other effort or group that provides a similar level of access or insight into global thinking and advancements in wildfire mitigation as the IWRMC.

Cost Estimate for Field Personnel Equipment (2022–2025)

The estimated system-wide expenditure for field personnel equipment (tools, mobile weather kits, and participation in the IWRMC) is $145,000 between 2023 and 2025.

[16] A Pulaski is a hand tool specifically used for fighting fires that combines an axe and an adze atop a single handle. The tool is the invention of Edward Crockett Pulaski, a ranger with the U.S. Forest Service who was based in Wallace, Idaho, in the early 1900s.

4.4.5. Transmission and Distribution (T&D) Programs for Wildfire Mitigation

Idaho Power's T&D-related wildfire mitigation activities primarily involve expanded asset management programs and system hardening efforts, discussed in detail in Section 8.2 of this WMP. The narratives below provide insight into Idaho Power's consideration and selection of certain mitigation and hardening practices.

4.4.5.1. Annual T&D Patrol, Maintenance, and Repairs

Visual inspections are a critical component of T&D line-related wildfire mitigation efforts. On an annual basis, Idaho Power uses helicopters for visual aerial inspection of transmission lines that are Western Electricity Coordinating Council (WECC) path lines. Under the WMP, Idaho Power will continue to use this method of line inspection for all transmission lines located in Red Risk Zones. Idaho Power strives to complete these inspections prior to the start of the wildfire season; however, spring weather and snow levels may create access issues and delay the completion until June 15 in some areas.

Distribution lines that are located within RRZs are inspected on an annual basis to identify 'Priority 1' defects, or conditions that may result in an outage or potential ignition. The patrols will be completed by personnel that have been trained in distribution line inspection procedures and have experience in distribution line construction. Targeted defects may include cracked/broken crossarms, avian nesting hazards, damaged equipment and hardware, floating conductors, NESC violations, and other obvious defects that pose an immediate threat to the continued operation of the line. Similar to visual inspections for transmission lines, Idaho Power will strive to complete distribution inspections prior to the start of each wildfire season; however, access issues may delay the completion until June 15 in some areas.

Helicopters are not practical for carrying out all distribution patrols due to greater population, structural, and vegetation density, so unmanned aerial vehicles (UAV) with high-definition cameras are used to aid in these inspections in certain situations. These inspections allow personnel to look for potential line defects that may not be obvious from the ground. Priority 1 defects are immediately reported and repaired as soon as possible.

The company will continue to explore the expanded use of UAVs, as the detailed images and data collected through high-resolution aerial inspections can provide several co-benefits, including more granular data on vegetation growth and line and facility conditions.

Cost Estimate for Annual T&D Patrol, Maintenance, and Repairs (2023–2025)

The estimated system-wide incremental expenditure for annual T&D patrols, maintenance, and repairs is $150,000 from 2023 to 2025.

4.4.5.2. Thermography Inspections

While Idaho Power periodically conducts infrared thermography inspections as part of reliability and maintenance programs, the company is expanding these inspections in Red Risk Zones on an annual basis. These inspections are conducted using hand-held and drone-mounted cameras with thermal-sensing technology and can help identify defects associated with the overheating of equipment, connections, splices, or conductors.

As part of the thermography inspections, temperature gradients are analyzed to detect potential problems and issues found are prioritized based on their severity and repaired. Idaho Power recently created a new Thermography Technician position to carry out the inspections and coordinate repair activities, and additional resources may be added to perform this function across more of Idaho Power's service area if a single technician proves insufficient. To prioritize the use and information gained from this technology, it will initially be employed only in RRZs. 2022 is the test year to determine how many inspections can be performed, and the overall cost-benefit of the technology to help evaluate the possibility of expanding use and adding more resources.

Thermography inspections are uniquely valuable in that they are able to uncover problems undetectable to the naked eye. From the company's perspective, there is not a viable alternative to this practice. The technology enables more proactive identification of potential issues than would otherwise be possible.

Cost Estimate for Thermography Inspections (2023–2025)

The estimated expenditure for thermography inspections is $645,000 from 2023 to 2025. Idaho Power will prioritize the use of this mitigation practice in its highest risk zones, which are exclusively in Idaho, as detailed in Table 4.

4.4.5.3. Wood Pole Fire-Resistant Wraps

To help improve the resiliency of the company's wood transmission poles, Idaho Power now wraps them with a fire-resistant mesh in Red and Yellow Risk Zones. The mesh wrap helps protect the integrity of the pole if it is exposed to fire and improves the resiliency of Idaho Power's transmission system. An alternative to installing fire-proof mesh wrap is to replace wood poles with structures made of non-combustible material, such as steel. With 3,863 existing wood transmission poles in Idaho Power's Red and Yellow Risk Zones, the cost of replacing all wood poles is much higher than the cost of covering with a fire-resistant mesh.

Prior to developing the WMP, Idaho Power evaluated different products to determine the most cost-effective approach for protecting existing wood poles from fire. Several products were considered and trialed, including short-term spray-on and paint-on fire retardants, long-term retardants, and steel wraps. In 2020, the company evaluated a protective mesh wrap and compared the cost and performance to the alternatives. The evaluation found that the mesh wrap was approximately 53% less costly than the alternatives and offered the same level of risk reduction. The decision to use a mesh wrap product was not based solely on cost; other criteria were considered, including availability of the product, ease of installation, expected protective life span, and performance when exposed to fire. By all these measures, fire-resistant mesh was the best solution.

Cost Estimate for Wood Pole Fire-Resistant Wraps (2023–2025)

The estimated system-wide expenditure for applying fire-resistant mesh wraps to transmission poles in Red and Yellow Risk Zones is $577,000 between 2023 and 2025.

4.4.5.4. Covered Conductor Pilot

Idaho Power's Technology Strategy Initiative identified covered conductor as a potential mitigation measure to pilot. Benchmarking and feedback from other utilities highlighted the potential benefit of covered conductor as a mitigation measure. The company will conduct a pilot of covered conductor through 2024 to explore the benefits, tooling requirements for field personnel, and design parameters. While covered conductor may reduce the risk of wildfire, the company will analyze potential co-benefits, including improved reliability outside of wildfire season and reduced outage restoration costs.

Cost Estimate for the Covered Conductor Pilot (2023–2024)

The estimated cost of the pilot is $100,000 from 2023–2024. While this pilot will take place in Idaho, the lessons from it will extend across the company's service area.

4.4.6. Enhanced Vegetation Management

Idaho Power's enhanced vegetation management practices are discussed in detail in Section 8.3 of this WMP.

In the initial stage of developing its WMP, Idaho Power conducted an analysis to determine the most likely sources of ignition across the company's service area. Reliability data revealed vegetation contact as one of the most common causes of outages on Idaho Power's system. With the goal of eliminating potential ignition sources and to reduce risk, enhanced vegetation management was recognized as a critical aspect of Idaho Power's WMP.

To prioritize risk reduction from vegetation contact, Idaho Power determined it would move to a three-year pruning cycle and apply enhanced vegetation management practices in Red and Yellow Risk Zones. These enhanced practices include pre-fire season vegetation patrols, more targeted pole clearing and vegetation removal, and additional quality assurance for vegetation management practices.

The company considered other vegetation management alternatives, including shorter trimming cycles, longer trimming cycles, and strategies that evaluate each tree individually and only trim it once it has nearly grown back to the power line (known as "just-in-time trimming"). Each alternative presented challenges or resulted in negative impacts that undermined any potential benefits.

While shorter trimming cycles result in less vegetation being removed during each trimming cycle, this practice costs more due to the need for more resources and more frequent trimming of trees near the power lines. In contrast, longer cycles result in less frequent trimming of each tree but larger amounts of vegetation that must be removed to maintain larger clearance

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC

envelopes around the power lines to accommodate additional years of vegetative growth. Further, longer trimming cycles create logistical challenges that are exacerbated by tree biology. Some trees simply grow faster than a given trimming cycle and the longer the trimming cycle, the more pervasive this issue becomes. Longer cycles that call for heavy pruning also lead to hormonal imbalances between a tree's canopy and its root system. To correct this imbalance, the tree aggressively re-grows new sprouts to quickly replace its lost canopy. In this regard, heavier pruning results in a faster rate of tree regrowth than normal, making it even more difficult to consistently maintain longer trimming cycles. Finally, "just-in-time trimming" is primarily a reactive strategy that ultimately leads to challenges associated with securing qualified tree-trimming crews, as this ad hoc approach involves hiring crews on an as-needed basis rather than on a consistent schedule. After evaluating these alternative approaches, Idaho Power concluded that the goal of maintaining a consistent three-year trimming cycle is the most cost-effective and sustainable strategy to keep vegetation away from the power lines in a proactive manner.

Moving forward with a three-year cycle and performing the additional activities detailed above will involve a sizeable increase in incremental O&M expenditure. An alternative to enhancing Idaho Power's vegetation management program is to convert overhead distribution circuits to underground. While undergrounding is used in certain circumstances, undergrounding has generally not been determined to be a cost-effective expense relative to enhanced vegetation management. That said, the company continues to evaluate and implement underground solutions, as appropriate, as part of its WMP hardening efforts detailed below.

Although vegetation management is a sizeable increased wildfire mitigation expense, performing this work is expected to have notable co-benefits, including reduced vegetation-caused outages in Red and Yellow Risk Zones. Idaho Power plans to monitor performance and outage metrics to confirm the success of the enhanced program.

Decreasing vegetation outages was considered one of the most important, cost-effective measures Idaho Power could take to reduce the likelihood of an ignition event and protect utility infrastructure. Shifting vegetation management practices was deemed a prudent course of action based on the number of potential outages or ignition sources that may be eliminated. It is also the approach that has been adopted by many of Idaho Power's peer utilities.

Additionally, the company will participate in a regional fuel reduction program, in which Idaho Power will work in partnership with the Idaho Department of Lands, the National Forest Foundation, the U.S. Forest Service, and the U.S. Bureau of Land Management to remove hazard trees and other vegetation from utility rights-of-way. The partnership is designed to enhance forest resilience to wildfire, decrease hazardous fuel accumulations, increase powerline resiliency while minimizing the risk of ignitions, and improve forest conditions in the vicinity of Idaho Power infrastructure. This program is similar to what other western utilities have taken part in and is modeled after projects performed in Washington, California, Colorado, and Arizona. Participation in the effort is estimated to cost $225,000 through 2025.

The company also plans to deploy satellite and aerial patrols of vegetation in the company's wildfire risk zones. The technology used in these satellite and aerial patrols will help identify encroachment and clearance issues in areas that are growing faster than expected and hazard trees that have the potential of falling into powerlines. Data collected through this technology may reshape the company's vegetation management strategy and shift from a systemwide cycle to a more targeted approach that identifies and focuses on high-growth vegetation areas. The company will conduct limited vegetation-focused satellite and aerial patrols in 2023 before expanding to a larger area in 2024 and 2025, pending outcomes from the pilot program years. The company estimates spending $750,000 on this technology through 2025.

Cost Estimate for Enhanced Vegetation Management (2023–2025)

The estimated system-wide expenditure for enhanced vegetation management is $41.3 million from 2023 to 2025.

4.4.7. Communications and Information Technology Customer Notification Enhancements

Idaho Power's efforts to communicate with customers and the public about wildfire and mitigation are discussed in detail in Section 10 of this WMP.

Idaho Power considers communication a vital part of its wildfire mitigation efforts. Customer and public awareness and education are a vital part of ensuring that the communities that Idaho Power serves are protected and safe from the threat of wildfire. New communication expenses related to customer and community educational outreach include advertisements, printed media, social media, and public meetings. The purpose of these communications is to keep customers aware of mitigation and fire-related activities before, during, and after fire season. Additionally, the company is building out communication systems to be able to alert customers more quickly and easily about wildfire events and outages, including potential PSPS events.

Cost Estimate for Communication and Customer Notification Enhancements (2023–2025)

The estimated system-wide expenditure for communication expenses is $513,000 and $387,000 for customer notification system enhancements, totaling $900,000 from 2023 to 2025.

4.4.8. Incremental Capital Investments

Idaho Power's wildfire mitigation efforts include capital investments in system hardening practices including approaches deployed after internal testing and analysis, many of which also provide co-benefits to the company.

Idaho Power's capital investments for wildfire mitigation are discussed in detail in Section 8.2 (T&D Asset Management Programs) of this WMP.

4.4.8.1. Circuit Hardening and Infrastructure Upgrades

Idaho Power estimates spending $5.1 million annually through 2025 on circuit hardening and infrastructure upgrades across its system.

Idaho Power's WMP includes an overhead distribution hardening program for Red Risk Zones. The program includes systematic replacement of hardware, equipment, and materials to improve safety and reliability and reduce ignition risk. The first five years of the program are focused on circuits in Red Risk Zones, but it may be expanded to Yellow Risk Zones in the future. The company will review hardening outcome metrics annually to determine the benefit of the program and to determine whether to expand the program after 2025.

Prior to developing its WMP, Idaho Power successfully implemented many of the same hardening measures detailed below as part of the company's reliability program. Outage data and analytics showed that customer outages were reduced by approximately 38% in areas where hardening projects were carried out. With the success of reducing outages, some of these same activities to increase reliability were chosen to be part of the WMP to help reduce ignition potential in Red Risk Zones. Enhanced system hardening efforts include installation of fire safe fuses, Spark Prevention Units, and fiberglass crossarms.

All the hardening activities and equipment identified in this program were evaluated by patrolmen, troublemen, reliability engineers, and the company's Methods and Materials department to determine cost-effective solutions that balance overall costs with expected risk reduction.

As an alternative to conducting circuit hardening upgrades, the company considered converting overhead distribution circuits to underground. While underground conversions are used in certain circumstances, the cost is estimated to be 2–10 times higher than the cost of carrying out hardening work. In general, overhead hardening efforts provide the benefit of being able to impact a greater number of circuit miles and customers in a shorter time horizon with less investment than undergrounding. Idaho Power will continue to evaluate underground opportunities as part of overall system hardening efforts.

The following summarizes the incremental capital investments the company is making to harden its system and further reduce wildfire risk:

Wood Pole Replacement—The company will replace wood poles if field evaluations determine that significant deterioration or damage has occurred since the last inspection or treatment. Poles are inspected above the groundline to determine strength and climbability. Poles identified as "rejects" will be replaced. Furthermore, poles having wood stubs/structural reinforcements are changed out pursuant to current practices.

Fuse Replacements—Expulsion fuses located in Red Risk Zones will be changed out with energy-limiting and power fuses. Fuse applications include overhead transformers, line taps, risers, and capacitor banks. In 2018, Idaho Power began exploring different fusing technology to replace expulsion fuses with non-expulsion fuses. Three different fuse types were considered and subsequently piloted. The pilot was used to determine the performance of each fuse type, installation requirements, and coordination characteristics. Financial analysis included the cost of each fuse along with associated cutout and hardware and helped determine the most cost-effective option. This information was used to evaluate non-expulsion fuses. *Replacement of all expulsion fuses in Red Risk Zones is expected to take* *approximately three years at a cost of approximately $1.9 million. Because this work will be conducted in Red Risk Zones, the company does not anticipate replacing fuses in Oregon at this time.*

Spark Prevention Units—Porcelain arresters used for overvoltage protection will be changed out with arresters utilizing Spark Prevention Units (SPU). The SPU acts to eliminate the potential of catastrophic failure during arrester operation. This work includes all distribution arresters located on primary distribution lines in Red Risk Zones. In 2019, Idaho Power piloted new arrester technology to determine performance characteristics, installation requirements, and potential benefits in reducing ignition risk. As part of the pilot, Idaho Power compared different manufacturers with similar technology and conducted performance analysis to determine the most cost-effective solution. *Replacement of the arresters is expected to take approximately three years to complete and will cost approximately $1.7 million. Because this work will be conducted in Red Risk Zones, the company does not anticipate replacing arrestors in Oregon at this time.*

Fiberglass Crossarms—Idaho Power began piloting fiberglass crossarms in 2018 to determine potential cross-functional benefits associated with fiberglass. The pilot focused on cost, ease of installation, strength, supply availability, and reduced potential for tracking of electrical current. Tracking is known as the flow of current over an insulator, which can generate heat. The company compared different crossarm types and manufacturers and determined that fiberglass was most cost effective when considering up-front capital and installation costs. The pilot program, along with benchmarking of peer utilities, helped determine that fiberglass crossarms provided a number benefits relative to improved safety and reliability. Therefore, Idaho Power's hardening program includes the installation of both tangent and dead-end fiberglass crossarms in Red Risk Zones. However, Idaho Power does not intend to replace all wood crossarms with fiberglass immediately. As part of the fielding phase, company distribution designers will assess wood crossarms and initially change those showing signs of defects or damage. Identified crossarms utilizing wood pins will also be replaced with fiberglass. This approach will spread the cost out over time and help reduce the upfront cost of the program.

Small Conductor—In the early stages of developing the WMP, Idaho Power considered the possible risk associated with small conductor and the potential for breakage. As a result of this exercise, the company's WMP hardening program includes the replacement of overhead distribution conductor that meets certain criteria which includes approximately 60 miles in Red Risk Zones. Conductor losses were analyzed and showed that replacing the conductor will result in an approximately 50% reduction of line losses, resulting in co-benefits for the company and customers in terms of greater reliability and line loss improvements.

Porcelain Switches—Idaho Power's Outage Management System and feedback from field personnel revealed potential benefits of switches made of material other than porcelain. Therefore, porcelain switches installed in Red Risk Zones will be changed out with cutouts featuring Ethylene Propylene Diene Monomer Rubber (EPDM). Idaho Power's Methods and Materials Department trialed different cutout switches made up of different material, including silicone and polymer, to determine the most cost-effective solution. The results of the trial highlighted the potential for avian issues with silicone (i.e., ravens tended to eat the silicone), and the cost of EPDM versus polymer was nearly equivalent. The financial analysis determined that EPDM would preserve the integrity of the insulator body, prevent outages, and provide an estimated savings of $10,798 per year over silicone.

Avian Protection—Idaho Power employs several different protection measures to protect wildlife on existing structures including but not limited to covers, insulated conductor, diverters, perches, nesting platforms, and structural modifications. The company has an extensive history working with manufacturers of animal guards/covers and regularly seeks new solutions for avian issues to prevent mortalities, increase reliability, and eliminate other risks. The company's Avian Protection Plan (APP) was developed in the mid-2000s and many of the practices identified in the APP are used for wildfire mitigation in Red and Yellow Risk Zones. For example, new wildlife guards were recently developed and installed in conjunction with the installation of new power fuses and SPUs. Idaho Power consulted with different manufacturers to develop new products that would accomplish the dual goals of avian protection and wildfire mitigation. The best solution is determined on a case-by-case basis depending on the specific location, the type and extent of avian presence, and other relevant factors.

4.4.8.2. Overhead to Underground Conversions

Another aspect of Idaho Power's system hardening program is the select conversion of overhead to underground distribution lines in Red Risk Zones. In 2022, the company will convert 1.5 miles of overhead distribution lines to underground lines. In 2023 and beyond, the company will work to build a strategic undergrounding program to weigh the cost-benefit of undergrounding versus other circuit hardening measures. While underground distribution lines offer benefits associated with being less exposed to the elements and external forces, conversion may not be possible, advisable, or economical in certain situations. The company will continue to evaluate the feasibility of underground conversions as well as the relative value and cost effectiveness as part of the WMP.

4.4.8.3. Transmission Steel Poles

In 2021 and as part of its WMP, Idaho Power revised its transmission construction standards to utilize steel poles and structures for new line construction built to 138 kV and above in elevated wildfire risk zones. This change is intended to minimize the potential for wildfire damage, improve transmission line resiliency, and increase reliability for customers. Wood poles continue to be accepted and used in the industry, and the company will still utilize wood poles in many transmission system applications in consideration of the availability of steel poles, the specific engineering, right-of-way, permitting, and scheduling requirements for each project.

In addition, wood poles will continue to be the standard construction practice for transmission line voltages below 138 kV unless a different material is needed to meet specific engineering or planning requirements. As discussed above, Idaho Power will wrap wood poles located in Red and Yellow Risk Zones with fire-proof mesh.

5. Situational Awareness

5.1. Overview

Visibility and readily available access to current and forecasted meteorological conditions and fuel conditions is a key aspect of Idaho Power's wildfire mitigation strategy. Meteorological and fuel conditions can vary significantly across Idaho Power's service area. Idaho Power leverages its internal atmospheric science department's modeling/forecasting capabilities, its existing field weather stations, and publicly available weather/fuel data to develop projections of current and future wildfire potential across Idaho Power's service area. This wildfire potential information is then available to operations personnel to factor into their operational decision-making.

5.2. Fire Potential Index

Idaho Power has developed an FPI tool based upon original work completed by San Diego Gas and Electric, the National Forest Service, and the National Interagency Fire Center and modified for Idaho Power's Idaho and Oregon service area. This tool is designed to support operational decision-making to reduce fire threats and risks. This tool converts environmental, statistical, and scientific data into an easily understood forecast of the short-term fire threat which could exist for different geographical areas in the Idaho Power service area. The FPI is issued for a seven-day period to provide for planning of upcoming events by Idaho Power personnel.

The FPI reflects key variables, such as the state of native vegetation across the service area ("green-up"), fuels (ratio of dead fuel moisture component to live fuel moisture component), and weather (sustained wind speed and dew point depression). Each of these variables is assigned a numeric value and those individual numeric values are summed to generate a Fire Potential value from zero to sixteen, each of which expresses the degree of fire threat expected for each of the 7 days included in the forecast. The FPI scores are grouped into the following index levels:

- **Green**: FPI score of 1 through 11 indicates low potential for a large fire to develop and spread as there is normal vegetation and fuel moisture content as well as weak winds and high relative humidity.
- **Yellow**: FPI score of 12 through 14 indicates an elevated potential for a large fire to develop and spread as there are lower than normal vegetation and fuel moisture content as well as moderate winds and lower than normal relative humidity.
- **Red**: FPI score of 15 through 16 indicates a higher potential for a large fire to develop and spread as there are well below normal vegetation and fuel moisture content as well as strong winds and low relative humidity.

Fire Potential Index (FPI) Category			
	Normal	Elevated	High
FPI Range	1 to 11	12 to 14	15 - 16

The state of native grasses and shrubs, or **Green-Up Component**, of the FPI is determined using satellite data for locations throughout the Idaho Power areas of interest. This component is rated on a 0-to-5 scale ranging from very wet (or "lush") to very dry (or "cured"). The scale is tied to the Normalized Difference Vegetations Index (NDVI), which ranges from 0 to 1, as follows:

Green-Up Component						
NDVI	Very Wet/Lush: 1.00 to 0.65	0.64 to 0.60	0.59 to 0.55	0.54 to 0.50	0.49 to 0.40	Very Dry/Cured 0.39 to 0.00
Score	0	1	2	3	4	5

The **Fuels Component (FC)** of the FPI measures the overall state of potential fuels which could support a wildfire. Values are assigned based on the overall state of available fuels (dead or live) for a fire using the following equation:

$$\mathbf{FC = FD / LFM}$$

Where FC represents Fuels Component in the scale below, FD represents 10-hour Dead Fuel Moisture (using a 1-to-3 scale), and LFM represents Live Fuel Moisture (percentage). This data will be collected from satellite sources and regional databases supported by state and federal agencies.

The product of this equation represents the fuels component that is reflected in the FPI as follows:

Very Wet					Very Dry
0	1	2	3	4	5

The **weather component** of the FPI represents a combination of sustained wind speeds and dew-point depression as determined using the following scale. Regional adjustment to criteria limits for the upper wind speeds may occur after further discussion with subject matter experts from each of the regional operations. This data will be sourced from the weather, research and forecasting (WRF) products produced by Idaho Power using its High-Performance Computing (HPC) system. In addition to the HPC system produced WRF data, several national level meteorological products will be used. These products will include regional weather observations used to validate model information.

Dewpoint Depression/Wind	≤5 mph	6 to 11 mph	12 to 18 mph	19 to 25 mph	26 to 32 mph	≥33 mph
≥50ºF	4	4	4	5	5	6
40ºF to 49ºF	3	3	4	4	5	5
30ºF to 39ºF	3	3	3	4	4	5
20ºF to 29ºF	3	3	3	3	3	4
10ºF to 19ºF	2	2	2	2	2	3
<10ºF	0	1	1	1	1	2

5.3. FPI Annual Process Review

The FPI process will be reviewed annually after completion of the fire season and, with consultation of interested parties (e.g., Load Serving Operator, Line Crews, and others), will be updated to enhance Idaho Power's wildfire preparedness.

6. Mitigation—Field Personnel Practices

6.1. Overview

A component of Idaho Power's wildfire mitigation strategy is to prevent the accidental ignition and spread of wildfires due to employee work activities. Idaho Power developed the *Wildland Fire Preparedness and Prevention Plan* (Appendix A) to provide guidance to Idaho Power employees and contractors to help prevent the accidental ignition and spread of wildfires due to company work activities in locations and under conditions where wildfire risk is heightened. All Idaho Power crews and certain field personnel performing work on or near Idaho Power's facilities are expected to operate in accordance with the Plan and continue to conduct themselves in a fire-safe manner.

6.2. Wildland Fire Preparedness and Prevention Plan

The *Wildland Fire Preparedness and Prevention Plan* informs Idaho Power personnel and its line construction contractors about the following factors:

- Annual fire season tools and equipment to be available when on the job site
- Daily situational awareness regarding locations of heightened potential for fire risk and weather conditions in those areas
- Expected wildfire ignition prevention actions while working and reporting instructions in the event of fire ignition
- Training and compliance requirements

7. Mitigation—Operations

7.1. Overview

A component of Idaho Power's wildfire mitigation strategy is to continue safe and reliable operation of its T&D lines while also reducing wildfire risk. These operational practices primarily center around the following:

- Temporary operating procedures for transmission lines during the fire season[17]
- An operational strategy for T&D lines during time periods of elevated wildfire risk during the fire season
- A PSPS strategy for Idaho Power's service area and transmission corridors

7.2. Operational Protection Strategy

Operational protection strategies were developed to reduce the probability of ignition during fault events on Idaho Power's transmission and distribution system. Analysis was performed by Reliability Engineers to assess the available fault energy under different protection schemes and configurations and the effect each would have on customers in terms of increased and extended outages. Idaho Power analyzed the following configurations for automatic reclosing devices:

- Reclose off
- Limited energy reclose
- Limited energy lockout

The analysis performed included assessing Time Current Curves and fault energy of different circuits to gauge the overall reduction in energy between different protection configurations and coordination challenges. Figure 13 below summarizes the different protection configurations evaluated along with estimated benefits in terms of reduced fault energy and impacts to customers. At this time, reclose off appears to provide the best balance between reducing fire ignition risk and customer reliability impacts.

This analysis, along with consideration of historic outage events associated with reclose off, led to the determination that enhanced protection strategies were warranted only in RRZs due to their higher level of wildfire risk. Idaho Power plans to evaluate the effectiveness of protection strategies and will work to mature in this area. New advancements in relay protection used to decrease wildfire risk were evaluated in 2022. The company plans to further our understanding

[17] The duration of the fire season will be reviewed and defined annually.

of their capabilities and integration into existing relay apparatus by testing new algorithms and schemes as part of the company's wildfire technology roadmap from 2024 through 2028.

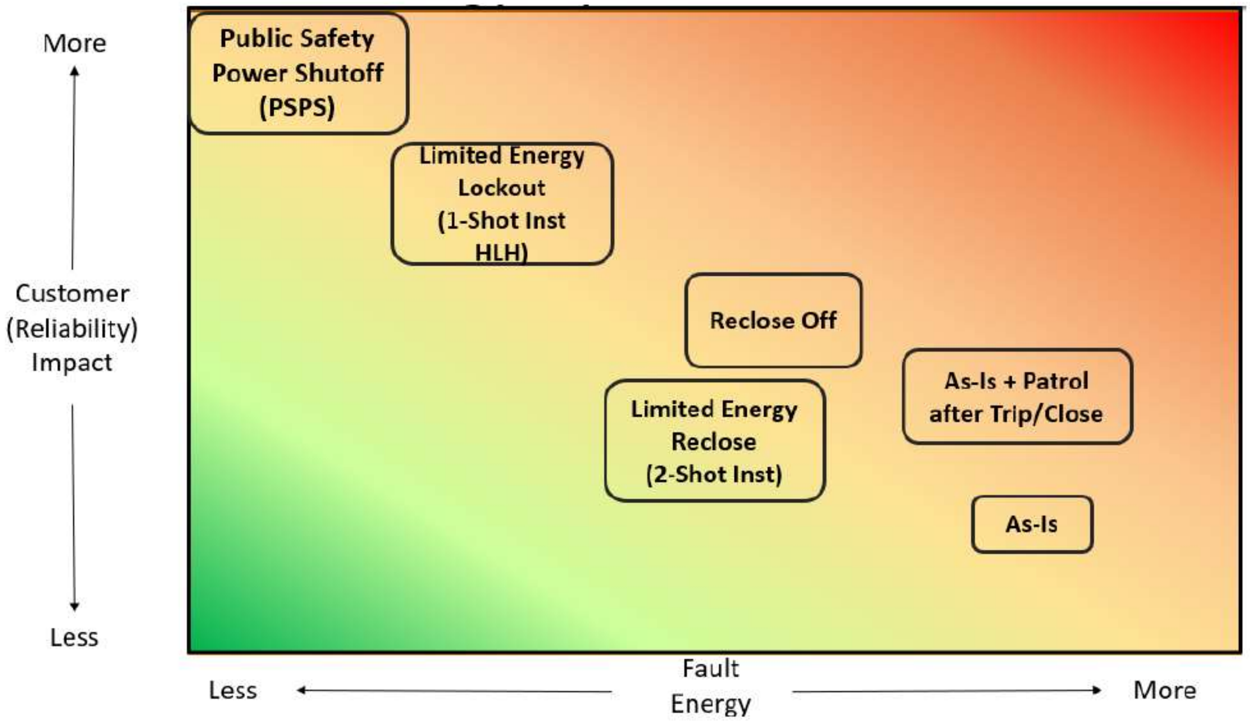


Figure 13
Comparison of reclosing strategies with respect to customer reliability and wildfire risk

7.3. Transmission Line Operational Strategy

7.3.1. Fire Season Temporary Operating Procedure for Transmission Lines

Each year, typically in May, leadership within Idaho Power's Load Serving Operations (LSO) department updates and issues its Fire Season Temporary Operating Procedure. The purpose of this temporary operating procedure is to provide LSO employees with guidelines for operating transmission lines during the summer fire season. The procedure aims to reduce wildfire risk through practices relating to information collection, notification, and procedures for testing/closing in on locked-out transmission lines.

7.3.2. Red Risk Zone Transmission Operational Strategy

During wildfire season, Idaho Power determines a daily FPI as described in Section 5 of this WMP. The FPI informs the transmission line operational strategy for those lines owned, operated, and located in RRZs. These lines will be operated in normal settings mode but with no "testing"[18] of a line that may have "locked out" during the time of a red FPI. Essentially, in the event of a fault on the specified transmission line(s) during a red FPI, the line will operate as normal and may "lock out," at which time the line(s) will either need to be patrolled before "testing" or wait until the FPI level drops out of the red category prior to being reenergized.

7.4. Distribution Line Operational Strategy

7.4.1. Red Risk Zone Distribution Operational Strategy

During wildfire season, Idaho Power determines a daily FPI as described in Section 5 of this WMP. The FPI informs the distribution line operational strategy for those lines located in the wildfire RRZs. These lines will be operated in a non-reclosing[19] state during the time of red FPI. Essentially, in the event of a fault on the specified distribution line(s) during the red FPI, the line(s) will be automatically de-energized with no reclosing attempts until either the line(s) has been patrolled or the FPI level drops out of the red category.

7.5. Public Safety Power Shutoff

7.5.1. PSPS Definition

PSPS, as used in this WMP, is defined as the proactive de-energization of electric transmission and/or distribution facilities during extreme weather events to reduce the potential of those electrical facilities becoming a wildfire ignition source or contributing to the spread of wildfires. The concept is as follows: if significant weather events can be predicted far enough in advance, the resulting proactive line de-energization before the forecasted weather conditions materialize could mitigate the risk of a wildfire. A PSPS event has significant customer impact and requires significant planning.

PSPS is <u>not</u> the practice of de-energizing lines in the following types of situations:

- Unplanned de-energization of lines required for emergencies and during outage restoration situations.
- Planned line or station work activities that require a planned outage (Idaho Power currently has a planned outage customer notification process in place for this).
- Reactive de-energization of electric transmission and/or distribution facilities, which may be either at Idaho Power's determination or at the request of fire managers (e.g., BLM,

[18] Transmission line "testing" refers to the human act of re-energizing a line without completing a physical field patrol or observation of a line.

[19] Distribution line "non-reclosing" refers to the deactivation of automatic re-energization of a distribution line or use of a non-reclosing device such as a fuse.

U.S. Forest Service, or other fire-fighting managers) in response to existing/encroaching wildfire threatening to burn into such facilities.

- Automated de-energization of electric transmission and/or distribution facilities due to smoke/fire from an existing fire causing a fault on the line.

Idaho Power will continue its current de-energization practices in the above referenced, and comparable situations. Such outage situations are not defined as PSPS events in the context used here and, as a result, would not trigger PSPS protocols.

7.5.2. PSPS Plan

Idaho Power developed a PSPS Plan (see Appendix B) that operates in parallel with its wildfire mitigation strategy. Although the wind patterns in Idaho Power's service area are generally of a much lower sustained velocity and often less predictable (i.e., micro-bursts) than other utilities' service areas where PSPS has most frequently been utilized (i.e., California), the company's PSPS Plan generally follows industry best practices by considering other utilities' PSPS plans and incorporating input from Idaho Power's external consultant, discussed in 3.2 above, which developed the company's WMP risk maps.

8. Mitigation—T&D Programs

8.1. Overview

Idaho Power's wildfire mitigation strategy relies in part on its various asset management programs and vegetation management program to maintain safe and reliable operation of its T&D facilities in reducing wildfire risk.

8.2. T&D Asset Management Programs

In addition to maintaining a number of existing and newly implemented robust asset management programs intended to reduce wildfire risk, Idaho Power continues to research, monitor, and pilot emerging technologies and strategies to manage its T&D infrastructure.

Idaho Power's key asset management programs supporting wildfire prevention and mitigation are summarized in the table below.

Table 7
Summarized T&D asset management programs (associated with the WMP)

Transmission
Transmission Asset Management Programs
Aerial Visual Inspection Program
Ground Visual Inspection Program
Detailed Visual (High Resolution Photography) Inspection Program
Wood Pole Inspection and Treatment Program
Cathodic Protection and Inspection Program
Thermal Imaging (Infra-Red) Inspections
Wood Pole Wildfire Protection Program (enhanced)
Steel Pole (Structures) (enhanced)
Distribution
Distribution Asset Management Programs
Ground Detail Inspection Program (enhanced)
Wood Pole Inspection and Treatment
Wood Pole Fire Protection Program (enhanced)
Line Equipment Inspection Program
Thermal Imaging (Infra-Red) Inspections
Overhead Primary Harden Program
Replace "small conductor" with new 4acsr or larger conductor (new)
Replace or repair damaged conductor
Re-tension loose conductors including "flying taps" and slack spans as required

- Replace wood-stubbed poles with new wood poles (enhanced)
- Replace white and yellow square tagged poles with new wood poles
- Replace wood pins/wood crossarm with new steel pins/fiberglass crossarms
- Replace steel insulator brackets with new steel pins/fiberglass crossarms (new)
- Replace wedge deadends on primary taps with new polymer deadend strain insulators
- Replace aluminum deadend strain insulators with new polymer deadend strain insulators (new)
- Replace porcelain switches with new polymer switches
- Replace hot line clamps
    - Replace aluminum stirrups
    - Install avian cover
    - Relocate arresters
- Install bird/animal guarding
- Update capacitor banks
    - Replace swelling capacitors
    - Replace oil-filled switches with vacuum style
    - Replace porcelain switches with polymer switches
- Install disconnect switches on CSP transformers
    - Install avian cover
- Update down guys
    - Replace/Install down-guy insulators with fiberglass insulators
    - Tighten down guys
- Tighten hardware
- Correct 3rd party pole attachment clearances (report to Joint Use Department)

Idaho Power has a robust and proven inspection and correction strategy and schedule. Current practices will continue in YRZs. Risk quantification and modeling performed shows that RRZs have a higher level of risk from wildfires so, in addition to its current practices, Idaho Power believes it is prudent to add an annual inspection to minimize the likelihood of a wildfire ignition as well as targeted infrared inspections in select RRZs to identify any potential issues that may not be apparent on visual inspection. As part of the ISO 31000 risk management process, Idaho Power plans to evaluate the effectiveness of inspection and correction activities and schedules and further grow in this area as wildfire risk evolves. The following table summarizes inspection work performed and inspection frequency with respect to wildfire risk zones.

Table 8
Summary of asset inspections and schedules by state and zone

	Inspection Interval				
Asset Inspection Type	**Idaho Non-Risk Zone**	**Oregon Non-Risk Zone**	**Idaho YRZ**	**Oregon YRZ**	**Idaho RRZ**
Transmission Defect Inspections					
Visual	Annually	Annually	Annually	Annually	Annually
Detailed	10 Years	10 Years	10 Years	10 Years	10 Years
Groundline (Wood Pole Test and Treat)	10 Years	10 Years	10 Years	10 Years	10 Years
Wildfire Mitigation Patrol	None	None	None	None	Annually
Infrared Patrol	None	None	None	None	Annually
Distribution OH Defect Inspections					
Visual/Detailed	3 Years	2 Years	3 Years	2 Years	3 Years
Groundline (Wood Pole Test and Treat)	10 Years	10 Years	10 Years	10 Years	10 Years
Wildfire Mitigation Patrol	None	None	None	None	Annually
Infrared Inspections	None	None	None	None	Targeted

8.2.1. Transmission Asset Management Programs

Several of Idaho Power's transmission management programs have been in place for decades and include condition-based aerial visual inspections, ground visual inspections, detailed visual (generally using high-resolution photography) inspections, transmission wood pole inspection and treatment, and cathodic protection. Additionally, Idaho Power has used various methods and materials to prevent wildfire from damaging wood structures and now intends to use a fire-resistant mesh wraps installed on structures located in the RRZ and YRZs.

8.2.1.1. Aerial Visual Inspection Program

Annually, Idaho Power uses helicopters to assist Idaho Power qualified personnel in the visual aerial inspection of transmission lines identified as WECC Path Lines. This method of line inspection is now used for transmission lines located in the RRZs. In addition, unmanned aerial vehicles with high-definition cameras are now used in certain situations to inspect facilities on these lines. These inspections allow personnel to look for potential line defects, which, if found, are noted and scheduled for repair.

All noted defects are prioritized as Priority 1, Priority 2, or Priority 3, based on the criteria listed below:

- **Priority 1**: Defects that, depending on the circumstances, require reporting and repair as soon as reasonably possible.
- **Priority 2**: Defects that, depending on the circumstances, generally require reporting and correction within 24 months of identification. The correction of these defects should be scheduled during crews' normal work schedules. Priority 2 defects not assigned a

corrective plan within 24 months will be reviewed by the T&D vegetation and maintenance engineering leader.

- **Priority 3**: Potential issues that may need correction but do not pose a threat to the system and should be monitored. A Priority 3 designation may also be used by Idaho Power personnel for tracking of certain line construction practices.

Corrective action plans for Priority 1 and 2 defects are determined by engineering personnel for each prioritized defect and are scheduled and repaired.

8.2.1.2. Ground Visual Inspection Program

Annually, Idaho Power qualified personnel (i.e., trained in transmission line inspection procedures and experienced in transmission line construction) complete ground visual inspections of all transmission lines. Ground patrols are completed using four-wheel-drive vehicles, all-terrain vehicles, utility terrain vehicles, and/or on foot. These inspections identify potential line defects that are noted and scheduled for repair following the same process as described in 8.2.1.1.

8.2.1.3. Detailed Visual (High-resolution Photography) Inspection Program

In addition to the annual inspections and associated maintenance, Idaho Power also completes detailed visual inspections generally utilizing high resolution photography. This detailed inspection is typically completed using helicopters, unmanned aerial vehicles, and contracted professionals operating high-definition cameras and, if potential line defects are noted, they are scheduled for repair following the same process as described in 8.2.1.1. The detailed inspections are completed on a 10-year cycle in conjunction with the 10-year cycle of wood pole ground line inspection and treatment (see 8.2.1.4).

8.2.1.4. Wood Pole Inspection and Treatment Program

All wood poles are visually inspected, sounded, and bored for defects and decay on a 10-year cycle. The poles are categorized according to the following:

- **Reported**: Any wood pole inspected and found to be installed within 10 years of the manufactured date or last inspection date.

- **Treated**: Any wood pole inspected and found to be installed 11 years or more prior to the inspection date and is determined to be in sound enough condition to warrant treatment.

- **Rejected**: Any wood pole determined to fit the following criteria:

    - Have less than 4 inches of shell at 48 inches above the ground line; and/or

    - Less than 2 inches of shell at 15 inches above the ground line; and/or

    - Less than 2 inches of shell at the ground line; or

  - Is deteriorated and does not meet minimum strength criteria; or
  - Fails a visual inspection.

  Rejected poles are categorized as: reinforceable with steel, non-reinforceable and are to be replaced.

- **Visually Rejected**: Any wood pole that has been damaged (i.e., burned, split, broken, hit by a vehicle, damaged by animals, etc.) above the ground line to such an extent as to warrant rejection and that cannot be further tested to determine priority status.
- **Sounded, Bored, and Treated**: Any wood pole set in concrete, asphalt, or solid rock 11 years or more prior to the inspection date is internally treated. Internal treatment involves fumigating the good wood and flooding the voids with fumigant.

8.2.1.5. Cathodic Protection and Inspection Program

Cathodic protection systems are employed on select steel transmission towers. These systems use either an impressed current corrosion protection system (ICCP) or direct-buried sacrificial magnesium anodes. Included in Idaho Power's tower maintenance plan, every 10 years, structure-to-soil potential testing is performed on select towers with direct-buried anodes. For ICCP systems, rectifiers and ground-beds are tested to ensure they are functioning properly. Based on test results repairs and adjustments are completed. Each year all rectifiers are inspected, and direct current (DC) voltage and DC current readings noted.

8.2.1.6. Thermal Imaging (Infra-red) Inspections

Idaho Power will complete annual inspections of lines and equipment using thermal imaging (infra-red) cameras. This inspection methodology, although not new to Idaho Power, is being expanded to specifically include the RRZs. Compromised electrical connections and overloaded equipment may be identified using thermal imagery. Identified risks will be prioritized and mitigated using the prioritization methodology noted in 8.2.2.1 of this WMP.

8.2.1.7. Wood Pole Wildfire Protection Program

Idaho Power has utilized numerous technologies to minimize the damage to wood poles that have been exposed to wildfires. The current technology of "mesh wraps" is utilized on transmission wood poles located in the RRZs and YRZs.

8.2.1.8. Transmission Steel Poles

Idaho Power will utilize steel poles or structures for new transmission line construction projects built to 138 kV standards and above in an attempt to minimize wildfire damage and improve transmission line resilience. Wood poles may be used on 138 kV structures for emergency and maintenance replacements based on the specific engineering, right-of-way, permitting, and scheduling requirements for each project. Wood construction is used for voltages below 138 kV unless a different material is needed to meet specific engineering or planning requirements.

8.2.2. Distribution Asset Management Programs

Idaho Power has several distribution asset management programs that are mature, have been implemented for decades, and will continue to be utilized in the RRZs. These programs include condition-based, detailed, and ground visual inspection; distribution wood pole inspection and treatment; and line equipment inspection.

Idaho Power also has an enhanced overhead distribution "hardening" program to implement in the RRZs. Examples of specific work include replacement of small conductors and associated hardware and replacement of wooden pins and associated wooden crossarms.

8.2.2.1. Ground Visual Inspection Program

Annually, qualified line patrol personnel (trained in distribution line inspection procedures and experienced in distribution line construction) complete visual wildfire mitigation inspections of the distribution lines located in the RRZs to identify Priority 1 defects and those that may cause an outage or possible ignition. The ground patrols are completed using four-wheel-drive vehicles, all-terrain vehicles, utility terrain vehicles, or on foot. These inspections identify potential line defects that are noted and scheduled for repair. Detailed distribution inspections are completed on a predetermined schedule and may be performed in conjunction with annual visual inspections.

All noted defects are prioritized as Priority 1, Priority 2, or Priority 3, based on the criteria listed below:

- **Priority 1**: Defects that, depending on the circumstances, require reporting and repair as soon as reasonably possible.
- **Priority 2**: Defects that, depending on the circumstances, generally require reporting and correction within 24 months of identification. The correction of these defects should be scheduled during crews' normal work schedules. Priority 2 defects not assigned a corrective plan within 24 months will be reviewed by the T&D Vegetation and maintenance engineering leader.
- **Priority 3**: Potential issues that may need correction but do not pose a threat to the system and should be monitored; or tracking of certain line construction practices.

Corrective action plans for Priority 1 and 2 defects are determined by engineering personnel for each prioritized defect and are scheduled and repaired.

8.2.2.2. Wood Pole Inspection and Treatment Program

All wood poles are visually inspected, sounded, and bored for defects and decay. The procedure is noted in 8.2.1.4.

8.2.2.3. Line Equipment Inspection Program

Line equipment in wildfire risk zones, including capacitor banks, automatic reclosing devices, and regulators, are inspected annually prior to wildfire season by line operations technicians. The inspection includes a visual inspection and, when electronic controls are present, data is retrieved and analyzed for proper operation.

8.2.2.4. Thermal Imaging (Infra-red) Inspections

Idaho Power will complete annual inspections of lines and equipment using thermal imaging (infra-red) cameras. This inspection methodology, although not new to Idaho Power, is being expanded to specifically include the RRZs. Compromised electrical connections and overloaded equipment may be identified using thermal imagery. Identified risks will be prioritized and mitigated using the prioritization methodology noted in 8.2.2.1 of this WMP.

8.2.2.5. Overhead Primary Hardening Program

Overhead distribution infrastructure located in the RRZs will be analyzed and may be inspected and hardened depending upon proximity to fuels conducive to wildfires in the unlikely event of failure of the line infrastructure. It is expected to take multiple years to inspect and harden all applicable overhead distribution lines.

The Overhead Primary Hardening program is intended to upgrade or repair certain overhead distribution infrastructure. Criteria as outlined in Table 7 drives the program work. Notable criteria are further explained in the following sections of this WMP.

8.2.2.5.1. Conductor "Small" Replacement

Idaho Power is implementing replacement of small conductors in the RRZs. Small conductors are those in sizes less than that of 4ACSR conductor. Examples of small wires include 6Cu, 6-3SS, 8A, 8A CW, 9IR, etc. These small conductors will be replaced with standard larger conductors, primarily with 4ACSR conductor.

8.2.2.5.2. Wood Pin and Crossarm Replacement

Wooden crossarms installed with wooden pins will continue to be replaced with fiberglass crossarms and steel pins. This work will be coordinated and included in the overhead primary hardening program. And, whenever work is being completed on a structure that requires replacement of wooden crossarms, Idaho Power will, generally, install fiberglass crossarms.

8.2.2.5.3. Porcelain Switch Replacement

Porcelain switches located in the RRZs will continue to be replaced with polymer switches. Additionally, associated hot clamps and stirrups will be replaced. This work will be coordinated and included in the overhead primary hardening program.

8.2.2.5.4. Fuse Options

Idaho Power investigated reasonable alternatives to replace certain expulsion fuses and expulsion arrestors. A pilot program was initiated in 2020 to replace several expulsion fuses with non-expulsion fuses in the vicinity of the Boise foothills. This pilot program was successful and Idaho Power implemented a subsequent program to replace expulsion fuses with non-expulsion fuses in RRZs as a part of its distribution overhead primary wildfire hardening program.

8.2.2.5.5. Wood Pole Wildfire Protection Program

Idaho Power has utilized numerous technologies to minimize the damage to wood poles that have been exposed to wildfires. The current technology of "mesh wraps" is utilized on certain distribution wood poles located in the RRZs.

8.3. T&D Vegetation Management

Idaho Power's T&D vegetation management program (VMP) addresses public safety and electric reliability and helps to safeguard T&D lines from trees and other vegetation that may cause an outage or damage to facilities. Specifically, the lines are inspected periodically, and trees and vegetation are cleared away from the line while certain trees are removed entirely. In addition, the VMP addresses the clearing of vegetation near the base of certain poles and line structures. The responsibilities of the VMP include the planning, scheduling, and quality control of VMP associated work. The VMP is active year-round and complies with applicable NESC, federal, and state requirements. Additional vegetation monitoring tools are in various stages of development, and Idaho Power will evaluate such tools for potential future implementation.

Idaho Power's key components of its VMP, relative to the WMP, are summarized in the table below.

Table 9
VMP summary

Vegetation Management
Transmission
Pre-Fire Season Inspection and Mitigation
Line Clearing Cycle Goal: 3-year cycle for valley areas & 6-year cycle for mountain areas
Tree Removals - Hazard Trees
Targeted Pole Clearing
100% Quality Assurance/Quality Control Auditing in RRZs and YRZs
Distribution
Pre-Fire Season Inspection and Mitigation
Line Clearing Cycle Goal: 3-year cycle in all areas with mid-cycle pruning occurring in 2nd year in RRZs and YRZs*
Tree Removals - Cycle Busters/Hazard Trees
Targeted Pole Clearing
100% Quality Assurance/Quality Control Auditing in RRZs and YRZs

*Distribution line clearing cycles vary by utility. Idaho Power has set a goal of achieving a 3-year cycle of distribution line clearing.

Vegetation contact with energized powerlines is a cause of outages and potential source of ignition for wildfires. Idaho Power's transition to a sustainable three-year pruning cycle will help reduce wildfire risk across the company's service area. In non-wildfire risk zones, distribution feeders and valley-located transmission lines will be patrolled and pruned on a three-year cycle. A six-year cycle will continue to be employed for transmission lines in mountain locations. Specific to each tree pruned, directional pruning methods will be employed where cuts will meet ANSI A300 standard and adequate clearance will be obtained that should accommodate regrowth without violating the prescribed minimum clearance throughout the cycle.

Reliability data has shown that vegetation contact is one of the most likely sources of faults and possible ignition on the system. As a result, Idaho Power employs the same enhanced vegetation management practices in both YRZs and RRZs despite the different levels of wildfire risk. These practices include mid-cycle patrols and pruning in the second year of the cycle to address "cycle buster" trees and annual "hotspot" patrols to address any new hazard trees or unexpected vegetative growth that poses an immediate threat of contact with energized facilities. In addition, the company strives to complete audits for all pruning work performed in YRZs and RRZs, regardless of reason for the pruning. The audits confirm that pruning cuts meet the specification and proper clearance was obtained. The following table summarizes vegetation management activities with respect to wildfire risk zones.

Table 10
Summary of vegetation management activities and schedules

Vegetation Management	Inspection Interval				
Inspections and Activity Schedule	**Idaho Non-Risk Zone**	**Oregon Non-Risk Zone**	**Idaho YRZ**	**Oregon YRZ**	**Idaho RRZ**
Transmission					
Hazard Tree Patrol	Annually	Annually	Annually	Annually	Annually
Cycle Patrol/Pruning—Valley Locations	3 Years	3 Years	3 Years	3 Years	3 Years
Cycle Patrol/Pruning—Mountain Locations	6 Years	6 Years	6 Years	6 Years	6 Years
Wildfire Mitigation Patrol/Pruning	None	None	None	None	Annually
Cycle Buster Patrol/Pruning	18 Months	18 Months	18 Months	18 Months	18 Months
Distribution					
Wildfire Mitigation Patrol/Pruning	None	None	Annually	Annually	Annually
Cycle Patrol/Pruning	3 Years	3 Years	3 Years	3 Years	3 Years
Mid-Cycle Patrol/Pruning	None	None	2 Years after Cycle Prune	2 Years after Cycle Prune	2 Years after Cycle Prune
Cycle Buster Patrol/Pruning	None	18 Months	None	18 Months	None
Quality Assurance (Transmission and Distribution)					
Post-Pruning Audit Inspections	Sampling	Sampling	100%	100%	100%

8.3.1. Definitions

Applicable Transmission Lines—Each overhead transmission line operated within the WMP RRZ at 46 kilovolts (kV) or higher.

Cycle Buster—Trees that grow at a rapid rate, requiring a more frequent trimming schedule than the normal trim cycle.

Hazard Tree—Any vegetation issue that poses a threat of causing a line outage but has either a low or medium risk of failure in the next month. Hazard trees will be further defined as posing either a medium hazard or low hazard.

High-Priority Tree—Any vegetation condition likely to cause a line outage with a high risk of failure in the next few days or weeks. High-priority trees could also be vegetation that is in good condition but has grown so close to the lines that it could be brought into contact with the line through a combination of conductor sag and/or wind-induced movement in the conductor or the vegetation.

Line Clearing Cycles—T&D clearing of lines defined on a periodic basis.

8.3.2. Transmission Vegetation Management

Maintaining a zone near transmission lines that is free of vegetation has long been a priority for Idaho Power. The clearance zone is voltage-level dependent and defined by federal and state regulations.

8.3.2.1. Transmission Vegetation Inspections

Utility arborists annually conduct aerial and/or ground patrols on each applicable transmission line to identify and mitigate vegetation hazards. In addition, transmission patrol personnel inspect all applicable transmission lines once a year to identify any transmission defects and vegetation hazards. During these inspections, the patrol personnel will identify hazardous vegetation, within or adjacent to the Right of Way (ROW), that could fall in or onto the transmission lines or associated facilities. The patrol personnel will evaluate the hazardous vegetation as to the level of threat posed by categorizing the vegetation as a *high priority*, *medium hazard*, or *low hazard*. Any hazardous vegetation found is reported to the utility arborist and documented. Any hazardous vegetation categorized as a *high priority* and that presents a risk to cause an outage at any moment shall also be reported without any intentional time delay to the grid operator. The utility arborist will conduct a follow-up inspection if potential hazard trees or grow-ins are identified. The utility arborist prioritizes and schedules any remedial action for all reported vegetation issues.

8.3.2.2. Transmission Line Clearing Cycles

Transmission lines will be cleared on long-term cycles based on 3 years for urban and rural valley areas and 6 years for mountain areas. However, shorter clearing cycles may occur if conditions dictate out-of-cycle trimming. In most cases, vegetation is cleared primarily through manual cutting of targeted trees and tall shrubs. However, when appropriate and in compliance and permission with federal and state requirements, tree-growth regulators and spot herbicide treatments are applied as effective techniques for reducing re-growth of sprouting deciduous shrubs and trees and extending maintenance cycles.

8.3.2.3. Transmission Line Clearing Quality Control and Assurance

In non-wildfire risk zones, audits are performed on a random sample of pruning worksites. These audits are performed through a combination of the contracted arborists that planned the work and Idaho Power's utility arborists. Due to the elevated risk of wildfire in YRZs and RRZs, audits will be performed on pruning work performed in YRZs and RRZs regardless of the reason for the patrols and pruning. The audits will be performed by a combination of contracted arborists and Idaho Power's utility arborists to check whether pruning cuts meet specification and proper clearance was achieved.

8.3.3. Distribution Vegetation Management

Idaho Power is actively working to clear distribution lines throughout Idaho Power's service area on a three-year cycle.[20] Additionally, in the RRZs and YRZs, Idaho Power completes annual vegetation line inspections and mid-cycle clearing of the lines in the second year, is increasing the number of trees removed, and is completing 100% quality control reviews of contractor line clearing work by certified arborists.

8.3.3.1. Distribution Line Clearing Cycles

Idaho Power is actively working to clear distribution lines on a three-year cycle. In RRZs and YRZs, Idaho Power's goal is to perform mid-cycle pruning in the second year to remove faster growing vegetation to ensure the lines are clear of vegetation for the full pruning cycle. In addition, Idaho Power clears lines based upon "special request" in the situations that fast growing, unexpected growth occurs and is reported by any employee or customer.

8.3.3.2. Distribution Vegetation Inspections

In addition to regular cycle pruning activities, utility arborists are annually conducting ground patrols to identify potential vegetation hazards of each distribution line identified in the RRZs and YRZs. In addition, distribution patrol personnel also inspect the lines in the RRZs annually. During these inspections, patrol personnel identify infrastructure defects and hazardous vegetation, within or adjacent to the ROWs, that could fall in or onto the distribution lines or associated facilities. The patrol personnel then evaluate the hazardous vegetation as to the level of threat posed by categorizing the vegetation as a *high priority*, *medium hazard*, or *low hazard*. Any hazardous vegetation found is reported to the utility arborist and documented.
Any hazardous vegetation categorized as a *high priority* and that presents a risk to cause an outage at any moment shall also be reported without any intentional time delay to the Grid

[20] Idaho Power will test a three-year cycle for a period of 4 or 5 years to verify that such a cycle can be maintained and that the expected benefits are realized.

Operator. The utility arborist will conduct a follow-up inspection if potential hazard trees or grow-ins are identified. The utility arborist prioritizes and schedules any remedial action for all reported vegetation issues.

8.3.3.3. Distribution Line Clearing Procedures

In most cases, vegetation is cleared as scheduled work and includes, but is not limited to, the removal of dead branches overhanging power lines, weak branch attachments, damaged root base or dead or dying trees leaning toward Idaho Power facilities. Vegetation clearing methods include crews using chain saws or specialized pruning machines. Trees are cleared using a pruning procedure called directional or natural pruning, a method recommended by the International Society of Arboriculture, and the ANSI A300 standards.

However, when appropriate and in compliance and permission with federal and state requirements, tree-growth regulators and spot herbicide treatments are applied as effective techniques for reducing re-growth of sprouting deciduous shrubs and trees and extending maintenance cycles.

Through its vegetation management program, Idaho Power has a target to maintain clearance distance between vegetation and conductors as follows:

- Five feet for conductors energized at 600 through 50,000 volts.
- Clearances may be reduced to three feet if the vegetation is not considered to be readily climbable because the lowest branch is greater than eight feet above ground level.
- New tree growth that is no larger than ½ inch in diameter may intrude into this minimum clearance area provided it does not come closer than six inches to the conductor. This new growth is identified during line patrols and removed.
- For conductors energized below 600 volts, vegetation is pruned to prevent the vegetation from causing unreasonable strain on electric conductors.

8.3.3.4. Distribution Line Clearing Quality Control and Assurance

Similar to the transmission section, in non-wildfire risk zones, audits are performed on a random sample of pruning worksites. These audits are performed through a combination of the contracted arborists that planned the work and Idaho Power's utility arborists. Due to the elevated risk of wildfire in YRZs and RRZs, audits will be performed on pruning work performed in YRZs and RRZs regardless of the reason for the patrols and pruning.

8.3.4. Pole Clearing of Vegetation

Idaho Power has historically cleared vegetation from the base of certain transmission wood poles and a limited number of distribution wood poles in Idaho. These vegetation clearing practices have been deemed an effective method of minimizing wildfire damage to existing wood poles. Where acceptable and permissible, Idaho Power removes or clears vegetation in a 20-foot radius surrounding the wood poles and applies a 10-year weed-control ground sterilant (SpraKil SK-26 Granular). Idaho Power submitted an SF-299 application with the Oregon BLM Vale District Office to prepare an Environmental Assessment to use the same ground sterilant on transmission and distribution facilities in Oregon. BLM staff estimate issuing herbicide permits in mid-2024.

9. Wildfire Response

9.1. Overview

Idaho Power responds to wildfires involving or impacting its facilities and/or resulting in a system outage; depending on the specific circumstances, Idaho Power may also respond to wildfires with the potential to result in an outage. Idaho Power's actions include without limitation:

- Taking appropriate steps, where safe to do so, to protect Idaho Power-owned facilities from fire damage;
- Restoring electrical service following an outages; and,
- Communicating with and informing customers.

These actions are taken on a 24-hour basis.

9.2. Response to Active Wildfires

Idaho Power field crews are trained to respond to active wildfires to monitor the situation regarding Idaho Power's facilities. Although they carry certain fire suppression equipment for use on very small fires in limited situations, Idaho Power's crews are not professionally trained firefighters and are instructed not to place themselves in a hazardous position when responding to wildfires. When responding to an active wildfire, Idaho Power personnel immediately report to, and take appropriate direction from, the Incident Commander (IC) or other fire response entity official with jurisdiction over the incident.

9.3. Emergency Line Patrols

At certain times, unplanned de-energization of lines requires qualified line personnel to conduct "emergency" patrols (inspections) of the de-energized lines. These patrols identify outage causes, damaged facilities, ingress/egress routes, and restoration requirements (number of crews, crew sizes, and necessary materials).

9.4. Restoration of Electrical Service

Idaho Power personnel restore electrical service when it is safe to do so following a wildfire. Trained field crews report to the site where damage has occurred with equipment and new materials and develop a plan to remove and rebuild damaged facilities. Depending on the situation, contracted field crews—such as line crews and vegetation management crews—are also deployed to assist in restoration efforts. Restoration work may take hours or, in some rare cases, days to complete. Depending on the extent of damage, customers may need to perform repairs on their facilities and pass inspections by local agencies prior to having full electric service restored.

Due to the unique construction, need for specialized equipment, and—in many cases—remote location of many of Idaho Power's transmission lines, Idaho Power developed a *Transmission Emergency Response Plan*. This plan includes restoration processes related to all transmission voltage classes from 46 through 500 kV. The plan outlines the basic approach and certain details about notification, materials, damage assessment, coordination, and preparedness.

9.4.1. Mutual Assistance

Idaho Power is a member of the Western Region Mutual Assistance Agreement (WRMAA), of which the majority of western United States electric utilities are also members. Member utilities provide emergency repair and restoration assistance to other member utilities requesting assistance when dealing with damaged electric facilities following a significant wildfire or weather event. In the event of a catastrophic wildfire that causes widespread damage to Idaho Power's system, Idaho Power may request restoration assistance via the WRMAA as a last resort option after utilizing available internal personnel and contracted entities.

9.5. Public Outreach and Communications

In 2022, Idaho Power developed and began following an *Outage Communication Playbook* (Playbook) to guide PSPS and load shed protocols. The Playbook ensures consistent and reliable communication to internal and external stakeholders. External communication includes targeted customers, Public Safety Partners, and operators of critical facilities. The Playbook guides activities and identifies key roles and responsibilities of internal Idaho Power employees. Supplemental information and resources are also included to ensure effective and consistent communication is made prior to, during, and after an event.

10. Communicating About Wildfire

10.1. Objective

Idaho Power communicates information about this WMP, including PSPS, and wildfire issues in general, to employees, customers, government officials, the public and other stakeholders. Topics of these communications vary due to timing and audience. For example, all customers can benefit from outage preparedness tips and information about how we are hardening the grid. We discuss PSPS plans in greater detail with Public Safety Partners and operators of critical facilities, as well as customers who live in PSPS zones.

The following core messages are the foundation for all wildfire-related communications:

- How customers can prepare for wildfire-related outages, including where to find outage and PSPS information and how to sign up for alerts and update contact information
- Ways customers can reduce wildfire risk
- Idaho Power's work to protect the grid from wildfire and reduce wildfire risk

10.2. Community Outreach

10.2.1. Community Engagement

Idaho Power presents and distributes information on its WMP to a wide variety of stakeholders including the BLM, U.S. Forest Service, and county and city officials.

Idaho Power engages with various Public Safety Partners, including local governments, emergency managers, and Idaho and Oregon's ESF-12 and social service and welfare agencies (e.g., Oregon's Department of Human Services). These engagements focus on wildfire awareness, prevention, and outage preparedness. For example, the company worked with the Boise City Fire Department to develop updates to the Boise City Fire Code related to Wildland-Urban interface areas.

Idaho Power meets with all Public Safety Partners at least once a year and more frequently as needed. In counties with active local emergency planning committees, Idaho Power is an engaged member. The company uses a variety of methods to communicate with Public Safety Partners, including personal contact via phone, email, and text. We meet with identified Public Safety Partners annually and document their communication preferences in our outreach database. During an event, this information will be used to contact each partner.

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC
Page 80 of 158

Idaho Power conducted over 20 WMP and PSPS plan presentations in 2022. At each one, stakeholders were asked to provide feedback to inform future versions of the WMP. Notable presentations included:

- Local emergency management planning committee meetings across our service area
- Public meetings in communities with PSPS zones and in all Oregon counties we serve
- Idaho Emergency Preparedness Conference
- Idaho Public Health Planning Conference
- Snake River Fire Chiefs annual meeting held in Oregon
- Idaho VOAD (Volunteer Organizations Active in Disasters) Annual Conference
- Seven public meetings in Ontario, Huntington, and Halfway at the end of fire season to gain feedback from customers and stakeholders to help inform future plans. Similar meetings will be held in Idaho counties prior to the 2023 fire season.

Idaho Power has also conducted functional exercises with Public Safety Partners before wildfire season. These exercises mimic fire emergencies, including PSPS events, to improve all parties' wildfire preparedness. For example, in June 2022, Idaho Power conducted a PSPS mock event in our Idaho service area. Several Public Safety Partners were included in the event to test our communication and coordination protocols. The event was held over a three-day period and assumed PSPS events across several wildfire risk zones. Following the event, participants were asked to provide feedback, which has been incorporated into our plan. Feedback received included:

- Public Health Districts were added as Public Safety Partner contacts. Previously, the Idaho Department of Health and Welfare had planned to communicate to the Public Health Districts in case of a PSPS event. Through the event, we identified that this created a delay in communication to the Public Health Districts.
- Back-up contacts for the Idaho Public Utility Commission were identified in case our primary ESF-12 contact is unavailable.
- The Idaho Office of Emergency Management requested they receive a list of critical facilities that could be impacted by the PSPS event. We added this step to our protocols for Idaho and Oregon.

In addition, Idaho Power participated in two mock events, one conducted by Malheur County and the second with the Idaho Office of Emergency Management's Cascade Rising event. Each event mimicked large power outages. While these were not PSPS-specific, we were able to test and discuss our outage communication protocols. Through those events, two opportunities were identified:

- The Red Cross was added as a Public Safety Partner in Malheur County based on their role in coordinating and supporting CRCs.

- The emPower program was identified as a tool to help notify customers on DMEs if a PSPS event is predicted. Idaho Power is working with the Idaho Department of Health and Welfare, the Independent Living Network, and the Idaho Office of Emergency Management to expand this program to all Idaho counties.

2022 Public Safety Partner Feedback Summary

County emergency managers, the Idaho Office of Emergency Management, the Oregon Office of Emergency Management, and the Idaho Department of Health and Welfare reviewed Idaho Power's WMP plan, PSPS protocols, community outreach strategy and materials, critical facilities, and CRC strategies. Feedback received has been incorporated into our programs. Improvements based on this feedback include:

- Updates to identified critical facilities

- Changes to outreach materials to include county specific information as requested

    - Example: Sign-up information was included for counties with active emergency alert systems

- Revised GIS tools that will be provided to Public Safety Partners if a PSPS event is forecasted

10.2.2. Community Resource Centers

Each county in Idaho Power's service area has unique needs during outage events and requires a customized, flexible approach. During annual meetings with county emergency managers, Idaho Power developed county-specific strategies in preparation for potential large-scale, extended outages. These strategies include working with emergency managers to identify CRC locations to be used, as needed, in a PSPS event. The company formulated strategies for Oregon counties in 2022 and will further explore county strategies for Idaho in 2023. If a PSPS event is forecasted, Idaho Power will strive to work directly with local Public Safety Partners to identify and meet the needs of the local community. Services provided in collaboration with emergency managers could include:

- Stand-up of CRC

- CRC location(s) and logistics included in community outreach/outage notifications

- CRC resources
  - Food, water, and other basic needs
  - Charging stations
  - Auxiliary service coordination such as medical services, housing assistance, family reunification, etc.

10.3. Customer Communications

Safety is one of Idaho Power's core values. It guides our communication strategy for wildfire-related communication to our customers. Communication methods and timing vary based on the audience we are trying to reach and the goal of the communication.

Communication generally falls into two categories: 1) broad outreach to all customers, and 2) targeted outreach to customers in PSPS zones. The company uses a variety of outreach methods to reach a broad customer base with messages about wildfire safety, summer outage preparedness, and grid hardening efforts.

Outreach to customers in PSPS zones was more targeted and frequent. Idaho Power repeatedly urged these customers to update or confirm accurate contact information.

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC
Page 83 of 158

Figure 14
Outreach samples for the 2022 wildfire season

10.3.1. Key Communication Methods

Idaho Power communicates with customers and the public before and throughout wildfire season to inform them of steps the company is taking to reduce wildfire risk and ways they can help prevent wildfires and prepare for outages. Various communication mediums used to accomplish this include:

- *Connections* (This monthly newsletter is an effective way to give customers more in-depth information about the work Idaho Power does, but it is not an effective way to communicate urgent information.)


MAY 2022
Connections
IDAHO POWER
Idaho Power Prepares for Wildfire Season
Reliability is one of Idaho Power's most important missions. We work hard every day to ensure your home, farm or business has as much energy as you need — when you need it.
NOW is the Time to be Wildfire Ready
Make a plan for your unique needs
Prepare now so you're ready when it counts
Stay Informed
Build a summer outage kit
From the Energy Efficient Kitchen
Slow Cooker Salsa Chicken
May 2022 Main Course
Can We Reach You During an Outage?
Update Your Contact Information
Sign Up for Outage Alerts

Figure 15
May 2022 edition of *Connections*

- Videos on topics like vegetation management and PSPS

Figure 16
Idaho Power developed an educational video on how we protect wooden poles from wildfire

- Emails, texts, and phone calls telling customers how to prepare for wildfires, encouraging them to update their contact information, and providing information about grid hardening efforts
    - The company used a new communication tool to notify all customers in PSPS zones by text message, phone call, or email. We mailed letters to customers we couldn't reach with this tool. Every year, the company will work to obtain accurate contact information for all customers in PSPS zones.
- News media (news releases, appearances on broadcast TV and radio shows, interviews, etc.)
- Social media (posts on Facebook, Instagram, and Twitter are an efficient way to reach large numbers of customers and the public in a timely manner). Social media continues to be a critical tool for engaging with customers and communicating wildfire safety. The company's social media campaign for wildfire season focused on three main themes:
    - Wildfire prevention: What Idaho Power is doing and what customers can do to reduce wildfire risk
    - Outage preparation: How customers, especially those who live or have businesses in high-risk areas, should prepare for wildfire-related outages
    - Grid maintenance: How Idaho Power protects the grid, keeping energy safe, reliable and affordable, even during wildfire season.

Figure 17
Sample image of social media post

Social media posts are focused on various aspects of each theme, such as putting out campfires as shown in Figure 18 below; creating defensible spaces around homes and businesses; building a summer outage kit as shown in Figure 17, above; and updating contact information. Posts also include information on installing SPUs on the power distribution system and wrapping wood poles with fire-resistant mesh.

Figure 18
Sample image of social media post

- Postcards and flyers
- Paid advertising (radio, digital, and print advertisements)

- Idaho Power's website (wildfire safety information, such as videos, safety tips, and the latest version of the WMP) can be found at https://www.idahopower.com/outages-safety/wildfire-safety/.

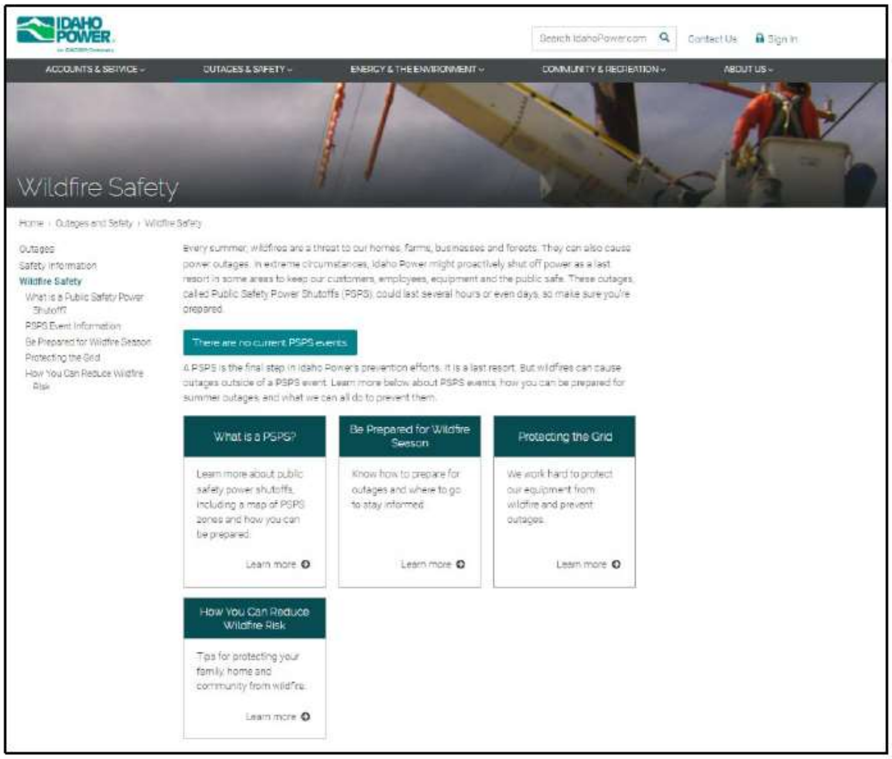


Figure 19
Idaho Power's Wildfire Safety landing webpage

- As shown in Figure 19, on this webpage, the company introduces wildfire and its relationship to delivering power, information on PSPS, and the following links:
  - What is a PSPS?: Explanation of PSPS events, including a map customers can use to determine if their homes or businesses are inside a PSPS zone
  - Be Prepared for Wildfire Season: Preparation tips like building an outage kit and making a plan for feeding livestock, etc.
  - Protecting the Grid: Idaho Power measures to enhance grid resiliency and reduce wildfire risk; an interactive map showing red and yellow risk zones and a link to the WMP
  - How You Can Reduce Wildfire Risk: Tips for preventing wildfires when camping, using fireworks, hauling trailers, etc.
  - PSPS Event Information: Real-time information on active PSPS events, estimated shutoff time, outage duration, and customers impacted

- Public engagement with the company holding at least one public meeting per year in both Oregon and Idaho, offering a virtual meeting with additional access and functionality options. Feedback opportunities are also provided during and after the meetings.

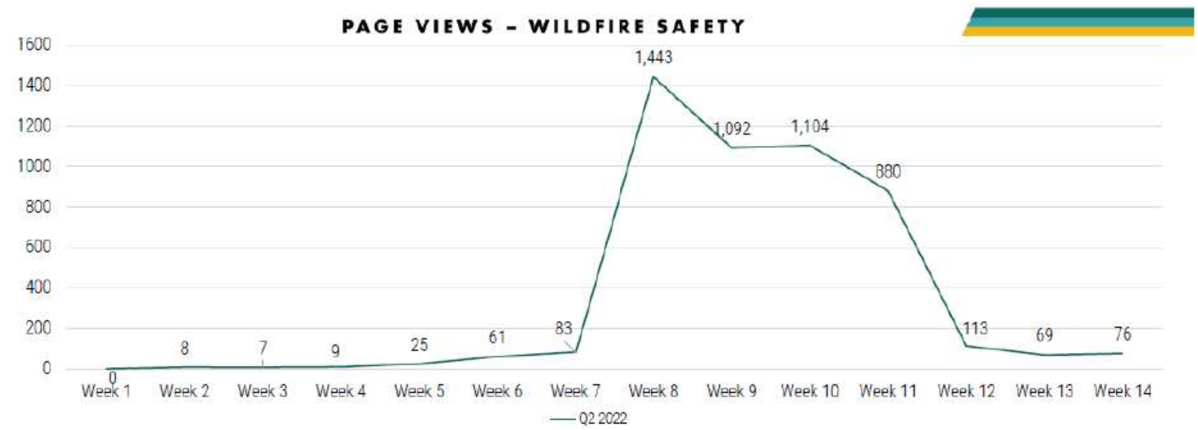
Figure 20
Wildfire mitigation meeting PowerPoint cover slide

10.3.2. Timing of Outreach

The timing of the outreach generally occurs before and during wildfire season. In 2022, Idaho Power originally planned to begin preseason wildfire outreach in early- to mid-April. Due to an unusually wet and cold spring (Boise had accumulating snow on the valley floor on May 9) and a desire to maximize impact, the company delayed release of social media posts, ads, and other communications until the weather changed such that wildfire was more prominently on people's minds. The tone of early communications was meant to encourage customers to think about wildfire season, how they could prepare for it, their role in preventing wildfires, and steps Idaho Power is taking to keep the grid safe and reduce wildfire risk. When the potential for wildfire increased, communications shifted in tone. Messaging put more emphasis on asking customers, especially those in PSPS zones, to update their contact information and prepare for wildfire.

10.3.3. Communication Metrics

Idaho Power uses metrics and monitoring of communication activities to evaluate the effectiveness of our outreach efforts. Idaho Power published a Wildfire Safety landing webpage in April 2022 with information on wildfire safety, PSPS, and interactive maps. In the roughly six weeks that followed, before general outreach efforts began, the page saw fewer than 200 hits. However, a campaign of radio, print, and online ads began in earnest in late June and traffic immediately jumped, with 1,443 hits the first week of the campaign as shown in the following graph. Traffic stayed high for about a month before dropping off again.



- This chart shows the Wildfire Safety page for Q2 2022 in green, (4/1/22-6/30/22; 4,970 page views).
- The campaign started during week 8, increasing the traffic drastically. Radio ended on the Sunday of Week 10, and Display ended during Week 11. Spotify ended during Week 14.

Figure 21
Wildfire safety webpage views

The following is a summary of metrics from Idaho Power's 2022 paid communication campaign.

- Radio—Idaho Power's wildfire-safety radio ad campaign ran from May 16 to July 31 in the Idaho Falls, Twin Falls, and Boise markets. The Boise market includes eastern Oregon, reaching as far west as Baker City. The campaign included a total of 4,327 paid and public safety announcement (PSA) match spots; 967 of which were in Spanish and played on Spanish language stations.

- Programmatic Display Ads—Idaho Power's digital display ads appeared on regional websites from May 16 to July 31. These ads resulted in a total of 3,496 clicks in Idaho and Oregon to our wildfire landing webpage, with almost 3.7 million impressions. Almost three-quarters (74.21%) of these impressions occurred via mobile devices.

- 2021 Versus 2022—Idaho Power's 2021 wildfire-safety campaign was comparable to what we deployed in previous years, with the company relying mainly on displays on the Idaho Power website. The 2022 campaign was a much more robust, intricately planned and carefully executed effort. It involved a larger outreach goal and more ads on radio and Spotify that ultimately led to 1.24 million more impressions than the 2021 wildfire-safety campaign.

2022 WMP Communication Summary

Idaho Power used traditional and social media in 2022 to inform customers about the company's WMP, efforts to protect the grid from wildfire, how customers could reduce wildfire risk, how to prepare for wildfire-related outages, and PSPS. Outlets included:

- Newspapers—Print ads and news coverage
- Radio—Paid ads in English and Spanish and news coverage
- TV news coverage
- Printed flyers
- Social media
- Idaho Power website
- Digital display ads
- Postcards—Used to inform customers of the PSPS program and invitations for public meetings
- Spotify—Paid ads
- News Releases—Includes news releases with other Oregon utilities
- Customer email
- Customer newsletters
- Text Messages—Customers in PSPS zones
- Phone Calls—Customers in PSPS zones
- Letters—Customers in PSPS zones

The following updates to the website were made to include new pages focused on wildfire safety in 2022:

- Searchable map of PSPS zones by customer address
- Summer outage preparation
- How Idaho Power protects the grid including mitigation efforts
- How customers can help prevent wildfires
- An active PSPS event page that provides details of active PSPS areas and outage duration information

Additionally:

- Postcards were sent to all customers in PSPS zones to inform them of program details
- Printed 2,600 outage preparedness flyers (English and Spanish) and gave to the Idaho Commission on Aging for delivery with Meals on Wheels
- Wildfire themed customer newsletter (*Connections*) was sent to all customers in May
- Wildfire themed customer email sent to all customers with email addresses on file (approx. 350,000) in May
- Implemented a "pop-up" in the customer My Account web page encouraging customers to update contact information
- Post fire-season postcards were mailed to all Oregon customers in November for invitation to public meetings

10.4. Idaho Power Internal Communications—Employees

Idaho Power communicates with its employees in a variety of ways:

- *News Scans* for all employees

Page 1 • May 2, 2022

NewsScans

Dave Spillett and Pule Alo Receive President's Awards for Safety

President and CEO Lisa Grow recently presented the President's Award for Safety to two deserving employees in Pocatello — Meter Specialist Pule Alo and Regional Customer Relations Manager Dave Spillett. Here are their stories.

In early February, Pule arrived at a customer's home in American Falls as part of an account call. As he walked up to the door, he thought he heard crying. Listening, he heard a faint voice calling out for help. He went inside and found the customer lying on the floor at the top of the stairs. The woman had fallen, seriously injured her hip and had been lying there for five days.

After reassuring her he would help, Pule went outside, found cell service and called 911. He returned to the customer, covered her with a blanket to keep her warm and gave her water to drink. He even helped gather some of her belongings she wanted to take with her to the hospital.

Reflecting on the event, Pule said, "I am thankful for the training that we have at Idaho Power and that I was able to help her. I assessed the situation, secured the area and called 911."

You made a difference." Lisa told Pule

This past winter, regional employees identified several safety issues at an apartment building that posed hazards to a tenant. The building owner had converted a meter-utility room into an apartment that was now occupied by a single mother and her young child.

Our employees immediately contacted the

The PSPS Plan is Here. What is it?

For the first time in company history, we've developed a Public Safety Power Shutoff (PSPS) plan.

A PSPS is when a company like Idaho Power proactively turns off power to certain areas where wildfire risk is high due to extreme weather conditions. The outage is an effort to protect our customers, communities, employees and equipment from wildfire in windy, dry conditions.

A PSPS is different from a load shed, which is a proactive outage used to protect the grid if customers' need for power is too high due to growth, extreme weather or other factors. It's also different from outages we've used occasionally *after* a wildfire starts to protect firefighters and other crews near our lines.

Figure 22
May 2, 2022, edition of *News Scans*

- Emails
- Leader communications
- GIS-based visual communication of risk zones and affected overhead lines
- Online training for employees influenced by the WMP
- In-person, hands-on, training for certain field employees

11. Performance Monitoring and Metrics

11.1. Wildfire Mitigation Plan Compliance

The Chief Operating Officer (COO) is the designated oversight officer for the Idaho Power WMP. The Vice President of Planning, Engineering and Construction (VP) is responsible for compliance monitoring, necessary training, and annual review of this WMP.

11.2. Internal Audit

Idaho Power's internal audit department, Audit Services, will periodically conduct an independent and objective evaluation of the WMP to assess compliance with policies and procedures and evaluate achievement of the Plan's objectives. Idaho Power's Compliance department will also periodically review Idaho Power's compliance with federal reliability standards regarding vegetation management practices.

11.3. Annual Review

Idaho Power will conduct an annual review of its WMP and incorporate necessary updates prior to wildfire season.

11.4. Wildfire Risk Map

The Wildfire Risk Map was established in 2020 by an external consultant. As noted in Section 2 of this report, the 2020 analysis was based, in part, on population census data from 2010. Idaho Power plans to reconduct risk modeling in 2023 to include 2020 Census data and explore other areas of consequence as described in Section 3.2.1. Idaho Power intends to review our risk modeling approach on an annual basis and perform modeling updates biennially.

11.5. Situational Awareness

Idaho Power will share its FPI regularly and broadly with Idaho Power personnel and contractors during wildfire season to ensure condition-specific operating requirements are met.

11.6. Wildfire Mitigation—Field Personnel Practices

Idaho Power crews and certain personnel are required to follow the *Field Personnel Practices* when working on lines in the RRZs and YRZs during a red FPI. Specific requirements are found in Idaho Power's *Field Personnel Practices* which is consulted by such crews working in these areas.

11.7. Wildfire Mitigation—Operations

Each year in preparation for the fire season, Idaho Power reviews and establishes:

- Temporary operating procedures for transmission lines during the fire season
- An operational strategy for distribution lines during time periods of elevated wildfire risk during the fire season
- Use of PSPS as a tool of last resort to prevent Idaho Power T&D facilities from becoming a wildfire ignition source or contributing to the spread of wildfires

11.8. Wildfire Mitigation—T&D Programs

This section lists metrics used to evaluate Idaho Power's asset management and vegetation management programs. The metrics are based on progress made towards completing mitigation activities, such as quantities of inspected units. Work is identified and prioritized each year and approved by executive management. Idaho Power's goal is to complete 100% of the work plan each year; however, emergencies or other unplanned events can occur and disrupt the annual work plan. All work is completed in accordance with safety and applicable requirements and industry standards.

Table 11
T&D programs metrics

Transmission	
Transmission Asset Management Programs	**Description**
Aerial Visual Inspection Program	Perform annual patrols and document identified defects according to priority. Complete repairs according to priority definition.
Ground Visual Inspection Program	Perform annual patrols and document identified defects according to priority. Complete repairs according to priority definition.
Detailed Visual (High Resolution Photography) Inspection Program	Perform 10-year cycle patrols and document identified defects according to priority. Complete repairs according to priority definition.
Wood Pole Inspection and Treatment Program	Perform 10-year cycle patrols and document identified defects according to priority. Complete repairs according to priority definition.
Cathodic Protection and Inspection Program	Perform 10-year structure-to-soil potential testing on select towers with direct-buried anodes. Perform 10-year rectifier and ground-bed testing on ICCP systems. Annually inspect and record DC voltage and current readings of rectifiers. Complete repairs and adjustments.
Wood Pole Wildfire Protection Program	Inspect and install wraps on selected poles.
Distribution	
Distribution Asset Management Programs	**Description**
Wood Pole Inspection and Treatment Program	Perform 10-year cycle patrols and document identified defects according to priority. Complete repairs according to priority definition.
Line Equipment Inspection Program	Complete annual inspections and data analysis and mitigate defects

Ground Detailed Inspection Program	Perform annual patrols and document identified defects according to priority. Complete repairs according to priority definition.
Thermography (Infra-Red) Inspections	Complete inspections of targeted lines and equipment using thermal imaging (infra-red) cameras.
Distribution Infrastructure Hardening Program	Complete annual work plan
Replace "small conductor" with new 4acsr or larger conductor	
Replace or repair damaged conductor	
Re-tension loose conductors including "flying taps" and slack spans as required	
Replace wood-stubbed poles with new wood poles	
Replace white and yellow square tagged poles with new wood poles	
Replace wood pins/wood crossarm with new steel pins/fiberglass crossarms	
Replace steel insulator brackets with new steel pins/fiberglass crossarms	
Replace wedge deadends on primary taps with new polymer deadend strain insulators	
Replace aluminum deadend strain insulators with new polymer deadend strain insulators	
Replace porcelain switches with new polymer switches Replace hot line clamps Replace aluminum stirrups Install avian cover Relocate arresters	
Install bird/animal guarding	
Update capacitor banks Replace swelling capacitors Replace oil-filled switches with vacuum style Replace porcelain switches with polymer switches	
Replace certain expulsion arrestors	
Install disconnect switches on CSP transformers Install avian cover	
Update down guys Replace/Install down-guy insulators with fiberglass insulators Tighten down guys	
Tighten hardware	
Correct 3rd party pole attachment violations (report to Joint Use Department)	
Replace certain expulsion fuses	
Vegetation Management	
Transmission	**Description**
Pre-Fire Season Inspection and Mitigation	Perform annual pre-fire season inspections no later than June 15 of each year and mitigate noted "hot spots"
Line Clearing Cycles: Strive to maintain 3-year cycle for valley areas & 6-year cycle for mountain areas	Complete annual cycle pruning work plan
Tree Removals - Hazard Trees	Remove targeted hazard trees
Targeted Pole Clearing	Complete annually targeted structures
100% QA/QC Audits in RRZs and YRZs	Complete annually QA/QC audits
Distribution	**Description**
Pre-Fire Season Inspection and Mitigation	Perform annual pre-fire season inspections no later than June 15 of each year in RRZs and YRZs and mitigate noted "hot spots"
Line Clearing Cycle: Strive to maintain 3-year cycle	Complete annual cycle pruning work plan
Mid-Cycle Pruning in RRZs and YRZs	Complete annual mid-cycle pruning work plan in RRZs and YRZs

Tree Removals - Cycle Busters/Hazard Trees	Complete annual cycle pruning work plan
Targeted Pole Clearing	Complete annually targeted structures
100% QA/QC Audits in RRZs and YRZs	Complete annually QA/QC audits

11.9. Long-term Metrics

In 2022, Idaho Power identified new metrics to measure the performance of the WMP and its effectiveness over time. Vegetation management and grid hardening work is expected to reduce outages and improve reliability in wildfire risk zones. A new approach in gauging the effectiveness of the WMP includes tracking reliability data and specific outage counts based on causes or failures that are considered potential drivers of ignition. The following outage causes were established as baseline potential drivers of ignition and will be monitored for each wildfire risk zone:

- Tree/Vegetation Contact
- Equipment Failure
- Loose Hardware
- Corrosion
- Animal Contact

Historical data was analyzed in 2022 in both RRZ and YRZ to establish baseline metrics that will be used to measure performance over time. Potential drivers of ignition in wildfire risk zones through October have decreased by 8% compared to the previous four-year average. This improvement occurred despite being in early stages of wildfire hardening and enhanced vegetation management activities. The use of outage data to gauge overall WMP performance is expected to be a long-term metric and it takes several years to develop trendlines and averages to draw definitive conclusions and a causal relationship to wildfire mitigation activities. In 2023, the company plans to continue to develop long-term benchmarks based on outage counts and cause codes and will refine our approach by expanding the use of data analytics.

Appendix A
The Wildland Fire Preparedness and Prevention Plan.

Wildland Fire Preparedness and Prevention Plan

Table of Contents

1. Plan Overview

A. Intent of Plan

The purpose of this Wildland Fire Preparedness and Prevention Plan (Plan) is to provide guidance to Idaho Power Company (IPC) employees to help prevent the accidental ignition and spread of wildland fires (wildfires) due to employee work activities in locations and under conditions where wildfire risk is heightened. It is expected that all IPC employees be aware of the provisions of this Plan, operate in accordance with the Plan and conduct themselves in a fire-safe manner.

B. Scope of Plan

The scope of this Plan includes tools, equipment, and field behaviors IPC employees incorporate when working in locations and under conditions where wildfire ignition is heightened.

Operations of Transmission and Distribution (T&D) lines facilities, vegetation management, and T&D lines programs that mitigate wildfire risks are not included in this Plan; they are referenced in the separate Wildfire Mitigation Plan.

2. Situational Overview and Applicability

A. Wildfire Season

The provisions of this Plan shall be applicable during wildfire season. Within IPC's service area, wildfire season is defined as the closed fire season of May 10 through October 20 of each year, as established by Idaho State Law, Title 38-115.

Should any local, state, or federal government land management agency (i.e., the BLM, U.S. Forest Service, Oregon Department of Forestry, Idaho Department of Lands, etc.) issue any wildfire related order that extends wildfire season beyond that specified above, then compliance with that agency's order shall govern.

Many variables—such as drought conditions, weather, and fuel moisture—can cause the wildfire season to begin and/or end earlier or later. In summary, flexibility, judgment, attention to current and forecasted field conditions, and attention to governmental agency issued wildfire orders are necessary such that operational practices can be adjusted accordingly.

B. Wildfire Risk Zones

IPC's Wildfire Mitigation Plan includes a Wildfire Risk Map of IPC's service area.
This Wildfire Risk Map may be accessed at the Idaho Power SharePoint site. All lands in the vicinity of IPC facilities are mapped as Red Zone, Yellow Zone or areas of minimal wildfire risk (i.e., not within a Red or Yellow Zone). Red and Yellow Zones are designated as wildfire risk zones (WRZ). The provisions of this Plan shall apply to work activities taking place during wildfire season in these WRZs.

Should any local, state, or federal government land management agency (i.e., BLM, U.S. Forest Service, Oregon Department of Forestry, Idaho Department of Lands, etc.) issue any wildfire related order, then compliance with that agency's order shall govern if their order is more restrictive than that set forth in this Plan.

C. Fire Potential Index

Idaho Power's Atmospheric Science department has developed an FPI rating system that forecasts wildfire potential across IPC's service area. The FPI considers many current and forecasted elements such as meteorological (winds-surface and aloft, temperatures, relative humidity, precipitation, etc.) and fuel state (both live and dead). The FPI is designed and calibrated for IPC's service area; specifically, those areas in proximity to IPC transmission, distribution, and generation facilities.

The FPI consists of a numerical score ranging from 1 (very green, wet fuels with low to no wind and high humidity) to 16 (very brown and dry, both live and dead dry fuels with low humidity and high temperatures). The FPI scores are grouped into the following 3 index levels:

- **Green:** FPI score of 1 through 11
- **Yellow:** FPI score of 12 through 14
- **Red:** FPI score of 15 through 16

During wildfire season, Idaho Power will determine a daily FPI as described in Section 5 of the WMP. This weather forecast and FPI dashboard is contained within IPC geographic information system (GIS) viewers available to all IPC employees.

D. Decision Making for Field Work Activities

Employees working in the field shall be cognizant of current and forecasted weather and field conditions. Awareness of these conditions, and exercising appropriate judgment, is essential when considering whether to undertake work activities when combinations of high temperatures, low humidity, dry fuels, and/or wind are present or forecasted to be present.

The following process steps shall apply to employees and crews contemplating field work during wildfire season:

<u>Planned or Scheduled Work Activities</u>:

1. Fire Potential Indices:

    a) Employees working in the field—NOT working on transmission or primary distribution lines should:

i. Be aware of the current and forecasted weather and the FPI level for the area in which the work will be performed, through the FPI dashboard.

ii. Once the FPI level for the work zone is identified, proceed with work but consider utilizing Prevention—Practices of Field Personnel (see Section 6 of this Plan).

b) Employees working in the field—working on transmission or primary distribution lines should:

i. Be aware of the current and forecasted weather and the FPI level for the area in which the work will be performed.

ii. Once the FPI level for the work zone is identified, proceed as follows for each FPI level:

1. **Green FPI in All Zones:** Proceed with the work.
Consider utilizing Prevention—Practices of Field Personnel
(see section 4 of this Plan)

2. **Yellow FPI in All Zones:** Proceed with the work.
Consider utilizing Prevention—Practices of Field Personnel
(see section 4 of this plan)

3. Red FPI

a) **In Normal Zone:** Proceed with the work.
Consider utilizing Prevention—Practices of Field Personnel
(see Section 6 of this plan)

b) **In Medium Zone:** Proceed with the work. However, it is a requirement to follow the Prevention—Practices of Field Personnel (see Section 6 of this plan)

c) **In High Zone: STOP.** No planned work activities shall take place unless approved by operations level manager. Work consideration will be restoration of electric service or work deemed critical to providing safe, reliable electric service. If work is approved to proceed it is a requirement to follow the Prevention—Practices of Field Personnel (see Section 6 of this plan).

Fire Potential Index (FPI)	High	15 to 16 (Red)	Proceed with work Utilize Prevention/ Practices of Field Personnel (Optional)	Proceed with work Utilize Prevention/ Practices of Field Personnel REQUIRED	STOP/NO WORK
	Elevated	12 to 14 (Yellow)	Proceed with work Utilize Prevention/ Practices of Field Personnel (Optional)	Proceed with work Utilize Prevention/ Practices of Field Personnel (Optional)	Proceed with work Utilize Prevention/ Practices of Field Personnel (Optional)
	Normal	1 to 11 (Green)	Proceed with work Utilize Prevention/ Practices of Field Personnel (Optional)	Proceed with work Utilize Prevention/ Practices of Field Personnel (Optional)	Proceed with work Utilize Prevention/ Practices of Field Personnel (Optional)
			None	Yellow (Tier 2)	Red (Tier 3)

2. Land Management Agency Restrictions: Follow the requirements and restrictions of any wildfire restrictions related order that is issued by local, state, or federal land management agencies.

   a) Immediately upon receiving knowledge of an order, The Environmental Services department will notify, via email, operations leadership within Power Supply, Customer Operations and Business Development, and T&D Engineering and Construction of wildfire related requirements and restrictions orders that are issued by local, state, or federal land management agencies.

<u>Emergency Response and Outage Restoration Work Activities</u>:

Follow the same steps as identified above for planned work activities. However, it is recognized that the nature of emergency response and outage restoration situations will often require exceptions to the above. In these situations, leadership should be consulted, and appropriate judgment should be used given the nature of the emergency or outage at hand.

3. Preparedness—Tools and Equipment

A. Required Personal Protective Equipment

Standard IPC Personal Protective Equipment (PPE) shall be worn in accordance with the IPC Safety Standard.

When entering a designated fire area being managed by the BLM or the U.S. Forest Service, additional PPE requirements may be in force by those agencies. These typically include:

- Hardhat with chinstrap
- Long sleeve flame-resistant (FR) shirt and FR pants
- Leather gloves
- Exterior leather work boots, 8" high, lace-type with Vibram type soles
- Fire shelter

B. Required Tools and Equipment

Employees NOT working on transmission or distribution lines: Standard tools and equipment in accordance with the IPC Safety Standard and Fleet Services.

Employees working on transmission or distribution lines: IPC and the State of Idaho BLM entered into a March 2019 Master Agreement that governs various IPC and BLM interactions, including wildfire prevention related provisions. In addition to State of Idaho BLM lands, IPC has elected to apply these requirements to all work activities taking place on all WRZ in Idaho, Nevada, Montana, and Oregon. These requirements include:

- During the wildfire season (May 10–October 20) or during any other wildfire season ordered by a local, state, or federal jurisdiction, IPC, including those working on IPC's behalf, will equip at least 1 on-site vehicle with firefighting equipment, including, but not limited to:

    a) Fire suppression hand tools (i.e. shovels, rakes, Pulaski's, etc.),
    b) a 16-20-pound fire extinguisher,
    c) a supply of water, sufficient for initial attack, with a mechanism to effectively spray the water (i.e. backpack pumps, water sprayer, etc.). This requirement to carry water is dependent on the vehicle type and weight restrictions. For example, a mini-excavator would not be required to carry water since there is no safe way to do so, or a loaded bucket truck may not be required to carry water because of weight limitations.

- At a minimum, equip each truck that will be driven in the WRZs during wildfire season with at least:
    a) One round, pointed shovel at least 8-inches wide, with a handle at least 26 inches long
    b) One axe or Pulaski with a 26-inch handle or longer
    c) A combination of shovels, axes, or Pulaskis available to each person on the crew

d) One fire extinguisher rated no less than 2A:10BV (5 pounds)
e) 30-200 gallons of water in a fire pumper and 5-gallon back packs

IPC personnel will be trained to use the above tools and equipment to aid in extinguishing a fire ignition before it gets out of control and take action that a prudent person would take to control the fire ignition while still accounting for their own personal safety.

C. Land Management Agency Restrictions and Waivers

The Environmental Services department will notify operations leadership within Power Supply, Customer Operations and Business Development, and T&D Engineering and Construction of any wildfire related requirements and restrictions orders that are issued by local, state, or federal land management agencies. Typical orders issued each fire season include:

- BLM. During BLM's Stage II Fire Restrictions, IPC's Environmental Services department will obtain an appropriate waiver. Field personnel shall take appropriate precautions when conducting work activities that involve an internal combustion engine, involve generating a flame, involve driving over or parking on dry grass, involve the possibility of dropping a line to the ground, or involve explosives. Precautions include a Fire Prevention Watch Person who will remain in the area for 1 hour following the cessation of that activity. Also, IPC personnel will not smoke unless within an enclosed vehicle, building, or designated recreation site or while stopped in an area at least 3 feet in diameter that is barren or cleared of all flammable materials. All smoking materials will be removed from work sites. No smoking materials are to be discarded.
- State of Oregon Department of Forestry (ODF). Prior to each summer fire season, the ODF issues a "Fire Season Requirements" document that specifies required tools, equipment, and work practices. In addition to State of Oregon lands, IPC has elected to apply these requirements to all work activities taking place on all WRZ, BLM lands, and Forest Service lands within the State of Oregon. Go to https://www.oregon.gov/ODF/Fire/Pages/Restrictions.aspx for ODF's Fire Season Requirements order.

- Other sites for reference that contain fire restriction orders include:
  - Oregon— Blue Mountain Interagency Fire Center at http://bmidc.org/index.shtml
  - Nevada—Fire Information at https://www.nevadafireinfo.org/restrictions-and-closures
  - Montana—https://firerestrictions.us/mt/

4. Prevention—Practices of Field Personnel

A. General Employee Practices

The below listing includes, but is not limited to, practices and behaviors employees shall incorporate depending on the FPI and level of WRZs during fire season.

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC
Page 105 of 158

1. Daily tailboards must include discussion around fire mitigation planning. Discussion topics include, but are not limited to:
    a. Items 2 through 7 below
    b. Water suppression
    c. Hand tools
    d. Welding blankets
    e. Mowing high brush areas (weed wacker)
    f. Watering down the worksite before setting up equipment

2. Weather conditions and terrain to be worked shall be considered and evaluated. Items to be considered include, but are not limited to:
    a. Identify the FPI for the area being worked (see Section 3.2.2)
    b. Monitor weather forecasts and wind and humidity conditions
    c. Identify surroundings. i.e., wildland-urban interface, BLM lands, Forest Service lands, proximity to any homes and structures, etc.
    d. Identify local fire departments and locations
    e. Evaluate the terrain you are working in (steep or flat)
    f. Consider whether the work will occur during the day or at night

3. Work procedures and tools that have potential to cause a spark or flash shall be considered and evaluated. Items to be considered include, but are not limited to:
    a. Performing energized work
    b. Grinding or welding
    c. Trees contacting electrical conductors
    d. Hot saws
    e. Chainsaws
    f. Weed wackers
    g. Sawzalls

4. Monitoring the worksite throughout the project.
   It is imperative that all crews and equipment working in the WRZs areas are continuously monitoring and thoroughly inspecting the worksite throughout the project. This includes prior to leaving the work area for the night or before moving on to the next structure.

5. Employee cooking stoves.
   When working in remote locations, often employees bring food that needs to be cooked. Open flames should not be allowed. Cook stoves may be permitted by leadership but special precautions must be followed to use:
    a. The stove or grill must be in good repair and of sturdy construction
    b. Stoves must be kept clean, grease build up is not allowed
    c. Fueling of the stove must follow the fueling procedures when liquid fuels are used
    d. Cooking must be in areas free of combustible materials

6. Smoking on the job site.
   Carelessly discarded smoking materials can result in wildfire ignition. The following practices shall be followed:
   a. Do not discard any tobacco products from a moving vehicle.
   b. Smoking while standing in or walking through forests or other outdoor areas when IPC's FPI rating is above a Green level is prohibited.
   c. All employees must smoke **only in designated areas** and smoking materials must be disposed of in half filled water bottles or coffee containers half filled with sand. Smoking materials shall not be discarded on any site.

7. Post job site inspection.
   Final inspection or post-checking the work site for any ignition hazards that may remain is essential to the proper completion of the work and true mitigation of the hazards. Post-checking the work will help ensure the hazards were mitigated and provide a final chance to see if any new hazards or hot spots exist before leaving the work site.

B. Behaviors Relating to Vehicles and Combustion Engine Power Tools

It is important to consider work procedures, equipment conditions, employee actions, potential causes, and other sources that could lead to fire ignition. Some work practices may be performed on roadways that have little to no risk of fire ignition. Leadership should consider scheduling off-road equipment use during times of green fire risk. Employees should also consider alternative tools, work methods or enhanced suppression tools to reduce the risk or spread of fire.

1. Additional heat may bring vegetative materials to an easier point of ignition.
   This includes, but is not limited to, the following vehicles:
   a. Pickups, crew cabs, line-beds, buckets trucks (large and small), backhoes, excavators and rope trucks, and any other motorized equipment.

2. Vehicle Procedures:
   a. Inspect all engine exhaust, spark arresters and electrical systems of vehicles used off road, daily for debris, holes or exposed hot components and to ensure that heat shields and protective components are in place.
   b. Conduct inspections of the vehicle undercarriage before entering or exiting the project area to clear vegetation that may have accumulated near the vehicle's exhaust system.
   c. Vehicles shall be parked overnight in areas free from flammable vegetation at a minimum distance of 10 feet.
   d. Vehicles and equipment will not be stationary or in use in areas where grass, weeds or other flammable vegetation will be in contact with the exhaust system.
   e. If there is no other workable option for the location that doesn't include weeds, grass or other flammable vegetation, the vegetation and debris will need to be removed.

   f. Consider using a fire-resistant material such as a welding blanket to cover flammable material to act as a heat shield; fire blankets may be a suitable option to avoid removal of vegetation.

3. Hot brakes on vehicles and equipment:
   a. Park vehicles in areas free of combustible materials.
   b. Hot brake emergency parking, during times of yellow or red FPI shall be cleared of combustible materials for a distance of at least 10 feet from the heat source.

4. Fueling procedures:
   a. Tools or equipment should NOT be fueled while running.
   b. Cool down period must be given to allow equipment time to no longer be considered a fire risk.
   c. Allow for a ten-foot radius from all ignition sources.
   d. Any combustible debris should be cleared from the immediate area.
   e. Never smoke while fueling.
   f. Designate fueling areas for all gas-powered tools.

5. Combustion engine power tools:
   Poorly maintained or missing spark arrester screens may allow sparks to escape and cause ignition of vegetation. Ensure proper spark arrester screens are in place for the following tools:
   a. Generators
   b. Pony motors
   c. Pumps
   d. Chain saws
   e. Hot saws
   f. Weed eaters
   g. Brush hog

   Inspect spark arresters daily; clean or replace when clogged, damaged or missing or remove from service until repaired.

5. Reporting

A. Fire Ignition

All fire ignitions shall be immediately reported to regional or system dispatch. Dispatch will notify local fire authorities. All work shall immediately stop and necessary steps taken to extinguish the fire with available tools, water, and equipment. If the fire gets too large to safely contain or extinguish, ensure all employees are accounted for and get to a safe location.

B. Fire Reporting

When reporting a fire ignition to regional or system dispatch provide the following information:

1. Your name
2. Location-reference points including an address, road or street name, cross streets, mountain range, GPS coordinates, as applicable
3. Fire information
4. Size and behavior of the fire
5. Weather conditions

6. Training

Each employee who performs work in wildland fire designated zones shall be trained on the content of this document and be required to complete annual refresher courses through the Workday system. Employees are required to complete fire extinguisher and fire shelter training annually as part of the lineman safety compliance. Documentation of all training shall be retained in Workday.

7. Roles and Responsibilities

Employee	1. Be familiar with the requirements specified in this Plan and operate in accordance with this Plan. 2. Be aware of daily weather forecast and FPI level. 3. Be aware of whether field work will be performed in a WMZ.
Crew Foreman and Front-Line Leaders	1. Establish expectations to direct report employees they are to be familiar with, and follow, Plan requirements. 2. Ensure the crew or team conducts field operations in accordance with this Plan. 3. Be aware of daily weather forecast and FPI level (by viewing the FPI dashboard or by calling into dispatch or a leader): a) Ensure employees are aware of the FPI level. b) Ensure work practices comply with this Wildland Fire Preparedness and Prevention Plan when the FPI is "Red" and the WMZ is Yellow. c) Ensure no work takes place when FPI is "Red" and the WMZ is Red. Any exceptions to be discussed with manager. 4. Ensure annual training of employees is completed prior to wildfire season. 5. Ensure required tools and equipment are in place prior to wildfire season.
Manager (Regional Operations Manager, Area Manager, T&D Construction Manager)	1. Establish expectations to Crew Foremen and Front-Line Leaders they are to operate in accordance with Plan requirements. 2. Support Crew Foremen and Front-Line Leaders in scheduling training and making required tools and equipment available. 3. View daily weather forecast and FPI dashboard: a) Authorize any exceptions to working when FPI is "Red" and the WRZ is Red. b) Ensure specified audits are timely completed.
Meteorology Department	1. Provide daily weather forecast and update the FPI dashboard contained within the IPC Enviro Viewer.
Environmental Services Department	1. Monitor local, state, and federal land management agencies for any wildfire restriction orders that are issued. 2. Communicate content of any orders issues to Power Supply, COBD, and PEC operations leadership.
Operations Procurement Department	1. Ensure contractors have a copy of this Plan and that contractual requirements are in place to ensure adherence to the Plan.
Vice-President of Planning, Engineering and Construction (VP of PEC)	1. Ensure annual review/update of this Plan is conducted following the completion of each wildfire season.

8. Audit

Prior to the start of wildfire season (May 10), all vehicles associated with work on transmission and distribution lines will be audited by leadership to ensure that those working in WRZs are properly equipped with firefighting equipment. The following checklist must be completed, dated, and signed by a member of leadership (front-line supervisor or above) and kept with the crew or individual until fire season has ended (Oct 20). A copy of each audit checklist shall be sent to the respective manager and senior manager.

Wildland Fire Preparedness Audit Checklist:

Inspector: ____

Signature: ____

Date: ____

Crew: ____

Crew:

At least 1 vehicle will be equipped with the following:

- Fire suppression hand tools (shovels, Pulaski, axes, etc.) for each member of the crew
- A 16–20-pound fire extinguisher (2-10-pound fire extinguishers)
- A supply of water, sufficient for initial attack, with an effective spraying mechanism (i.e., backpack pumps, water sprayer, etc.)
- 30–75-gallon mechanical fire pumper

Individual Truck:

- One round, pointed shovel at least 8-inches wide, with a handle at least 26 inches long
- One axe or Pulaski with a 26-inch handle or longer
- A combination of shovels, axes, or Pulaskis to each person on the crew
- One fire extinguisher rated no less than 2A:10BV (5 pounds)
- 30-200 gallons of water in a fire pumper and 5-gallon back packs

Personal protective equipment (PPE) IPC and BLM standards: Each employee will be required to have the following PPE:

- Hard hat with a chin strap
- Safety glasses
- Hearing protection
- Long sleeve FR shirt FR pants
- Leather gloves
- Exterior leather work boots 8″ high lace type with Vibram type soles
- Fire shelter

Appendix B
The Public Safety Power Shutoff (PSPS) Plan.

An IDACORP Company

Idaho Power Company's Wildfire Public Safety Power Shutoff Plan

December 2021

TABLE OF CONTENTS

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC
Page 116 of 158

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC
Page 118 of 158

List of Tables

List of Figures

1. INTRODUCTION

Wildfires in the Pacific west have increased in their intensity in recent years. In an effort to keep Idaho Power's customers and the communities it serves safe and continue improving the resiliency of Idaho Power's transmission and distribution facilities, Idaho Power implemented a Wildfire Mitigation Plan in 2021, focused on situational awareness, field personnel safety practices and operational wildfire mitigation strategies to prevent the accidental ignition of wildfires. As part of its operational mitigation practices, Idaho Power has developed this Public Safety Power Shutoff Plan (PSPS Plan or Plan) to proactively de-energize electrical facilities in identified areas of extreme wildfire risk to reduce the potential of those electrical facilities becoming a wildfire ignition source or contributing to the spread of wildfires. This Plan identifies the relevant considerations, process flow and implementation protocol before, during and after a PSPS event. The Plan will be active during wildfire season and reviewed annually and updated as necessary prior to the start of the next wildfire season.

This Plan identifies PSPS implementation considerations and responsibilities for different Idaho Power departments before, during and after PSPS events. Table 2 describes the different phases Idaho Power will use during PSPS events and Figure 7 depicts the communication audiences and timeline Idaho Power will ideally follow during an event. Finally, this Plan describes activities Idaho Power will undertake to prepare and improve the Plan over time, including interactions with local emergency agencies, and briefly describes the financial administration of the Plan.

2. List of Acronyms

AAR—After Action Review

BLM—Bureau of Land Management

COO—Chief Operations Officer

ECMWF—European Centre for Medium-Range Forecasts

EMT—Emergency Management Team

ERC—Energy Release Component

F100—100-Hour Fuel Moisture

FPI—Wildfire Mitigation Plan Fire Potential Index

FWW—Fire Weather Watch

GBCC—Great Basin Coordination Center

GIS—Geographic Information System

IPUC—Idaho Public Utility Commission

IRWIN—Integrated Reporting of Wildland-Fire Information

LSO—Load Serving Operations

NIFC—National Interagency Fire Center

NOAA—National Oceanic and Atmospheric Administration

NWS—National Weather Service

OPUC—Oregon Public Utility Commission

PEC—Planning, Engineering and Construction

PSPS—Public Safety Power Shutoff

RFW—National Weather Service issued Red Flag Warning

SGM—Smart Grid Meter

SME—Subject Matter Expert

T&D—Transmission & Distribution

TDER—Transmission & Distribution Engineering and Reliability

UKMET—United Kingdom Meteorological Office

WMP—Wildfire Mitigation Plan

WRF—Weather Research and Forecasting

3. Definitions

(1) Critical Facilities—Refers to the facilities identified by Idaho Power that, because of their function or importance, have the potential to threaten life safety or disrupt essential socioeconomic activities if their services are interrupted.

(2) ESF-12—Refers to Emergency Support Function-12 and is the Idaho Power Company liaison from the State Office of Emergency Management for energy utilities issues during an emergency for both Idaho and Oregon.[1]

(3) Exercise—Refers to planned activities and assessments that ensure continuity of operations, provide and direct resources and capabilities and gather lessons-learned to develop core capabilities needed to respond to incidents.

(4) Community—Refers to a group of people that share goals, values and institutions.[2]

(5) Local Emergency Manager—Refers to a jurisdiction's role that oversees the day-to-day emergency management programs and activities.[3]

(6) Public Safety Partners—As defined by Idaho Power refers to ESF-12, Local Emergency Management and Idaho's and Oregon's Department of Human Services (or equivalent).

(7) Public Safety Power Shutoff or PSPS—A proactive de-energization of a portion of an Electric Utility's electrical network, based on the forecasting of and measurement of extreme wildfire weather conditions.

[1] Federal Emergency Management Institute (FEMA) National Response Framework (NRF) Emergency Support Functions (ESF) National Response Framework | FEMA.gov.

[2] FEMA definition under "Communities" (pg. 26) National Response Framework (fema.gov).

[3] FEMA definition under "Local Government" (pg. 29) National Response Framework (fema.gov).

4. Public Safety Power Shutoff Overview

In recent years, the western United States (U.S.) has experienced an increase in the intensity of wildland fires (wildfires). A variety of factors have contributed in varying degrees to this trend, including climate change, increased human encroachment in wildland areas, historical land management practices and changes in wildland and forest health. Recent events in western states have increased awareness of electric utilities' role in wildfire prevention and mitigation.

In an effort to keep Idaho Power's customers and the communities it serves safe and continue improving the resiliency of Idaho Power's transmission and distribution (T&D) facilities, Idaho Power implemented a Wildfire Mitigation Plan (WMP) in 2021 focused on situational awareness, field personnel safety practices and operational wildfire mitigation strategies. As part of its operational mitigation practices, Idaho Power developed this Wildfire Public Safety Power Shutoff Plan (PSPS Plan or Plan) to proactively de-energize electrical facilities in identified areas of extreme wildfire risk to reduce the potential of those electrical facilities becoming a wildfire ignition source or contributing to the spread of wildfires. Based on the inherently disruptive nature of power outages, Public Safety Power Shutoff (PSPS) events must be carefully evaluated under this Plan to balance wildfire risk with potential PSPS impacts on Idaho Power customers and the communities it serves.

The unpredictable nature of wildfire and weather patterns create significant challenges with forecasting PSPS events. Real-time evaluations and decision-making are therefore critical in making PSPS determinations and, depending on the associated wildfire risk, those determinations may result in proactive de-energization in areas not originally anticipated.

5. Scope

This PSPS Plan identifies the relevant considerations, process flow and implementation protocol before, during and after a PSPS event. The Plan will be active during wildfire season and reviewed and updated annually as necessary prior to the start of the next wildfire season. Wildfire season (also known as "closed season") is defined by Idaho Code § 38-115 as extending from May 10 through October 20 each year, or as otherwise extended by the Director of the Idaho Bureau of Land Management (BLM). Oregon's wildfire season generally aligns with Idaho's wildfire season and is designated by the State Forester each year pursuant to Oregon Revised Statute 477.505.

6. Key Tenets

- Advancing the safety of Idaho Power employees, customers and the general public
- Collaborating with key external stakeholders (agencies, counties, local governments, public safety partners, first responders)

- Minimizing both potential wildfire risk and power outage impacts on communities and customers
- Maintaining reliable electric service

7. Wildfire Zones

Idaho Power's WMP identifies areas of heightened wildfire risk within its service territory reflected by the following risk zones:

- Tier 2 Yellow Risk Zones are deemed increased risk areas.
- Tier 3 Red Risk Zones are deemed higher risk areas.

In its WMP, Idaho Power identifies operational practices specific to these zones of heightened wildfire risk for purposes of (1) reducing potential wildfire risk associated with Idaho Power's T&D facilities and field operations, and (2) improving the resiliency of the Idaho Power's T&D system impacted by wildfire. This PSPS Plan sets forth Idaho Power's PSPS evaluation criteria and processes, including operational and communication protocol, for implementing a PSPS.

8. PSPS Implementation Considerations

Idaho Power will initiate a PSPS if the company determines a combination of critical conditions indicate the T&D system at certain locations is at an extreme risk of being an ignition source and wildfire conditions are severe enough for the rapid growth and spread of wildfire. Idaho Power will evaluate as a whole (not relying on one single factor but a combination of all factors), without limitation, the criteria set forth in 9.1–9.17 below.

8.1. Fire Potential Index

In addition to the Risk Zone designations in its WMP, Idaho Power developed a Fire Potential Index (FPI) to forecast wildfire potential across Idaho Power's service area. The FPI converts data on weather; prevalence of fuel (shrubs, trees, grasses); and topography into a numerical FPI score to forecast the short-term wildfire threat in geographical areas throughout Idaho Power's service area. FPI scores range from 1 (very green, wet fuels with low to no wind and high humidity) to 16 (very brown and dry, both live and dead dry fuels with low humidity and high temperatures). FPI scores are grouped into the following 3 index levels:

1) Green—lower fire potential: FPI score of 1 through 11
2) Yellow—elevated fire potential: FPI score of 12 through 14
3) Red—highest fire potential: FPI score of 15 and 16

The FPI supports operational decision-making to reduce potential wildfire risk. During wildfire season, Idaho Power will determine a daily FPI as described in Section 5.2 of the WMP. The FPI forecast is broken into four 6-hour time periods throughout each seven-day forecast. FPI information is provided via email, certain Geographic Information System (GIS) viewers and an FPI dashboard accessible to both Idaho Power employees and contractors from Idaho Power's website. The WMP details operational mitigation efforts in Red Risk Zones when the FPI score in that Red Risk Zone is also Red, including stopping planned work and changing distribution protection operations. A Red FPI score will be a consideration in Idaho Power's determination of whether to initiate a PSPS.

8.2. National Weather Service Red Flag Warning

A Red Flag Warning (RFW) is a forecast warning issued by the National Weather Service (NWS) to inform the public, firefighters and land management agencies that conditions are ideal for wildland fire combustion and rapid spread. RFWs are often preceded by a Fire Weather Watch (FWW), which indicates weather conditions that could occur in the next 12–72 hours. The NWS has developed different zones across the nation for providing weather alerts (such as RFWs) to more discrete areas. These zones are shown on this NWS webpage: Fire Weather. RFWs for Idaho Power's service territory include Idaho Zones (IDZ) 401, 402, 403, 413, 420 and 422; and Oregon Zones (OR) 636, 637, 642, 634, 644, 645 and 646; and are monitored and are factored into Idaho Power's determination of whether to initiate a PSPS. Boise and Pocatello NWS offices will not issue RFWs if fuels are moist and fire risk is low. The following thresholds are used by most NWS offices:

- Daytime:
    - Relative humidity of 25% or less
    - Sustained winds greater than or equal to 10 miles per hour (mph) with gusts greater than or equal to 20 mph over a four-hour time period
- Nighttime:
    - Relative humidity of 35% or less
    - Sustained winds greater than or equal to 15 mph with gusts greater than or equal to 25 mph over a three-hour time period
- Lightning:
    - The NWS rarely issues RFWs for lightning in the western United States. For this to occur, the Lightning Activity Level—a measure of lightning potential specifically as it relates to wildfire risk—needs to be at 3 or higher.

8.3. NWS Fire Weather Forecasts

The NWS provides detailed forecasts for the different weather zones with an emphasis on fire weather indicators (wind speed, relative humidity, lightning potential). A discussion summarizing the weather patterns and highlighting fire threats is included in their extended forecast.

8.4. Publicly Available Weather Models

Idaho Power's Atmospheric Science department uses the following weather models to predict weather timing, duration and intensity:

- Pivotal Weather Link (pivotalweather.com/model.php): Provides numerical weather data, including a NWS blend of models, European Centre for Medium-Range Weather Forecasts (ECMWF), United Kingdom Meteorological Office weather service information and GOES-16 satellite information.

- Graphical Weather Link (graphical.weather.gov/sectors/conusFireWeek.php): A NWS website providing weather, water and climate data, forecasts and warnings for the United States for the protection of life and property. The Fire Weather page provides a daily and weekly view of multiple weather and environmental conditions influencing wildfire activity.

8.5. Idaho Power Weather Model

Idaho Power maintains its own Weather Research and Forecasting (WRF) model using high-resolution data from Idaho Power's weather stations across its service area. This model, along with publicly available weather models, helps develop weather forecasts that include timing, duration and intensity of weather systems. An Idaho regional WRF low-resolution map view is available to the public at atmo.boisestate.edu/view/.

8.6. Storm Prediction Center Fire Weather Outlooks

The Storm Prediction Center's Fire Weather Outlook provides a current, one-day-ahead and three- to eight-day forecast for wildfires over the contiguous United States. This forecast takes into account pre-existing fuel conditions combined with predicted weather conditions that result in a significant risk of wildfire ignition or spread.

8.7. Current Weather Observations

Identifying real-time wildfire weather and associated risks requires predicting conditions that could trigger a PSPS based on observing current weather conditions. Resources available for observing current weather conditions include direct, real-time data from Idaho Power's network of weather stations, available real-time wind speed information from Idaho Power's network of Smart Grid Meters (SGM), as well as Windy: Wind Map and Weather Forecast and the National Weather Service National Oceanic and Atmospheric Administration's (NOAA) Weather and Hazards Viewer.

8.8. National Significant Wildland Fire Potential Forecast Outlook

The National Significant Wildland Fire Potential Forecast Outlook provides wildland fire expectations for the current month, the following month and a seasonal look at the two months beyond that. The main objective of this tool is to provide information to fire management decisionmakers for proactive wildland fire management, reducing firefighting costs and improving firefighting efficiency.

8.9. Great Basin Coordination Center Morning Briefing

The Great Basin Coordination Center (GBCC) is the focal point for coordinating the mobilization of resources for wildland fire and other incidents throughout the Great Basin Geographic Area, which encompasses Utah, Nevada, Idaho south of the Salmon River, the western Wyoming mountains and the Arizona Strip. The GBCC hosts a morning briefing (around 10 a.m. most mornings) that provides situational awareness for Idaho Power's service area.

8.10. GBCC Current and Predicted ERC and F100

The GBCC as described above also provides day-ahead Energy Release Component (ERC), 100-Hour Fuel Moisture (F100) and other fuels conditions information that helps Idaho Power understand wildfire potential in the service area.

8.11. Agency Input

Idaho Power works with Boise NWS Fire Forecasters through daily briefings and NIFC Predictive Service Forecasters on an as-needed basis, generally regarding data clarification, to streamline the transfer of data, information and communications about wildland fire critical to Idaho Power's service area.

Idaho Power works with other agencies, including the U.S. BLM and U.S. Forest Service, as wildland fires approach and impact Idaho Power T&D facilities.

8.12. De-Energization Windspeed Considerations

Idaho Power's service area covers 24,000 square miles across southern Idaho and eastern Oregon. The environmental factors across this area vary drastically from high desert landscape to mountainous terrain. Weather and environmental conditions also vary greatly within this area. Regional vegetation becomes "conditioned" to withstand different environmental conditions, which also influences de-energization thresholds. Idaho Power developed windspeed considerations, which it will continue to refine with additional data and weather technology based on historic wind conditions compared to system outage information.

8.13. Engineering Assessment

Idaho Power follows robust transmission and distribution maintenance and inspection practices. When a potential PSPS event is identified, Idaho Power's T&D Maintenance and Engineering department will evaluate potential impacts to current or planned maintenance activities.

8.14. Alternative Protective Measures

Considering the significant potential impact of a PSPS to customers, Idaho Power will thoroughly evaluate other potential alternatives for reducing wildfire risk prior to implementing a PSPS.

8.15. Real-time Field Observations

Idaho Power uses SGMs for various purposes on its the distribution systems, including communication (where available) to provide near real-time information and to detect wind speed with anemometers. This information is displayed on a GIS viewer and used to inform Idaho Power's evaluation and decision-making during storm events.

Idaho Power may also deploy field personnel to evaluate if a PSPS event should be initiated.

8.16. Other

Idaho Power plans to evaluate expanding existing capabilities to enhance weather forecasting and add new capabilities to detect fires.

9. Responsibilities

Developing and implementing PSPS protocol involves various groups throughout the company. Below is a non-exhaustive list of responsibilities by department, representatives of which will work together to promote organized, consistent and safe implementation of PSPS events.

9.1. Load Serving Operations

- Develop and implement safe and reliable power shutoff protocols and procedures
- Ensure System and Regional Dispatch employees are appropriately trained to perform relevant responsibilities under this PSPS Plan, and that such employees receive timely information regarding wildfire risk and weather conditions for purposes of performing those responsibilities in the event of a PSPS
- Assist with PSPS evaluation and decision-making

- Safely restore service to PSPS areas when notified by Customer Operations it is safe to re-energize
- Provide required notifications to public safety partners to enhance public safety
- Participate in After-Action Reviews (AAR) (further discussed in Section 13 below) and ensure modifications to PSPS protocol are implemented as necessary

9.2. Atmospheric Science

- Monitor daily, weekly and long-term weather forecasts
- Monitor fuels conditions and trends
- Monitor Fire Weather Watches, Red Flag Warnings and High Wind Watches and Warnings
- Communicate with external agencies for increased situational and conditional awareness. Increase communications as conditions require
- Communicate internally to Idaho Power's Transmission & Distribution Engineering and Reliability (TDER) senior manager when extreme conditions indicate a PSPS event is likely
- Support PSPS activities such as planning, training and exercises
- Assist in PSPS information-gathering, evaluation and decision-making
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.3. TDER Senior Manager

- Oversee wildfire mitigation program and support cross-departmental collaboration
- Monitor daily, weekly and long-term weather and wildfire forecasts
- Monitor Fire Weather Watches, Red Flag Warnings and High Wind Watches and Warnings
- Develop and lead training modules for PSPS implementation
- Activate the PSPS Assessment Team if a PSPS is likely
- Communicate with Oregon and Idaho ESF-12

- Ensure PSPS activities such as operations planning, training and exercises occur annually
- Ensure a coordinated and cohesive external and internal communication and notification plan is in place and reviewed annually
- Coordinate with Atmospheric Science to continue evaluating enhancements to situational awareness capabilities
- Participate in AARs and provide input on, and monitor as necessary, modifications to PSPS protocol

9.4. Customer Operations and T&D Construction

- Develop and implement safe and reliable power shutoff protocols and procedures
- Ensure field personnel are appropriately trained to perform all relevant responsibilities under this PSPS Plan
- Assist in PSPS information-gathering, evaluation and decision-making
- Ensure crews and equipment are available to support PSPS events
- Perform field observations, line patrols and other PSPS tasks as necessary
- Perform required repairs to safely re-energize the system after a PSPS event
- Request/obtain air patrol contractors for line inspections as required
- Participate, with assistance from Corporate Communications, in Idaho Power's general external education campaign
- Develop, with assistance from Corporate Communications, a cohesive notification framework with public safety partners while consistently evaluating ways to increase communication and outreach effectiveness
- Engage with public safety partners and critical facilities before, during and after a PSPS event
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.5. Supply Chain/Stores

- Ensure preparedness for wildfire season with materials readily available for restoration purposes

- Work with Customer Operations and T&D Construction in response to a PSPS event, which could include pre-event activities such as staging materials and supplies
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.6. Fleet/Equipment Resource Pool

- Ensure employees are appropriately trained to perform all relevant responsibilities under this PSPS Plan
- Ensure readiness of employees and resource pool equipment for a PSPS event
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.7. Supply Chain Contracting

- Ensure contract resources are appropriately trained to perform all relevant responsibilities under this PSPS Plan
- Work with Customer Operations to provide contracting resources as required
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.8. Substation Operations

- Monitor substations and perform actions to support PSPS operations
- Coordinate activities with Dispatch and Customer Operations
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.9. Corporate Communications

Corporate Communications will develop and execute PSPS communications to Idaho Power customers and employees and support other business units in their communication efforts with regulators, critical facility operators, public safety partners and other stakeholders.

Corporate Communications will:

- In coordination with Customer Operations and Regulatory Affairs, work with public safety partners, critical facilities, regulators and other stakeholders to develop a comprehensive, coordinated and cohesive customer notification framework.
- With input from public safety partners, develop and implement a wildfire education and awareness campaign focused on wildfire prevention and mitigation, PSPS awareness and outage preparedness for customers.
- In the event of a PSPS:
    - To the extent possible and in coordination with Customer Service and IT, notify customers before, during and after a PSPS event with the following information:
        - Expected timing and duration of the PSPS event
        - 24-hour contact information and website resources
    - Provide up-to-date information on a dedicated Idaho Power PSPS webpage prominently linked on the Idaho Power homepage.
    - Distribute information via media and social media channels.
- Participate in AARs and modify communication practices as necessary.

9.10. Distribution Engineering and Reliability

- Support Dispatch and Customer Operations in developing de-energization and re-energization plans for PSPS events
- Monitor and verify the protection system operated correctly after any device operations caused by events on the circuit as appropriate
- Evaluate and enact protective device setting changes as required.
- Support rapid repairs of damaged infrastructure as needed.
- Support Load Serving Operations in planning improvements to PSPS operational capabilities
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.11. Safety

- Ensure the safety professionals are appropriately trained to perform all relevant responsibilities under this PSPS Plan
- Provide PSPS training for field personnel
- Assist in AARs after a PSPS event (or potential event in which the PSPS Team is activated)

9.12. Vegetation Management

- Following de-energization, and when it is safe to do so, Customer Operations will report impacts to infrastructure and assets from vegetation, as appropriate.
  Vegetation Management will then work toward removing vegetation debris necessary for re-energization.
- Ensure contractors and field personnel are appropriately trained to perform all relevant responsibilities under this PSPS Plan.
- Use reasonable efforts to ensure contract resources are available and prepared for PSPS events.
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary.

9.13. Geographic Information Systems

- Work with Customer Operations and Corporate Communications to develop PSPS boundary information for PSPS GIS maps required for the PSPS website
- Before wildfire season and during preliminary notifications of a potential PSPS event, provide relevant GIS data within the confines of applicable law to public safety partners

9.14. Customer Service

- Respond to customer calls and respond to questions with information provided by Corporate Communications
- Ensure customer service representatives are trained to manage customer interactions during a PSPS event

9.15. Communication Systems (Stations)

- Provide monitoring and on-call presence for the following:
    - Radio communications and infrastructure
    - Network infrastructure and connectivity
    - SCADA communications
- Ensure readiness to deploy mobile 2-way radio trailer during a PSPS event
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.16. Customer Operations Support

- May lead AARs to ensure modifications to PSPS protocol are implemented as necessary

9.17. Legal

- Provide legal guidance in evaluating a potential PSPS event
- May direct AARs after a PSPS event (or potential event in which the PSPS Team is activated)
- May be involved in reviewing communications to customers, public safety partners and critical facilities

9.18. Regulatory

- May provide regulatory guidance in evaluating a potential PSPS event
- May be involved in reviewing communications to customers, public safety partners and critical facilities
- Assist in/direct regulatory reporting/filing activities

10. PSPS Operations

10.1. General

Section 11 details the phases, and protocol within each phase, of a PSPS event. Additional procedures are found in plans linked below and the attached Appendices as referenced herein.

Table 2 below summarizes the PSPS phases.

Table 1
Incident phase decision triggers

Incident Phase		Considerations	Condition	Recommendation
Normal Operations	TDER Sr. Manager	Seasonal	All Seasons	Prepare
			Fire Seasons	Readiness & Monitoring
PHASE 1	TDER Sr. Manager	Location	PSPS Zone	Activate the EWSO assessment team. Review PSPS plan and supporting implementation guidance.
		FPI Level	Red	
		Red Flag Warning	Within Idaho Zones 401, 402, 403, 413, 420 or 422	
		High Forecast Winds	PSPS Zone Dependent	
		Storm Prediction Canter Fire Weather Outlook	PSPS Zones contained within an Elevated and/or Critical Fire Outlook Zone	
		Agency Input	Preparedness level of 4 or5	
		Other	Operations risk analysis	
PHASE 2	EWSO Commander COO Decision	Phase 1 Consideration	Conditions remain the same or worsen	Activate the full EWSO team. Define PSPS strategy (PSPS Zone, timing, duration, etc.) Deliver PSPS warning messaging. Prepare for PSPS (resources, materials staging, etc.)
		Field Observations	Vegetation failure, flying debris, slapping conductor, wind speeds, weather	
		SGM Data	Real-time wind-speed information	
		Other	Operations risk analysis	
PHASE 3	Event Coordinator (Storm Operations Management	PSPS Event Plan	Implement the Plan	Execute PSPS event protocols
PHASE 4	Event Coordinator (Storm Room Operations Model)	PSPS Recovery Plan	Implement the Plan	Execute PSPS Recovery protocols
Post-Incident Review (AAR)	Regional Manager/ Customer Ops Support	PSPS AAR Plan	Post PSPS Event and Recovery	Update PSPS Plan as required

10.2. PSPS Preparedness

PSPS preparedness is a cyclical effort involving Idaho Power, public safety partners, state and local governments, communities and customers. Idaho Power's main objectives of preparedness are: 1) performing wildfire prevention and mitigation activities; and 2) engaging with external public safety partners, critical facilities and communities to develop relationships and provide education to safely and effectively implement this plan. The TDER senior manager coordinates and facilitates activities of multiple Idaho Power business units for wildfire prevention and mitigation activities while Customer Operations and Corporate Communications facilitates public outreach and coordination efforts with external stakeholders.

Figure 1
PSPS Preparedness Cycle

Idaho Power's goal is to take a community approach to wildfire preparedness by educating and encouraging individual preparedness and relying on existing protocols and procedures currently available through local governments and emergency response professionals.

10.2.1. Idaho Power Programs

Idaho Power's WMP facilitates PSPS preparedness through vegetation management protocol specific to wildfire season, distribution and transmission hardening efforts, situational awareness coinciding with wildfire operational protocol, training programs, communications strategies and coordinated planning with both internal and external stakeholders. This PSPS Plan and emergency response protocol correspond with Idaho Power's WMP preparedness measures in an effort to further reduce wildfire risk consistent with industry best practices and regulatory requirements.

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC
Page 136 of 158

10.2.2. Coordination with Government Entities

Coordination with local government and emergency response entities is critical to Idaho Power's reliance on existing protocols and procedures developed by these external stakeholders. Customer Operations engages in these coordination efforts through ongoing communications and additional activities as required by this Plan. Activities include, without limitation:

- Being a trusted energy advisor to mayors, city managers, county leaders, elected officials and other stakeholders
- Educating and encouraging individual preparedness
- Educating stakeholders about Idaho Power wildfire preparedness and mitigation efforts, PSPS planning and capabilities
- Enhancing relationships with external stakeholders for improving interoperability and wildfire coordination
- Enhancing relationships with community services partnerships

10.2.3. Community Preparedness

Engage with public sector agencies and communities where PSPS events are likely to leverage existing emergency response plans and resources to increase the effectiveness of PSPS communications.

10.2.4. Information Sharing

Coordinate with public safety partners in advance of a PSPS event to prepare information needed by these partners and establish communication protocols for critical decision-making before and during a PSPS event, including restoration activities.

10.2.5. Notifications and Emergency Alerts

Collaborate with agencies in advance of PSPS events to allow for use of existing notification methods to communicate effectively during PSPS events.

10.2.6. Training and Exercises

Coordinate and participate in tabletop exercises with public safety partners to enhance knowledge of each other's emergency operations for smooth interactions during PSPS events.

10.3. Proactive Communications

Although the size of Idaho Power's service area, geographic and environmental diversity, and unpredictable nature of Idaho and Oregon weather make it challenging, Idaho Power is committed to providing as much advance notice as reasonably possible in preparation for a PSPS event. Table 3 provides Idaho Power's optimal communication timeline for PSPS events, circumstances permitting.

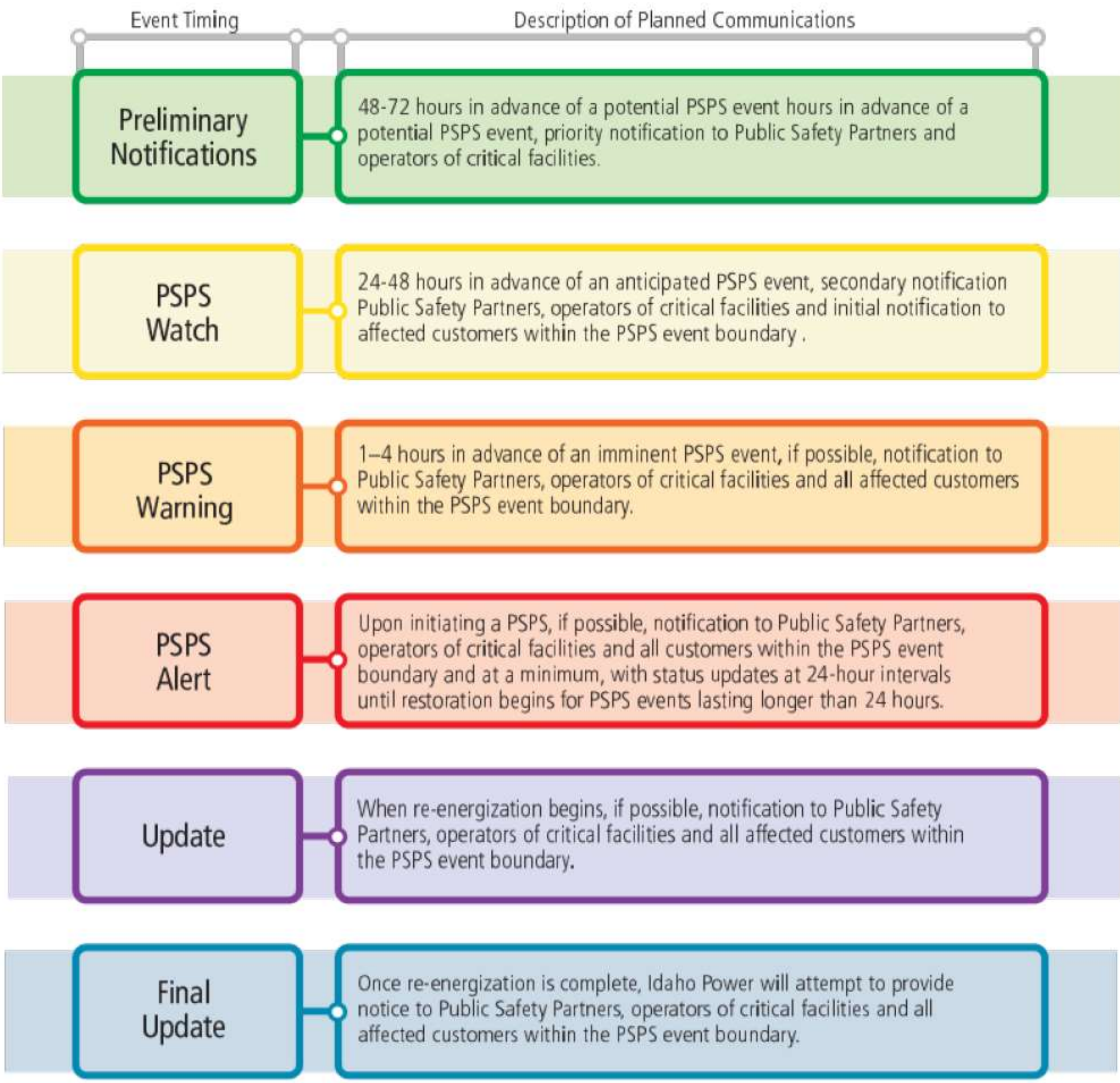


Figure 2
PSPS Event Communication Timeline

10.4. Wildfire Season Operations

As described here and in Idaho Power's WMP, normal operations during wildfire season differs from normal operations during the rest of the year based on heightened requirements specifically targeted at predicting and reducing wildfire risk.

10.4.1. Situational Awareness Activities

During wildfire season, Idaho Power closely monitors fire conditions and weather patterns. Idaho Power's Atmospheric Science team prepares a monthly "Seasonal Wildfire Outlook" report beginning in April and continuing through wildfire season containing information on regional drought conditions obtained from the National Drought Monitor, weather and climate outlook, seasonal precipitation and temperature outlooks from NOAA and the NWS, and a regional wildfire outlook.

During wildfire season, the Atmospheric Scientists will determine a daily FPI as described in Section 5.2 of the WMP describing shorter-term weather and fire conditions specific to WMP risk zones across Idaho Power's service territory and in identified risk zones where transmission facilities extend beyond service territory boundaries.

10.4.2. GIS Wildfire Information

Idaho Power's GIS team pulls regional wildfire information from a feature layer sourced by the GIS mapping software company ESRI, which pulls the data from the Integrated Reporting of Wildland-Fire Information (IRWIN) and the National Interagency Fire Center (NIFC). This information is added to multiple GIS viewers utilized by Idaho Power employees. These viewers also overlay current wildfire information to geospatially show physical relationships to transmission and distribution lines which provides valuable situational awareness in understanding wildfire activity near Idaho Power's T&D systems. This information is updated near real-time.

10.4.3. Key Grid Interdependent Utilities and Agencies

Idaho Power exchanges dispatch information with key grid interdependent utilities and energy providers to expedite communication and coordination during wildfire events. These contacts include Avista, Bonneville Power Administration, Northwestern Energy, NVEnergy, Oregon Trail Electric Cooperative, PacifiCorp, Raft River Electric, Seattle City Light and U.S. Bureau of Reclamation. Idaho Power also exchanges dispatch information with NIFC, BLM Fire Dispatch and various National Forest Service District Offices—including Idaho Power dispatch receiving BLM and US Forest Service incident command information during wildfire events—to improve communication and coordinate fire-related activities.

10.5. Phase 1

The decision to implement a PSPS event will be based on the best available data for weather and other fire-related conditions as detailed above in Section 8—PSPS Implementation Considerations. Multiple events may require simultaneous management such as other storm-related outages or other PSPS events.

10.5.1. PSPS Assessment Team Activation

Idaho Power will transition from normal wildfire season operations to Phase 1 of a PSPS event at the direction of the TDER senior manager. During Phase 1, Idaho Power will activate the PSPS Assessment Team, which includes the TDER senior manager, a regional senior manager of the area potentially impacted, Load Serving Operations (LSO) senior manager, a documentation subject matter expert (SME), and representatives from the Atmospheric Science team and Corporate Communications. The PSPS Assessment Team will hold conference calls as needed to discuss current and forecasted weather conditions and other critical information regarding a potential PSPS event. The TDER senior manager will facilitate PSPS Assessment Team meetings and conference calls and the PSPS Assessment Team will be responsible for determining whether to recommend maintain Phase 1, escalate to Phase 2, or de-escalate to normal operations. The PSPS Assessment Team will decide if Idaho Power will issue a preliminary notification of a potential PSPS event to public safety partners, critical facilities operators and ESF-12 as described in Table 3 above. During Phase 1, the PSPS Assessment Team will review the PSPS Plan and supporting documents. An operational risk assessment will be performed as well to determine current operational factors (existing outages, facilities under construction, personnel availability, etc.), risks and vulnerabilities. Ultimate determination will be made whether to escalate to Phase 2 by the TDER senior manager. Within one hour of Phase 2 notification, the full PSPS team will be placed on stand-by and team member availability will be determined. The full PSPS team is the PSPS Assessment Team plus the VP of Planning, Engineering and Construction, the Customer Operations VP and VP of Power Supply or their assigns.

10.5.2. Community Notifications

Depending on the situation and timing, public safety partners and critical facility operators may be notified during this phase. These notifications may include emails, text messages and/or phone calls as described in Idaho Power internal processes and procedures.

10.6. Phase 2

Phase 2 actions are determined by additional situational awareness activities, timing of forecasted weather events and risk tolerance. Upon transitioning to Phase 2, Idaho Power will provide external notifications as called out in Table 3 above with specific roles and responsibilities as described in internal process and procedure documents.

10.6.1. Activate Event Coordinator

Idaho Power will assign an Event Coordinator as outlined in Wildfire Mitigation and PSPS Plan. The event coordinator's main role is to coordinate activities across the region associated with PSPS implementation and restoration.

10.6.2. Conduct Operational Risk Analysis

The PSPS Assessment Team will present its operational risk analysis recommendation to the VP of PEC, VP of Customer Operations and the COO who will then evaluate the PSPS Assessment Team's recommendation, and the COO will make the final determination of whether to proceed to Phase 3 implementation of a PSPS event.

10.6.3. Request to Delay a PSPS Event

There may be requests to delay proactive de-energization from the public safety partners. This may occur for several reasons, with the most anticipated being loss of power for pumping water to fight wildfires. Delay requests should be routed through dispatch and sent to the PSPS Team for evaluation. The PSPS Team will provide the COO a recommendation on whether to approve the proactive de-energization delay and the COO will make the final decision. As soon as practicable after receiving the request, Idaho Power will notify the ESF-12 liaison of the delay request and basis of such request, as well as the final determination and the underlying justification.

10.6.4. PSPS Event Strategy

Regional operations personnel developed action plans and switching orders as part of their preparedness activities. These plans and switching orders will be reviewed and refined as necessary based on the current and forecasted conditions and will include situation-specific tactics and detailed instructions.

10.6.5. Field Observations and Response Teams

Regional Operations will coordinate field personnel to be mobilized and dispatched to strategic locations, including areas with limited weather and system condition visibility, to perform field observations for on-the-ground, real-time information critical to inform decisions on proactive de-energization. Field observations include—without limitation—conditional assessments of system impacts from wind and vegetation, flying debris and slapping conductors.

10.6.6. Customer and Community Notifications

Depending upon the timing and situation, Idaho Power may use various forms of communication (including media outreach) to provide information and updates to public safety partners, critical facility operators, and customers, particularly those impacted by the PSPS event. Information and updates will include the reason for the potential de-energization, where to find real-time updates on outage status and other relevant safety and resources. Internal processes and procedures will be followed to ensure accurate, up-to-date communication is provided.

10.7. Phase 3

Upon the COO making a determination to proactively de-energize, the LSO representative of the PSPS Team will inform System and Regional Dispatch Operations and request coordination of the estimated time to begin the PSPS. The regional manager, or their assigned representative of the region in which the PSPS will take place, will coordinate with the event coordinator to pre-position field personnel where manual de-energization is required and to stand by for orders to de-energize. System and Regional Dispatch Operations will implement the PSPS according to their established processes. Stations and communications system operations personnel will be prepared to support PSPS activities as needed. Idaho Power will take the following community-centered actions as soon as safely possible. Regional teams will follow internal processes and procedures to safely and effectively implement a PSPS event.

10.7.1. Customer and Community Notification

Relying on internal processes and procedures, Idaho Power will use various forms of communication (including media outreach) to provide information and updates to customers and other stakeholders, particularly those impacted by the PSPS event. Information and updates will include the reason for the de-energization, where to find real-time updates on outage status and other relevant safety and resource information regarding the PSPS. Specific protocols may be included in individual work group plans.

10.8. Phase 4

10.8.1. System Inspections

When it is safe to do so, Idaho Power will begin line patrolling activities to inspect T&D circuits and other potentially impacted Idaho Power facilities. Patrol personnel will report system conditions back to System and Regional Dispatch Operations for coordination with field crews. Patrols will be performed as required to ensure conditions and equipment are safe to re-energize.

10.8.2. Repair and Recovery

Line crews will repair T&D facilities as coordinated with System and Regional Dispatch Operations, replacing damaged equipment and performing other actions to support safe re-energization of the T&D system.

10.8.3. Incident Management Support

Support throughout the PSPS event will continue as described in Idaho Power's Wildfire Mitigation and PSPS Operational Plan. The PSPS Team will continue to monitor fire and weather conditions. Logistics and mutual assistance requirements will be determined and acted upon per existing plans and processes. If timely re-energization is not possible based on the magnitude of the event, the EMT will be notified for additional support.

10.8.4. Communicate PSPS Event Conclusion

Idaho Power will use various forms of communication (including media outreach) to inform customers and other stakeholders, particularly those impacted by the PSPS event, when repairs are complete and it is safe to re-energize the system. This may occur in stages as different feeders or feeder sections are repaired and safe to re-energize. This will be viewable on the outage map on Idaho Power's website during the event. Idaho Power will also leverage existing public agency outreach and notification systems as done at other points in the PSPS process.

10.8.5. Re-energization

Once re-energization activities are completed and service is restored, crews and support staff will demobilize and return to normal fire season operations as described in internal process and procedure documents.

10.9. Post-incident Review

During the PSPS phases the documentation SME will collect and maintain in the Regional Dispatch Operations logs incident information required for reporting purposes.

Following conclusion of a PSPS event, the Regional Manager or their assigned representative will conduct informal, high-level debriefs to identify potential modifications to PSPS protocol based on lessons learned during the event. The regional manager or assigned representative will consolidate the feedback and provide to the documentation SME.

Also following the PSPS event, the TDER senior manager will conduct an AAR with the PSPS Team to identify potential modifications to PSPS protocol based on lessons learned during the event. The TDER senior manager will consolidate the feedback and provide to the documentation SME.

After wildfire season, the Customer Operations support leader may conduct an AAR focusing on operational processes, communications, customer support as well as emergency response and restoration. Idaho Power may also request feedback from external stakeholders on coordination efforts, communications and outreach effectiveness for integration into the AAR report.

11. Financial Administration

Idaho Power will track expenses related to PSPS events for OPUC and IPUC reporting and potential recovery. Expense should be tracked for the entire PSPS event (Phase 1 through conclusion of the Post-Incident Review and filing the PSPS event report with the OPUC) to include, without limitation, time reporting, equipment and supplies used to set up customer resource centers and provided to customers (e.g., water, ice, etc.)

12. Reporting

Employees are required to manage information regarding PSPS events pursuant to Idaho Power's Information Retention Policy and underlying standards. Idaho Power will submit reports to the IPUC and OPUC as required.

13. After-Action Report

An AAR is a structured review or de-brief process used to evaluate the effectiveness of the Plan and potential areas for improvement. This process may be performed after a PSPS event and may be confidential at the direction of Legal to improve the PSPS processes and procedures.

14. Training

Idaho Power will strive to provide annual training, prior to or shortly after the beginning of wildfire season, to relevant employees on their respective roles in performing this PSPS Plan.

15. Exercises

Idaho Power will exercise this PSPS Plan at least annually using various scenarios and testing all or any portion(s) of the Plan which may include:

- Testing text and/or phone alerts with a test group of public safety partners
- Testing tactical operational plans such as reporting field observations or positioning employees at manually operated disconnects to test timing for de-energization and field inspections of T&D assets
- Discussing and/or practicing roles and responsibilities of both strategic and tactical operations, including decision-making handoffs and hypothetical scenarios
- Discussing and/or developing re-energization plans
- Testing capacity limits on incoming and outgoing communications systems

Appendix C
Oregon Wildfire Requirements and Recommendations.

Oregon Requirements and Recommendations

This appendix provides additional information specific to wildfire-related requirements, as well as wildfire-related recommendations, in Oregon.

Oregon Administrative Rule (OAR) Requirements

Below is a mapping of wildfire mitigation plan rules to sections within Idaho Power's WMP.

Wildfire Protection Plan Filing Requirements—OAR 860-300-0020

Oregon Requirement—OAR 860-300-0020	Corresponding Location in WMP
(1) Wildfire Protection Plans and Updates must, at a minimum, contain the following requirements as set forth in Section 3(2)(a)-(h), chapter 592, Oregon Laws 2021 and as supplemented below: *(a) Identified areas that are subject to a heightened risk of wildfire, including determinations for such conclusions, and are:*	See Section 3: Quantifying Wildland Fire Risk See Idaho Power website for details of wildfire risk zones outside of service territory
(A) Within the service territory of the Public Utility, and *(B) Outside the service territory of the Public Utility but within the Public Utility's right-of-way for generation and transmission assets.*	See Section 3.2.2: Wildfire Risk Areas See Figure 3: Boardman to Hemingway (B2H) Proposed Route Risk Zones
(b) Identified means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk.	See Section 4: Costs and Benefits of Wildfire Mitigation
(c) Identified preventative actions and programs that the Public Utility will carry out to minimize the risk of utility facilities causing wildfire.	See Section 5: Situational Awareness; Section 6: Mitigation—Field Personnel Practices; Section 7: Mitigation—Operations; Section 8: Mitigation—T&D Programs; and Section 8.3: T&D Vegetation Management
(d) Discussion of outreach efforts to regional, state, and local entities, including municipalities regarding a protocol for the de-energization of power lines and adjusting power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure.	See Section 10.2 Community Outreach and Section 10.2.1: Community Engagement See Appendix B: Idaho Power's Public Safety Power Shutoff Plan, Section 10.2.1: Coordination with Government Entities and Section 10.2.2: Community Preparedness
(e) Identified protocol for the de-energization of power lines and adjusting of power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure.	See Section 7.4: Public Safety Power Shutoff and Appendix B: Idaho Power's Public Safety Power Shutoff Plan
(f) Identification of the community outreach and public awareness efforts that the Public Utility will use before, during and after a wildfire season.	See Section 10: Communicating About Wildfire

Oregon Requirement—OAR 860-300-0020	Corresponding Location in WMP
(g) Description of procedures, standards, and time frames that the Public Utility will use to inspect utility infrastructure in areas the Public Utility identified as heightened risk of wildfire.	For Transmission, see Section 8.2.1: Transmission Asset Management Programs (with information on aerial, ground, detailed visual, pole, and other protection programs) For Distribution, see Section 8.2.2: Distribution Asset Management Programs (with information on visual, pole, and line equipment inspection programs)
(h) Description of the procedures, standards, and time frames that the Public Utility will use to carry out vegetation management in in areas the Public Utility identified as heightened risk of wildfire.	See Section 8.3.2: Transmission Vegetation Management and Section 8.3.3: Distribution Vegetation Management
(i) Identification of the development, implementation, and administrative costs for the plan, which includes discussion of risk-based cost and benefit analysis, including consideration of technologies that offer co-benefits to the utility's system.	See Section 4: Costs and Benefits of Wildfire Mitigation, specifically Section 4.3: Wildfire Mitigation Cost Summary and Section 4.4: Mitigation Activities
(j) Description of participation in national and international forums, including workshops identified in Section 2, chapter 592, Oregon Laws 2021, as well as research and analysis the Public Utility has undertaken to maintain expertise in leading edge technologies and operational practices, as well as how such technologies and operational practices have been used develop implement cost effective wildfire mitigation solutions.	See Section 2: Government, Industry, and Peer Utility Engagement

Risk Analysis—OAR 860-300-0030

Oregon Requirement—OAR 860-300-0030	Corresponding Location in WMP
(1) The Public Utility must include in its Wildfire Mitigation Plan risk analysis that describes wildfire risk within the Public Utility's service territory and outside the service territory of the Public Utility but within the Public Utility's right of way for generation and transmission assets. The risk analysis must include, at a minimum: *(a) Defined categories of overall wildfire risk and an adequate discussion of how the Public Utility categorizes wildfire risk. Categories of risk must include, at a minimum:*	See Section 3: Quantifying Wildland Fire Risk See Section 3.2.2: Wildfire Risk Areas and risk zone map on Idaho Power's website for detailed map of wildfire risk zones
(A) Baseline wildfire risk, which include elements of wildfire risk that are expected to remain fixed for multiple years. Examples include topography, vegetation, utility equipment in place, and climate; *(B) Seasonal wildfire risk, which include elements of wildfire risk that are expected to remain fixed for multiple months but may be dynamic throughout the year or from year to year; Examples include cumulative precipitation, seasonal weather conditions, current drought status, and fuel moisture content;* *(C) Risks to residential areas served by the Public Utility; and*	See Section 3.2 for discussion of fixed risk elements See Section 3.2.1 for discussion of variable risk elements that change throughout the year See Section 3.2.1 paragraph 4 addresses the consideration of residential areas in risk analysis

Oregon Requirement—OAR 860-300-0030	Corresponding Location in WMP
(D) Risks to substation or powerline owned by the Public Utility.	See Section 3.2.1 paragraph 4 addresses overhead power lines. Note: Idaho Power does not model wildfire progression or spread within substations due to zero vegetation within the fenced area. Also see Section 3.2.2.1 for discussion of risk modeling of proposed Boardman to Hemingway transmission line
(b) a narrative description of how the Public Utility determines areas of heightened risk of wildfire using the most updated data it has available from reputable sources.	See Section 3.2.2: Wildfire Risk Modeling Process and the 2023 Risk Modeling Update
(c) a narrative description of all data sources the Public Utility uses to model topographical and meteorological components of its wildfire risk as well as any wildfire risk related to the Public Utility's equipment.	See Section 11.4: Wildfire Risk Map
(A) The Public Utility must make clear the frequency with which each source of data is updated; and *(B) The Public Utility must make clear how it plans to keep its data sources as up to date as is practicable.*	See Section 11.4: Wildfire Risk Map
(d) The Public Utility's risk analysis must include a narrative description of how the Public Utility's wildfire risk models are used to make decisions concerning the following items: *(A) Public Safety Power Shutoffs* *(B) Vegetation Management;* *(C) System Hardening;* *(D) Investment decisions; and* *(E) Operational decisions.*	A) See Section 7.5.2: PSPS Plan B) See Section 8.3: T&D Vegetation Management C) See Executive Summary on Infrastructure Hardening; Section 8.2.2: Distribution Asset Management Programs; Section 11.9: Long-Term Metrics D) Risk analysis informs Red and Yellow Risk Zones mitigation activities. See Section 4: Costs and Benefits of Wildfire Mitigation and Section 4.4 Mitigation Activities E) See Section 7.2: Operational Protection Strategy and Appendix A: Wildland Fire Preparedness and Prevention Plan
(e) For updated Wildfire Mitigation Plans, the Public Utility must include a narrative description of any changes to its baseline wildfire risk that were made relative to the previous plan submitted by the utility, including the Public Utility's response to changes in baseline wildfire risk, seasonal wildfire risk, and Near-term Wildfire Risk.	For the 2023 WMP, Idaho Power did not make changes to baseline wildfire risk, but will evaluate and discuss changes in the 2024 WMP.

Oregon Requirement—OAR 860-300-0030	Corresponding Location in WMP
(2) To the extent practicable, the Public Utility must confer with other state agencies when evaluating the risk analysis included in the Public Utility's Wildfire Mitigation Plan.	See Executive Summary section on Lessons Learned: Community Feedback

Wildfire Mitigation Plan Engagement Strategies—OAR 860-300-0040

Oregon Requirement—OAR 860-300-0040	Corresponding Location in WMP
(1) The Public Utility must include in its Wildfire Mitigation Plan a Wildfire Mitigation Plan Engagement Strategy. The Wildfire Mitigation Plan Engagement Strategy will describe the utility's efforts to engage and collaborate with Public Safety partners and Local Communities impacted by the Wildfire Mitigation Plan in the preparation of the Wildfire Mitigation Plan and identification of related investments and activities. The Engagement Strategy must include, at a minimum:	See Section 10: Communicating About Wildfire
(a) Accessible forums for engagement and collaboration with Public Safety Partners, Local Communities, and customers in advance of filing the Wildfire Mitigation Plan. The Public Utility should provide, at minimum:	See Section 10.2: Community Outreach and Section 10.2.1: Community Engagement
(A) One public information and input session hosted in each county or group of adjacent counties within reasonable geographic proximity and streamed virtually with access and functional needs considerations; and *(B) One opportunity for engagement strategy participants to submit follow-up comments to the public information and input session.*	See Section 10.2.1: Community Engagement and Section 10.3.1: Key Communication Methods
(b) A description of how the Public Utility designed the Wildfire Mitigation Plan Engagement Strategy to be inclusive and accessible, including consideration of multiple languages and outreach to access and functional needs populations as identified with local Public Safety Partners.	See Section 10.2.1: Community Engagement and Section 10.3.1: Key Communication Methods
(2) The Public Utility must include a plan for conducting community outreach and public awareness efforts in its Wildfire Mitigation Plan. It must be developed in coordination with Public Safety Partners and informed by local needs and best practices to educate and inform communities inclusively about wildfire risk and preparation activities.	See Section 10.2.1: Community Engagement and Section 10.3.1: Key Communication Methods
(a) The community outreach and public awareness efforts will include plans to disseminate informational materials and/or conduct trainings that cover: *(A) Description of PSPS including why one would need to be executed, considerations determining why one is required, and what to expect before, during, and after a PSPS;* *(B) A description of the Public Utility's wildfire mitigation strategy;* *(C) Information on emergency kits/plans/checklists;* *(D) Public Utility contact and website information.*	For (A) – (D), see Section 10.2.1: Community Engagement; Section 10.3: Customer Communications; and Section 10.3.1: Key Communication Methods

Exhibit No. 5
Case No. IPC-E-23-11
M. Colburn, IPC
Page 148 of 158

Oregon Requirement—OAR 860-300-0040	Corresponding Location in WMP
(d) Discussion of outreach efforts to regional, state, and local entities, including municipalities regarding a protocol for the de-energization of power lines and adjusting power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure. *(b) In formulating community outreach and public awareness efforts, the Wildfire Mitigation Plan will also include descriptions of:* *(A) Media platforms and other communication tools that will be used to disseminate information to the public;* *(B) Frequency of outreach to inform the public;* *(C) Equity considerations in publication and accessibility, including, but not limited to:* *(i) Multiple languages prevalent to the area;* *(ii) Multiple media platforms to ensure access to all members of a Local Community.*	See Section 10.2.1: Community Engagement For (A)-(C): See Section 10.2.1: Community Engagement; Section 10.3: Customer Communications, and Section 10.3.1: Key Communication Methods
(3) The Public Utility must include in its Wildfire Mitigation Plan a description of metrics used to track and report on whether its community outreach and public awareness efforts are effectively and equitably reaching Local Communities across the Public Utility's service area.	See Section 10.3.3: Communication Metrics
(4) The Public Utility must include a Public Safety Partner Coordination Strategy in its Wildfire Mitigation Plan. The Coordination Strategy will describe how the Public Utility will coordinate with Public Safety Partners before, during, and after the fire season and should be additive to minimum requirements specified in relevant Public Safety Power Shut Off requirements described in OAR 860-300-0050. The Coordination Strategy should include, at a minimum: *(a) Meeting frequency and location determined in collaboration with Public Safety Partners;* *(b) Tabletop Exercise plan that includes topics and opportunities to participate;* *(c) After action reporting plan for lessons learned in alignment with Public Safety Partner after action reporting timeline and processes.*	See Section 10.2.1: Community Engagement

OPUC Order Nos. 22-133 and 22-312

This appendix also addresses recommendations received from Oregon Public Utility Commission (OPUC) Staff in Docket No. UM 2209 and approved by the OPUC Order Nos. 22-133 and 22-312. The italicized text below reflects OPUC Staff's specific recommendations for the company.

Recommendations Pertaining to OPUC Order No. 22-312

Category: Cost Allocation

1) *Provide detailed cost allocation assumptions of the transmission and distribution patrol, maintenance, and repair program, separated by transmission and distribution, as well as any associated maintenance and repair program including justification and reasoning for the cost allocation between Idaho and Oregon.*

2) *Provide details explaining the proposed cost allocation between Idaho and Oregon associated with wildfire mitigation program capital investments.*

Idaho Power removed the cost allocation information contained in an earlier version of the WMP, as the WMP is intended as an evolving document and not one related to prudency of specific investments.

To address Staff's interest in this subject, the company will file a wildfire mitigation-related cost deferral application with the OPUC in December 2022 so it may be reviewed in concert with the 2023 WMP.

Category: Risk Framework

3) *Provide detailed explanation of the strategy pertaining to its risk analysis framework.*

See Executive Summary of WMP. Idaho Power carried out a review of risk management processes and will consider the ISO 31000-2018 framework and process in the 2023 WMP.

Recommendations Pertaining to OPUC Order No. 22-133

The following summarizes OPUC Staff's recommendations for the company to include in its 2023 WMP.

Risk Modeling—OAR 860-300-0020 (1)(a)(A) & (B):

1) *Provide details regarding the mileage of overhead facilities that lie within its designated YRZs and RRZs.*

See Section 3.2.2. for details of overhead line mileage in designated wildfire risk zones.

2) *Idaho Power provide details of the analysis completed for establishing the risk tiers and the threshold values utilized for classifying the YRZs and RRZs.*

See Section 3.2.2. Tier levels were established based on quantitative results of modeling and numerous workshops held with our consultant and individuals having local knowledge of topography, fuels, fire history, and overhead facilities in their area. Tier levels were generated algorithmically as a starting point in the analysis and refined through workshops. Idaho Power did not base tier levels solely on risk scores.

3) *Idaho Power provide information regarding an analysis of the risk from specific utility asset types.*

See Section 3.2.1. The company used equal probability of ignition occurring on overhead transmission and distribution facilities in quantifying wildfire risk. As we mature our risk modeling methodology, the company plans to include reliability data to improve risk models.

4) *Idaho Power provide details of the process and timing that will be followed to evaluate the established heightened wildfire risk zones, and what data inputs and portions of the analysis will be reviewed annually.*

See sections 3.2.1. and 11.4. Idaho Power is planning to update its risk modeling in 2023.

5) *Idaho Power address the concerns raised by STOP B2H Coalition as thoroughly as possible.*

Idaho Power met with Stop B2H Coalition representative Jim Kreider on November 11, 2022, to provide an overview of the risk analysis performed for the Boardman to Hemingway (B2H) route. A presentation was delivered that highlighted Idaho Power's approach to quantifying wildfire risk and provided details of analysis performed along the B2H route that exceeded analysis performed in other locations within the service area. Risk analysis conducted along the B2H route includes quantifying wildfire risk similarly to other overhead facilities as described in Section 3. In addition, the following was also performed:

- Analysis of surface fuels within 1 mile of the B2H route to determine the potential of crown fire
- Determination of the influence of topographical slope on resistance to control and spread rate within 1 mile of the B2H route
- A review of temperature, precipitation, and relative humidity of the project site
- A review of the wildland urban interface and estimation of land use area within 1 and 10 miles of the project site
- A review of historic ignitions and the perimeter of historic fires within 50 miles of the project site going back 50 years

Transmission design engineers at Idaho Power also reviewed the design of lattice and H-frame structures proposed for B2H construction. A review was performed to identify the design characteristics that lead to decreased potential of ignition. This information was shared with Mr. Kreider and the overall fire potential for the area surrounding Morgan Lake. Mr. Kreider provided good feedback and recommended that Idaho Power meet with the new fire chief for the La Grande Rural Fire District and Baker County to compare risk maps and methodology. Idaho Power agreed and will have more engagement with Mr. Kreider and agencies in 2023. Additionally, the company plans to include the B2H route when reconducting risk modeling in 2023.

<u>*WMP Effectiveness—OAR 860-300-0020 (1)(b):*</u>

6) *Include a description of how it will measure the overall effectiveness of its wildfire mitigation activities, as well as information on wildfires in the service territory for the prior year.*

See the Executive Summary and Section 11.9. Metrics include tracking and monitoring mitigation programs to identify gaps and areas requiring corrective action. Long-term metrics were incorporated in 2022 to track potential drivers of ignition with respect to outage counts.

<u>*Plan Objectives—OAR 860-300-0020 (1)*</u>

7) *Idaho Power include details on whether the objectives of key preventative actions outlined in previous year's WMP have been met.*

See the Executive Summary.

8) *Idaho Power describe, to what degree, the preventable measures outlined in previous year's WMP have reduced the risk of the utility's infrastructure from causing ignitions.*

See Section 11.9. Idaho Power believes that mitigation activities have reduced wildfire risk but we need more time in concluding the magnitude of risk reduction. Idaho Power expects that reliability data and outage analytics will provide greater confidence of risk reduction with time.

9) *Idaho Power describe any adjustments made to its wildfire prevention programs that were included in previous year's WMP.*

See the Executive Summary. Adjustments were made to pre-season wildfire patrols due to snow levels. Also, Idaho Power did not meet all vegetation management production goals set for the year and had to adjust quality assurance and control audits from 100% in wildfire risk zones to a random sample approach.

<u>*Outreach Efforts—OAR 860-300-0020 (1)(d)*</u>

10) *Idaho Power include more detailed information about how it used learnings from the previous year to improve its 2023 Plan. The company should consider Public Safety Partner input through After Action Reports (from exercises and events), surveys or other feedback mechanisms, and company lessons learned.*

See the Executive Summary and Section 10.2.1.

11) *Idaho Power include clarification about CRCs in its 2023 WMP Update, to include:*

See sections 10.2.1. and 10.2.2.

12) *Idaho Power incorporate the following in its 2023 WMP:*

- *Map showing areas of its service territory at higher risk for PSPS events.*

See PSPS program in Appendix B.

- *List of Public Safety Partners the company engages with related to WMP.*

Idaho Power maintains routine contact with county emergency managers and state-level Public Safety Partners for both Oregon and Idaho. Specific contacts can be provided upon request.

- *Frequency of communication with Public Safety Partners.*

See sections 10.2.1. and 10.2.2.4.

- *Methods of communication with Public Safety Partners.*

See Section 10.2.1.

- *Feedback received from Public Safety Partners, and description of how the information influences the WMP.*

See Section 10.2.1.

<u>Lessons Learned—OAR 860-300-0020 (1)(e)</u>

13) *Idaho Power include previous year's lessons learned regarding de-energization of power lines to include findings from after action reports, including survey results from exercises and actual events (when available), in its 2023 WMP.*

See the Executive Summary. While Idaho Power did not call a PSPS event in 2022, there were several lessons learned from functional exercises and one near PSPS event that was subsequently canceled due to precipitation.

14) *Idaho Power include more information about the analysis completed to make their programmatic decisions of modifying system operations. The information should clarify why the company describes plans for RRZs not YRZs, and differences in system operations between transmission lines and distribution circuits.*

See Section 7.2.

<u>Communication and Outreach—OAR 860-300-0020 (1)(f)</u>

15) *Idaho Power incorporate the following its 2023 WMP:*

- *Examples of messaging;*
- *Selection process for methods of outreach;*
- *Determination of target audience;*

- *Metric and criteria used to evaluate effectiveness of outreach;*
- *Outcome of previous year's outreach evaluation;*
- *Description of company personnel and external resources responsible for outreach efforts;*
- *Description of timing of the outreach, including before, during, and after wildfire season;*
- *Description of Wildfire Mitigation Information/Resources maintained by the company on its website; and*
- *Description of Social Media Campaign developed and implemented by the company to inform customers about potential wildfire impacts (i.e., potential loss of power, preparedness, safety and awareness, etc.).*

See Section 10.2.

16) Idaho Power conduct wildfire training and exercises and include a discussion about community outreach and public awareness efforts prior to the upcoming fire season to clarify these activities, and to solicit input from participating Stakeholders.

See the Executive Summary and Section 10.2.

Asset Inspections—OAR 860-300-0020 (1)(g)

17) Idaho Power clearly identify inspection and correction procedures and protocols for non-wildfire risk zones, inspection and correction procedures and protocols for RRZs, and inspection and correction procedures and protocols for YRZs, along with the impacted line miles and structure counts for transmission and distribution assets in Oregon.

See Section 3.2.2. for line miles in wildfire risk zones and Section 8.2. for details of programs taking place in those zones.

18) Idaho Power include logic and details of analysis completed for their inspection and correction programming decisions in YRZs (and if any future RRZs) in Oregon.

See Section 8.2.

Vegetation Management—OAR 860-300-0020 (1)(h)

19) Idaho Power clearly identify vegetation management practices and protocols for non-wildfire risk zones, vegetation management practices and protocols for RRZs, and vegetation management practices and protocols for YRZs, along with the impacted line miles and structure counts for transmission and distribution assets in Oregon.

See Section 8.3.

20) Idaho Power provide logic and details of analysis completed for their programming decisions in YRZs (and if any future RRZs) in Oregon regarding vegetation management practices and protocols.

See sections 4.4.6. and 8.3.

21) Idaho Power provide more information regarding their quality control/quality assurance program and audits for vegetation management work completed in the RRZs, YRZs, including measures employed and resource types.

See sections 8.3.2. and 8.3.3.4.

22) Idaho Power provide analysis of any historical events pertaining to its power lines, specific equipment type, vegetation, and wildfires that informed the program's design and monitoring approach.

See Section 3.2.2.

Expert Forums—OAR 860-300-0020 (1)(i)

23) Idaho Power discuss the impact of participation in expert forums (see OAR 860-300-0020(1)U)) on identification of solutions most likely to provide the benefits anticipated. This should include:

- *Cited research, reports, and studies used in any analysis, unless the source is confidential.*
- *How the factors unique to the company's facilities and service territory were used when considering the applicability of specific options to its systems.*

See Section 2.3. In addition to participation in wildfire mitigation forums, Idaho Power spent significant time in 2022 developing a six-year roadmap to integrate new technology into the WMP. This consisted of researching products and meeting with 30 different companies throughout the year. We worked with the Electric Power Research Institute on gaining feedback of the performance and mitigation benefit of different technologies. Covered conductor was a key area of focus and helped develop a pilot plan. Additionally, the company has invested in the Westly Group, a fund that invests in startups focused on the digitalization and sustainability of energy, mobility, buildings, and industrial technology. One of our focus areas with the Westly Group in 2022 was reviewing new wildfire technologies.

The following were references used during the year to form changes in the 2023 WMP.

Wildfire Mitigation

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Advanced Relay Protection

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Eaton Power Systems (2021). *Overcurrent Fault Data in The Form6*

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United Nations Industrial Development Organization. 2021. *ISO 31000:2018 Risk Management, A Practical Guide.*

Group Participation and Learnings—OAR 860-300-0020 (1)0)

24) Idaho Power include more specifics on what it has learned by participating in these groups. Staff would like assurance the company is leveraging the learnings from other utilities and experts to facilitate implementation of solutions with the highest benefit cost ratio.

See Section 2.3.

25) Idaho Power include its contribution to these forums including any research projects it is supporting or participating in.

See Section 2.3.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JAMES "BO" HANCHEY

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is James "Bo" Hanchey. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as Vice President of Customer Operations and Chief Safety Officer.

Q. Please describe your educational background and what educational opportunities you have had while at Idaho Power.

A. I received an Associate Degree in Applied Science in electric power technology from Bismarck State College in 2019 and a Bachelor of Science degree in business management from the same school in 2023. Additionally, in 2021 I completed the University of Idaho's Energy Executive Course.

Q. Please describe your work experience with Idaho Power.

A. I began working with the Company in 1997 at the Twin Falls Operations Center as a materials handler and have held various field operations and customer service-related positions of increasing responsibility since. Specifically, in 1999 I became an apprentice lineman and in 2003 obtained my Bureau of Apprenticeship and Training certificate from the United States Department of Labor. By

2014 I had advanced through different leadership and management roles to become a Regional Manager. In 2018, I assumed the role of Customer Service Senior Manager, and in 2019 I was promoted to my current position as Vice President of Customer Operations and Chief Safety Officer.

Q. What are your duties as Vice President of Customer Operations and Chief Safety Officer?

A. I am responsible for the planning, directing, and strategic oversight of all activities within Idaho Power’s Safety and Customer Operations organizations.

Q. Please describe Idaho Power’s Safety and Customer Operations organizations.

A. The Safety organization within Idaho Power is comprised of 11 employees, excluding myself, all of whom are focused on ensuring the safety of employees and contractors doing business on behalf of Idaho Power, as well as providing service safely to customers and within the communities we serve. These employees are tasked with continuously evaluating and identifying process and behavior improvements to enhance all aspects of Idaho Power’s Safety First culture.

The Customer Operations organization within Idaho Power is comprised of over 600 employees that are engaged in activities that provide direct service to the Company’s retail customers and in the communities it serves.

Specifically, the organization includes Customer Service, Customer Relations and Energy Efficiency, Regional Operations, and Regional Operations Support. Generally, activities that directly serve the customer are conducted within this organization, which allows the employees in the organization to achieve synergies and work together in a seamless manner. The Customer Operations organization exists to provide excellent service to customers in the most cost-effective way possible.

Q. What is the purpose of your testimony in this matter?

A. First, I will briefly describe the Company's Safety First culture and how Idaho Power promotes a culture of safety with its customers and in the communities it serves, as well as with the organizations the Company frequently works and partners with.

I will then provide a high-level overview of various initiatives that the Company has and continues to undertake to provide an exceptional customer experience and enhance customer choices and services. I will also discuss how the Company promotes demand-side management ("DSM") opportunities, provides superior customer service, and pursues efficiencies in its operations.

I. SAFETY

Q. Please briefly explain Idaho Power's philosophy regarding safety.

A. Safety is a core value at Idaho Power and accordingly, Idaho Power embraces a Safety First culture. The Safety First culture recognizes that Idaho Power's family of employees is the Company's greatest asset and emphasizes that each employee's most important responsibility in their daily work is safety and that no work is so critical that safety should be disregarded. The Company is committed to the safety of its employees, customers, and the public.

Q. How does the Company promote its Safety First culture with employees?

A. The Company routinely conducts regular safety and job-specific trainings for all employees in relation to their respective area of coverage. While these safety trainings vary in cadence based on role and responsibility, the Company's approximately 400 field operations employees, who are largely tasked with constructing and maintaining the Company's system, attend safety meetings on at least a monthly basis to ensure continual safety and best practice updates. Additionally, since 2017, the Company has provided training to employees emphasizing how certain behaviors and mental statuses, such as rushing, complacency, multitasking and fatigue, may impact one's ability to make safe decisions. By training employees to be consciously aware of these factors, it allows them to continually assess their environment and try to mitigate risk. Another example of a program implemented by the Company to enhance its Safety First culture is the development of the Company's safety accountability framework in 2018. This framework was created and trained to all employees in 2018 to promote the Company's Safety First culture as being one of trust, openness, learning and accountability.

Q. How does the Company promote its Safety First culture with its customers?

A. The Company routinely sponsors print, digital or radio ads related to overhead line safety, downed power lines, wildfire, and water safety, among other topics. In 2022, the Company also authored 33 safety-related social media posts. Additionally, for customers that the Company has an email on file for, the Company frequently emails targeted safety-related tips and reminders. For example, in Spring and Fall of 2022, the Company emailed irrigation safety tips to customers who receive irrigation service. Similarly, in December 2022, the Company emailed residential customers various tips to promote safe decorating practices during the winter and holiday season.

Aside from the above stated outreach channels, the Company frequently publishes news briefs that discuss differing safety topics, six of which were picked up by local media in 2022, as well as including safety-focused inserts within customers’ bills, an example of which is included as Exhibit No. 6.

Q. How does the Company promote its Safety First culture within the communities it serves?

A. The Company frequently provides training to fire, police, and other first responders to inform them how to remain safe around power lines. Fundamental to that training, Idaho Power employees educate first responders on Idaho Power’s process for de-energizing electrical equipment as part of their response to house fires and other emergencies. Similarly, the Company has also published an online first responder training aid called “Responding to Utility emergencies.” This short online course is available at no-cost to participants and teaches emergency response personnel how to recognize potential hazards involving electricity.

Idaho Power’s education and outreach energy advisors also work with schools and community groups to conduct educational presentations. These presentations vary in content based on the audience but typically aim to promote general safety awareness and certain vital behaviors to help minimize the occurrence of electrical accidents.

The Company also conducts safety presentations at numerous contractor, customer, or partner agency events throughout the year. For example, in 2022, Idaho Power's Safety Director presented information regarding the Company's safety programs to approximately 200 Idaho Transportation Department leaders and executives from across the state. The Company also held two Contractor Safety Summits in 2022 whereby the Company shared best practices and information related to the Company's safety culture and programs with contractors doing business on behalf of Idaho Power.

Q. Has the Company been recognized for its employee safety efforts and commitment to safety?

A. Yes. I am proud to share that after achieving one of the Company's safest years on record in 2021, the Company was presented with Edison Electric Institute's ("EEI") Thomas F. Farrell, II Safety Leadership and Innovation Award in the Member Company Project category. EEI selected Idaho Power for this award due to the Company's approach of combining psychological safety and behavioral safety with practical application of human performance principles. While the Company is incredibly proud of EEI's recognition and the corresponding award, it remains cognizant that the pursuit of safety excellence is a never-ending journey.

II. **CUSTOMER RELATIONS**

Q. What is the Company's overall approach to customer relations?

A. Idaho Power strives to be regarded as an exceptional utility by the customers it serves. To accomplish this, the Company must provide superior and satisfying customer service and experiences that meet or exceed its customers' needs and expectations.

Q. How does the Company determine the focus for improving customer relations?

A. The Company continually focuses on ways to cost-effectively improve its relationships with customers by assessing customer perception of the Company, identifying performance and experience gaps based on customer feedback, and reviewing industry best practices and trends.

Q. What is presently being done to address areas with opportunity for improvement?

A. The Company's strategy for addressing areas of improvement involves integrating customer input into its processes, systems, and culture while also leveraging cost-effective technologies to improve service. For instance, activities supporting this strategy include focusing on improving system reliability, offering new digital experiences, and enhanced automated customer service options.

Q. Please describe Idaho Power's continuing practice of surveying its customers regarding their levels of satisfaction with the Company.

A. Idaho Power has contracted with Burke, Inc. to conduct quarterly customer relationship surveys since 1995. Burke is a full-service customer market research and decision support company headquartered in Cincinnati, Ohio, with regional offices throughout the United States. These surveys represent Idaho Power's primary customer satisfaction research and determine the Company's customer relationship index ("CRI"), which is a key metric used to evaluate the Company's overall customer satisfaction rate. Burke offers an extensive survey for the following four customer segments: Residential, Small Business, Irrigation, and Large Commercial and Industrial.

In addition to the customer satisfaction surveys performed by Burke, Idaho Power acquires the results of the annual J.D. Power Electric Utility Residential Customer Satisfaction Study ("J.D. Power Study"). The J.D. Power Study is comprised of over 100,000 customer responses nationwide, including Idaho Power's customers, and is used by the Company primarily as a benchmark to other electric utilities and, as its name implies, is for residential customers only.

In addition to Burke surveys and the annual J.D. Power Study, Idaho Power also utilizes customer focus groups and ad hoc surveys, such as within its online Empowered Community group, for project-specific qualitative research, when the situation is appropriate. Further, the Company also conducts post-construction surveys to help ensure that working with Idaho Power on new construction projects remains a satisfying and streamlined experience.

Q. Please describe the Company’s customer satisfaction performance results in recent years.

A. I am proud to say that based on recent years’ customer satisfaction surveys performed by Burke, Idaho Power customers’ satisfaction remains at a consistently high level. In addition, the Company has recently experienced levels of customer satisfaction that were significantly higher than compared to the Company’s customer satisfaction results presented as part of Idaho Power’s last general rate case (“GRC”) in Case No. IPC-E-11-08. While 2022’s customer satisfaction survey performed by Burke did indicate the Company’s level of customer satisfaction decreased to 83.95 percent, which is a slight decline compared to the five years immediately prior, which had an average customer satisfaction score of approximately

85.5 percent, the Company understands the decrease to be a trend within the industry and likely to be partially attributable to factors outside of the Company's control, such as inflationary pressures affecting the price of all goods and services. Despite this decrease, Burke still attributes the Company's 2022 customer satisfaction results as signifying that overall, customers have very strong positive attitudes toward Idaho Power and the level and quality of service it provides.

The results of the 2022 J.D. Power Study indicate the Company achieved very compelling residential customer satisfaction results compared to many of its peers. Specifically, the 2022 J.D. Power Study indicated that Idaho Power ranked 3rd out of 17 within the West Midsize electric utility segment for overall residential customer satisfaction, and the Company ranked 6th out of 92 investor-owned utilities in overall residential customer satisfaction.

Q. Please summarize the Burke methodology and the resulting information made available to the Company.

A. On a quarterly basis, Idaho Power receives results from Burke based on customer interviews. Quarterly results include an overall index score, thereby determining the Company's quarterly CRI, as well as more detailed information in the form of average response data collected for questions in five general categories:(1) Overall Satisfaction, (2) Excellent Overall Quality, (3) Excellent Overall Value, (4) Likelihood to Recommend, and (5) Idaho Power Cares.

Q. What is Idaho Power's primary way of measuring its success in providing customer satisfaction?

A. Idaho Power's primary measure for customer satisfaction is the CRI derived by Burke from quarterly customer surveys. The CRI is based on research that is conducted at various points in time throughout the year. This reduces the potential for any one event or circumstance to have a significant influence, either good or bad, on the overall customer satisfaction levels. It is a statistically reliable measurement of customers' opinions, and it provides a historical trend that allows the Company to track its performance over time.

The CRI is the best single satisfaction measure available to Idaho Power because it depicts customers' overall attitudes toward the Company in five distinct criteria. The CRI is comprised of five key questions where a rating ranging from zero (very dissatisfied) to four (very satisfied) is given for a maximum of 20 points possible among all five questions. The following are the five criteria questions that are asked in the quarterly customer surveys:

(1) What is your overall level of satisfaction with Idaho Power?

(2) How much do you agree or disagree that the overall quality of the electricity and customer service and support you get from Idaho Power is excellent?

(3) Thinking about the price you pay, how much do you agree or disagree that the overall value of the electricity and customer service and support you get from Idaho Power is excellent?

(4) If asked (by a neighbor new to your area, by a company that just moved into the area, or by an irrigator new to your area) how likely would you be to tell them that Idaho Power is a good company to work with?

(5) How much do you agree or disagree that Idaho Power cares about you as a customer and has done everything possible to earn your loyalty?

Responses for each customer are totaled and divided by the maximum possible points to establish a percentage CRI score that is weighted by customer segment revenue. The CRI can range from a minimum of 0 percent to a maximum of 100 percent.

III. CUSTOMER DRIVEN ENHANCEMENTS

Q. Based on the various surveys and focus groups that the Company subscribes to or conducts, what recent initiatives has Idaho Power undertaken to enhance customer satisfaction?

A. Recently, the Company has focused on pursuing the enhancement of its digital offerings and solutions to better align with industry trends and evolving customer preferences and expectations. Specifically, the Company's investment in modernizing its My Account platform stemmed from customers' desire to digitally self-serve and manage their accounts. Not only does the newest iteration of the Company's My Account provide increased security measures to better protect enrolled customers' personal information, it also allows for flexible payment options for a variety of circumstances and streamlines enrollment in other optional, account-related offerings such as Paperless Billing, Auto Pay, Budget Pay, and Green Power, as well as contributing to Project Share.

Q. What other notable enhancements are part of the Company's updated My Account Platform?

A. As part of the Company's updated My Account platform, enrolled customers can efficiently self-manage and update their contact information and notification preferences, as well as easily complete a home energy profile, which provides customers with continuous insights on how to save energy and thereby reduce their monthly bills.

Additionally, the Company's updated My Account platform allows for one-stop enrollment in outage and account-related alerts, which are provided via each customer's preferred communication channel(s).

Q. Has the Company implemented any other digital offerings based on customer feedback or changed preferences?

A. Yes. In early 2022, the Company released a Mobile Application ("App") on the Apple and Google Play stores due to the increasing shift in customers' preferences toward accessing their account and service-related information on the go. While the App provides customers with nearly all the same previously stated My Account enhancements from the palm of their hand, in addition to increased security and login functionality using face or touch identification, it also allows for optional push notification functionality, thereby providing enrolled customers with real-time alerts regarding important billing information or an outage affecting one of their registered addresses.

Q. Why is the emphasis of improved outage communications as part of the Company's enhanced My Account and App so important?

A. Unsurprisingly, reliability of service is a key driver of customer satisfaction. Though the Company keeps customers’ lights on more than 99.9 percent of the time, if a customer does experience an outage, they expect timely and relevant information to be provided via their preferred communication channel, which has increasingly shifted to digital means. The Company has routinely seen and heard this growing customer preference when evaluating the various surveys and focus groups’ results.

Q. Are customers required to install the App or register for My Account to receive outage communications?

A. No. Although the App and My Account are required for users to receive address specific, real-time outage alerts, all customers have the option to view outage-related information and elect to receive outage-specific text messages via the Company’s outage webpage. Customers opting to receive outage-specific communications in this manner are not required to register for My Account. Instead, only a mobile phone number is required so that outage-specific text message updates can be provided.

Q. What sort of outage updates are provided to enrolled customers?

A. While the content and frequency of outage communications is constantly evolving to better align with customers’ changing preferences, the Company has made continual improvements to its outage communications over the years, all of which have currently culminated in customers receiving updates related to the below topics:

- Outage location
- Probable cause of the outage
- Status of the outage, such as a crew being enroute or onsite
- Estimated time of restoration
- Power restoration

Q. For planned and unplanned outages, has the Company made any other improvements to enhance customer communications and the delivery thereof?

A. Yes. As part of the Customer Operations Support group, an Enterprise Communication Coordinator has been established to oversee all aspects surrounding the Company's preparation, planning and communication of planned and unplanned outages. Additionally, the Enterprise Communication Coordinator is also responsible for identifying and implementing process and technological improvements for all outages that may impact customers, such as the Emergency Outage Notification System implemented in 2022 which allows the Company to promptly and, when practicable, proactively notify customers of pertinent information regarding outage or load shed events through text and voice messaging. By channeling all these functions and responsibilities through the Enterprise

Communication Coordinator, customer experience and potential impact can remain forefront.

Q. Does the Company conduct mock events to simulate situations that may require an emergency load shed or public safety power shutoff?

A. Yes. The Company routinely conducts mock events ahead of wildfire season for these types of situations so that it can try to identify process improvements prior to actually needing to enact any such processes.

Q. Are there any other customer-driven enhancements that the Company has recently implemented?

A. Since Idaho Power's last GRC, the Company has implemented various web portals or webpages to improve different customer groups' experiences. In particular, the Company has implemented the following:

- Energy Assistance Portal: a portal that streamlines the process for energy assistance providers to pledge and commit funds to eligible customers' accounts.
- Large Business Portal: a portal that allows Large Commercial and Industrial customers the ability to view their interval usage data, down to 15-minute intervals, for the most recent 18 months.

- Construction Portal: a portal that allows customers to electronically submit new service and meter installation requests, as well as receive notifications and project updates.
- Landlord Webpage: a webpage that allows landlords to more easily manage service at their various properties.

IV. DEMAND-SIDE MANAGEMENT

Q. What is the Company's goal or philosophy toward energy efficiency and demand response programs?

A. The Company is committed to pursuing all cost-effective energy efficiency on behalf of its customers. Idaho Power also pursues cost-effective demand response programs based on system needs identified in the Company's Integrated Resource Plan ("IRP").

Q. How does the Company view energy efficiency and demand response?

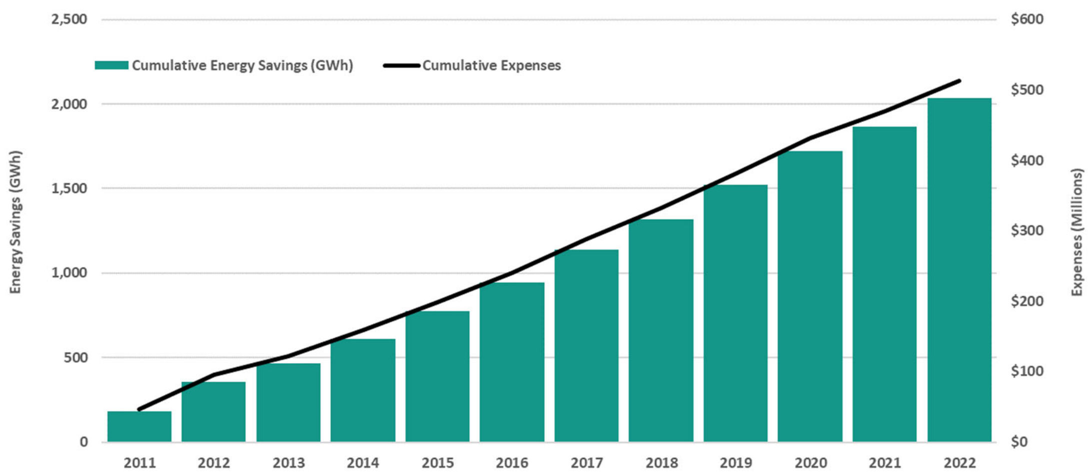
A. Cost-effective energy efficiency and demand response programs are the Company's resource of choice - both from a cost standpoint and from an environmental perspective. The cleanest, most efficient resource in the Company's portfolio is the one it does not have to build or acquire. To that end, the Company believes that cost-effective energy efficiency should be pursued aggressively. Idaho Power also believes demand response is a resource that should be pursued based on system needs to meet the highest risk hours during the summer season. Because the Company is able to dispatch demand response and potentially reduce the necessary amount of load, building or acquiring an additional resource to meet load for a relatively few number of hours a year might be avoided, which ultimately benefits all customers by avoiding these costs and keeping prices lower.

Q. Please describe the progress made by the Company in providing energy efficiency programs.

A. The Company's *Demand-Side Management 2022 Annual Report* was filed with the Commission on March 15, 2023. As noted in the Annual Report, Idaho Power offers a combined total of 17 energy efficiency and outreach programs for all customer segments. Energy savings from energy efficiency activities increased on a system-wide basis by 19 percent, as compared to 2021, and overall energy efficiency activities in 2022 resulted in 169,889 megawatt-hours in energy savings. As shown in Chart 1 below, the Company has spent over $513 million on energy efficiency and demand response since 2011 for an average of about $43 million per year. These expenses have cumulatively resulted in over 2,000 gigawatt-hours of energy savings for the Company's service area. Because these are cumulative incremental annual savings, the

Company believes this is the lower boundary of the total energy efficiency savings realized by customers since 2011.

Chart 1.
Cumulative Energy Savings & Expenses Since 2011



Q. Are Idaho Power's energy efficiency programs proving to be successful?

A. Yes. The Company believes that the quantifiable benefits since its last GRC, as outlined above, have been substantial and only serve as a starting point for all the non-quantifiable benefits the energy efficiency programs have provided. Each program offered has directly benefited customers and the Company. Programs either provide monetary incentives to customers for participation, target educational efforts and long-term energy saving opportunities, or encourage energy efficient behavioral changes by customers. Increased participation in the Company's programs benefits all customers by using resources wisely while avoiding or delaying the development of supply-side resources.

Q. Please describe the progress made by the Company in providing demand response programs.

A. As described in the Company's *Demand-Side Management 2022 Annual Report*, Idaho Power offers three demand response programs with program options for Residential, Commercial & Industrial, and Irrigation customers respectively. In 2022, the demand response programs had a maximum non-coincident load reduction of 200 megawatts ("MW") from 312 MW of capacity, and the Company has had an average of 272 MW of demand response capacity for the Company's service area since its last GRC. Chart 2 shows the total demand response portfolio capacity, the actual maximum load reduction, and the annual expenses since 2011. In 2022, about 60 percent of expenses were in the form of program incentives paid to customers.

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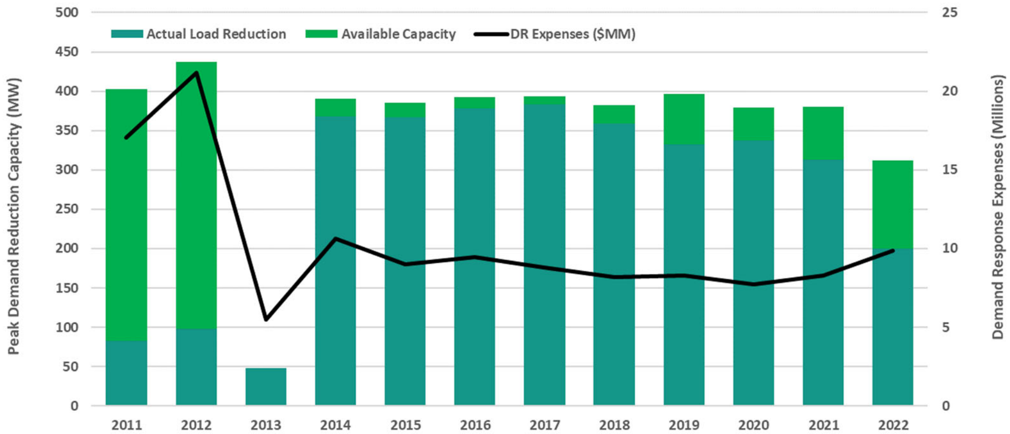
Chart 2.
Demand Response Capacity, Load Reduction, and Expenses



Q. Are Idaho Power's demand response programs proving to be successful?

A. Yes. The Company's demand response programs are designed to minimize or delay the need to build or acquire new supply-side resources. The demand response programs are also intended to address the highest need electricity demand hours, thus minimizing the need for selecting supply-side alternatives that would only be needed for a few hours. These potential hours typically occur during low hydro generation and high load events, and the programs are designed to be available to meet potential system capacity deficits during these hours. The deficits are expected to be relatively large in magnitude but short in duration. Therefore, Idaho Power has determined it can be cost-effective for its customers to utilize demand response programs rather than building or acquiring a supply-side resource that would only be required to operate for a small number of hours. Overall, the Company's demand response programs have been cost-effective every year since the last GRC and have been successful in accomplishing the goals stated above.

Q. Are there any other benefits outside energy saving and demand reduction that you consider to be a good outcome of Idaho Power's energy efficiency and demand response programs?

A. Yes. These programs, along with the Company's education outreach and customer energy usage information, provide more opportunities for customer engagement in their energy management decisions. For example, through the Company's outreach programs, the customer has opportunities to learn about their energy consumption and how to use energy more efficiently. By using My Account, customers can see how their hourly energy usage is affected by their energy management decisions and the products they use in their homes and businesses.

Q. What are the sources of funding for the Company's energy efficiency and demand response activities?

A. The majority of the funding for energy efficiency activities in Idaho comes from the Energy Efficiency Rider ("Rider") with a lesser amount funded through base rates. The Company's demand response incentives are funded through base rates and tracked through the Company’s Power Cost Adjustment (“PCA”) with the remaining demand response program expenses, such as overheads, funded through the Rider.

Q. What energy efficiency programs are funded through base rates?

A. Idaho Power funds its low-income weatherization program, called Weatherization Assistance for Qualified Customers(“WAQC”), through base rates in compliance with Commission Order No. 29505.

Q. Do Idaho Power’s energy efficiency activities affect customer satisfaction?

A. Yes. Results of independent surveys show Idaho Power’s efforts to educate and inform customers are successful: the Company remains one of the top-ranked utilities for energy efficiency awareness and, as indicated within the 2022 J.D. Power Study, ranked 3rd in the West Midsize Segment for the same.

According to the 2022 customer satisfaction survey performed by Burke, customers were very satisfied with Idaho Power regarding offering programs to help customers save energy and providing customers with information on how to save energy and money. These results in regard to energy efficiency undoubtedly play a part in overall customer satisfaction.

Q. Does Idaho Power offer energy efficiency programs to its income-qualified customers?

A. Yes. Idaho Power has two programs designed to assist income-qualified customers with energy efficiency at no cost: WAQC and Weatherization Solutions for Eligible Customers ("Solutions"). The WAQC and Solutions programs provide financial assistance to regional Community Action Partnership agencies in Idaho Power's service area. This assistance helps fund weatherization costs of electrically heated homes occupied by qualified customers who have limited incomes. Weatherization improvements enable residents to maintain a more comfortable, safe, and energy-efficient home while reducing their monthly electricity consumption and are available at no cost to qualified customers who own or rent their homes.

V. CUSTOMER SERVICE

Q. Please briefly describe Idaho Power's customer service organization.

A. Idaho Power operates a centralized Customer Service Center ("CSC") that provides customers with full-service access to Customer Service Representatives ("CSR") weekdays from 7:30 a.m. to 6:30 p.m. MST, and outage and emergency access to Outage Specialists 24 hours a day, seven days a week. Idaho Power also employs bilingual CSRs that provide service to the Company's Spanish-speaking customers. Additionally, the Company utilizes a third-party language service to help it communicate with other non-English speaking customers. Over the last five years, an average of approximately 1.2 million inbound customer calls were received by the CSC each year.

Q. How does the Company try to ensure that customers calling the CSC have a positive experience?

A. "First Call Resolution" is a priority of the Company's. If a CSR can resolve a customer's concerns on the first call, the customer is likely to have a more positive experience. As such, a strong emphasis is placed on ensuring customers' concerns are addressed as efficiently and effectively as possible.

Q. Please describe how CSRs assist customers who express having difficulty paying their electric bill.

A. The Company's CSRs are committed to helping all customers expressing difficulty paying their electric bill and work to identify and offer reasonable payment arrangement options that may be best suited to assist with each customer's individual circumstances. Additionally, when a customer declares their inability to make a payment, CSRs will provide the customer with the contact information of their local energy assistance agency so that the customer may call and request receipt of Low-Income Home Energy Assistance Program funds or any other bill assistance that may be available.

Q. Does Idaho Power support any energy assistance programs for customers who are having difficulty paying their electricity bill?

A. Yes. Project Share is a year-round energy assistance program, which was started by Idaho Power in 1982. It is administered by the Salvation Army and funded by customer donations and Idaho Power shareholder funds. For Idaho Power's customers, grants from this program can be used for the payment of electricity bills. During the last program year, more than 1,300 households in Idaho Power's communities benefited from Project Share to keep their homes warm during cold winter months and cool during hot summer days. In the last five program years ending September 30, 2022, Idaho Power customers and shareholders have combined to contribute more than $1 million to the program.

In recognition of the cost pressures that customers in need may be experiencing, the contribution amount from Idaho Power's shareholders to Project Share will be increased from $25,000 to $125,000 during 2023. This increased contribution amount to Project Share is in addition to shareholders continuing to cover the entirety of the program's administrative costs, which ensures 100 percent of customer donations go toward helping those in need.

Q. Do customers calling the CSC need to speak with a CSR to retrieve account information, conduct account transactions, or inquire about an outage affecting their service address?

No. Idaho Power customers have access to account and outage information 24 hours a day, seven days a week through an Interactive Voice Response ("IVR") unit, which has undergone numerous enhancements over the years to enable additional customer self-serve functionality. As a result of these updates, the IVR unit was able to contain and resolve, within the last five years, approximately 48 percent of customer calls.

Through the IVR, customers can make payment arrangements; retrieve billing, payment, and meter reading information; sign up for Budget Pay; access energy efficiency and usage information; and receive personalized, address-specific outage information. Notably, Idaho Power's IVR system and its enhanced self-serve functionality has been nationally recognized in recent years by the IVR Doctors, a leading human factors and usability-consulting firm in evaluating and improving customer experience and system performance in automated phone systems.

Q. Has the CSC experienced an impact from the various self-serve features implemented through the Company's IVR, App and My Account enhancements?

A. Yes. The CSC has experienced decreases in annual call volumes, which is likely a result of the various self-serve enhancements implemented by the Company. However, the types of calls fielded by CSRs are now typically related to more complex situations, for which a self-serve option does not currently exist, or to help troubleshoot questions that customers may have related to the App or My Account.

Q. As a result of the reduced call volume, has the Company made any reorganizations to its CSC?

A. Yes. As the Company continues to intently focus on continuously improving customers' overall experience, several positions within the CSC were recalibrated to focus on operational efficiencies and identify ways to enhance customers' satisfaction when interacting with Idaho Power. As an example, Idaho Power's call routing system was improved after the Company identified that customers were too often being placed in the wrong call queue, thereby necessitating transfers between CSRs. As a result of the improved call routing system, customers are now more frequently placed in the correct call queue and able to have their questions answered in a more timely and effective manner.

Q. How have call handle times been affected?

A. As part of the Company’s effort to ensure customers are placed in the right call queue, customers likelier to be facing a more complex situation are routed to CSRs best equipped to handle such questions, which may result in slightly longer hold and handle times, whereas calls more routine in nature are typically placed in a separate queue with lower hold and handle times. The result of this approach is that customers’ hold times are minimized for relatively simple requests because CSRs can handle them in quicker fashion. Conversely, situations necessitating additional handle time and care are afforded the same.

Q. Have there been other types of positions added within the CSC to enhance customer experience?

A. Within the last few years, the Company shifted several CSRs to a Customer Solution Advisor ("CSA”) role. CSAs are an extension of the Company’s field representatives and assist with customer engagement when a field visit is not possible or practicable. While CSAs typically engage with new commercial and irrigation customers to explain their bills or discuss energy efficiency options, they are also responsible for answering customers’ questions related to on-site generation. Often the types of calls CSAs handle require thorough knowledge of the Company’s field practices and tariff schedules, thereby necessitating a more specialized role.

Q. Are there any other recently implemented customer experience initiatives that you believe have resulted in positive customer experiences?

A. In 2017, Idaho Power implemented its Idaho Power Cares Greeting Card program. The program enables CSRs and other customer-facing employees to send a greeting card produced by Hallmark Cards, Inc. to a customer when they feel it is warranted. Such examples of these cards’ topics include, but are not limited to, thank you, care and concern, sympathy, new home, baby, and birthday. In 2022, the Idaho Power Cares program sent an average of 14 cards each day.

Q. Does the Company believe its Idaho Power Cares program has a positive impact on customers?

A. Yes. Idaho Power often receives thank you cards, emails, phone calls or social media posts from customers thanking the Company for sending them a personalized card. In doing so, the Company reaffirms to customers its commitment to them and to try and provide an exceptional customer service experience.

Q. Aside from the CSC, are there other positions within your organization that routinely engage with customers?

A. Yes. The Company has several Energy Advisors who are responsible for engaging with their respective customer segment, typically in the field, and conducting education and outreach efforts. Like CSAs, Energy Advisors assist customers with understanding their bills and promote Idaho Power's energy efficiency programs; however, they also act as energy consultants during customers' projects and help resolve any concerns that customers may have.

Q. Do you believe the initiatives and various enhancements within the Customer Operations organization have met the Company's commitment to provide superior service to its customers?

A. Yes. believe the organizational changes and technological improvements made over the last several years demonstrate Idaho Power's commitment to its customers to provide superior and satisfying service.

Q. In your opinion, should the Company's requested rate increase be viewed as reasonable based upon the Company's customer service and customer satisfaction performance?

A. Yes. By providing the Company with fair and timely recovery of its revenue requirement, the Commission will be recognizing that the Company has adequately addressed customer needs and that the Company's investments that support customer service and satisfaction have been appropriately incurred on behalf of customers.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF BO HANCHEY

I, Bo Hanchey, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Bo Hanchey. I am employed by Idaho Power Company as Vice President of Customer Operations and Chief Safety Officer.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit No. 6 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibit are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: ____________________
Bo Hanchey

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

HANCHEY, DI
TESTIMONY

EXHIBIT NO. 6

JULY • 2022

Connections

Safety is a Value at Idaho Power

We work in an industry where hazards are part of the everyday job. That's why Safety First is a core value we live by at Idaho Power. It means our employees will return home to their families in the same condition they left, and that our customers can count on us to take care of them as well.

As part of our safety culture, Idaho Power employees go through rigorous training, adhere to strict safety standards and are empowered to speak up if they notice hazards. This has led to some of our safest years on record.

This January, Idaho Power was recognized by the Edison Electric Institute (EEI) with the Thomas F. Farrell, II Safety Leadership and Innovation Award for our approach of combining psychological and behavioral safety with practical human performance principles. Put simply, we teach our employees how our brains process information and how we can use the right mindset combined with vital behaviors to perform work safely.

"I applaud Idaho Power for its leadership and commitment to protecting the health and safety of its employees. Idaho Power's continuous innovations have helped to shape health and safety education and many of the protocols used across our industry, and this award is well deserved."

~ Tom Kuhn, EEI President

We're proud of our safety record, but most importantly, we're proud of our safety culture and grateful that our employees return home safely to their families. We're also privileged to serve as a pillar of safety in our communities, whether it's helping tend to car crash victims or giving electrical safety presentations to classrooms (see below!). You can count on Idaho Power to put safety first!

We Offer Free Safety Presentations!

Did you know Idaho Power's education and outreach energy advisors work with schools and community groups to increase understanding about the energy industry, including electrical safety?

For school children (K–6), topics range from basic concepts of electricity and its safe use around the home to high-voltage safety demonstrations. For older students and adults, we offer a presentation centered on electrical safety in our communities. We can also customize sessions to suit your needs.

For more information about the presentations we offer and additional resources, visit our website at **idahopower.com/learn** or view our **Community Education Guide**. To schedule a presentation, email **learn@idahopower.com** or contact your education and outreach energy advisor.

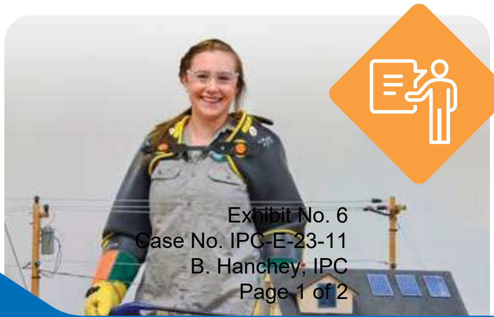


Exhibit No. 6
Case No. IPC-E-23-11
B. Hanchey, IPC
Page 1 of 2

Lee esta edición de Connections en español a idahopower.com/connections.

Comments about *Connections* are welcome at idahopower.com or Corporate Communications, P.O. Box 70, Boise, ID 83707.

31180-I-0185

Do You Know What to Do Around Downed Power Lines?

You should always assume power lines are energized and dangerous — most are. But most are also high in the air or buried underground for your safety. So, what should you do if a power line has fallen on the ground, or on your vehicle? High winds, heavy snowfall and wildfires can cause power lines to fall. So can vehicle accidents with power poles. Here's the essential information you need to stay safe.

- Stay at least 100 feet back from any downed line and keep others away as well.
- Call 911, and contact Idaho Power immediately at 208-388-2323 or 1-800-488-6151 (outside the Treasure Valley).
- Never touch a downed line or use any object to move a downed power line.
- Never remove tree limbs or other objects near or touching a downed line.
- If someone touches a downed power line, do not touch or try to rescue them. You risk becoming a victim yourself. Call 911 immediately.

If a power line falls on your vehicle:

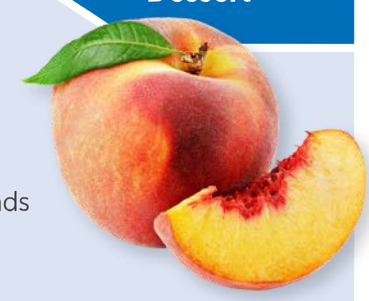
- Stay inside until help arrives, and warn others not to touch the vehicle. Call for help.
- If you must leave the vehicle because of a fire or other life-threatening situations, jump out and as far away as possible with both feet landing on the ground at the same time. Keeping your feet together, shuffle away from the scene at least 100 feet. **DO NOT** touch the vehicle and the ground at the same time. For a demonstration, watch our Downed Power Line Safety video at **idahopower.com/PowerLineSafety**.

From the Energy Efficient Kitchen

July 2022
Dessert

Peach Melba Yogurt Parfait

1½ cups Greek-style honey yogurt
1½ cups nonfat plain yogurt
3 fresh peaches, pitted and cut into bite-sized pieces
1½ cups fresh raspberries
¼ cup sliced, toasted almonds



In a medium bowl, stir together yogurts until smooth. Spoon ½ cup fresh peaches into six parfait glasses. Top each with ¼ cup yogurt mixture, ¼ cup raspberries and additional ¼ cup yogurt mixture. Garnish with sliced almonds. Makes six servings.

Recipe selected from Idaho Power's Centennial Celebration Cookbook.

How Idaho Power Keeps the Grid Safe

Ever wonder what measures Idaho Power takes to ensure the safety of the power grid and how it might affect your community? Maintaining a safe, reliable power system is at the heart of what we do every day. Here are some of the ways we strive to keep the grid safe:

- We design and build equipment to meet or exceed industry standards.
- Our personnel monitor the grid 24/7, and employees stand ready to respond anytime in the event of an emergency.
- We proactively inspect and regularly maintain our equipment using visual inspections and technology like thermal imaging, drones and helicopters.
- We replace older underground power lines and install them in more modern, safer conduit.
- We protect against wildfires by wrapping high-risk poles in mesh, clearing vegetation from around their base, and trimming trees to keep them away from power lines. We also replace or install new equipment to protect or "harden" our grid against wildfires.
- We work with emergency responders and de-energize our equipment if the need arises.

For more information on how Idaho Power protects the grid for wildfire season — and what you can do to prepare — visit **idahopower.com/wildfire**.

Exhibit No. 6
Case No. IPC-E-23-11
B. Hanchey, IPC
Page 2 of 2

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SARAH GRIFFIN

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Sarah Griffin. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as Vice President of Human Resources ("HR").

Q. Please describe your educational background.

A. I currently hold a Bachelor of Art degree in English from the University of Utah, and an Executive Master of Business Administration degree from Boise State University. I have been a member of the Society for Human Resource Management since 1997 and have held both the Professional and Senior Professional certifications, although these are no longer active. I was appointed to the Idaho Personnel Commission in 2017 and the Idaho Workforce Development Council in 2019 and have been reappointed to both positions.

Q. Please describe your work experience with Idaho Power Company.

A. I possess nearly 30 years of experience working in HR, with over 15 years of experience in the HR department at Idaho Power. Between 1996 and 2007, I served various HR roles at Delta Dental, Thoratec Corporation, and NPS Pharmaceuticals, culminating in my role as Corporate HR

Manager at Boise Cascade. I began my employment with Idaho Power in October 2007 as an HR Professional where my role was to provide guidance to leaders in managing performance, developing and delivering leader and employee training, and conducting workplace investigations. Since my initial hire, I have served in increasingly broad and expansive roles, including HR Leader, HR Manager, and Director of HR, ultimately moving into my current role of Vice President of HR in October 2019.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide justification for the labor and total compensation costs included in the Company's test year. I will describe the Company's overall compensation philosophy and explain why the level of compensation requested in this case is necessary to provide safe, reliable, affordable electricity to customers. As part of this discussion, I will also provide the justification for the requested increase in cost recovery related to the Company's pension plan, which serves as a key component of Idaho Power's overall compensation package.

Q. How is the remainder of your testimony organized?

A. My testimony consists of seven sections that address the current labor market, the components of Idaho

Power’s total compensation or “Total Rewards” package, and how those components are determined. My testimony then concludes with a summary of costs related to Total Rewards included in the Company’s filing.

- Section I: Idaho Power’s Total Rewards Philosophy
- Section II: Current Labor Market Challenges
- Section III: Base Wage Benchmarking
- Section IV: Incentive Compensation
- Section V: Benefits Benchmarking
- Section VI: Retirement Benefits
- Section VII: Total Rewards Costs in 2023 Test Year

I. IDAHO POWER’S TOTAL REWARDS PHILOSOPHY

Q. Please provide a general discussion of Idaho Power’s Total Rewards philosophy.

A. Idaho Power’s Total Rewards philosophy is to provide a balanced, competitive, and sustainable total compensation and benefits package, ensuring it attracts and retains high-quality employees and motivates them to achieve performance goals that benefit customers at a fair and just cost. Maintaining a competitive Total Rewards package allows the Company to recruit and retain a highly skilled workforce that possesses a deep knowledge and understanding of the complex energy business that builds and becomes more valuable as employees gain more experience over time. The competitiveness of Idaho Power's Total Rewards package also supports the Company's intent to maintain a flexible workforce that can easily adjust work duties and assignments to meet changing demands and operational needs. In support of this philosophy, the Company monitors its Total Rewards package, and adjusts it accordingly in order to maintain a market-competitive total compensation package.

Q. What are the components of Idaho Power's Total Rewards package?

A. The Total Rewards package is comprised of base wages and "at-risk" incentive pay, as well as competitive benefits programs including health and welfare, retirement and other benefits.

Q. How often is the Company's Total Rewards package reviewed?

A. While certain components of the Company's Total Rewards package are reviewed annually, a comprehensive benchmarking analysis that evaluates the total cost of Idaho Power's employee benefits (as a percentage of pay) as compared to peer utility companies is performed biennially. Table 1 below summarizes the frequency of review for the various components of the Company's Total Rewards package, as well as the actions that are taken based on each review. I will describe each of these review processes in greater detail later in my testimony.

Table 1: Total Rewards Review Frequency by Component

Total Rewards Component	Review Frequency	Outcome
Salary Structure	Annually	General Wage Adjustment %
Benefits Programs	Annually	Program/rate changes
Comprehensive Compensation Analysis	Continually, targeting each position every 5-7 years or less	Market adjustment, up or down

Q. How does Idaho Power analyze whether it is providing market-competitive compensation and benefits?

A. Idaho Power's compensation benchmarking process evaluates positions on an ongoing basis, with the goal of a comprehensive review occurring approximately every 5-7 years, particularly for positions that have a significant number of incumbents, to ensure that Idaho Power maintains market-competitive compensation levels and remains an employer of choice.

Q. What data sources does Idaho Power rely on for these analyses?

A. The Company uses a variety of data sources in the compensation benchmarking process. Non-exempt[1] trade positions are typically benchmarked against intermountain

[1] "Exempt" positions refer to non-hourly, salaried positions, while "non-exempt" positions are paid on an hourly basis.

utility peer contract data. The Company also participates in and purchases data from Willis Towers Watson's ("WTW") *Energy Services Middle Management, Professional and Support Compensation Survey* to benchmark management, professional exempt, office-based non-exempt, and other non-exempt support roles.

Q. What is WTW and how does Idaho Power utilize their survey data?

A. WTW is a nationally recognized HR consulting firm, and the *Energy Services Middle Management, Professional and Support Compensation Survey* is the most widely used salary survey in the utility industry. WTW also provides a biennial review of the cost to Idaho Power of providing benefits (as a percentage of pay) compared to the corresponding costs incurred by a peer group of "Energy Services" and "General Industry" companies. Benefits reviewed and benchmarked include health, retirement, and other services, including time off and disability programs. The Company utilizes WTW's *Benefits Online* survey data and benchmarking information from Idaho Power's benefits consulting firm, KPD, when reviewing benefit programs and cost.

Q. How does the Company use the Total Rewards benchmarking information to adjust employee compensation and benefit offerings?

A. The Company uses the Total Rewards benchmarking information as the basis for decision-making regarding salary structure adjustments, compensation grade levels and appropriate benefit levels, with the goal of aligning the overall employee total compensation with the market.

Q. Does the Company believe that the benchmarking review process for Total Rewards is an effective method for establishing its compensation and benefit levels?

A. Yes. The Company believes that the review process for Total Rewards has been successful in maintaining a competitive, cost-effective Total Rewards package that is in line with its industry peers, attracts and retains a quality workforce, and ensures that labor costs included in customer rates are fair, just, and reasonable.

II. CURRENT LABOR MARKET CHALLENGES

Q. Please generally describe how the labor market has changed since the Company filed its last general rate case ("GRC") in 2011.

A. The electric utility industry is changing at a rapid pace, and along with it so are the needs and expectations of Idaho Power's employees. In the past, Idaho Power's compensation and benefits program has been effective in recruiting and retaining talent. However, recently this has become more difficult, particularly for employees with specialized or high-demand skills, and the Company anticipates this trend will continue. In light of these challenges, which I will describe in more detail later in my testimony, ensuring the Company offers a competitive Total Rewards package that emphasizes long-term employment is increasingly important in order to attract and retain a high-quality workforce.

Q. What factors have caused the labor market to become more challenging since 2011?

A. Multiple factors have caused a paradigm shift in the labor market since 2011. Primary factors impacting Idaho Power have been increased competition for local workers due to remote work options resulting from the COVID-19 pandemic ("pandemic"), historic increases in housing costs in Idaho Power's service area, and the need to hire and retain talent to operate in an increasingly complex environment, exemplified by new processes such as participation in the Energy Imbalance Market ("EIM") and more sophisticated resource modeling and planning within the integrated resource planning ("IRP") process.

Q. How did the pandemic impact the ability to attract and retain qualified employees?

A. Due to mandatory remote working conditions that resulted from the pandemic, many companies throughout the world transitioned to a higher percentage of full remote or hybrid remote job offerings. While certain hands-on positions were less impacted by this change, many in-office positions in the Company saw a paradigm shift in the labor market, which directly impacts Idaho Power's ability to attract and retain high-quality employees.

Rather than competing strictly in the local job markets, Idaho Power is now competing for employees with any company throughout the world that offers the ability to work remotely, many of whom are paying wage rates that are much higher and often reflective of those offered in much larger cities. This impact – most acutely felt by Information Technology ("IT") and Cyber Security positions – comes at a time when technology and security have grown increasingly complex.

Q. Has Idaho Power's workforce changed over the last decade with respect to age and proximity to retirement?

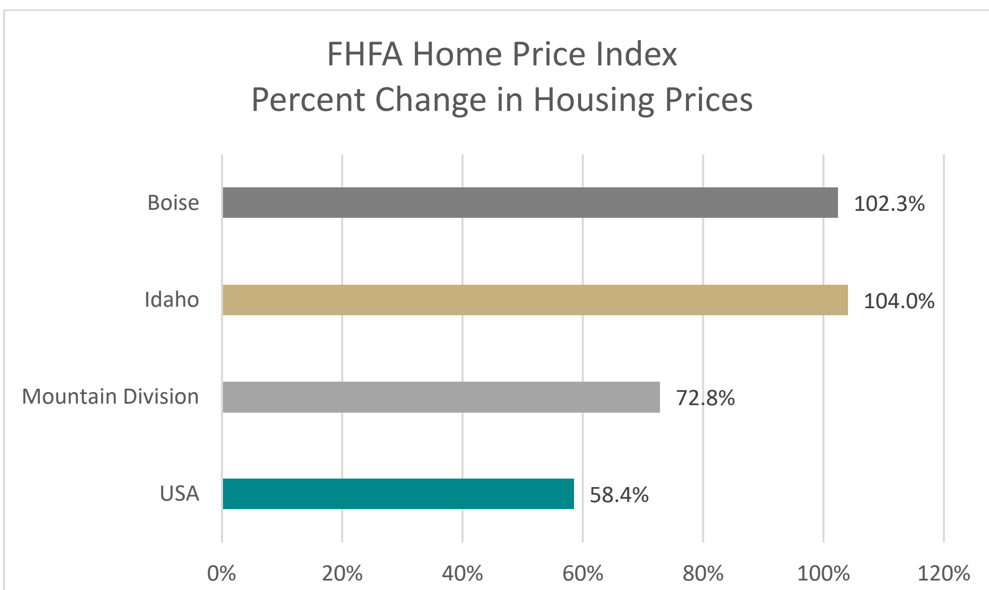
A. Yes. At the time of the Company's last GRC, as of December 31, 2011, approximately 39 percent of employees were eligible to retire within five years while 43 percent of employees had fewer than 10 years of service. As of April 2023, the Company now has approximately 30 percent eligible to retire within five years while more than half of the Company's employees have fewer than 10 years of service.

Q. How have housing costs in Idaho changed since the Company filed its last GRC in 2011?

A. According to the most recent House Price Index ("HPI") Quarterly Report (Q4 2022) issued by the Federal Housing Financing Agency ("FHFA"), Idaho leads the nation in the five-year increase in housing prices, as demonstrated in Figure 1 below. These elevated housing prices serve as an additional hurdle to hiring employees who do not currently reside within the area.

Figure 1.

Home Price Index Percent Changes, Q4 2022



Q. How do higher housing costs impact Idaho Power's ability to hire quality candidates?

A. For candidates external to Idaho Power's service area, housing costs serve as a key decision point when evaluating whether to accept a job offer. While Idaho Power prefers to and focuses on hiring locally, many specialized positions require broader recruiting sources, especially in light of the recruiting challenges detailed previously in my testimony. Where Idaho Power was historically able to market Idaho as high quality-of-life and low cost-of-living compared to other states, the historic increase in housing costs has degraded the Company's ability to market Idaho as low cost-of-living.

Q. How have changes in the electric utility industry resulted in the need to hire and retain specialized talent since the Company's last general rate case?

A. As discussed further in the Direct Testimony of Company Witness Ms. Lisa Grow, Idaho Power's business has become increasingly complex for a number of reasons, including unprecedented customer growth and changing technology that requires talented, long-term employees to operate and maintain. While I am not the Company's technical expert in these areas, from an HR perspective, implementing and maintaining initiatives such as participation in the EIM, the development of long-term capacity expansion modeling for IRP and resource procurement purposes, and complex billing procedures for increasingly prominent technologies such as rooftop solar all impact Idaho Power's labor needs.

Q. How have the challenges you described impacted Idaho Power's labor recruitment and retention?

A. The challenges above have led to increased difficulty in hiring and retaining employees, as evidenced by the Company's time-to-fill open positions, the size of qualified applicant pools, and the Company's employee turnover rates.

Q. What does the time-to-fill metric measure?

A. Time-to-fill measures the number of days it takes to fill an open position, from the date a job requisition is posted to the date a new hire accepts the position.

Q. How have Idaho Power's time-to-fill open positions and the size of qualified applicant pools changed in recent years?

A. The Company has experienced longer hiring times in recent years, with a time-to-fill rate increasing from an average of 38 days in 2019 to 43 days in 2022. Although this change may appear small, the compounded effects of a longer time-to-fill rate and smaller candidate pools for job postings have impacted Idaho Power's ability to hire qualified candidates in a timely manner.

Q. Can you provide some examples of the smaller candidate pools for job postings, as indicated in the previous response?

A. Yes. For example, Idaho Power's external Journeyman Lineworker postings received an average of 22 applicants in 2020 compared to fewer than six in 2022. For more technical positions, this decrease has been even more dramatic. The System Administrator positions that were posted in 2020 had an average candidate pool size of 73, while the same position posted in 2022 had an average candidate pool size of fewer than nine. Further, Engineer postings averaged over 50 candidates in 2020 compared to fewer than 20 in 2022

Q. Are these hiring challenges unique to Idaho Power?

A. No. In an article dated May 11, 2023, the Idaho Press reported that the City of Boise is experiencing similar hiring challenges and has a 10 percent vacancy rate. The article further states that "in Idaho, there are 1.5 jobs per each available person."[2]

Q. How has increased scarcity in candidate pools impacted Idaho Power?

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[2] 'Has not resolved itself': City of Boise still facing job vacancies | Local News | idahopress.com

A. Due to relatively limited candidate pools, the Company has had to resort to hiring at an entry level for many professional positions where someone with more experience is needed to fill the position but there are no or a limited number of candidates. This has particularly been the case for technical positions where there were not sufficient qualified applicants or the salary requirements of qualified applicants could not be met. This results in additional training resources and time to get candidates up to speed in the position and makes retention of these workers even more critical as they gain valuable knowledge and experience. This further supports the need to emphasize long-term retention in the Company's Total Rewards package, exemplified by the structure of the Company's defined benefit pension plan.

Q. How has the Company's turnover rate changed as a result of the current labor market?

A. The labor market forces detailed above have resulted in increased turnover rates in recent years. The overall voluntary turnover rate, which includes both regular voluntary terminations and retirements, increased by 49 percent from 2012 to 2022. The Company's voluntary turnover rate (excluding retirements) as of December 31, 2022 nearly doubled compared to prior to 2020. According to exit interview data, 48 percent of these employees left the

Company for more pay and/or additional advancement opportunities. Furthermore, these statistics are not unique to Idaho Power. Within the Idaho Press article referenced previously, the City of Boise HR Director Sarah Borden stated that last January "45 percent of non-retirees said that either compensation or cost of living was driving them to make this decision (to leave)."[3]

Q. Has Idaho Power experienced a corresponding increase in declined job offers?

A. Yes. The number of declined offers more than tripled from 2020 to 2022. The majority of these declined offers were situations where either salary requirements could not be met or there were competing offers that were beyond what the Company could provide.

Q. How has Idaho Power responded to the changing labor market and the challenges it presents?

A. In light of these challenges, Idaho Power has modified its recruiting approach with the ultimate goal of attracting and retaining a talented workforce while keeping costs low for customers. First, where Idaho Power formerly was able to rely solely on local sources for its job postings, the Company has expanded its use of nationwide job boards to help promote and target qualified candidates and has attempted to source candidates through resumé

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[3] *Id.*

databases. Additionally, in the post-pandemic era in which many job seekers prioritize remote work opportunities, Idaho Power began offering hybrid work options for qualified positions.

Q. How do these challenges impact the Company's Total Rewards philosophy?

A. Given these challenges, now more than ever, offering an attractive Total Rewards package is crucial not only for the hiring of high-quality employees, but for the retention of employees as well. It is vital that Idaho Power's Total Rewards package can attract quality employees who will serve as long-term productive members of the Company's workforce. Given challenges in hiring, it is even more crucial that the Company's Total Rewards package incents long-term employment, highlighting the need for the Company's defined benefit pension plan that I will detail later in my testimony. In its entirety, the setting of a competitive Total Rewards package is crucial to the ability of Idaho Power to cost-effectively maintain safe and reliable service. Each component of the Total Rewards package - Base Wages, Incentive Pay, Benefits, and Pension – will be detailed in Sections III through VI of my testimony, respectively.

III. BASE WAGE BENCHMARKING

Q. What are base wages?

A. Base wages are the base level compensation an employee receives as part of the Company’s Total Rewards. For non-exempt employees, base wages are determined by an hourly wage applied to hours worked, while for exempt employees base wages reflect the employee’s annual base salary.

Q. How does Idaho Power determine the market-based pay structure for a job?

A. Base compensation is established when a job is created using peer utility wage data obtained from salary surveys and union contracts, along with similar internal positions already matched to market data. These reviews typically involve at least three years of wage data to ensure that compensation trends are considered and to prevent frequent changes to position wages based on one to two years of data.

In addition to market survey data, the job evaluation process includes a review of the basic education and experience requirements, physical requirements, and behavioral competencies for the position. This proactive, comprehensive review ensures the Company has accurate, competitive, and safe job requirements and descriptions.

Q. Please describe the standard the Company uses to set base wages.

A. The Company has a grade and step pay system. The highest step in any grade is step 13. Each position is assigned a grade as reflective of the market, and the Company standard for remaining competitive is to set the step 13 pay of each grade to be approximately equal to the median pay for a comparable position in the peer-compared market. Targeting the median of market pay is a compensation-setting best practice. It is a conservative approach that allows Idaho Power to manage costs while ensuring the Company is able to provide competitive pay within the grade and step system.

Q. How does Idaho Power ensure its base wages do not exceed the market median over time?

A. On an annual basis, the Company reviews a variety of data to determine the appropriate General Wage Adjustment ("GWA") to remain competitive. The Company reviews market survey data from WTW and peer utility contracts, the Consumer Price Index ("CPI"), and other economic data that ultimately informs the recommendation to the Board of Directors for the Company's GWA. On a longer-term basis, Idaho Power performs a comprehensive job review for individual positions to ensure base wages are competitive and appropriate relative to market.

Q. Has the Company's job review process evolved since the last GRC?

A. Yes. The Company's 2011 base wage and total compensation benchmarking analysis focused on five specific positions.[4] The information and resulting decisions regarding compensation levels were then used to inform decisions for a broader set of jobs with similar functions referred to as a job category or "job family."[5]

In 2017, the Company developed a process to expand this review from five specific positions and their associated "job family" to performing a review of all jobs on an ongoing proactive basis. This is in addition to the practice of reviewing jobs when there are significant changes in job responsibilities or market conditions resulting in challenges for the Company in recruiting and/or retaining the talent necessary to provide safe, reliable, and affordable energy to customers.

Q. Please generally describe the current job review process.

A. Positions are evaluated using market data from third-party salary surveys, primarily from WTW. The Company relies on data specific to the energy services industry, with a focus on information from companies with comparable levels of annual revenue and regulation. Where appropriate,

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[4] These five positions represented approximately 11 percent of the total employees at Idaho Power in 2011 and 2012.

[5] The combined number of employees in each of the selected jobs represented approximately 22 percent of the total workforce in 2011 and 2012.

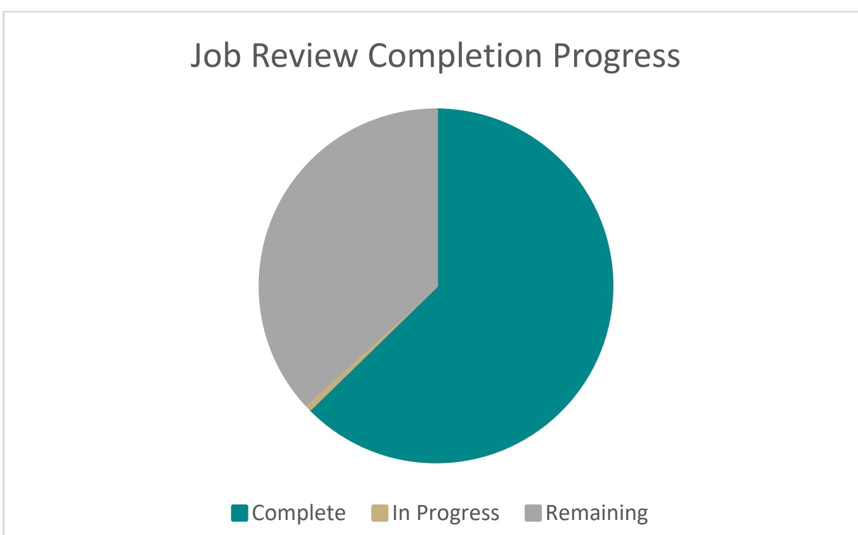
peer utility contracts are also reviewed along with similar internal positions. The Company also reviews job postings of peer utilities.

Q. Has the Company made progress in reviewing all jobs at Idaho Power using this job review process?

A. Yes. While the job review process slowed in 2020 due to the impact of the pandemic on the Company's workforce and HR staff, Idaho Power is currently progressing through its full review of all positions within the Company. The table below shows the number of jobs that have been reviewed since implementing this new process in 2017. When this program was implemented, the Company focused first on jobs with the highest number of incumbents, rather than smaller or single incumbent positions.

Figure 2.

Job Review Completion Progress, 2017 - Current



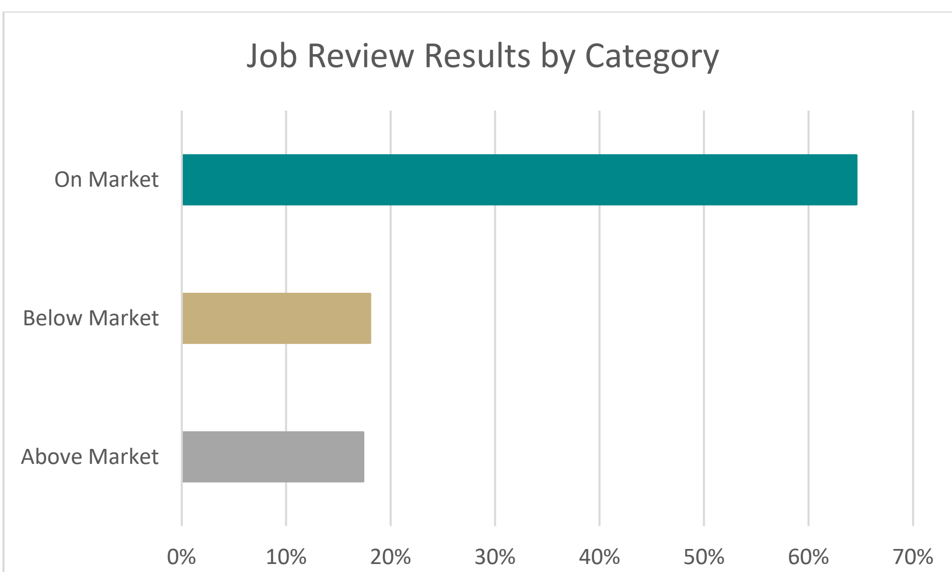
As of 2023, there are 665 total distinct jobs in the Company. Of those, reviews for 417 are complete, 4 are in progress, and 244 remain.

Q. What changes have occurred as a result of the Company's broader job review?

A. As shown in the chart below, the majority of the jobs reviewed were on-market, indicating that Idaho Power's wage-setting process is functioning as intended. For jobs that were found to be above market, employees are placed into a reduction-in-grade program that brings them into alignment with the lower rate of the new reduced grade of the position. When positions are determined to be below market, the incumbents are generally moved to the equivalent step of the position's new grade.

Figure 3.

Comprehensive Job Review Results by Category



Q. What has been the recent trend for wages and salaries in the marketplace?

A. Data indicates that wages and salaries are generally increasing in the marketplace. The Company reviews several factors to determine appropriate increases based on what is trending in the market, including salary budget surveys, union contract negotiations, and cost-of-living and economic factors.

Q. Have you observed any recent trends in salary budget surveys and union contract negotiations?

A. Yes. Recent salary survey projections for merit and salary structure movement showed an increase over prior years. Union contract annual adjustments, as well as market adjustments for many positions were negotiated at an all-time high, with several peer utilities granting increases in the double digits for certain roles. As shown in Table 2 below, first year contract wage increases for lineman ranged from 7-18 percent.

Table 2: Peer Utility Wage Increases for Lineman

Northwest Peer Utilities	Old Hourly Rate [1,2]	New Hourly Rate[1,3]	% of Increase
Avista	$48.63	$55.39	13.90%
Northwestern	$48.24	$51.94	7.70%
NV Energy	$52.38	$62.18	18.70%
Pacific Power	$48.91	$56.03	14.60%
Rocky Mountain Power	$49.29	$54.40	10.40%

1) All data collected from publicly available job postings or union contracts
2) Hourly rate effective final year of old union contract
3) Hourly rate effective first year of new union contract

Q. Have you observed any changes in cost-of-living and economic factors impacting employee compensation?

A. With respect to cost-of-living and economic factors, CPI indicates a continued upward trend through 2022, as indicated in Table 3 below, with inflation spiking in 2021 and 2022 relative to prior years. In 2022 alone, CPI in the Mountain Division CPI-U ("Urban") increased 9.6 percent.

Table 3: Consumer Price Index, 2018–2022

Consumer Price Index – CPI-U (12 mo. Change through September)	2018	2019	2020	2021	2022	Average
US City Average	2.30%	1.70%	1.40%	5.40%	8.20%	3.80%
West (Includes AK, AZ, CA, CO, HI, ID, MT, NV, NM, OR, UT, WA, WY)	3.40%	2.60%	1.60%	5.30%	8.30%	4.20%
West - Size Class B/C (2.5 million or less)	2.80%	2.30%	2.00%	5.70%	8.30%	4.20%
Mountain Division (Includes AZ, CO, ID, MT, NV, NM, UT, WY)	n/a	2.90%	1.80%	6.00%	9.60%	5.10%

As discussed earlier in my testimony, housing prices have increased at a historic rate in Idaho. This is further evidenced in Table 4 below, which shows a 37.06 percent increase in housing costs in 2021, and a 19.13 percent increase in 2022.

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Table 4: Home Price Index, 2018-2022

Home Price Index	2018	2019	2020	2021	2022
National	6.50%	5.10%	6.10%	18.80%	17.67%
Mountain Division (AZ, CO, ID, MT, NV, NM, UT, WY)	9.60%	5.90%	7.90%	25.50%	21.36%
Idaho	13.05%	11.40%	10.78%	37.06%	19.13%
Boise	16.59%	13.60%	11.25%	41.11%	15.00%

Source: Federal Housing Finance Agency (12 Mo. Change Through Q2 2022)

Q. What is the result of the Company's general wage benchmarking process in light of these recent trends, and how does this impact the base wage levels reflected in the Company's filing?

A. Since the filing of the Company's last GRC, Idaho Power has adjusted base wages through annual GWAs, as well as the comprehensive job review process described previously in my testimony. This approach ensures that the Company's base wages are regularly reviewed, resulting in competitive market-based rates that effectively balance Idaho Power's ability to attract and retain a quality workforce while keeping costs low for customers. Idaho Power's annual GWA process has assisted the Company in keeping pace with recent market trends, while the position-by-position review has indicated that Idaho Power's base wages are competitive relative to market for the majority of positions.

As shown in the Figure 3 above, for a small proportion of reviewed positions, up or down adjustments have been applied in the event the comprehensive review indicated an adjustment was warranted. The graph also shows that the number of positions that experienced wage decreases is very similar to the number of positions that experienced wage increases, indicating that on average the Company’s benchmarking process is functioning as intended.

This process, combined with the market forces described earlier in my testimony, results in total operations and maintenance (“O&M”) base wage costs included in the 2023 test year of $133.7 million. Company Witness Mr. Matthew Larkin discusses the 2023 test year O&M labor forecast in more detail in his testimony.

IV. INCENTIVE COMPENSATION

Q. What is incentive pay?

A. Incentive pay is an “at-risk” part of Idaho Power’s Total Rewards package that is awarded based on performance goals established by the Compensation Committee of the Company’s Board of Directors. Unlike base pay, which is guaranteed, incentive pay will not be paid unless the Company’s performance meets or exceeds predetermined metrics.

Q. How is Idaho Power’s incentive pay designed?

A. Idaho Power’s incentive plan consists of three components: 1) an electrical network reliability goal, 2) a customer satisfaction goal, and 3) a profit-sharing goal based on net income. The intent of the plan is to focus on key areas where employees can have an impact.

Q. Please generally describe the incentive metrics.

A. The three metrics are intended to motivate employee performance in ways that positively impact customers. The network reliability goal considers the frequency and duration of customer outages. The customer satisfaction goal is based on the 12-month average of the customer relationship index ("CRI"), which details the Company's performance through the eyes of the customer. The CRI consists of five specific questions asked of Idaho Power's customers by an independent survey company and addresses issues such as overall satisfaction, quality, value, advocacy, and loyalty. The profit-sharing component is based on achievement against financial targets, motivating employees to work toward the financial health of Idaho Power, which is necessary to provide safe, reliable, and affordable service.

Each component has an identified threshold, target, and maximum, or in other words, a low, medium, and high level of payout based on actual results compared to predetermined metrics. The payout levels are set each year by the Board of Directors to ensure they continue to stretch employee performance in service of customers.

Q. Which components of the Company’s incentive plan are included in the Company’s 2023 test year?

A. Consistent with prior Commission direction,[6] Idaho Power has only included the components of incentive pay that the Commission has determined are directly related to identifiable customer benefits, which in this case are network reliability and customer satisfaction. These components are included in the test year at the 2 percent target (medium) incentive level. Idaho Power has excluded any costs related to the profit-sharing component.

Q. Has Idaho Power excluded any other components of its incentive pay from its request in this case?

A. Yes. Idaho Power has excluded executive incentive pay. This is consistent with Commission treatment of these costs in prior ratemaking proceedings.

Q. What is the Company requesting in this case with regard to incentive-related costs?

A. As discussed by Mr. Larkin, incentive pay totaling $10.2 million related to the customer satisfaction and reliability components is included in the 2023 test year.

V. BENEFITS BENCHMARKING

Q. What is Idaho Power’s benefits strategy?

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[6] IPC-E-08-10, Order No. 30722 at 17.

A. Idaho Power strives to offer its employees a comprehensive and competitive package of health and welfare, retirement, and insurance benefits programs. As with base compensation and at-risk pay, it is important for the Company to offer a cost-competitive benefits package with features that address the needs of employees and is sufficient to attract and retain well-qualified and skilled employees. As discussed previously in my testimony, benefits that incent long-term employment are crucial in today's environment.

Q. What are the major components of Idaho Power's benefits package?

A. Major components of Idaho Power's benefits package include health and welfare benefits (medical, prescription, dental, and vision programs), other benefits (disability, life insurance, and flexible time off), and retirement benefits.

Q. Does Idaho Power benchmark its total benefits and compare overall benefit costs?

A. Yes. The Company monitors its benefit programs on an ongoing basis to ensure the appropriate balance between benefit cost and maintaining a competitive position in the market.

Q. What is Idaho Power's annual benefits benchmark review process?

A. On an annual basis, Idaho Power utilizes benchmarking data from WTW's Benefits Online and the *Health Care Financial Report*, KPD's regional and national survey data, and peer utility contracts to address the Company's benefit plan's overall cost, offerings, and market competitiveness. For example, medical, dental, and vision premiums are evaluated and generally adjusted each year. Further, the medical plan's cost-sharing balance target is 20 percent employee and 80 percent employer (which is competitive with peer utilities) and annual rates are evaluated and adjusted to align with this target percentage. The results of this review are presented annually to the Board of Directors Compensation Committee and are generally implemented the following year.

Q. How does Idaho Power benchmark longer-term benefits?

A. Every other year, Idaho Power participates in WTW's Energy Services "BENVAL" Study. BENVAL is a comparison of benefit values among peer utilities with similar revenues. BENVAL provides a complete competitive analysis of the value of a benefit program, including a comparison of the Company's benefit plan against utility companies of similar sizes. Benefit plan design that affects medical costs can vary greatly, so BENVAL gathers all relevant information related to a company's healthcare and other benefit plan offerings in order to accurately benchmark them against other peers. For consistency of comparison, the results of the study are typically presented as benefits costs as a percentage of pay.

In addition to the Energy Services BENVAL study, the Company also contracts WTW to create a custom BENVAL study that uses all industry survey data and provides an in-depth peer utility comparison of the Company's health and welfare and retirement benefits design. This information is included in the Company's analysis of its Total Rewards package and is provided to Idaho Power's Board of Directors Compensation Committee. The results of this report are used to broadly evaluate the total value and cost of the Company's benefits and market competitiveness.

Q. What is Idaho Power's peer group in the BENVAL study?

A. Idaho Power's BENVAL peer group consists of upwards of 34 similarly situated energy services companies across the nation, as well as a subset of utility companies of similar size. In 2021, there were 663 All Industry companies included in the analysis, as detailed in Table 5 below.

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Table 5: BENVAL Survey Participant Composition, 2017-2021

Year	All Industry	Energy
2017	460	41
2019	469	34
2021	663	34

Q. According to the most recent BENVAL study, how do Idaho Power's total benefit costs compare to its energy peer group?

A. As can be seen in Figure 4 below, the value of Idaho Power's total benefits package (health, retirement, and other benefits) for the most recent studies show that Idaho Power's benefit ratio to pay is 36.3 percent while the Company's peers are 35.9 percent -- relatively the same total benefit ratio. It is important to note that Idaho Power manages its benefits package as a whole and the BENVAL survey is a useful tool that ensures that the Company's combined benefit offerings as a percent of pay remain at market even though each component may differ in the peer group. As can be seen in the chart below, Idaho Power's benefit costs as a percentage of pay are generally consistent with the energy industry.

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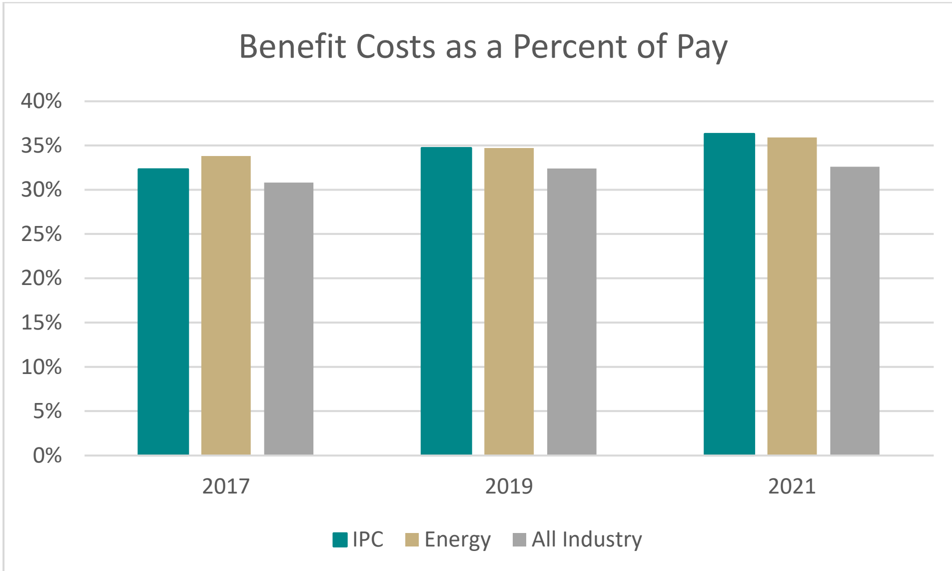
Figure 4.

Composite BENVAL Results: 2017, 2019, 2021



Q. What benefit cost trends can be seen from the recent BENVAL survey results?

A. A review of the data from the 2017, 2019, and 2021 studies shows that total benefit costs are rising across the board. As indicated in the prior figure, percentage of pay has increased between surveys from 2017, 2019, and 2021. These trends, coupled with the increase in CPI and overall wages discussed earlier in my testimony, indicate that the costs of maintaining a market-competitive benefits package are increasing over time.

Q. What has been the Company's approach to managing rising health and welfare care costs?

A. The Company is continually evaluating trends and actively working with KPD and associated third-party administrators on strategies to manage overall healthcare costs. These strategies include prescription benefits and formularies, conservative care strategies, case management, medical policy review, and telemedicine. In addition, there is ongoing vendor evaluation and management to ensure the Company is getting the best service at the lowest cost.

Q. Given the upward pressure on health and other benefit costs, what is Idaho Power doing to ensure its total benefit costs remain in line with the market?

A. The Company continues to benchmark benefit program offerings and costs on an annual basis to ensure its offerings remain in line with market.

Q. Are there any final conclusions that can be drawn from the benefits benchmarking information you have provided?

A. Yes. As demonstrated by the BENVAL results provided in my testimony, Idaho Power’s total benefits offered as a percentage of pay are in line with the peer utilities, indicating the Company’s benefits package and its underlying benchmarking process are functioning as intended. Additionally, given the labor market challenges discussed throughout my testimony, Idaho Power believes it is prudent to more heavily weight its benefits package toward components that incent long-term employment (i.e., retirement benefits). In light of recent trends in rising costs, Idaho Power has actively managed the costs of its benefit programs while simultaneously ensuring its offerings are competitive, to support the hiring and retention of long-term, quality employees.

Q. What is the Company requesting in this case with regard to benefits-related costs?

A. The O&M benefits-related costs (excluding pension) included in the 2023 test year are approximately $68.1 million.

VI. <u>RETIREMENT BENEFITS</u>

Q. What are the components of the Company's retirement benefits package?

A. The Company's retirement benefits package includes three components: (1) a defined contribution or 401(k) benefit plan, (2) a defined benefit (pension) plan, and (3) a retiree medical benefit plan.

Q. Why are retirement benefits important?

A. The retirement benefits package is a significant part of the overall Total Rewards desired by employees that have a long-term view of their employment future. As discussed earlier in my testimony, changes in the labor market have made the hiring of quality, experienced employees more difficult, which is exacerbated by the shift to a younger, more transient workforce.

Because of this, retirement benefits that encourage long-term employment are more important than ever.

Consistent with the high value the electric industry places on long-term planning and reliability, Idaho Power likewise values employees with a long-term perspective as part of its highly skilled workforce. In structuring a retirement benefits package as part of its Total Rewards, the Company strives to have a competitive package that supports employees' financial needs in retirement while appropriately sharing market risk between the Company and its retirees.

Q. What is the Company requesting in this case with respect to defined benefit pension plan expense?

A. As discussed further in Mr. Larkin’s testimony, the Company seeks approval of $35 million of Idaho jurisdictional pension cost amortization.

Q. Why is the defined benefit plan so important to the Company and its employees?

A. The Company has placed additional weight in its Total Rewards package on the defined benefit plan because it rewards and incents longevity, which in turn facilitates reduced employee development costs due to the retention of knowledge and expertise. As a result, the Company is able to better maintain the needed skilled workforce with less time and expense incurred for training and developing new employees.

Q. What changes have been made to Idaho Power's retirement plans?

A. The Company's retirement benefits package has evolved over the years. Prior to 1984, the Company had just two components to its retirement benefits package: (1) a defined benefit plan, and (2) a retiree medical benefit plan.

In 1984, the Company adjusted the overall retirement benefits package to include the third component of a 401(k) benefit plan. With the addition of this component in 1984 and adjustment to the other components, the Company has shifted portions of the overall package cost and benefit risks to retirees in order to maintain a competitive risk sharing balance between the Company and retirees. Simultaneously with the inclusion of a 401(k) component of the retirement benefits package, the Company eliminated cost of living adjustments as part of its defined benefit component, thus shifting inflationary market risk to retirees.

In 1999, the Company further reduced its inflationary market risk by: (1) capping the Company contribution expenditures toward retiree medical plan costs for employees hired prior to 1999, and (2) eliminating

Company contributions toward retiree medical plan costs for employees hired in or after 1999.

In 2010, the Company reduced the current defined benefit percentage factor for employees hired on or after January 1, 2011, to 1.2 percent per year from the previous factor of 1.5 percent per year.

Q. Why does the Company continue to offer a defined benefit plan when many of its peers have closed their defined benefit plan offerings to new entrants and transitioned to alternative retirement plan options such as enhanced defined contribution plans or 401(k) plans?

A. On an ongoing basis, the Company considers alternatives that could provide similar retiree benefits, including retention incentives, but continues to find the defined benefit plan is the least-cost way to provide retirement benefits as part of the Company’s Total Rewards package for employees, which I will address in more detail later in my testimony. The Company also believes the defined benefit plan rewards and incents longevity, which in turn facilitates retention of essential knowledge and expertise in the Company’s employees and reduces development and training costs due to turnover, ultimately resulting in savings for customers.

Q. Why does the Company's defined benefit plan better promote retention relative to a defined contribution plan?

A. When an employee separates from the Company before retirement, the defined benefit is frozen and the former employee will not earn any additional benefit from the plan, nor will the value of the earned benefits continue to grow. For a defined contribution plan such as an enhanced 401(k), the result for an employee who separates from the Company before retirement is the opposite of the Company's defined benefit plan. The growth of a former employee's 401(k) benefit for work already performed is unaffected by whether they stay with the Company.

To state the distinction between the two plans more concisely: a defined pension participant's already-earned benefits only grow due to staying with the Company and do not grow after separation, while a 401(k) participant's already-earned benefits at separation from the Company will grow at the same amount as they would have if they had continued employment with the Company due to the growth in the underlying investments. Due to these differences, only the Company's defined pension plan provides an incentive to remain employed at Idaho Power.

Q. How do defined contribution and defined benefit plans differ with regard to plan costs if employees choose to separate from Idaho Power within the first five years of employment?

A. Under Idaho Power's defined benefit plan, if an employee separates before they reach five full years of service they will not be vested in the plan and the separated employee will leave the Company with no pension benefits, which ultimately results in no cost to customers. The highest voluntary turnover rate at Idaho Power is the 0-to-5-year group, which results in lower costs for customers from the defined benefit plan compared to other options. Alternately, a defined contribution plan is portable and is required to vest more quickly, so an employee separating from the Company essentially owns the investments, including any Company contribution once vested. Therefore, this would result in higher costs to customers compared to the defined benefit plan if the employee chooses to separate from the Company.

To compound this issue, as previously stated in my testimony, there is less incentive to stay with Idaho Power under the defined contribution plan because at the time of separation the investment will continue to grow over time, which matches the pattern that would occur if the employee were to remain employed by the Company. So, under the defined contribution plan, there is less incentive for an employee to stay with Idaho Power long-term, while there is more potential harm to customers in terms of elevated labor costs if the employee chooses to separate within five years of service.

Q. Does offering a defined benefit plan cause additional costs for Idaho Power's customers compared to a defined contribution plan?

A. No – the opposite is true. Over the career of an employee, the cost for providing a defined contribution benefit that is roughly the equivalent of a defined benefit plan is more expensive.

Q. Has Idaho Power procured an analysis that details the comparative long-term costs and benefits of these plans?

A. Yes. Idaho Power asked its third-party actuary, Milliman, to prepare an analysis comparing one of Idaho Power's Northwest regional peer's recently negotiated retiree benefit program with its union. Under this plan, the utility will offer new hires after December 31, 2023, an enhanced defined contribution plan that roughly provides the equivalent income replacement to Idaho Power's current 1.2 percent defined benefit plan and defined contribution plan to those that work at the company until age 65. The results of this analysis show the financial cost over the career of a new employee to be roughly 40 percent higher under the enhanced 401(k) plan to provide for the same level of benefits as shown in the following table.

Table 6: Employer Cost for Benefit Plans – as a percentage of total pay (salary + bonus)

	Idaho Power	NW Peer Utility
Defined Benefit (1.2% Formula)	6.1%	N/A
Matching Defined Contribution	3.9%	5.6%
Guaranteed Defined Contribution	N/A	8.4%
Total	10.0%	14.0%
Age 65 Replacement Ratio*	52.0%	53.0%

* Based on a hire age of 32, bonus percentage of 6%, and defined contribution investment returns of 6.5% pre-retirement and 5% post retirement

Q. Did Idaho Power Perform any analysis in addition to Milliman’s enhanced 401(k) plan comparison?

A. Yes. In addition to the enhanced 401(k) plan comparison, Idaho Power asked Milliman to re-perform a similar analysis but with actual data as presented in the Company’s last pension-related case (Case No. IPC-E-10-25). The analysis provided by the Company in that case indicated that under a range of economic conditions and investment return scenarios that could occur over a nine-year period, the Company’s defined pension plan was the lowest cost retirement plan option relative to a defined contribution plan. After reviewing this analysis, the Commission accepted Idaho Power’s 2011 retirement benefits package in Order No. 32239.

To refresh this analysis, Milliman evaluated all new employees hired after Idaho Power reduced the defined benefit percentage factor for employees hired on or after January 1, 2011, to 1.2 percent per year from the previous factor of 1.5 percent. Milliman compared the costs incurred for those employees for the Company’s current defined benefit plan to a defined contribution plan that provides the same estimated income replacement for employees that work at Idaho Power until retirement, with the goal of resulting in the same total retirement benefits for each of those employees hired from January 1, 2011, through December 31, 2022.

Q. What was the result of the analysis performed by Milliman?

A. Looking at actual Idaho Power employees that were hired on or after January 1, 2011, through December 31, 2022, the current defined benefit plan saved an estimated $36 million in required contributions when compared to the modeled cost of the defined contribution plan.

Q. What are the primary reasons for these cost savings?

A. There are two primary reasons for the difference: 1) asset returns, and 2) differences in termination benefits.

Q. How did expected asset returns differ between defined benefit and defined contribution plans?

A. The asset return for the defined benefit plan was assumed to be 7.4 percent, while the defined contribution plan was assumed to earn 6.5 percent during employment and 5 percent during retirement. The defined benefit plan is professionally managed with access to a larger universe of investments, including private illiquid investments that cannot be utilized in a defined contribution plan.

In addition, the defined benefit plan can consistently invest for the long-term, resulting in a higher expected long-term rate of return, whereas a defined contribution participant typically chooses to de-risk their investments prior to retirement to avoid short-term market risk. Participants, therefore, typically respond by reducing risk and earnings potential while leading up to and living in retirement. This reduced earnings potential reduces the efficiency of a defined contribution plan as compared with a defined benefit plan and also increases costs to customers. In addition, the defined contribution participant does not have the benefit of sharing longevity risk with all of the other plan participants, so participants will need to save more money prior to retirement.

Q. How do differences in termination benefits cause the defined benefit plan to be less expensive?

A. In Idaho Power's defined benefit plan, employees are not vested in their benefit until they work a full five years with the Company. Defined contribution plans are required by law to have faster vesting schedules. For the comparison prepared for Idaho Power, Milliman used a three-year vesting assumption, which is the maximum cliff vesting allowed by law for a defined contribution plan.

The Milliman study confirmed what the Company testified would happen in 2010[7] and also validated the conclusions reached by the Commission in Order No. 32239. This study confirms that defined contribution plans are more expensive than defined benefit plans in achieving similar levels of benefits. As demonstrated by the Milliman studies, Idaho Power's defined benefit pension plan will continue to save customers money going forward compared to an enhanced defined contribution plan.

Q. What is the requested level of cost recovery associated with pension expense in this case?

A. Mr. Larkin quantifies and details the requested level of pension-related cost recovery at $35 million.

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[7] *Id.*

Q. Do you believe the Company's current defined benefit plan is in the best interest of the Company, its employees, and customers?

A. Yes. Idaho Power's defined benefit plan serves as a key component of its Total Rewards package. As discussed throughout my testimony, labor recruitment and retention has experienced significant challenges in recent years, and these trends are expected to continue. A defined benefit plan that not only rewards employees at an appropriate level, but does so while encouraging long-term employment, benefits the Company and customers through the retention of a highly skilled workforce and avoided costs associated with hiring, onboarding, and training.

VII. TOTAL REWARDS COSTS IN 2023 TEST YEAR

Q. What are the expected Total Reward costs for the 2023 test year?

A. As shown in Table 7 below, the cost for the Company's Total Rewards in the 2023 test year is approximately $247.2 million. This is comprised of $133.7 million in O&M wages, $68.1 million for O&M benefits, $10.2 million for incentive, and $35.2 million for pension. The test year labor costs are discussed more fully in Mr. Larkin's testimony.

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Table 7: Total Reward Costs – 2023 Test Year

Total Reward Component	2023 Test Year	
O&M Wages*	$	133.7
O&M Benefits*	$	68.1
Incentive	$	10.2
Pension	$	35.2
Total	$	247.2

* Includes DSM wages and benefits

Q. What has the Company done to manage its Total Rewards costs since the last GRC?

A. As discussed in the testimony of Ms. Grow, the Company manages its labor budget carefully, requiring the vice president responsible for each business unit to approve of unbudgeted positions. This careful management of labor costs is evidenced by the fact that even with adding approximately 117,000 customers between 2012 and 2022, employee headcount has decreased by a total of 17 people over the same period.

Furthermore, the Company actively manages labor costs by benchmarking each component of its Total Rewards package to make sure it is competitive with the market and makes adjustments when necessary, while balancing its Total Rewards package to ensure it can attract and retain high-quality employees and motivate them to achieve performance goals that benefit customers and shareholders.

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Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF SARAH GRIFFIN

I, Sarah Griffin, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Sarah Griffin. I am employed by Idaho Power Company as Vice President of Human Resources.

2. To the best of my knowledge, my pre-filed direct testimony is true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: Sarah Griffin ____________________
Sarah Griffin

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	)	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

ADRIEN M. MCKENZIE, CFA

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am President of Financial Concepts and Applications, Inc. ("FINCAP"), a firm providing financial, economic, and policy consulting services to business and government.

Q. Please describe your educational background and qualifications.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit 7.

A. Overview

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to present to the Idaho Public Utilities Commission ("IPUC" or "Commission") my independent assessment of the just and reasonable return on equity ("ROE") for the jurisdictional utility operations of Idaho Power Company ("Idaho Power" or the "Company"). In addition, I also examine the reasonableness of Idaho Power's common equity ratio, considering both the specific risks faced by the Company and other industry guidelines.

Q. Please summarize the information and materials you rely on to support the opinions and conclusions contained in your testimony.

A. To prepare my testimony, I use information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with the organization, finances, and operations of Idaho Power from my involvement in prior proceedings before the IPUC, the Public Utility Commission of Oregon ("OPUC"), and the Federal Energy Regulatory Commission ("FERC"). In connection with this filing, I consider and rely upon corporate disclosures, publicly available financial reports and filings, and other published information relating to Idaho Power. I also review information relating generally to capital market conditions and specifically to investor perceptions, requirements and expectations for utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for Idaho Power, and they form the basis of my analyses and conclusions.

Q. How is your testimony organized?

A. First, I summarize my conclusions and recommendations, giving special attention to the importance of financial strength and the implications of regulatory mechanisms and other risk factors. I also comment on the reasonableness of the Company's proposed capital structure.

Next, I briefly review Idaho Power's operations and finances. I discuss current conditions in the capital markets and their implications in evaluating a just and reasonable return for the Company. I then explain the development of the proxy group of electric utilities used as the basis for my quantitative analyses. With this as a background, I discuss well-accepted quantitative analyses to estimate the current cost of equity for the proxy group of electric utilities. These include the discounted cash flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the empirical CAPM ("ECAPM"), an equity risk premium approach based on allowed ROEs, and reference to expected earned rates of return for electric utilities, which are all methods that are commonly relied on in regulatory proceedings.

Based on the results of my analyses, I evaluate a fair ROE for Idaho Power. My evaluation takes into account the specific risks for the Company's utility operations and Idaho Power's requirements for financial strength. Further, consistent with the fact that utilities must compete for capital with firms outside their own industry, I corroborate my utility quantitative analyses by applying the DCF model to a group of low-risk non-utility firms.

B. Summary and Conclusions

Q. What is your recommended ROE for Idaho Power?

A. I apply the DCF, CAPM, ECAPM, risk premium, and expected earnings analyses to a proxy group of electric utilities, with the results being summarized on Exhibit 8. As shown there, I recommend a cost of equity range for the Company’s electric operations of 10.0 percent to 11.0 percent, or 10.1 percent to 11.1 percent after adjusting for the impact of common equity flotation costs. It is my conclusion that the 10.6 percent midpoint of this range represents a just and reasonable ROE that is adequate to compensate Idaho Power’s investors, while maintaining the Company’s financial integrity and ability to attract capital on reasonable terms.

II. RETURN ON EQUITY FOR IDAHO POWER

Q. What is the purpose of this section?

A. This section presents my conclusions regarding the fair ROE applicable to Idaho Power’s jurisdictional utility operations. I also describe the relationship between ROE and preservation of a utility’s financial integrity and the ability to attract capital. Finally, I discuss the reasonableness of the Company’s capital structure request in this case.

A. Importance of Financial Strength

Q. What is the role of the ROE in setting a utility’s rates?

A. The ROE is the cost of attracting and retaining common equity investment in the utility’s physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. Moreover, a just and reasonable ROE is integral in meeting sound regulatory economics and the standards established by the U.S. Supreme Court. The Bluefield case set the standard against which just and reasonable rates are measured:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . . The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.[1]

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) (“*Bluefield*”).

The *Hope* case expanded on the guidelines for a reasonable ROE, reemphasizing its findings in *Bluefield* and establishing that the rate-setting process must produce an end-result that allows the utility a reasonable opportunity to cover its capital costs. The Court stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. . . . By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain credit and attract capital.[2]

In summary, the Supreme Court's findings in *Hope* and *Bluefield* established that a just and reasonable ROE must be sufficient to 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. These standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but the Supreme Court's requirements can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

While the *Hope* and *Bluefield* decisions did not establish a particular method to be followed in fixing rates (or in determining the allowed ROE),[3] these and subsequent cases enshrined the importance of an end result that meets the opportunity cost standard of finance. Under this doctrine, the required return is established by investors in the capital markets based on expected returns available from comparable risk investments. Coupled with modern financial theory, which has led to the development of formal risk-return models (*e.g.*, DCF and CAPM), practical application of the *Bluefield* and *Hope* standards involves the independent, case-by-case consideration of capital market data in order to evaluate an ROE that will produce a balanced and fair end result for investors and customers.

Q. Throughout your testimony you refer repeatedly to the concepts of "financial strength," "financial integrity" and "financial flexibility." Would you briefly describe what you mean by these terms?

A. These terms are generally synonymous and refer to the utility's ability to attract and retain the capital that is necessary to provide service at reasonable cost, consistent with the Supreme Court standards. Idaho Power's plans call for

[3] *Id.* at 602 (finding, "the Commission was not bound to the use of any single formula or combination of formulae in determining rates." and, "[I]t is not theory but the impact of the rate order which counts.)

a continuation of capital investments to preserve and enhance service reliability for its customers. The Company must generate adequate cash flow from operations, together with access to capital from external sources, to fund these requirements and for repayment of maturing debt.

Rating agencies and potential debt investors tend to place significant emphasis on maintaining strong financial metrics and credit ratings that support access to debt capital markets under reasonable terms. This emphasis on financial metrics and credit ratings is shared by equity investors who also focus on cash flows, capital structure and liquidity, much like debt investors. Investors understand the important role that a supportive regulatory environment plays in establishing a sound financial profile that will permit the utility access to debt and equity capital markets on reasonable terms in both favorable financial markets and during times of potential disruption and crisis.

Q. What part does regulation play in ensuring that Idaho Power has access to capital under reasonable terms and on a sustainable basis?

A. Regulatory signals are a major driver of investors' risk assessment for utilities. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity. Security analysts study commission orders and regulatory policy statements to advise investors about where to put their money. As Moody's Investors Service ("Moody's") noted, "the regulatory environment is the most important driver of our outlook because it sets the pace for cost recovery."[4] Similarly, S&P Global Ratings ("S&P") observed that, "Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile."[5] The Value Line Investment Survey ("Value Line") summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[6]

In addition, the ROE set by regulators impacts investor confidence in not only the jurisdictional utility, but also in the ultimate parent company that is the entity that actually issues common stock.

Q. Do customers benefit from the utility's financial flexibility?

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[4] Moody's Investors Service, *Regulation Will Keep Cash Flow Stable As Major Tax Break Ends*, Industry Outlook (Feb. 19, 2014).

[5] S&P Global Ratings, *Assessing U.S. Investors-Owned Utility Regulatory Environments*, RatingsExpress (Aug. 10, 2016).

[6] Value Line Investment Survey, *Water Utility Industry* (Jan. 13, 2017) at p. 1780.

A. Yes. Providing an ROE sufficient to maintain the Company's ability to attract capital under reasonable terms, even in times of financial and market stress, is not only consistent with the economic requirements embodied in the U.S. Supreme Court's Hope and Bluefield decisions, but it is also in customers' best interests. Customers enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure safe and reliable service.

B. Conclusions and Recommendations

Q. What are your findings regarding the fair ROE for Idaho Power?

A. Considering the economic requirements necessary to support continuous access to capital under reasonable terms and the results of my analysis, I recommend a 10.6 percent ROE for Idaho Power's electric utility operations, which is consistent with the case-specific evidence presented in my testimony. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with Idaho Power's electric utility operations, my analyses focus on a proxy group of twenty other electric utilities.
- Because investors' required ROE is unobservable and no single method should be viewed in isolation, I apply the DCF, CAPM, ECAPM, and risk premium methods to estimate a just and reasonable ROE for Idaho Power, as well as referencing the expected earnings approach.

- As summarized on Exhibit 8, considering the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I conclude that the cost of equity for a regulated electric utility is in the 10.0% to 11.0% range.
- My evaluation of a fair ROE also incorporated an upward adjustment of 10 basis points to account for flotation costs, which are a legitimate cost incurred to raise equity capital supporting Idaho Power's investment in utility infrastructure. Incorporating this flotation cost adjustment resulted in my recommended ROE range of 10.1% to 11.1%.
- My ROE recommendation for Idaho Power's electric operations is the midpoint of this range, or 10.6%.

Q. What did the DCF results for your select group of non-utility firms indicate with respect to your evaluation?

A. As shown on page 3 of Exhibit 18, average DCF estimates for a low-risk group of firms in the competitive sector of the economy ranged from 10.4 percent to 10.9 percent. While I did not base my recommendations on these results, they confirm that an ROE of 10.6 percent falls in a reasonable range to maintain Idaho Power's financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital.

III. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. This section briefly reviews the operations and finances of Idaho Power. As a predicate to my quantitative analyses, it examines conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Idaho Power

Q. Briefly describe Idaho Power and its utility operations.

A. Idaho Power is a wholly-owned subsidiary of IDACORP, Inc. ("IDACORP") and is principally engaged in providing integrated retail electric utility service to approximately 618,000 customers in a 24,000 square mile area in southern Idaho and eastern Oregon. Approximately 95 percent of Idaho Power's retail revenue is attributable to customers located in Idaho. During 2022, Idaho Power's energy deliveries totaled 17.1 million megawatt-hours ("MWh"). Sales to residential customers comprised 39 percent of operating revenues, with 21 percent to commercial, 13 percent to industrial end-users, and 10 percent attributable to irrigation pumping. Idaho Power also participates in the wholesale power market, with wholesale energy sales accounting for 4 percent of operating revenues during 2022. At year-end 2022, Idaho Power had total assets of $7.4 billion, with total revenues amounting to approximately $1.6 billion.

In addition to its three natural gas-fired generating facilities in southern Idaho and interests in two coal-fired plants located in Wyoming and Nevada, Idaho Power's existing generating units include 17 hydroelectric generating plants located in southern Idaho and eastern Oregon with a nameplate capacity of 1,799 Megawatts ("MW"), or 51.6 percent of Company-owned generating capacity. The electrical output of these hydro plants, which has a significant impact on total energy costs, is dependent on stream flows. The Company has experienced prolonged periods of persistent below-normal water conditions, with hydroelectric generation supplying approximately 31 percent of total energy needs in 2022, versus an average of about 43 percent over the 2017 to 2021 period. Additionally, Idaho Power has undertaken a substantial capital program for new capacity and energy resources, and in 2022 began construction of two utility-scale battery storage facilities.

Idaho Power's retail electric operations are subject to the jurisdiction of the IPUC and the OPUC, with the interstate jurisdiction regulated by FERC. Additionally, Idaho Power's hydroelectric facilities are subject to licensing under the Federal Power Act, which is administered by FERC, as well as the Oregon Hydroelectric Act. Relicensing is not automatic under federal law, and Idaho Power must demonstrate that it has operated its facilities in the public interest, which includes adequately addressing environmental concerns.

Q. What credit ratings have been assigned to Idaho Power?

A. Moody's has assigned the Company an issuer rating of Baa1, while S&P has assigned a corporate credit rating of BBB to Idaho Power.

Q. Has Idaho Power made significant capital investments in its system?

A. Yes. Idaho Power has made significant new investments to maintain and modernize its utility infrastructure, and to otherwise meet customer demand and provide adequate and reliable service. Since its last rate case in 2011, Idaho Power's rate base has increased by more than one-third.[7]

Q. Does Idaho Power anticipate the need for capital going forward?

A. Yes. The Company must undertake investments for necessary replacement and expansion of its electric utility system as it continues to provide safe and reliable service to its customers. For 2023 to 2027, Idaho Power is estimating

[7] IDACORP, Inc., *Spring 2023 Investor Outreach*, Investor Information (February/March 2023) at 6.

annual capital expenditures of approximately $650 million.[8] This represents almost a two-fold increase over the previous five years. In addition, the Company remains obligated to repay maturing long-term debt. Continued support for Idaho Power's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

B. Outlook for Capital Costs

Q. Please summarize current economic conditions.

A. U.S. real GDP contracted 3.4% during 2020, but with the easing of COVID-19 lockdowns, the economic outlook improved significantly in 2021, with GDP growing at a pace of 5.7 percent. Regional increases in COVID-19 cases, expiration of government assistance payments, and declines in wholesale trade led GDP to decline in the first two quarters of 2022. More recently, expanding exports and higher consumer spending led real GDP to grow by 3.2 percent and 2.6 percent in the third and fourth quarters of 2022, respectively.[9] Meanwhile, indicators of employment remained stable, with the national unemployment rate at 3.5 percent in March 2023.[10]

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[8] *Id.* at 5.
[9] https://www.bea.gov/news/2023/gross-domestic-product-fourth-quarter-and-year-2022-third-estimate-gdp-industry-and (last visited Apr. 22, 2023).
[10] https://www.bls.gov/news.release/pdf/empsit.pdf (last visited Apr. 16, 2023).

The underlying risk and price pressures associated with the COVID-19 pandemic were overshadowed by a dramatic increase in geopolitical risks in early 2022. These events have also been accompanied by heightened economic uncertainties as inflationary pressures due to COVID-19 supply chain disruptions were further stoked by sharp increases in global commodity prices. The substantial disruption in the energy economy and dramatic rise in inflation led to sharp declines in global equity markets as investors reacted to the related exposures. S&P concluded that:

> The balance of risks is firmly on the downside—with rapid monetary tightening potentially pushing major economies into recession; growing geopolitical tensions exacerbating Europe's energy crisis; lingering high prices pressuring costs and eroding households' purchasing power; and China grappling with structural factors that are undermining its economic growth.[11]

Stimulative monetary and fiscal policies, coupled with economic ramifications stemming from supply-chain disruptions and rapid price rises in the energy and commodities markets, have led to increasing concern that inflation may remain significantly above the Federal Reserve's longer-run benchmark of 2 percent. In June 2022, inflation, as measured by the Consumer Price Index ("CPI"), peaked at its highest level since November 1981. Since then, CPI inflation has gradually

[11] S&P Global Ratings, *Global Credit Conditions Q4 2022: Darkening Horizons*, Comments (Sept. 29, 2022).

moderated to 5.0 percent in March 2023[12]. The so-called "core" price index, which excludes more volatile energy and food costs, rose at an annual rate of 5.6 percent in March 2023. Similarly, Personal Consumption Expenditures ("PCE") inflation rose 5.0 percent in February 2023, or 4.6 percent after excluding more volatile food and energy costs[13]. As Federal Reserve Chair Powell has noted:

> Although inflation has moderated recently, it remains too high. The longer the current bout of high inflation continues, the greater the chance that expectations of higher inflation will become entrenched.[14]

More recently, turmoil in the banking sector has shaken investor confidence and increased volatility in bond and equity markets. The Federal Reserve and U.S. Treasury took quick and dramatic action to shore up banks' liquidity needs and strengthen public confidence in the banking system, but as Moody's noted, "bank stress has added uncertainty to the outlook."[15]

Q. How have these developments impacted the Federal Reserve's monetary policies?

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[12] https://www.bls.gov/news.release/cpi.nr0.htm (last visited Apr. 14, 2023).

[13] https://www.bea.gov/news/2023/personal-income-and-outlays-february-2023 (last visited Apr. 14, 2023).

[14] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Feb. 1, 2023), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20230201.pdf (last visited Feb. 21, 2023).

[15] Moody's Investors Service, *Baseline US macro forecasts unchanged but outlook more uncertain*, Sector Comment (Apr. 12. 2023).

A. As of its policy meeting in May 2023, the Federal Open Market Committee ("FOMC") has responded to concerns over accelerating inflation by raising the benchmark range for the federal funds rate by a total of 5.00 percent since March 2022.[16] In addition to these increases, Chair Powell has surmised that the significant draw-down of its balance sheet holdings that began in June 2022 could be the equivalent of another one quarter percent rate hike over the course of a year.[17] Chair Powell noted that, "The process of getting inflation back down to 2 percent has a long way to go and is likely to be bumpy,"[18] with the recent banking crisis amply demonstrating these latent risks.

Q. What impact do rising inflation expectations have on the return that equity investors require from Idaho Power?

A. Implicit in the required rate of return for long-term capital—whether debt or common equity—is compensation for expected inflation. This is highlighted in the textbook, *Financial Management, Theory and Practice*:

[16] The FOMC is a committee composed of twelve members that serves as the monetary policymaking body of the Federal Reserve System.
[17] Federal Reserve, *Transcript of Chair Powell's Press Conference* (May 4, 2022), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20220504.pdf.
[18] https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20230322.pdf.

> The four most fundamental factors affecting the cost of money are (1) production opportunities, (2) time preferences for consumption, (3) risk, and (4) inflation.[19]

In other words, a part of investors' required return is intended to compensate for the erosion of purchasing power due to rising price levels. This inflation premium is added to the real rate of return (pure risk-free rate plus risk premium) to determine the nominal required return. As a result, higher inflation expectations lead to an increase in the cost of equity capital.

Q. Have these developments impacted the risks faced by utilities and their investors?

A. Yes. Concerns over weakening credit quality prompted S&P to revise its outlook for the regulated utility industry from "stable" to "negative."[20] As S&P explained:

> Even before the current downturn and COVID-19, a confluence of factors, including the adverse impacts of tax reform, historically high capital spending, and associated increased debt, resulted in little cushion in ratings for unexpected operating challenges.[21]

Meanwhile, rising inflation expectations also pose a challenge for utilities, with S&P recently noting that "the threat of

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[19] Eugene F. Brigham, Louis C. Gapenski, and Michael C. Ehrhardt, *Financial Management, Theory and Practice*, Ninth Edition (1999) at 126.
[20] S&P Global Ratings, *COVID-19: The Outlook For North American Regulated Utilities Turns Negative*, RatingsDirect (April 2, 2020).
[21] S&P Global Ratings, *North American Regulated Utilities Face Tough Financial Policy Tradeoffs To Avoid Ratings Pressure Amid The COVID-19 Pandemic*, RatingsDirect (May 11, 2020).

inflation comes at a time when credit metrics are already under pressure relative to downside ratings thresholds."[22] S&P noted that "risk will continue to pressure the credit quality of the industry in 2022."[23] As S&P elaborated:

> Recently, several new credit risks have emerged, including inflation, higher interest rates, and rising commodity prices. Persistent pressure from any of these risks would likely lead to a further weakening of the industry's credit quality in 2022.[24]

Similarly, on November 10, 2022, Moody's revised its outlook for the regulated utilities sector to "negative" from "stable," citing "increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates."[25]

In affirming its negative outlook on the industry, S&P recently cited weak financial measures, rising energy prices and capital spending, and increased environmental risks as key challenges, noting that, "The industry outlook remains negative and has been negative since early 2020."[26] Value Line

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[22] S&P Global Ratings, *Will Rising Inflation Threaten North American Investor-Owned Regulated Utilities' Credit Quality?* (Jul. 20, 2021).
[23] S&P Global Ratings, *For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The 'BBB' Category*, RatingsDirect (Jan. 20, 2022).
[24] *Id.*
[25] Moody's Investors Service, *Regulated Gas Utilities--US, 2023 outlook negative due to higher natural gas prices, inflation and rising interest rates,* Outlook (Nov. 10, 2022).
[26] S&P Global Ratings, *North American Regulated Utilities, The industry's outlook remains negative*, Industry Top Trends (Jan. 23, 2023).

echoed these sentiments for electric utilities in the Western US, concluding that:

> The current macroeconomic environment is a challenging period for this group. The main difficulties are wage inflation, higher interest rates, and high commodity prices for raw materials and purchased power.[27]

Q. Do changes in utility company beta values corroborate an increase in industry risk?

A. Yes. Beta measures a utility's stock price volatility relative to the market as a whole and reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. As shown later in my testimony in Table 2, the average beta for the Electric Group is 0.89.[28] Prior to the pandemic, the average betas for this same group of electric utilities was 0.57.[29] The significant shift in pre- and post-pandemic beta values for the Electric Group is further exemplified in Figure 1 below. As illustrated there, the average beta value for the

[27] The Value Line Investment Survey, *Electric Utility (West) Industry* (Apr. 21, 2023).
[28] As indicated on Exhibit 13, this is based on data as of March 31, 2023.
[29] The Value Line Investment Survey, *Summary & Index* (Feb. 14, 2020).

Electric Group increased significantly with the beginning of the pandemic in March 2020, continued to increase during 2021, and have remained elevated. This dramatic increase in a primary gauge of investors' risk perceptions is further proof of the rise in the risk of utility common stocks.

FIGURE 1
ELECTRIC GROUP BETA VALUES

Q. Have increased risks and higher inflation resulted in higher capital costs?

A. Yes. While the cost of equity is unobservable, yields on long-term bonds provide a widely referenced benchmark for the direction of capital costs, including required returns on common stocks. Table 1 below compares the average yields on Treasury securities and Baa-rated public utility bonds during March 2023 with those prevailing in 2021.

TABLE 1
BOND YIELD TRENDS

Series	March 2023	2021	Change (bps)
10-Year Treasury Bonds	3.66%	1.44%	222
30-Year Treasury Bonds	3.77%	2.05%	172
Baa Utility Bonds	5.68%	3.35%	233

Source: https://fred.stlouisfed.org/series/GS30; Moody's Credit Trends.

As shown above, trends in bond yields document a substantial increase in the returns on long-term capital demanded by investors. With respect to utility bond yields—which are the most relevant indicator in gauging the implications for the Company's common equity investors—average yields are now over 230 basis points above the level prevailing during 2021.

Q. What implications do these trends have in evaluating a fair ROE for Idaho Power?

A. The upward move in interest rates suggests that long-term capital costs—including the cost of equity—have increased significantly. Exposure to rising interest rates, inflation, and capital expenditure requirements also reinforce the importance of buttressing Idaho Power's credit standing. Considering the potential for financial market instability, competition with other investment alternatives, and investors' sensitivity to risk exposures in the utility industry, maintaining credit strength is a key ingredient in maintaining access to capital at reasonable cost.

Q. Would it be reasonable to disregard the implications of current capital market conditions in establishing a fair ROE for Idaho Power?

A. No. They reflect the reality in which Idaho Power must attract and retain capital. The standards underlying a fair rate of return require an authorized ROE for the Company that is competitive with other investments of comparable risk and sufficient to preserve its ability to maintain access to capital on reasonable terms. These standards can only be met by considering the requirements of investors over the time period when the rates established in this proceeding will be in effect. If the upward shift in investors’ risk perceptions and required rates of return for long-term capital is not incorporated in the allowed ROE, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital. From a more practical perspective, failing to provide investors with the opportunity to earn a rate of return commensurate with Idaho Power’s risks will weaken its financial integrity, while hampering the Company’s ability to attract the capital necessary to provide safe and reliable service.

IV. **COMPARABLE RISK PROXY GROUP**

Q. What is the purpose of this section of your testimony?

A. This section explains the basis of the proxy group of publicly traded companies I use to estimate the cost of equity, examines alternative objective indicators of investment risk for these firms, and compares the investment risks applicable to Idaho Power with my reference group.

Q. What key principles underpin the evaluation of a proxy group?

A. The United States Supreme Court's *Hope* and *Bluefield* decisions[30] establish a standard of comparison between a subject utility and other companies of comparable risk in determining a just and reasonable ROE. The generally accepted approach is to select a group of companies that are of similar risk to the subject utility (the "proxy group"), and then to perform various quantitative analyses based on the proxy group to estimate investors' required returns. The results of these analyses, in turn, are used to evaluate a range of reasonableness and a final recommendation for the ROE attributable to the subject utility.

[30] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) (*Bluefield*); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).

Q. As an initial matter, does the fact that Idaho Power is wholly owned by IDACORP alter these fundamental standards?

A. No. While the Company has no publicly traded common stock and IDACORP is Idaho Power's only shareholder, this does not change the standards governing the determination of a just and reasonable ROE for the Company. Ultimately, the common equity required to support the utility operations of Idaho Power must be raised in the capital markets, where investors consider the Company's ability to offer a rate of return that is competitive with other risk-comparable alternatives. Idaho Power must compete with other investment opportunities and unless there is a reasonable expectation that investors will have the opportunity to earn returns commensurate with the underlying risks, capital will be allocated elsewhere, the Company's financial integrity will be weakened, and investors will demand an even higher rate of return. Idaho Power's ability to offer a reasonable return on investment is a necessary ingredient to ensure that customers continue to enjoy economical rates and reliable service and, by extension, the preservation of the Company's ability to attract equity capital.

A. Determination of the Proxy Group

Q. How do you implement quantitative methods to estimate the cost of common equity for Idaho Power?

A. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices and beta values. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable. The results of the analysis on the sample of companies are relied upon to establish a range of reasonableness for the cost of equity for the specific company at issue.

Q. How do you identify the proxy group of electric utilities relied on for your analyses?

A. To reflect the risks and prospects associated with Idaho Power's jurisdictional electric operations, I begin with those companies included in the Electric Utility industry groups compiled by Value Line.[31] Value Line is one of the most widely available sources of investment advisory information, and its industry groups provide an objective source to identify publicly traded firms that investors would regard to be similar in operations. I then apply the following criteria to identify a proxy group of utilities:

1. Corporate credit ratings from Moody's and S&P within one notch of the Company's current ratings. For Moody's, this resulted in a ratings range of Baa2, Baa1, and A3; for S&P the range is BBB-, BBB, and BBB+.

2. A Value Line Safety Rank of 1 or 2.

3. No cuts in common dividend payments during the past six months and no announcement of a dividend cut since that time.

4. No ongoing involvement in a major merger or acquisition that would distort quantitative results.

These criteria result in a proxy group composed of twenty companies, which I refer to as the "Electric Group."

B. Relative Risks of the Electric Group and Idaho Power

Q. How do you evaluate the risks of the Electric Group relative to Idaho Power?

A. My evaluation of relative risk considers four published benchmarks that are widely relied on by investors—

[2] In addition to the companies included in Value Line's electric utility industry groups, I also considered Algonquin Power & Utilities Company and Emera, Inc, which would both be regarded as comparable utility investment opportunities by investors. Neither of these companies met my required screening criteria.

credit ratings from Moody's and S&P, along with Value Line's Safety Rank, Financial Strength Rating, and beta values. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "+" or "-") are used to show relative standing within a category. Because the rating agencies' evaluation includes all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide broad, objective measures of overall investment risk that are readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

As previously mentioned, beta measures a utility's stock price volatility relative to the market as a whole and reflects the tendency of a stock's price to follow changes in the market.

Q. How does the overall risk of your proxy group compare to Idaho Power?

A. Table 2 compares the Electric Group with the Company across the four key indices of investment risk discussed above. Because Idaho Power has no publicly traded common stock, the Value Line risk measures shown reflect those published for its parent, IDACORP.

TABLE 2
COMPARISON OF RISK INDICATORS

	Credit Ratings		Value Line		
	S&P	Moody's	Safety Rank	Financial Strength	Beta
Electric Group	BBB+	Baa2	2	A	0.89
Idaho Power	BBB	Baa1	1	A+	0.80

Q. What does this comparison indicate regarding investors' assessment of the relative risks associated with your Electric Group?

A. The average S&P credit rating corresponding to the Electric Group is one notch higher than those of Idaho Power, while the average Moody's credit ratings for the proxy group is one notch lower, indicating about the same amount of risk overall. With respect to Value Line's Safety Rank, Financial Strength and beta measures, the average values for the Electric Group indicate slightly greater risk than Idaho Power. Considered together, a comparison of these objective measures, which incorporate a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors, indicates that investors would likely conclude that the overall investment risks for

Idaho Power are generally comparable to, or slightly less than those of the firms in the Electric Group.

Q. How does Idaho Power's generating resource mix affect investors' risk perceptions?

A. Because a significant portion of Idaho Power's total energy requirements are provided by hydroelectric facilities, the Company is exposed to a level of uncertainty not faced by most utilities. While hydropower confers advantages in terms of fuel cost savings and diversity, reduced hydroelectric generation due to below-average water conditions forces the Company to rely more heavily on wholesale power markets or more costly thermal generating capacity to meet its resource needs. As S&P explained:

> A reduction in hydro generation typically increases an electric utility's costs by requiring it to buy replacement power or run more expensive generation to serve customer loads. Low hydro generation can also reduce utilities' opportunity to make off-system sales. At the same time, low hydro years increase regional wholesale power prices, creating potentially a double impact – companies have to buy more power than under normal conditions, paying higher prices.[32]

With respect to Idaho Power specifically, S&P recently observed that:

[32] Standard & Poor's Corporation, *Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality*, RatingsDirect (Jan. 28, 2008).

> The company relies heavily on hydropower generation and purchased power. Low-cost hydropower provides more than 50% of the company's generation under normal water-level conditions, leading to lower electricity rates. However, when hydroelectric generation is low, the company relies on more expensive purchased power, which exposes the company to the volatile spot power market. Idaho Power saw reduced hydropower generation in both 2021 and 2020 due to precipitation and snow conditions.[33]

Q. Have utilities and their customers recently experienced increased uncertainty in energy markets?

A. Yes. The onset of military conflict in Ukraine led to a dramatic rise in energy market volatility. As with major weather events, market conditions that lead to significant spikes in energy prices can place extraordinary pressure on liquidity as utilities seek to fund higher procurement costs and maintain service to customers. With respect to Idaho Power specifically, the Pacific Northwest recently faced a dramatic increase in gas costs. As the Energy Information Administration reported:

> On December 21, 2022, daily natural gas spot prices at three major trading hubs in the western United States—Pacific Gas & Electric ("PG&E") Citygate, Sumas on the Canada-Washington border, and Malin, Oregon—settled higher than $50.00 per million British thermal units ("MMBtu"), the highest level of any other market and an average

[33] S&P Global Ratings, *Idaho Power Co.*, RatingsDirect (May 26, 2022).

of $48.12/MMBtu above Henry Hub, the national benchmark natural gas price.[34]

While prices have since moderated, investors recognize that volatile energy markets, unpredictable stream flows, and Idaho Power's reliance on wholesale purchases to meet a significant portion of its resource needs can expose the Company to the risk of reduced cash flows and unrecovered power supply costs. The Company's reliance on purchased power to meet shortfalls in hydroelectric generation magnifies the importance of strengthening financial flexibility, which is essential to guarantee access to the cash resources and interim financing required to cover inadequate operating cash flows.

Q. How has climate change impacted investors' assessment of Idaho Power's risk exposure?

A. The risk posed by climate-related weather events has served to magnify concerns over Idaho Power's exposure to below-average water conditions. S&P concluded that "water-intensive assets like power plants [are] especially vulnerable in the absence of adaptation," and concluded that Idaho Power had the highest exposure to water stress of any U.S. utility.[35]

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[34] Energy Information Administration, *Natural Gas Weekly Update* (Dec. 22, 2022). https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/12_22/#itn-tabs-1 (last visited Apr. 25, 2023).

[35] S&P Global Ratings, *Keeping The Lights On: U.S. Utilities' Exposure To Physical Climate Risks*, RatingsDirect (Sep. 16, 2021).

While noting that the risks of such events are generally manageable under recovery mechanisms that allow related costs to be recuperated, S&P also observed that:

> In the most extreme events, including those of late, utility companies' exposure to acute and chronic climate risks can damage assets or disrupt supplies, which can weaken their financial position and ultimately credit quality.[36]

Q. Do financial pressures associated with Idaho Power's planned capital expenditures also impact investors' risk assessment?

A. Yes. Idaho Power's customer growth and regional transmission constraints are driving the need for additional resources to meet projected energy and capacity deficits. As noted earlier, Idaho Power's capital additions are expected to total approximately $650 million annually over the 2023 to 2027 period. This represents a substantial investment given the Company's current rate base of approximately $3.8 billion. As Value Line recently observed:

> The company's system is stressed, and new capacity resources are entering the pipeline and they do not come cheap. . . . All this pressure comes at a time when inflation is still well higher than usual and the interest on borrowings is more punishing to the bottom line.[37]

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[36] *Id.*

[37] The Value Line Investment Survey, *IDACORP, Inc.* (Apr. 21, 2023).

In addition, Idaho Power remains obligated to repay maturing long-term debt. Continued support for the Company’s financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects and debt repayments in an effective manner.

Q. Do utilities such as Idaho Power continue to face environmental risks?

A. Yes. Environmental concerns are leading to a profound transformation in the utility industry. In the electricity sector, the generation segment is undergoing material changes in fuel mix, as natural gas and renewable sources increasingly supplant coal. Over the next decade, renewable sources are widely expected to account for a rising share of the electricity generated in the U.S., including a significant expansion in distributed generation, which will accompany declining costs and increased efficiency of energy storage technologies. Accommodating efforts to decarbonize electric generation will also require significant investment to modernize the transmission grid. And while this disruption offers the potential for growth through increased capital investment, it also conveys higher risks. With respect to Idaho Power, the Company’s carbon emission targets call for achieving 100 percent clean electricity by 2045.

Q. What other consideration is relevant to investors' risk assessment?

A. Rising temperatures and reduced rainfall have led to unusually large and damaging wildfires in the Pacific Northwest. While Idaho Power does not face the same degree of exposure attributed to California utilities due to that state's inverse condemnation laws, S&P nonetheless classifies the Company as having the second highest exposure to wildfires in the nation.[38]

C. Regulatory Mechanisms

Q. What regulatory mechanisms are applicable to Idaho Power's utility operations?

A. In addition to a mechanism that accounts for changes in power supply costs ("PCA"), Idaho Power operates under the Fixed Cost Adjustment mechanism ("FCA"), which is designed to break the link between a utility's revenues and the energy usage of residential and small commercial customers. The IPUC has also authorized a rider to collect most of the Company's energy efficiency program costs and a deferral account for wildfire resiliency costs.

Q. Would investors consider the implications of regulatory mechanisms in evaluating a utility's relative risks?

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[38] S&P Global Ratings, *Keeping The Lights On: U.S. Utilities' Exposure To Physical Climate Risks*, RatingsDirect (Sep. 16, 2021).

A. Yes. In response to increasing sensitivity over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation, and safety, utilities and their regulators have sought to mitigate cost recovery uncertainty and align the interest of utilities and their customers. As a result, decoupling mechanisms, cost trackers, and future test years have been increasingly prevalent in the utility industry in recent years, along with alternatives to traditional ratemaking such as formula rates and multi-year rate plans. S&P Global Market Intelligence, *RRA Regulatory Focus* concluded in its recent review of adjustment clauses that:

> More recently and with greater frequency, commissions have approved mechanisms that permit the costs associated with the construction of new generation or delivery infrastructure to be used, effectively including these items in rate base without the need for a full rate case. In some instances, these mechanisms may even provide the utilities a cash return on construction work in progress.
> . . . [C]ertain types of adjustment clauses are more prevalent than others. For example, those that address electric fuel and gas commodity charges are in place in all jurisdictions. Also, about two-thirds of all utilities have riders in place to recover costs related to energy efficiency programs, and roughly half of the utilities have some type of decoupling mechanism in place.[39]

[39] S&P Global Market Intelligence, *Adjustment Clause: A state-by-state overview*, RRA Regulatory Focus (Jul. 18, 2022).

Q. How do the regulatory mechanisms approved for Idaho Power compare to other firms operating in the utility industry?

A. A broad array of adjustment mechanisms is also available to the companies in my proxy group of electric utilities. As documented on Exhibit 9, the companies in the Electric Group operate under a wide variety of cost adjustment mechanisms, which encompass revenue decoupling and adjustment clauses designed to address rising capital investment outside of a traditional rate case, increasing costs of environmental compliance measures, as well as riders to address the costs of energy conservation programs, bad debt expenses, certain taxes and fees, post-retirement employee benefit costs, storms, and transmission-related charges. The majority of these proxy firms also operate in regulatory jurisdictions that allow for future test years, formula rates, and multi-year rate plans.

Meanwhile, under the PCA that currently governs recovery of electric supply costs for the Company's Idaho-jurisdictional electric utility operations, 95 percent of the difference between actual costs and base level costs are passed through to customers, with 5 percent absorbed/retained by shareholders.[40] Thus, in addition to the fact that recovery is deferred when power costs rise above the level included in

[40] Amounts related to power supplied by Qualifying Facilities are not subject to cost sharing under the PCA.

current retail rates, investors recognize that this sharing mechanism exposes the Company to unrecovered electric supply costs. Both of these considerations can adversely affect Idaho Power's operating cash flow and liquidity.

In contrast to many of the specific operating companies associated with the firms in the Utility Group, Idaho Power does not have an approved cost tracking mechanisms to address ongoing investment in new generation capacity. Further, the Idaho jurisdiction has routinely relied on a historical test year approach, which also creates a lag in cost recovery. Thus, while investors would consider Idaho Power's regulatory mechanisms to be supportive of the Company's financial integrity, they are more limited than those approved for other firms in the industry.

D. Capital Structure

Q. Is an evaluation of a utility's capital structure relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio and lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive their contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow that will remain.

Q. What common equity ratio is implicit in Idaho Power's capital structure?

A. As discussed in the direct testimony of Company Witness Mr. Brian Buckham, the capital structure used to compute the overall rate of return for Idaho Power includes 51.0 percent common equity.

Q. How does this compare to the average equity ratios maintained by the Electric Group?

A. As shown on page 1 of Exhibit 10, common equity ratios for the individual firms in the Electric Group ranged between 33.3 percent and 63.5 percent and averaged 45.0 percent. Meanwhile, the three-to-five-year forecasts published by Value Line result in common equity ratios ranging from 33.0 percent to 59.5 percent for the Electric Group, with an average of 45.8 percent.

Q. Are there other industry benchmarks that are more relevant in evaluating Idaho Power's capital structure?

A. Yes. Because this proceeding focuses on the ROE for the regulated electric utility operations of Idaho Power, the capital structures maintained by other operating electric utilities provide a consistent basis of comparison.

Q. What capitalization ratios are maintained by comparable utility operating companies?

A. Pages 2 and 3 of Exhibit 10 display capital structure data for the group of electric utility operating companies owned by the firms in the Electric Group. As shown there, common equity ratios for these utilities range from 42.8 percent to 60.9 percent and average 51.8 percent. This benchmark provides a direct guide to financing policies that are consistent with industry-specific risks and the need to maintain adequate borrowing capacity and financial flexibility.

Q. Do ongoing economic and capital market uncertainties also influence the appropriate capital structure for Idaho Power?

A. Yes. Financial flexibility plays a crucial role in ensuring the wherewithal of a utility to meet funding needs. Utilities with higher financial leverage may be foreclosed from or have limited access to additional borrowing, especially during times of financial market stress. As Moody's observed:

> Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to capital markets to assure adequate sources of funding and to maintain financial flexibility. During times of distress and when capital markets are exceedingly volatile and tight, liquidity becomes critically important because access to capital markets may be difficult.[41]

S&P recently reiterated these concerns, noting that:

> Because of the industry's high capital spending and consistent dividends, negative discretionary cashflow is regularly more than $100 billion annually. To fund this large deficit, the industry requires consistent access to the capital markets. Rising interest rates, decreasing equity prices, and inflation could hamper consistent access to the capital markets, potentially pressuring credit quality.[42]

As a result, the Company's capital structure must maintain adequate equity to preserve the flexibility necessary to maintain continuous access to capital even during times of unfavorable energy or financial market conditions.

Q. What other factors do investors consider in their assessment of a company's capital structure?

A. Utilities, including Idaho Power, are facing significant capital investment plans. Coupled with the potential for turmoil in capital markets, this warrants a

[41] Moody's Investors Service, *FAQ on credit implications of the coronavirus outbreak*, Sector Comment (Mar. 26, 2020).
[42] S&P Global Ratings. *North American Regulated Utilities, The industry's outlook remains negative*, Industry Top Trends (Jan. 23, 2023).

stronger balance sheet to deal with an uncertain environment. As S&P recently noted:

> Under our base case, we expect that by 2024 the industry's capital spending will exceed $180 billion. Because of the industry's continued robust capital spending, we expect that industry will continue to generate negative discretionary cash flow. This requires that the industry has consistent access to the capital markets to finance capital spending and dividends requirements.[43]

In addition, the investment community also considers the impact of other considerations, such as postretirement benefit and asset retirement obligations, in its evaluation of a utility's financial standing.

A conservative financial profile, in the form of a reasonable common equity ratio, is consistent with the need to accommodate these uncertainties and maintain continuous access to capital under reasonable terms that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Q. What does this evidence suggest with respect to Idaho Power's proposed capital structure?

A. Idaho Power's ratemaking capital structure falls within the range of capital structure ratios maintained by the proxy group and is consistent with industry benchmarks for

[43] S&P Global Ratings, *For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The 'BBB' Category*, RatingsDirect (Jan. 20, 2022).

other electric utility operating companies. While industry guidelines provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. Idaho Power’s proposed capital structure reflects the Company’s ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of the Company’s capital structure is reinforced by the ongoing uncertainties associated with the utility industry and the importance of supporting continued system investment, even during times of adverse industry or market conditions. Based on this evidence, I conclude that the Company’s capital structure represents a reasonable mix of capital sources from which to calculate Idaho Power’s overall rate of return.

V. CAPITAL MARKET ESTIMATES AND ANALYSES

Q. What is the purpose of this section of your testimony?

A. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe the quantitative analyses I conducted to estimate the cost of common equity for the Electric Group.

A. Economic Standards

Q. What fundamental economic principle underlies the cost of equity concept?

A. The concept of the cost of equity is based on the tenet that investors are risk averse. In capital markets where relatively risk-free assets are available (e.g., U.S. Treasury securities), investors will hold riskier assets only if they are offered an additional return, or risk premium, above the rate of return on a risk-free asset. Because all assets compete for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. Yes. The risk-return tradeoff can be documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets—including common stock—required rates of return cannot be observed. Yet there is every reason to believe that investors demonstrate risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. As noted earlier, the last investors in line are common shareholders. They share in the net earnings, if any, that remain after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. What are the challenges in determining a just and reasonable ROE for a utility?

A. The actual return investors require is not directly observable. Different methodologies have been developed to estimate investors' expected return on capital, but these theoretical tools produce a range of estimates, based on different assumptions and inputs. The DCF method, which is frequently referenced and relied on by regulators, is only one theoretical approach to evaluate the return investors require. There are a number of other accepted methodologies for estimating the cost of capital and the ranges produced by these approaches can vary widely.

Q. Is it customary to consider the results of multiple methods when evaluating a just and reasonable ROE?

A. Yes. In my experience, financial analysts and regulators routinely consider the results of alternative approaches in evaluating a fair ROE. No single method can be regarded as failsafe, with all approaches having advantages and shortcomings. As FERC has noted, "[t]he determination of rate of return on equity starts from the premise that there is no single approach or methodology for determining the correct rate of return."[44] Similarly, a publication of the Society of Utility and Regulatory Financial Analysts concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[45]

As this treatise observed, "no single model is so inherently precise that it can be relied on solely to the exclusion of other theoretically sound models."[46] Similarly, *New Regulatory Finance* concluded that:

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[44] *Northwest Pipeline Co.*, Opinion No. 396-C, 81 FERC ¶ 61,036 at 4 (1997).
[45] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Society of Utility and Regulatory Financial Analysts (2010) at 84.
[46] *Id.*

> There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises that cannot be validated empirically. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no monopoly as to which method is used by investors. In the absence of any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities.[47]

Thus, while the DCF model is a recognized approach, it is not without shortcomings and does not otherwise eliminate the need to ensure that the "end result" is fair. The Indiana Utility Regulatory Commission has recognized this principle:

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[47] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 429.

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is. . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[48]

More recently, FERC recognized the potential for any application of the DCF model to produce unreliable results.[49] As this discussion indicates, consideration of the results of alternative approaches reduces the potential for error associated with any single method. Just as investors inform their decisions through the use of a variety of methodologies, my evaluation of a fair ROE for the Company considered the results of multiple financial models.

Q. What does this discussion imply with respect to estimating the ROE for a utility?

A. Although the ROE cannot be observed directly, it is a function of the returns available from other alternatives

[48] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).

[49] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).

and the risks of the investment. Because it is not readily observable, the ROE for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing alternative quantitative methods that focus on investors' required rates of return. These methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. Discounted Cash Flow Analysis

Q. How is the DCF model used to estimate the cost of common equity?

A. DCF models are based on the assumption that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[50]

[50] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in coming year;
k_e = Cost of equity; and,
g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. What steps are required to apply the constant growth DCF model?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to add the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q. How do you determine the dividend yields for the utilities in the Electric Group?

A. I rely on Value Line's estimates of dividends to be paid by each of these utilities over the next twelve months as D_1. This annual dividend is then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Electric Group are presented on page 1 of Exhibit 11. As shown there, dividend yields for the firms in the Electric Group range from 2.5 percent to 5.0 percent and averaged 3.9 percent.

Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate long-term growth expectations, or "g", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. When I implement the DCF model, we are solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. Utility dividend policies reflect the need to accommodate business risks and investment requirements in the industry, as well as potential uncertainties in the capital markets. As a result, dividend growth in the utility industry generally lags growth in earnings as utilities conserve financial resources.

A measure that plays a pivotal role in determining investors' long-term growth expectations is future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS").

The availability of projected EPS growth rates is also key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q. Do the growth rate projections of security analysts also consider historical trends?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. What growth rates are security analysts currently projecting for the firms in the proxy group?

A. EPS growth projections for each of the firms in the Electric Group reported by Value Line, IBES,[51] and Zacks

[51] Formerly Institutional Brokers Estimate System, IBES growth rates are now compiled and published by Refinitiv.

Investment Research (Zacks) are displayed on page 2 of Exhibit 11.

Q. What other technique can be used to estimate investors' expectations of future long-term growth when applying the constant growth DCF model?

A. In constant growth theory, growth in book equity is equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is sometimes proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. The sustainable, "br+sv" growth rates for each firm in the proxy group are summarized on page 2 of Exhibit 11, with the underlying details being presented on Exhibit 12.

The sustainable growth rate analysis shown on Exhibit 12 incorporates an "adjustment factor" because Value Line's reported returns are based on year-end book values. Since earnings is a flow over the year while book value is determined at a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and a point estimate (book value) that makes it necessary to adjust to mid-year in calculating the ROE. Given that book value will increase or decrease over the year, using year-end book value (as Value Line does) understates or overstates the average investment that corresponds to the flow of earnings. To address this concern, earnings must be matched with a corresponding measure of book value, or the resulting ROE will be distorted. The adjustment factor determined in Exhibit 12 is solely a means of converting Value Line's end-of-period values to an average return over the year, and the formula for this adjustment is supported in recognized textbooks and has been adopted by other regulators.[52]

[52] *See,* Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 305-306; *Bangor Hydro-Electric Co. et al.*, 122 FERC ¶ 61,265 at n.12 (2008).

Q. Are there significant shortcomings associated with the "br+sv" growth rate?

A. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b", "r", "s", and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value, such as share prices, as are analysts' EPS growth forecasts.[53] The "sustainable growth" approach is included for completeness, but evidence indicates that analysts' forecasts provide a superior and more direct guide to investors' growth expectations. Accordingly, I give less weight to cost of equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

Q. What cost of common equity estimates are implied for the Electric Group using the DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting

[53] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 307.

cost of common equity estimates are shown on page 3 of Exhibit 11.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate illogical estimates at the extreme low or high end of the range?

A. Yes. It is essential that the cost of equity estimates produced by quantitative methods pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated.

Q. Have other regulators employed such tests?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach and other methods produce illogical results. FERC evaluates low-end DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold.[54] FERC's current practice is to exclude low-end cost of estimates that fall below the six-month average yield on Baa-rated utility bonds, plus 20 percent of the CAPM market risk premium.[55] In addition, FERC also excludes estimates that are

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[54] *See, e.g.*, *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010).

[55] Based on the six-month average yield at March 2023 of 5.75 percent and the 7.8 percent market risk premium shown on Exhibit 13, this implies a current low-end threshold of approximately 7.3 percent.

"irrationally or anomalously high."[56] Similarly, the Staff of the Maryland Public Service Commission ("MDPSC") has also eliminated DCF values where they do not offer a sufficient premium above the cost of debt to be attractive to an equity investor.[57]

Q. Do you exclude any estimates at the low or high end of the range of DCF results?

A. Yes. As highlighted on page 3 of Exhibit 11, after considering these benchmarks and the distribution of individual estimates, I eliminate low-end DCF estimates ranging from -7.6 percent to 7.3 percent, as well as a high-end DCF result of 19.8 percent. After removing these illogical values, the lower end of the DCF results is set by a cost of equity estimate of 7.4 percent, while the upper end is established by a cost of equity estimate of 14.9 percent. While a 14.9 percent cost of equity estimate may exceed the other values, low-end DCF estimates in the 7.4 percent to 8.1 percent range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the results, the remaining values provide a reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return.

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[56] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 171 FERC ¶ 61,154 at P 152 (2020).
[57] See, *e.g.*, Maryland Public Service Commission, Case No. 9670, *Direct Testimony and Exhibits of Drew M. McAuliffe* (Dec. 2, 2021) at 15-16.

Q. What cost of equity estimates are implied by your DCF results for the Electric Group?

A. As shown on page 3 of Exhibit 11 and summarized in Table 3, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following ROE estimates:

TABLE 3
DCF RESULTS - ELECTRIC GROUP

Growth Rate	Average	Midpoint
Value Line	9.2%	9.4%
IBES	10.3%	10.2%
Zacks	10.0%	11.5%
br + sv	9.0%	9.4%

C. Capital Asset Pricing Model

Q. Please describe the CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a firm's stock price to follow changes in the market. A stock that tends to respond less to market movements has a beta of less than 1.0, while stocks that tend to move more than the market have betas greater than 1.0. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Under the CAPM formula above, a stock's required return is a function of the risk-free rate (R_f), plus a risk premium that is scaled to reflect the relative volatility of a firm's stock price, as measured by beta (β). Like the DCF model, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. Why is the CAPM approach relevant when evaluating the cost of equity for Idaho Power?

A. The CAPM approach (which also forms the foundation of the ECAPM) generally is considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is the dominant model for estimating the cost of equity outside the regulatory sphere, the CAPM (and ECAPM) provides important insight into investors' required rate of return for utility stocks.

Q. How do you apply the CAPM to estimate the ROE?

A. Application of the CAPM to the Electric Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented in Exhibit 13. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return is estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm is obtained from Value Line, and the growth rate is equal to the average of the earnings growth projections for each firm published by IBES, Value Line, and Zacks, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. After removing companies with growth rates that were negative or greater than 20 percent, the weighted average of the projections for the individual firms implies an average growth rate over the next five years of 9.5 percent. Combining this average growth rate with a year-ahead dividend yield of 2.1 percent results in a current cost of common equity estimate for the market as a whole (R_m) of 11.6 percent. Subtracting a 3.8 percent risk-free rate based on the average yield on 30-year Treasury bonds for the six-months ending March 2023 produces a market equity risk premium of 7.8 percent.

Q. What is the source of the beta values you use to apply the CAPM?

A. I rely on the beta values reported by Value Line, which in my experience Value Line is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[58]

Q. What else should be considered in applying the CAPM?

A. Financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. Accordingly, a modification is required to account for this size effect. As explained by Morningstar:

> One of the most remarkable discoveries of modern finance is the finding of a relationship between firm size and return. On average, small companies have higher returns than large ones. . . . The relationship between firm size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks.[59]

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[58] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 71.

[59] Morningstar, *2015 Ibbotson SBBI Classic Yearbook*, at 99.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, researchers have developed size premiums that need to be added to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[60] Accordingly, my CAPM analysis also incorporates an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the firms in the Electric Group.

Q. What is the basis for the size adjustment?

The size adjustment required in applying the CAPM is based on the finding that *after controlling for risk differences reflected in beta*, the CAPM overstates returns to companies with larger market capitalizations and understates returns for relatively smaller firms. The size adjustments utilized in my analysis are sourced from Kroll, who now publish the well-known compilation of capital market series originally developed by Professor Roger G. Ibbotson of the Yale School of

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[60] Originally compiled by Ibbotson Associates and published in their annual yearbook entitled, *Stocks, Bonds, Bills and Inflation*, these size premia are now developed by Kroll and presented in its *Cost of Capital Navigator*.

Management, and most recently published by Kroll. Calculation of the size adjustments involve the following steps:

1. Divide all stocks traded on the NYSE, NYSE MKT, and NASDAQ indices into deciles based on their market capitalization.
2. Using the average beta value for each decile, calculate the implied excess return over the risk-free rate using the CAPM.
3. Compare the calculated excess returns based on the CAPM to the actual excess returns for each decile, with the difference being the increment of return that is related to firm size, or "size adjustment."

New Regulatory Finance observed that "small market-cap stocks experience higher returns than large market-cap stocks with equivalent betas," and concluded that "the CAPM understates the risk of smaller utilities, and a cost of equity based purely on a CAPM beta will therefore produce too low an estimate."[61]

Q. What is the implied ROE for the Electric Group using the CAPM approach?

A. As shown on Exhibit 13, after adjusting for the impact of firm size, the CAPM approach implies an average ROE for the Electric Group of 11.2 percent.

D. Empirical Capital Asset Pricing Model

Q. How does the ECAPM approach differ from traditional applications of the CAPM?

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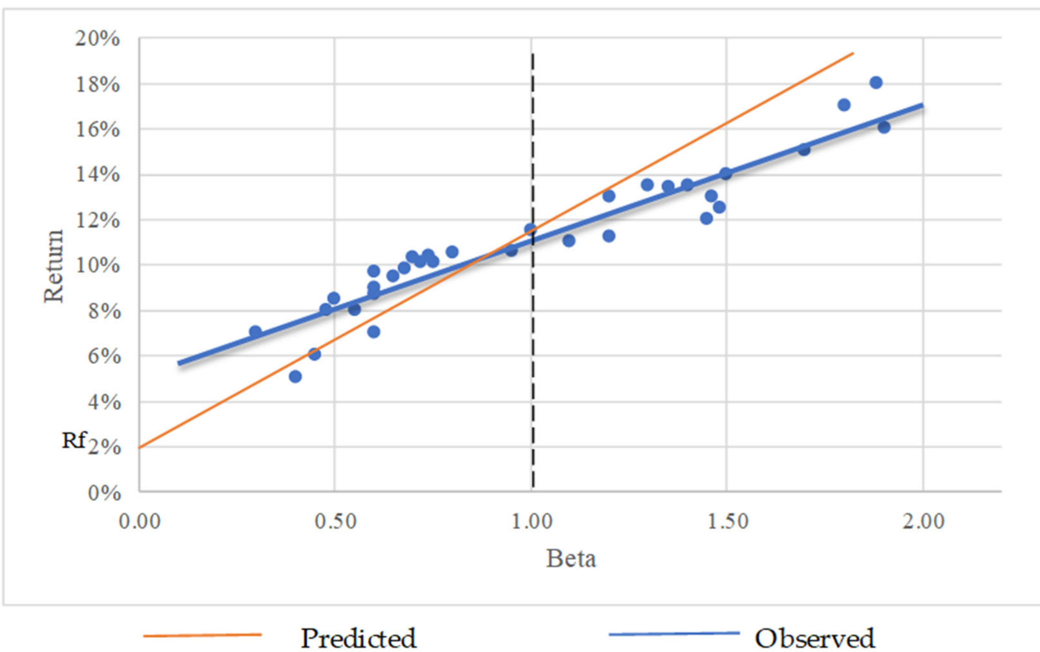
[61] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 187.

A. Empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This is illustrated graphically in the figure below:

FIGURE 2

CAPM – PREDICTED VS. OBSERVED RETURNS



Because the betas of utility stocks, including those in the Electric Group, are generally less than 1.0, this implies that cost of equity estimates based on the traditional CAPM would understate the cost of equity. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[62]

Based on a review of the empirical evidence, *New Regulatory Finance* concluded the expected return on a security is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

Like the CAPM formula presented earlier, the ECAPM represents a stock's required return as a function of the risk-free rate (R_f), plus a risk premium. In the formula above, this risk premium is composed of two parts: (1) the market risk premium ($R_m - R_f$) weighted by a factor of 25 percent, and (2) a company-specific risk premium based on the stock's relative volatility [$\beta_j(R_m - R_f)$] weighted by 75 percent. This ECAPM equation, and its associated weighting factors, recognizes the observed relationship between standard CAPM estimates and the cost of capital documented in the financial

[62] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 189.

research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

Q. Have other regulators relied on the ECAPM?

A. Yes. Staff witnesses for the MDPSC have relied on this approach in prior testimony, noting that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluding that, "the ECAPM gives a more realistic measure of the ROE than the CAPM model does."[63] The Staff of the Colorado Public Utilities Commission has recognized that, "The ECAPM is an empirical method that attempts to enhance the CAPM analysis by flattening the risk-return relationship,"[64] and relied on the same ECAPM equation presented above.[65]

The New York Department of Public Service also routinely incorporates the results of the ECAPM approach, which it refers to as the "zero-beta CAPM."[66] The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM

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[63] *Direct Testimony and Exhibits of Julie McKenna*, Maryland PSC Case No. 9299 (Oct. 12, 2012) at 9.
[64] Proceeding No. 13AL-0067G, *Answer Testimony and Schedules of Scott England* (July 31, 2013) at 47.
[65] *Id.* at 48.
[66] *See, e,g.,* New York Department of Public Service, Cases 19-E-0065 19-G-0066, *Prepared Fully Redacted Testimony of Staff Finance Panel* (May 2019) at 94-95.

> results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.[67]

The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has also relied on this ECAPM formula,[68] as has a witness for the Office of Arkansas Attorney General.[69] In a 2018 decision, the Montana Public Service Commission determined that "[t]he evidence in this proceeding has convinced the Commission that the [ECAPM] should be the primary method for estimating . . . the cost of equity."[70]

Q. What cost of equity estimate is indicated by the ECAPM?

A. My application of the ECAPM was based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the CAPM. As shown on Exhibit 14, applying the forward-looking ECAPM approach to the firms in the Electric Group results in an average cost of equity estimate of 11.4 percent, after

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[67] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002) at 145.
[68] Wyoming Public Service Commission, Docket No. 30011-97-GR-17, *Pre-Filed Direct Testimony of Anthony J. Ornelas* (May 1, 2018) at 52-53.
[69] Arkansas Public Service Commission, Docket No. 17-071-U, *Direct Testimony of Marlon F. Griffing, PH.D.* (May 29, 2018) at 33-35.
[70] Montana Public Service Commission, Docket No. D2017.9.80, Order No. 7575c (Sep. 26, 2018) at P 114.

incorporating the size adjustment corresponding to the market capitalization of the individual utilities.

E. Utility Risk Premium

Q. Briefly describe the risk premium method.

A. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. Is the risk premium approach a widely accepted method for estimating the cost of equity?

A. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely referenced by the investment community and in academia and regulatory proceedings and provides an important tool in estimating a fair ROE for Idaho Power.

Q. How do you implement the risk premium method?

A. I estimate equity risk premiums for utilities based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. When considered in the context of a complete and rigorous analysis, this data provides a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q. How do you calculate the equity risk premiums based on allowed returns?

A. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by S&P Global Market Intelligence and published in its *RRA Regulatory Focus* report. On page 2 of Exhibit 15, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2022.[71] As shown there, over this period these equity risk premiums for electric utilities average 3.89 percent, and the yields on public utility bonds average 7.83 percent.

Q. Is there any capital market relationship that must be considered when implementing the risk premium method?

A. Yes. The magnitude of equity risk premiums is not constant and equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1 percent increase or decrease in interest rates, the cost of equity may only rise or fall some fraction of 1 percent. When implementing the risk premium method, adjustments are required to incorporate this inverse relationship if the current interest rates is different from the average interest rate over the study period.

Current bond yields are lower than those prevailing over the risk premium study period. Given that equity risk premiums move inversely with interest rates, these lower bond

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[71] My analysis encompasses the entire period for which published data is available.

yields also imply an increase in the equity risk premium. In other words, higher required equity risk premiums partially offset the impact of declining interest rates on the ROE.

Q. Is this inverse relationship confirmed by published financial research?

A. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater. This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. As summarized by *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[72]

Other regulators have also recognized that, while the cost of equity trends in the same direction as interest rates,

[72] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 128.

these variables do not move in lock-step.[73] This relationship is illustrated in the figure on page 3 of Exhibit 15.

Q. What ROE is implied by the risk premium method using surveys of allowed returns?

A. Based on the regression output between the interest rates and equity risk premiums displayed on page 3 of Exhibit 15, the equity risk premium for electric utilities increases by approximately 43 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit 15 with an average yield on public utility bonds for the six-months ending March 2023 of 5.75 percent, this implies a current equity risk premium of 4.89 percent for electric utilities. Adding this equity risk premium to the average yield on Baa-rated utility bonds implies a current ROE of 10.64 percent.

F. Expected Earnings Approach

Q. What other analysis do you conduct to estimate the ROE?

A. I also evaluate the ROE using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an

[73] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-7, https://www.entergy-mississippi.com/userfiles/content/price/tariffs/eml_frp.pdf (last visited Apr. 25, 2023); *Martha Coakley et al. v. Bangor Hydro-Elec. Co. et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a just and reasonable rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What economic premise serves as the foundation for the expected earnings approach?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. This outcome would violate the *Hope* and *Bluefield* standards and undermine the utility’s access to capital on reasonable terms.

Q. How is the expected earnings approach typically implemented?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these projected returns on book value equity are analogous to the forward-looking allowed ROE on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices—both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. What ROE is indicated for Idaho Power based on the expected earnings approach?

A. For the firms in the Electric Group, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit 16. As I explained earlier in my discussion of the br+sv growth rates used in applying the DCF model, Value Line's returns on common equity are calculated using year-end equity balances, which understates the average return earned over the year.[74] Accordingly, these year-end values were converted to average returns using the same adjustment factor discussed earlier and

[74] For example, to compute the annual return on a passbook savings account with a beginning balance of $1,000 and an ending balance of $5,000, the interest income would be divided by the average balance of $3,000. Using the $5,000 balance at the end of the year would understate the actual return.

developed on Exhibit 12. As shown on Exhibit 16, Value Line's projections for the Electric Group suggest an average ROE of 11.0 percent.

G. Flotation Costs

Q. What other consideration is relevant in setting the return on equity for a utility?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q. Is there academic evidence that supports a flotation cost adjustment?

A. Yes. The financial literature and evidence in this case provides a sound theoretical and practical basis to include consideration of flotation costs for Idaho Power. An adjustment for flotation costs associated with past sales of common stock is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past common stock offerings has been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[75] Similarly, *New Regulatory Finance* contains the following discussion:

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[76]

[75] E. F. Brigham, D. A. Aberwald, and L. C. Gapenski, *Common Equity Flotation Costs and Rate Making*, Pub. Util. Fortnightly (May 2, 1985).
[76] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 335.

Q. Can you illustrate why investors will not have the opportunity to earn their required ROE unless a flotation cost adjustment is included?

A. Yes. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5 percent of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 10.5 percent, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5 percent), and that growth is expected to be 5.5 percent annually. As developed in Table 4 below, if the allowed rate of return on common equity is only equal to the utility's 10.5 percent "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will only be 5.25 percent, instead of 5.5 percent:

TABLE 4
NO FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	EPS	DPS	Payout Ratio
1	$9.52	$ -	$ 9.52	$10.00	1.050	10.50%	$1.00	$0.50	50.0%
2	$9.52	$0.50	$10.02	$10.52	1.050	10.50%	$1.05	$0.53	50.0%
3	$9.52	$0.53	$10.55	$11.08	1.050	10.50%	$1.11	$0.55	50.0%
Growth			5.25%	5.25%			5.25%	5.25%	

The reason that investors never really earn 10.5 percent on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Including a flotation cost adjustment allows investors to be fully compensated for the impact of these costs. One commonly referenced method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5 percent dividend yield and a 5 percent flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown in Table 5 below, by allowing a rate of return on common equity of 10.75 percent (a 10.5 percent cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 10.5 percent required rate of return, since actual growth is now equal to 5.5 percent:

TABLE 5
INCLUDING FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	EPS	DPS	Payout Ratio
1	$9.52	$ -	$ 9.52	$10.00	1.050	10.75%	$1.02	$0.50	48.9%
2	$9.52	$0.52	$10.04	$10.55	1.050	10.75%	$1.08	$0.53	48.9%
3	$9.52	$0.55	$10.60	$11.13	1.050	10.75%	$1.14	$0.56	48.9%
Growth			5.50%	5.50%			5.50%	5.50%	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether the utility is expected to issue additional shares of common stock in the future.

Q. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A. The most common method used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. In Exhibit 17, I present a survey of recent open-market common stock issues for each company in Value Line's electric and gas utility industries. For all companies in the electric and gas industries, flotation costs averaged 2.7 percent, or 2.6 percent for electric utilities. Applying the average 2.6 percent expense percentage for electric utilities to the Electric Group dividend yield of 3.8 percentage produces a flotation cost adjustment on the order of 10 basis points.

Q. Have other regulators recognized flotation costs in evaluating a fair and reasonable ROE?

A. Yes. For example, In Case No. INT-G-16-02 the IPUC staff noted that applying a flotation cost percentage to the dividend yield "is referred to as the 'conventional' approach. Its use in regulatory proceedings is widespread, and the formula is outlined in several corporate finance textbooks."[77] In Docket No. UE-991606 the Washington Utilities and Transportation Commission concluded that a flotation cost adjustment of 25 basis points should be included in the allowed return on equity.[78]

More recently, the Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, recommended a 10 basis point flotation cost adjustment.[79] Similarly, the South Dakota Public Utilities Commission has recognized the impact of issuance costs, concluding that, "recovery of reasonable flotation costs is appropriate."[80] Another example of a regulator that approves common stock issuance costs is the Mississippi Public Service Commission, which routinely includes a flotation cost adjustment in its Rate Stabilization Adjustment Rider formula.[81] The Public Utilities Regulatory Authority of Connecticut[82] the Minnesota Public Utilities Commission,[83] and

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[77] Idaho Public Utilities Commission, Case No. INT-G-16-02, *Direct Testimony of Mark Rogers* (Dec. 16, 2016) at 18.
[78] Washington Utilities and Transportation Commission Docket No. UE-991606, *et al., Third Supplemental Order* (September 2000) at 95.
[79] Wyoming Public Service Commission, Docket No. 30011-97-GR-17, *Pre-Filed Direct Testimony of Anthony J. Ornelas* (May 1, 2018) at 52-53.
[80] South Dakota Public Utilities Commission, *Northern States Power Co*, EL11-019, Final Decision and Order at P 22 (2012).
[81] *See, e.g.*, Entergy Mississippi Formula Rate Plan FRP-7, https://cdn.entergy-mississippi.com/userfiles/content/price/tariffs/eml_frp.pdf (last visited Apr. 25, 2023).
[82] *See, e.g.*, The Public Utilities Regulatory Authority of Connecticut, Docket No. 14-05-06, Decision (Dec. 17, 2014) at 133-134.
[83] *See, e.g.,* Minnesota Public Utilities Commission, Docket No. E001/GR-10-276, Findings of Fact, Conclusions, and Order at 9.

the Virginia State Corporation Commission[84] have also recognized that flotation costs are a legitimate expense worthy of consideration in setting a fair and reasonable ROE.

VI. NON-UTILITY BENCHMARK

Q. What is the purpose of this section of your testimony?

A. This section presents the results of my DCF analysis for a group of low-risk firms in the competitive sector, which I refer to as the "Non-Utility Group." This analysis is not directly considered to arrive at my recommended ROE range of reasonableness; however, it is my opinion that this is a relevant consideration in evaluating a fair ROE for the Company.

Q. Do utilities have to compete with non-regulated firms for capital?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only a small fraction of total common stock investment, and there is a plethora of other alternatives available to investors. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. This

[84] Virginia State Corporation Commission, Roanoke Gas Company, Case No. PUR-2018-00013, *Final Order*, (Jan. 24, 2020) at 6.

understanding is consistent with modern portfolio theory, which is built on the assumption that rational investors will hold a diverse portfolio of stocks and not just companies in a single industry.

Q. Is it consistent with the *Bluefield* and *Hope* cases to consider investors' required ROE for non-utility companies?

A. Yes. The cost of equity capital in the competitive sector of the economy forms the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[85]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

[85] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 391 (1944).

Q. Does consideration of the results for the Non-Utility Group improve the reliability of DCF results?

A. Yes. Growth estimates used in the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. Such distortions could result in biased DCF estimates for utilities. Because the Non-Utility Group includes low risk companies from more than one industry, it helps to insulate against any possible distortion that may be present in results for a particular sector.

Q. What criteria do you apply to develop the Non-Utility Group?

A. My comparable risk proxy group was composed of those United States companies followed by Value Line that:

1) pay common dividends;
2) have a Safety Rank of "1";
3) have a Financial Strength Rating of "A" or greater;
4) have a beta of 0.95 or less; and
5) have investment grade credit ratings from S&P and Moody's.

Q. How do the overall risks of your Non-Utility Group compare to the proxy group of electric utilities?

A. Table 6 compares the Non-Utility Group to the Electric Group and Idaho Power across the four key indices of investment risk discussed earlier.

TABLE 6

COMPARISON OF RISK INDICATORS

	Credit Ratings		Value Line		
	S&P	Moody's	Safety Rank	Financial Strength	Beta
Non-Utility Group	A-	A2	1	A+	0.81
Electric Group	BBB+	Baa2	2	A	0.89
Idaho Power	BBB	Baa1	1	A+	0.80

Note: Idaho Power's Value Line ratings are for its parent company, IDACORP.

As shown above, the risk indicators for the Non-Utility Group suggest equivalent or less risk than for the Electric Group and Idaho Power.

The companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Kellogg, Procter & Gamble, and Walmart, have long corporate histories, well-established track records, and conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group at 2.3 percent.[86] Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

[86] Exhibit 18 at page 1.

Q. What are the results of your DCF analysis for the Non-Utility Group?

A. I apply the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Electric Group, with the results being presented on page 3 of Exhibit 18. As summarized in Table 7, below, after eliminating illogical values, application of the constant growth DCF model results in the following cost of equity estimates:

TABLE 7
DCF RESULTS – NON-UTILITY GROUP

Growth Rate	Average	Midpoint
Value Line	10.9%	11.9%
IBES	10.4%	10.7%
Zacks	10.9%	12.1%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for Idaho Power.

Q. Does this conclude your direct testimony?

A. Yes, it does.

DECLARATION OF Adrien M. McKenzie, CFA

I, Adrien M. Mckenzie, CFA, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Adrien M. McKenzie. I am President of Financial Concepts and Applications, Inc. ("FINCAP"), a firm providing financial, economic, and policy consulting services to business and government.

2. On behalf of Idaho Power, I present this pre-filed direct testimony in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Austin, Texas.

Signed: ______________________
Adrien M. McKenzie

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI TESTIMONY

EXHIBIT NO. 7

EXHIBIT 7

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Adrien M. McKenzie. My business address is 3907 Red River Street, Austin, Texas 78751.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a principal in FINCAP, Inc., a firm engaged primarily in financial, economic, and policy consulting in the field of public utility regulation.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin and hold the Chartered Financial Analyst (CFA®) designation. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have personally sponsored direct and rebuttal testimony in over 180 proceedings filed with the Federal Energy Regulatory Commission ("FERC") and regulatory agencies in Alaska, Arkansas, Colorado, District of Columbia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Montana, Nebraska, New Mexico, Ohio, Oklahoma, Oregon, South Dakota, Texas, Virginia, Washington, West Virginia, and Wyoming. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair rate of return on equity for regulated electric, gas, and water utility operations. In connection with these assignments, my responsibilities have included critically evaluating the positions of other parties and preparation of rebuttal testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs.

FINCAP was formed in 1979 as an economic and financial consulting firm serving clients in both the regulated and competitive sectors. FINCAP conducts assignments ranging from broad qualitative analyses and policy consulting to technical analyses and research. The firm's experience is in the areas of public utilities, valuation of closely-held businesses, and economic evaluations (e.g., damage and cost/benefit analyses). Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I am a member of the CFA Institute. A resume containing the details of my qualifications and experience is attached below.

ADRIEN M. McKENZIE

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Economic and Financial Counsel

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Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA®) designation. He has over 30 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

President FINCAP, Inc. (June 1984 to June 1987) (April 1988 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.
Manager, McKenzie Energy Company (Jan. 1981 to May. 1984)	Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA®) designation in 1990.

Member – CFA Institute.

Bibliography

“A Profile of State Regulatory Commissions,” A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

“The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test,” with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

“ROE at FERC: Issues and Methods,” *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014).

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012).

“Cost-of-Service Studies and Rate Design,” General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and sponsored prefiled testimony submitted in over 150 regulatory proceedings. In addition to filings before regulatory agencies in Alaska, Arkansas, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Montana, Nebraska, New Mexico, Ohio, Oklahoma, Oregon, South Dakota, Texas, Virginia, Washington, West Virginia, and Wyoming, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of rate of return on equity ("ROE"), and has broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE. Other representative assignments have included developing cost of service and cost allocation studies, the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI
TESTIMONY

EXHIBIT NO. 8

SUMMARY OF RESULTS

Method	Average
DCF	
Value Line	9.2%
IBES	10.3%
Zacks	10.0%
Internal br + sv	9.0%
CAPM	11.2%
ECAPM	11.4%
Utility Risk Premium	10.6%
Expected Earnings	11.0%

ROE Recommendation			
Cost of Equity	**10.0%**	**--**	**11.0%**
Flotation Cost Adjustment			
Electric Group Dividend Yield		3.88%	
Flotation Cost Expense Factor		2.56%	
Flotation Cost Adjustment		0.10%	
Recommended ROE Range			
Range	**10.1%**	**--**	**11.1%**
Midpoint		**10.6%**	

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI TESTIMONY

EXHIBIT NO. 9

ELECTRIC GROUP

	Company	Type of Adjustment Clause (a)				New Capital					(b)	(c)
			Conserv. Program	Decoupling		Trad.	Renewables/	Delivery	Environ.	Trans.	Future Test	Formula Rates /
		Fuel/PPA	Expense	Full	Partial	Generation	Non-Trad.	Infra.	Compliance	Costs	Year	MRP
1	ALLETE	✓	✓	--	--	--	--	--	✓	✓	C	✓
2	Ameren Corp.	✓	✓	✓	✓	--	✓	✓	✓	✓	O,P	✓
3	Avista Corp.	✓	✓	✓	--	--	--	--	--	--	P	✓
4	Black Hills Corp.	✓	✓	--	✓	✓	✓	--	✓	✓	O	✓
5	CMS Energy Corp.	✓	✓	--	--	--	✓	--	--	✓	C	--
6	Dominion Energy	✓	✓	--	--	✓	✓	✓	✓	✓	--	✓
7	DTE Energy Co.	✓	✓	--	--	--	✓	--	--	✓	C	--
8	Duke Energy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	C,O,P	✓
9	Entergy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	O,P	✓
10	Exelon Corp.	D	✓	✓	✓	--	✓	✓	✓	--	O,P	✓
11	Hawaiian Elec.	✓	✓	--	--	--	✓	--	--	--	C	✓
12	IDACORP, Inc.	✓	✓	✓	--	--	--	--	--	--	C,P	--
13	NorthWestern Corp.	✓	✓	--	--	--	--	--	--	--	--	--
14	OGE Energy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	P	✓
15	Otter Tail Corp.	✓	✓	--	--	✓	✓	✓	✓	✓	C,O	✓
16	Pinnacle West Capital	✓	✓	--	✓	--	✓	--	✓	✓	--	✓
17	Portland General Elec.	✓	✓	--	--	✓	✓		✓	✓	C	--
18	Pub Sv Enterprise Grp.	D	✓	--	✓	--	--	✓	✓	--	P	--
19	Sempra Energy	✓	✓	✓	--	--	--	✓	--	✓	C	✓
20	Southern Company	✓	--	--	✓	✓	✓	--	✓	--	C,O	✓

Notes
D - Delivery-only utility.
C - Fully-forecasted test years commonly used in the state listed for this operating company.
O - Fully-forecasted test years occasionally used in the state listed for this operating company.
P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

Source: Exhibit 9, pages 2-4, contain operating company data that are aggregated into the parent company data on this page.

ELECTRIC GROUP OPERATING COS.

			Type of Adjustment Clause (a)									(b)	(c)
				Conserv.	Decoupling		New Capital					Future	Formula
				Program			Trad.	Renewables/	Delivery	Environ.	Trans.	Test	Rates /
	Company	**State**	**Fuel/PPA**	**Expense**	**Full**	**Partial**	**Generation**	**Non-Trad.**	**Infra.**	**Compliance**	**Costs**	**Year**	**MRP**
1	**ALLETE**												
	Minnesota Power Enterprises Inc.	MN	✓	✓	--	--	--	✓	--	--	✓	C	✓
2	**AMEREN CORP.**												
	Ameren Illinois Co.	IL	D *	✓	--	✓ *	--	✓	--	✓ *	✓	O	✓
	Union Electric Co.	MO	✓	✓ *	--	✓ *	--	✓ *	✓ *	-- *	✓ *	P	--
3	**AVISTA CORP.**												
	Alaska Electric Light & Power Co.	AK	✓	--	--	--	--	--	--	--	--	--	--
	Avista Corp.	ID	✓ *	✓	✓ *	--	--	--	--	--	--	P	--
	Avista Corp.	WA	✓ *	✓	✓	-- *	--	--	--	--	--	--	✓
4	**BLACK HILLS CORP.**												
	Black Hills Colorado Electric Inc.	CO	✓	✓	--	--	✓ *	✓	--	--	✓	--	✓
	Black Hills Power Inc.	SD	✓	--	--	--	--	--	--	✓ *	✓ *	--	--
	Cheyenne Light Fuel & Power Co.	WY	✓	✓	--	✓ *	--	--	--	--	--	O	--
5	**CMS ENERGY**												
	Consumers Energy Co.	MI	✓	✓	-- *	--	--	✓	--	--	✓ *	C	--
6	**DOMINION ENERGY**												
	Virginia Electric & Power Co.	NC	✓	✓ *	--	-- *	--	✓ *	--	✓	--	--	--
	Dominion Energy South Carolina	SC	✓	✓	--	--	✓ *	--	--	✓	--	--	✓
	Virginia Electric & Power Co.	VA	✓	✓	--	--	✓	✓	✓	✓	✓	--	✓
7	**DTE ENERGY CO.**												
	DTE Electric Co.	MI	✓	✓	-- *	--	--	✓	--	--	✓ *	C	--
8	**DUKE ENERGY**												
	Duke Energy Florida LLC	FL	✓	✓	--	--	✓ *	✓ *	-- *	✓	--	C	✓
	Duke Energy Indiana LLC	IN	✓	✓	--	✓ *	--	✓	✓ *	✓ *	✓	--	✓
	Duke Energy Kentucky Inc.	KY	✓	✓	--	✓ *	--	--	--	✓	--	O	--
	Duke Energy Carolinas LLC	NC	✓	✓ *	--	-- *	--	✓ *	--	✓	--	--	--
	Duke Energy Progress LLC	NC	✓	✓ *	--	-- *	--	✓ *	--	✓	--	--	--
	Duke Energy Ohio Inc.	OH	D *	✓ *	--	✓ *	--	✓	✓ *	--	✓	P	✓
	Duke Energy Progress LLC	SC	✓	✓	--	--	-- *	--	--	✓	--	--	✓
	Duke Energy Carolinas LLC	SC	✓	✓	--	--	-- *	--	--	✓	--	--	✓

ELECTRIC GROUP OPERATING COS.

			Type of Adjustment Clause (a)									(b)	(c)
				Conserv.			New Capital					Future	Formula
				Program	Decoupling		Trad.	Renewables/	Delivery	Environ.	Trans.	Test	Rates /
	Company	State	Fuel/PPA	Expense	Full	Partial	Generation	Non-Trad.	Infra.	Compliance	Costs	Year	MRP
9	**ENTERGY CORP.**												
	Entergy Arkansas LLC	AR	✓	✓	--	✓ *	✓ *	✓ *	✓ *	--	✓	P	✓
	Entergy New Orleans LLC	LA	✓	✓	--	--	--	✓	--	✓ *	✓ *	O	✓
	Entergy Louisiana LLC	LA	✓	✓ *	--	✓ *	--	--	--	✓	--	O	✓
	Entergy Mississippi LLC	MS	✓	--	--	✓ *	--	--	--	--	✓	O	✓
	Entergy Texas Inc.	TX	✓ *	✓	--	--	✓ *	--	✓	--	✓	--	✓
10	**EXELON CORP.**												
	Delmarva Power & Light Co.	DE	D *	✓	--	--	--	--	✓ *	--	✓	P	--
	Potomac Electric Power Co.	DC	D *	--	--	✓ *	--	✓ *	✓ *	--	--	P	--
	Commonwealth Edison Co.	IL	D *	✓	--	--	--	✓	✓ *	✓ *	✓	O	✓
	Baltimore Gas & Electric Co.	MD	D *	✓	✓	--	--	--	--	--	--	P	--
	Delmarva Power & Light Co.	MD	D *	✓	✓	--	--	--	--	--	--	P	--
	Potomac Electric Power Co.	MD	D *	✓	✓	--	--	--	✓ *	--	--	P	--
	Atlantic City Electric Co.	NJ	D *	✓ *	--	✓ *	--	--	✓ *	✓ *	--	P	--
	PECO Energy Co.	PA	D *	✓	--	--	--	--	✓ *	--	✓	O	--
11	**HAWAIIAN ELEC.**												
	Hawaiian Electric Co.	HI	✓	✓	--	--	--	✓ *	--	--	--	C	✓
	Hawaii Electric Light Co.	HI	✓	✓	--	--	--	--	--	--	--	C	✓
	Maui Electric Co.	HI	✓	✓	--	--	--	✓ *	--	--	--	C	✓
12	**IDACORP**												
	Idaho Power Co.	ID	✓ *	✓	✓ *	--	--	--	--	--	--	P	--
	Idaho Power Co.	OR	✓	✓	--	--	--	--	--	--	--	C	--
13	**NORTHWESTERN CORP.**												
	NorthWestern Corp.	MT	✓ *	✓	--	--	--	--	--	--	--	--	--
	NorthWestern Corp.	SD	✓	✓	--	--	--	--	--	--	--	--	--
14	**OGE ENERGY CORP.**												
	Oklahoma Gas & Electric Co.	AR	✓	✓	--	✓ *	✓	✓	✓	✓	✓	P	--
	Oklahoma Gas & Electric Co.	OK	✓	✓ *	--	✓ *	--	--	✓ *	✓ *	✓ *	--	✓
15	**OTTER TAIL CORP.**												
	Otter Tail Power Co.	MN	✓	✓	--	--	--	✓	--	✓	✓	C	--
	Otter Tail Power Co.	ND	✓	--	--	--	✓ *	✓ *	✓ *	✓ *	✓ *	O	✓
	Otter Tail Power Corp.	SD	✓	✓	--	--	✓ *	--	✓	✓	--	--	--
16	**PINNACLE WEST CAPITAL**												
	Arizona Public Service Co.	AZ	✓	✓	--	✓ *	--	✓	--	✓	✓	--	✓
17	**PORTLAND GENERAL ELECTRIC**												
	Portland General Electric Co.	OR	✓	✓	--	--	✓ *	✓ *	--	✓ *	✓	C	--

<u>ELECTRIC GROUP OPERATING COS.</u>

		Type of Adjustment Clause (a)									(b)	(c)
			Conserv.	Decoupling		New Capital					Future	Formula
			Program			Trad.	Renewables/	Delivery	Environ.	Trans.	Test	Rates /
Company	**State**	**Fuel/PPA**	**Expense**	**Full**	**Partial**	**Generation**	**Non-Trad.**	**Infra.**	**Compliance**	**Costs**	**Year**	**MRP**
18 PUB SV ENTERPRISE GRP												
Public Service Electric & Gas Co.	NJ	D *	✓ *	--	✓ *	--	--	✓ *	✓ *	--	P	--
19 SEMPRA ENERGY												
San Diego Gas & Electric Co.	CA	✓	--	✓	--	--	--	--	--	--	C	✓
Oncor Electric Delivery Co.	TX	D *	✓	--	--	--	--	✓	--	✓	--	✓
20 SOUTHERN CO.												
Alabama Power Co.	AL	✓ *	--	--	--	✓ *	✓	--	✓ *	--	C	✓
Georgia Power Co.	GA	✓	--	--	--	✓ *	--	--	✓ *	--	C	✓
Mississippi Power Co.	MS	✓	--	--	✓ *	--	--	--	✓ *	--	O	✓

(a) S&P Global Market Intelligence, *Adjustment clauses: A state by state overview* , Regulatory Focus Topical Special Report (Jul. 18, 2022).
(b) Edison Electric Institute, *Alternative Regulation for Emerging Utility Challenges: 2015 Update* (Nov. 11, 2015).
(c) Formula rates and Multiyear Rate plans approved in the state listed for this operating company. *See* , U.S. Department of Energy, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities* ,GRID Modernization Laboratory Consortium (Jul. 2017); The Brattle Group, *Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates* , Joint Utilities of Maryland (Mar. 29, 2018); SEC Form 10-K Reports.

<u>Notes</u>
D - Delivery-only utility.
C - Fully-forecasted test years commonly used in the state listed for this operating company.
O - Fully-forecasted test years occasionally used in the state listed for this operating company.
P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.
* For additional context around the specific recovery mechanisms available to the particular operating companies in each state, see the source document.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI
TESTIMONY

EXHIBIT NO. 10

ELECTRIC GROUP

		At Year-end 2022 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Preferred	Common Equity
1	ALLETE	36.5%	0.0%	63.5%	40.5%	0.0%	59.5%
2	Ameren Corp.	56.9%	0.0%	43.1%	51.0%	0.5%	48.5%
3	Avista Corp.	49.6%	0.0%	50.4%	48.5%	0.0%	51.5%
4	Black Hills Corp.	57.2%	0.0%	42.8%	50.0%	0.0%	50.0%
5	CMS Energy Corp.	65.2%	1.0%	33.8%	61.5%	1.0%	37.5%
6	Dominion Energy	60.2%	2.5%	37.2%	57.0%	2.0%	41.0%
7	DTE Energy Co.	63.4%	0.0%	36.6%	61.0%	0.0%	39.0%
8	Duke Energy Corp.	57.9%	1.6%	40.5%	61.0%	1.5%	37.5%
9	Entergy Corp.	66.1%	0.6%	33.3%	67.0%	0.0%	33.0%
10	Exelon Corp.	60.0%	0.0%	40.0%	64.5%	0.0%	35.5%
11	Hawaiian Elec.	57.9%	0.6%	41.4%	50.0%	0.5%	49.5%
12	IDACORP, Inc.	43.8%	0.0%	56.2%	50.0%	0.0%	50.0%
13	NorthWestern Corp.	48.3%	0.0%	51.7%	49.0%	0.0%	51.0%
14	OGE Energy Corp.	50.8%	0.0%	49.2%	50.0%	0.0%	50.0%
15	Otter Tail Corp.	40.4%	0.0%	59.6%	42.5%	0.0%	57.5%
16	Pinnacle West Capital	55.8%	0.0%	44.2%	54.5%	0.0%	45.5%
17	Portland General Elec.	58.8%	0.0%	41.2%	55.0%	0.0%	45.0%
18	Pub Sv Enterprise Grp.	56.8%	0.0%	43.2%	54.5%	0.0%	45.5%
19	Sempra Energy	44.9%	1.6%	53.5%	46.0%	1.5%	52.5%
20	Southern Company	61.4%	0.0%	38.6%	63.0%	0.0%	37.0%
	Minimum	**36.5%**	**0.0%**	**33.3%**	**40.5%**	**0.0%**	**33.0%**
	Maximum	**66.1%**	**2.5%**	**63.5%**	**67.0%**	**2.0%**	**59.5%**
	Average	**54.6%**	**0.4%**	**45.0%**	**53.8%**	**0.4%**	**45.8%**

(a) SEC Form 10-K reports. Debt includes current maturities.
(b) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).

ELECTRIC GROUP OPERATING COS.

		At Year-End 2022 (a)		
	Operating Company	Debt	Preferred	Common Equity
1	**ALLETE**			
	ALLETE, Inc. (Minnesota Power)	40.3%	0.0%	59.7%
2	**AMEREN CORP.**			
	Ameren Illinois Co.	43.9%	0.4%	55.6%
	Union Electric Co.	48.6%	0.6%	50.7%
3	**AVISTA CORP.**			
	Avista Corp.	49.3%	0.0%	50.7%
	Alaska Electric Light & Power	39.1%	0.0%	60.9%
4	**BLACK HILLS CORP.**			
	Black Hills Power	49.9%	0.0%	50.1%
	Cheyenne Light Fuel & Power	57.2%	0.0%	42.8%
	Black Hills/Colorado Electric Utility Co	52.1%	0.0%	47.9%
5	**CMS ENERGY**			
	Consumers Energy Co.	50.2%	0.2%	49.6%
6	**DOMINION ENERGY**			
	Virginia Electric & Power	48.4%	0.0%	51.6%
	Dominion Energy South Carolina	45.2%	0.0%	54.8%
7	**DTE ENERGY CO.**			
	DTE Electric Co.	50.0%	0.0%	50.0%
8	**DUKE ENERGY**			
	Duke Energy Carolinas	48.0%	0.0%	52.0%
	Duke Energy Florida	51.8%	0.0%	48.2%
	Duke Energy Indiana	47.8%	0.0%	52.2%
	Duke Energy Ohio	40.5%	0.0%	59.5%
	Duke Energy Progress	51.8%	0.0%	48.2%
	Duke Energy Kentucky	47.0%	0.0%	53.0%
9	**ENTERGY CORP.**			
	Entergy Arkansas Inc.	52.4%	0.0%	47.6%
	Entergy Louisiana LLC	53.0%	0.0%	47.0%
	Entergy Mississippi Inc.	53.3%	0.0%	46.7%
	Entergy New Orleans Inc.	52.4%	0.0%	47.6%
	Entergy Texas Inc.	51.9%	0.7%	47.4%
10	**EXELON CORP.**			
	Delmarva Power and Light	49.8%	0.0%	50.2%
	Baltimore Gas & Electric Co.	46.0%	0.0%	54.0%
	Commonweath Edison Co.	44.5%	0.0%	55.5%
	PECO Energy Co.	46.3%	0.0%	53.7%
	Potomac Electric Power Co.	49.8%	0.0%	50.2%
	Atlantic City Electric Co.	50.1%	0.0%	49.9%

ELECTRIC GROUP OPERATING COS.

	Operating Company	At Year-End 2022 (a) Debt	Preferred	Common Equity
11	**HAWAIIAN ELEC.**			
	Hawaiian Electric Co.	41.5%	0.8%	57.7%
12	**IDACORP**			
	Idaho Power Co.	45.5%	0.0%	54.5%
13	**NORTHWESTERN CORP.**			
	NorthWestern Corporation	49.7%	0.0%	50.3%
14	**OGE ENERGY CORP.**			
	Oklahoma G&E	44.2%	0.0%	55.8%
15	**OTTER TAIL CORP.**			
	Otter Tail Power Co.	45.1%	0.0%	54.9%
16	**PINNACLE WEST CAPITAL**			
	Arizona Public Service Co.	49.1%	0.0%	50.9%
17	**PORTLAND GENERAL ELECTRIC**			
	Portland General Electric	56.8%	0.0%	43.2%
18	**PUB SV ENTERPRISE GRP**			
	Pub Service Electric & Gas Co.	44.7%	0.0%	55.3%
19	**SEMPRA ENERGY**			
	San Diego Gas & Electric	49.8%	0.0%	50.2%
	Oncor Electric Delivery	43.3%	0.0%	56.7%
20	**SOUTHERN CO.**			
	Alabama Power Co.	47.6%	0.0%	52.4%
	Georgia Power Co.	44.2%	0.0%	55.8%
	Mississippi Power Co.	44.4%	0.0%	55.6%

	Debt	Preferred	Common Equity
Minimum	**39.1%**	**0.0%**	**42.8%**
Maximum	**57.2%**	**0.8%**	**60.9%**
Average	**48.1%**	**0.1%**	**51.8%**

(a) Data from 2022 SEC Form 10-K and FERC Form 1 reports. Debt includes current maturities.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI TESTIMONY

EXHIBIT NO. 11

DCF MODEL - ELECTRIC GROUP **Exhibit 11**

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	ALLETE	$ 61.92	$ 2.71	4.4%
2	Ameren Corp.	$ 84.03	$ 2.52	3.0%
3	Avista Corp.	$ 41.11	$ 1.84	4.5%
4	Black Hills Corp.	$ 61.80	$ 2.50	4.0%
5	CMS Energy Corp.	$ 60.10	$ 1.95	3.2%
6	Dominion Energy	$ 55.51	$ 2.75	5.0%
7	DTE Energy Co.	$ 108.71	$ 3.81	3.5%
8	Duke Energy Corp.	$ 95.49	$ 4.02	4.2%
9	Entergy Corp.	$ 104.69	$ 4.28	4.1%
10	Exelon Corp.	$ 41.21	$ 1.44	3.5%
11	Hawaiian Elec.	$ 39.02	$ 1.44	3.7%
12	IDACORP, Inc.	$ 104.16	$ 3.16	3.0%
13	NorthWestern Corp.	$ 56.81	$ 2.56	4.5%
14	OGE Energy Corp.	$ 36.13	$ 1.70	4.7%
15	Otter Tail Corp.	$ 69.99	$ 1.76	2.5%
16	Pinnacle West Capital	$ 75.82	$ 3.48	4.6%
17	Portland General Elec.	$ 47.58	$ 1.88	4.0%
18	Pub Sv Enterprise Grp.	$ 59.49	$ 2.28	3.8%
19	Sempra Energy	$ 149.16	$ 4.80	3.2%
20	Southern Company	$ 65.96	$ 2.72	4.1%
	Average			**3.9%**

(a) Average of closing prices for 30 trading days ended Mar. 29, 2023.

(b) The Value Line Investment Survey, Summary & Index (Mar. 31, 2023).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			**br+sv**
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	ALLETE	6.0%	8.7%	7.3%	4.8%
2	Ameren Corp.	6.5%	6.7%	6.9%	5.8%
3	Avista Corp.	3.5%	5.2%	5.2%	4.3%
4	Black Hills Corp.	6.0%	5.4%	2.2%	6.2%
5	CMS Energy Corp.	6.5%	8.0%	8.0%	6.5%
6	Dominion Energy	4.0%	6.1%	14.9%	5.9%
7	DTE Energy Co.	4.5%	7.4%	6.0%	6.2%
8	Duke Energy Corp.	5.0%	5.3%	5.4%	3.6%
9	Entergy Corp.	0.5%	6.6%	6.0%	3.2%
10	Exelon Corp.	n/a	6.3%	6.6%	4.5%
11	Hawaiian Elec.	4.5%	1.3%	3.1%	4.6%
12	IDACORP, Inc.	4.5%	3.0%	3.0%	3.6%
13	NorthWestern Corp.	3.5%	4.5%	1.7%	3.5%
14	OGE Energy Corp.	6.5%	-12.3%	10.2%	5.0%
15	Otter Tail Corp.	4.5%	9.0%	n/a	4.7%
16	Pinnacle West Capital	0.5%	7.1%	n/a	3.3%
17	Portland General Elec.	5.0%	4.2%	6.1%	5.2%
18	Pub Sv Enterprise Grp.	4.5%	2.4%	4.3%	4.9%
19	Sempra Energy	7.0%	4.1%	5.4%	4.7%
20	Southern Company	6.5%	7.3%	4.0%	6.8%

(a) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).
(b) www.finance.yahoo.com (retreived Mar. 30, 2023).
(c) www.zacks.com (retrieved Mar. 30, 2023).
(d) See Exhibit 12.

DCF MODEL - ELECTRIC GROUP **Exhibit 11**

COST OF EQUITY ESTIMATES

	Company	(a) V Line	(a) IBES	(a) Zacks	(a) br+sv Growth
1	ALLETE	10.4%	13.1%	11.7%	9.2%
2	Ameren Corp.	9.5%	9.7%	9.9%	8.8%
3	Avista Corp.	8.0%	9.7%	9.7%	8.8%
4	Black Hills Corp.	10.0%	9.4%	6.2%	10.2%
5	CMS Energy Corp.	9.7%	11.2%	11.3%	9.8%
6	Dominion Energy	9.0%	11.0%	19.8%	10.9%
7	DTE Energy Co.	8.0%	10.9%	9.5%	9.7%
8	Duke Energy Corp.	9.2%	9.5%	9.6%	7.8%
9	Entergy Corp.	4.6%	10.7%	10.1%	7.3%
10	Exelon Corp.	n/a	9.8%	10.1%	7.9%
11	Hawaiian Elec.	8.2%	5.0%	6.8%	8.3%
12	IDACORP, Inc.	7.5%	6.0%	6.0%	6.7%
13	NorthWestern Corp.	8.0%	9.0%	6.2%	8.1%
14	OGE Energy Corp.	11.2%	-7.6%	14.9%	9.8%
15	Otter Tail Corp.	7.0%	11.5%	n/a	7.2%
16	Pinnacle West Capital	5.1%	11.6%	n/a	7.8%
17	Portland General Elec.	9.0%	8.1%	10.0%	9.2%
18	Pub Sv Enterprise Grp.	8.3%	6.2%	8.2%	8.7%
19	Sempra Energy	10.2%	7.4%	8.6%	7.9%
20	Southern Company	10.6%	11.4%	8.1%	10.9%
	Average (b)	**9.2%**	**10.3%**	**10.0%**	**9.0%**

(a) Sum of dividend yield (Exhibit 11, p. 1) and respective growth rate (Exhibit 11, p. 2).

(b) Excludes highlighted values.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI
TESTIMONY

EXHIBIT NO. 12

BR+SV GROWTH RATE

ELECTRIC GROUP

		(a)	(a)	(a)	(b)	(c)	(d)	(e)		(f)	(g)		
		2027					**Adjustment**			**"sv" Factor**			
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adjusted r**	**br**	**s**	**v**	**sv**	**br + sv**
1	ALLETE	$5.00	$3.00	$54.00	40.0%	9.3%	1.0246	9.5%	3.8%	0.0271	0.3647	0.99%	4.8%
2	Ameren Corp.	$5.50	$3.30	$55.00	40.0%	10.0%	1.0296	10.3%	4.1%	0.0339	0.5000	1.70%	5.8%
3	Avista Corp.	$2.85	$2.05	$34.95	28.1%	8.2%	1.0305	8.4%	2.4%	0.0498	0.3922	1.95%	4.3%
4	Black Hills Corp.	$5.25	$2.95	$50.75	43.8%	10.3%	1.0297	10.7%	4.7%	0.0340	0.4514	1.53%	6.2%
5	CMS Energy Corp.	$3.75	$2.30	$26.00	38.7%	14.4%	1.0105	14.6%	5.6%	0.0148	0.6000	0.89%	6.5%
6	Dominion Energy	$5.10	$3.30	$43.40	35.3%	11.8%	1.0392	12.2%	4.3%	0.0305	0.5308	1.62%	5.9%
7	DTE Energy Co.	$8.30	$4.65	$60.75	44.0%	13.7%	1.0192	13.9%	6.1%	0.0007	0.5881	0.04%	6.2%
8	Duke Energy Corp.	$6.80	$4.30	$70.00	36.8%	9.7%	1.0133	9.8%	3.6%	0.0004	0.4043	0.02%	3.6%
9	Entergy Corp.	$6.50	$5.00	$73.00	23.1%	8.9%	1.0289	9.2%	2.1%	0.0277	0.3787	1.05%	3.2%
10	Exelon Corp.	$3.00	$1.80	$28.75	40.0%	10.4%	0.9820	10.2%	4.1%	0.0078	0.4524	0.35%	4.5%
11	Hawaiian Elec.	$2.60	$1.60	$25.50	38.5%	10.2%	1.0209	10.4%	4.0%	0.0124	0.4632	0.57%	4.6%
12	IDACORP, Inc.	$6.10	$4.00	$67.30	34.4%	9.1%	1.0238	9.3%	3.2%	0.0101	0.4272	0.43%	3.6%
13	NorthWestern Corp.	$4.00	$2.68	$50.00	33.0%	8.0%	1.0277	8.2%	2.7%	0.0361	0.2308	0.83%	3.5%
14	OGE Energy Corp.	$3.15	$1.85	$26.00	41.3%	12.1%	1.0091	12.2%	5.0%	-	0.3882	0.00%	5.0%
15	Otter Tail Corp.	$3.65	$2.20	$34.25	39.7%	10.7%	1.0195	10.9%	4.3%	0.0079	0.4731	0.37%	4.7%
16	Pinnacle West Capital	$5.25	$3.66	$59.25	30.3%	8.9%	1.0172	9.0%	2.7%	0.0139	0.3763	0.52%	3.3%
17	Portland General Elec.	$3.50	$2.24	$37.00	36.0%	9.5%	1.0316	9.8%	3.5%	0.0398	0.4308	1.71%	5.2%
18	Pub Sv Enterprise Grp.	$4.50	$2.80	$33.75	37.8%	13.3%	1.0151	13.5%	5.1%	(0.0037)	0.5645	-0.21%	4.9%
19	Sempra Energy	$11.25	$5.82	$102.65	48.3%	11.0%	1.0224	11.2%	5.4%	(0.0145)	0.4736	-0.69%	4.7%
20	Southern Company	$5.15	$3.10	$32.25	39.8%	16.0%	1.0216	16.3%	6.5%	0.0050	0.6206	0.31%	6.8%

BR+SV GROWTH RATE

ELECTRIC GROUP

		(a)	(a)	(h)	(a)	(a)	(h)	(i)	(a)	(a)		(j)	(a)	(a)	(i)
		2022			2027			Chg	2027				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2022	2027	Growth
1	ALLETE	57.8%	$4,465	$2,581	59.5%	$5,550	$3,302	5.1%	$100.0	$70.0	$85.0	1.574	56.01	61.00	1.72%
2	Ameren Corp.	44.0%	$24,193	$10,645	48.5%	$29,500	$14,308	6.1%	$120.0	$100.0	$110.0	2.000	262.00	285.00	1.70%
3	Avista Corp.	52.5%	$4,105	$2,155	51.5%	$5,675	$2,923	6.3%	$65.0	$50.0	$57.5	1.645	71.50	83.00	3.03%
4	Black Hills Corp.	40.3%	$6,914	$2,786	50.0%	$7,500	$3,750	6.1%	$105.0	$80.0	$92.5	1.823	64.74	71.00	1.86%
5	CMS Energy Corp.	34.5%	$20,350	$7,021	37.5%	$20,800	$7,800	2.1%	$75.0	$55.0	$65.0	2.500	291.30	300.00	0.59%
6	Dominion Energy	38.5%	$66,344	$25,542	41.0%	$92,200	$37,802	8.2%	$105.0	$80.0	$92.5	2.131	810.40	870.00	1.43%
7	DTE Energy Co.	37.0%	$28,000	$10,360	39.0%	$32,200	$12,558	3.9%	$170.0	$125.0	$147.5	2.428	205.69	206.00	0.03%
8	Duke Energy Corp.	43.1%	$109,744	$47,300	37.5%	$144,100	$54,038	2.7%	$135.0	$100.0	$117.5	1.679	769.00	770.00	0.03%
9	Entergy Corp.	35.2%	$36,810	$12,957	33.0%	$52,410	$17,295	5.9%	$135.0	$100.0	$117.5	1.610	211.18	230.00	1.72%
10	Exelon Corp.	49.1%	$70,107	$34,423	35.5%	$81,000	$28,755	-3.5%	$60.0	$45.0	$52.5	1.826	979.00	1000.00	0.43%
11	Hawaiian Elec.	52.8%	$4,524	$2,389	49.5%	$5,950	$2,945	4.3%	$55.0	$40.0	$47.5	1.863	109.31	113.00	0.67%
12	IDACORP, Inc.	57.2%	$4,669	$2,671	50.0%	$6,775	$3,388	4.9%	$130.0	$105.0	$117.5	1.746	50.52	52.00	0.58%
13	NorthWestern Corp.	47.8%	$4,893	$2,339	51.0%	$6,050	$3,086	5.7%	$75.0	$55.0	$65.0	1.300	54.06	62.00	2.78%
14	OGE Energy Corp.	53.0%	$8,962	$4,750	50.0%	$10,400	$5,200	1.8%	$50.0	$35.0	$42.5	1.635	200.20	200.20	0.00%
15	Otter Tail Corp.	58.5%	$2,041	$1,194	57.5%	$2,525	$1,452	4.0%	$75.0	$55.0	$65.0	1.898	41.63	42.50	0.41%
16	Pinnacle West Capital	46.1%	$12,820	$5,910	45.5%	$15,425	$7,018	3.5%	$110.0	$80.0	$95.0	1.603	113.01	118.00	0.87%
17	Portland General Elec.	43.2%	$6,265	$2,706	45.0%	$8,250	$3,713	6.5%	$75.0	$55.0	$65.0	1.757	89.41	100.00	2.26%
18	Pub Sv Enterprise Grp.	48.7%	$29,657	$14,443	45.5%	$36,900	$16,790	3.1%	$85.0	$70.0	$77.5	2.296	504.00	500.00	-0.16%
19	Sempra Energy	53.3%	$47,069	$25,088	52.5%	$59,800	$31,395	4.6%	$225.0	$165.0	$195.0	1.900	316.92	305.00	-0.76%
20	Southern Company	35.6%	$78,285	$27,869	37.0%	$93,500	$34,595	4.4%	$100.0	$70.0	$85.0	2.636	1060.00	1070.00	0.19%

(a) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).
(b) "b" is the retention ratio, computed as (EPS-DPS)/EPS.
(c) "r" is the rate of return on book equity, computed as EPS/BVPS.
(d) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(e) Product of average year-end "r" for 2027 and Adjustment Factor.
(f) Product of change in common shares outstanding and M/B Ratio.
(g) Computed as 1 - B/M Ratio.
(h) Product of total capital and equity ratio.
(i) Five-year rate of change.
(j) Average of High and Low expected market prices divided by 2027 BVPS.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI TESTIMONY

EXHIBIT NO. 13

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	CAPM
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	Result
1	ALLETE	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$3,500	0.93%	11.8%
2	Ameren Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.85	10.4%	$22,000	0.45%	10.9%
3	Avista Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$3,200	0.93%	11.8%
4	Black Hills Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.95	11.2%	$4,600	0.58%	11.8%
5	CMS Energy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.80	10.0%	$17,400	0.45%	10.5%
6	Dominion Energy	2.1%	9.5%	11.6%	3.8%	7.8%	0.80	10.0%	$52,200	-0.26%	9.8%
7	DTE Energy Co.	2.1%	9.5%	11.6%	3.8%	7.8%	0.95	11.2%	$22,900	0.45%	11.7%
8	Duke Energy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.85	10.4%	$78,300	-0.26%	10.2%
9	Entergy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.95	11.2%	$23,000	0.45%	11.7%
10	Exelon Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	n/a	n/a	$41,500	-0.26%	n/a
11	Hawaiian Elec.	2.1%	9.5%	11.6%	3.8%	7.8%	0.85	10.4%	$4,600	0.58%	11.0%
12	IDACORP, Inc.	2.1%	9.5%	11.6%	3.8%	7.8%	0.80	10.0%	$5,500	0.58%	10.6%
13	NorthWestern Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$3,400	0.93%	11.8%
14	OGE Energy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	1.00	11.6%	$7,300	0.57%	12.2%
15	Otter Tail Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$3,000	0.93%	11.8%
16	Pinnacle West Capital	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$8,500	0.57%	11.4%
17	Portland General Elec.	2.1%	9.5%	11.6%	3.8%	7.8%	0.85	10.4%	$4,400	0.58%	11.0%
18	Pub Sv Enterprise Grp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$30,500	0.45%	11.3%
19	Sempra Energy	2.1%	9.5%	11.6%	3.8%	7.8%	0.95	11.2%	$49,400	-0.26%	11.0%
20	Southern Company	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$71,300	-0.26%	10.6%
	Average							**10.7%**			**11.2%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Mar. 16, 2023).

(b) Average of weighted average earnings growth rates from IBES, Value Line, and Zacks for dividend-paying stocks in the S&P 500 based on data from Refinitiv, as provided by fidelity.com (retrieved Mar. 16, 2023), www.valueline.com (retrieved Mar. 16, 2023), and www.zacks.com (retrieved Mar. 16, 2023). Eliminated growth rates that were greater than 20%, as well as all negative values.

(c) Average yield on 30-year Treasury bonds for six-months ending Mar. 2023 based on data from Moody's Investors Service.

(d) The Value Line Investment Survey, Summary & Index (Mar. 31, 2023).

(e) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).

(f) Kroll, 2023 Supplementary CRSP Decile Size Study Data Exhibits.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI TESTIMONY

EXHIBIT NO. 14

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)														
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Unadjusted	Market	Size	ECAPM
	Company	Yield	Growth	Equity	Rate	Premium	Weight	*RP*[1]	Beta	Weight	*RP*[2]	Total RP	K_e	Cap	Adjustment	Result
1	ALLETE	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$3,500	0.93%	11.9%
2	Ameren Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.85	75%	5.0%	6.9%	10.7%	$22,000	0.45%	11.2%
3	Avista Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$3,200	0.93%	11.9%
4	Black Hills Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.95	75%	5.6%	7.5%	11.3%	$4,600	0.58%	11.9%
5	CMS Energy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.80	75%	4.7%	6.6%	10.4%	$17,400	0.45%	10.9%
6	Dominion Energy	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.80	75%	4.7%	6.6%	10.4%	$52,200	-0.26%	10.2%
7	DTE Energy Co.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.95	75%	5.6%	7.5%	11.3%	$22,900	0.45%	11.8%
8	Duke Energy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.85	75%	5.0%	6.9%	10.7%	$78,300	-0.26%	10.5%
9	Entergy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.95	75%	5.6%	7.5%	11.3%	$23,000	0.45%	11.8%
10	Exelon Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	n/a	75%	n/a	n/a	n/a	$41,500	-0.26%	n/a
11	Hawaiian Elec.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.85	75%	5.0%	6.9%	10.7%	$4,600	0.58%	11.3%
12	IDACORP, Inc.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.80	75%	4.7%	6.6%	10.4%	$5,500	0.58%	11.0%
13	NorthWestern Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$3,400	0.93%	11.9%
14	OGE Energy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	1.00	75%	5.9%	7.8%	11.6%	$7,300	0.57%	12.2%
15	Otter Tail Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$3,000	0.93%	11.9%
16	Pinnacle West Capital	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$8,500	0.57%	11.6%
17	Portland General Elec.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.85	75%	5.0%	6.9%	10.7%	$4,400	0.58%	11.3%
18	Pub Sv Enterprise Grp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$30,500	0.45%	11.5%
19	Sempra Energy	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.95	75%	5.6%	7.5%	11.3%	$49,400	-0.26%	11.0%
20	Southern Company	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$71,300	-0.26%	10.8%
	Average												**11.0%**			**11.4%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Mar. 16, 2023).
(b) Average of weighted average earnings growth rates from IBES, Value Line, and Zacks for dividend-paying stocks in the S&P 500 based on data from Refinitiv, as provided by fidelity.com (retrieved Mar. 16, 2023), www.valueline.com (retrieved Mar. 16, 2023), and www.zacks.com (retrieved Mar. 16, 2023). Eliminated growth rates that were greater than 20%, as well as all negative values.
(c) Average yield on 30-year Treasury bonds for six-months ending Mar. 2023 based on data from Moody's Investors Service.
(d) Roger A. Morin, *New Regulatory Finance* , Pub. Util. Reports, Inc. (2006) at 190.
(e) The Value Line Investment Survey, Summary & Index (Mar. 31, 2023).
(f) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).
(g) Kroll, 2023 Supplementary CRSP Decile Size Study Data Exhibits.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI TESTIMONY

EXHIBIT NO. 15

UTILITY RISK PREMIUM **Exhibit 15**

<u>COST OF EQUITY ESTIMATE</u>

Current Equity Risk Premium	
(a) Avg. Yield over Study Period	7.83%
(b) Average Utility Bond Yield	5.49%
Change in Bond Yield	-2.34%
(c) Risk Premium/Interest Rate Relationship	-0.4273
Adjustment to Average Risk Premium	1.00%
(a) Average Risk Premium over Study Period	3.89%
Adjusted Risk Premium	**4.89%**

Implied Cost of Equity	
(b) Baa Utility Bond Yield	5.75%
Adjusted Equity Risk Premium	4.89%
Risk Premium Cost of Equity	**10.64%**

(a) Exhibit 15, page 2.
(b) Average bond yield on all utility bonds and 'Baa' subset for six-months ending Mar. 2023 based on data from Moody's Investors Service at www.credittrends.com.
(c) Exhibit 15, page 3.

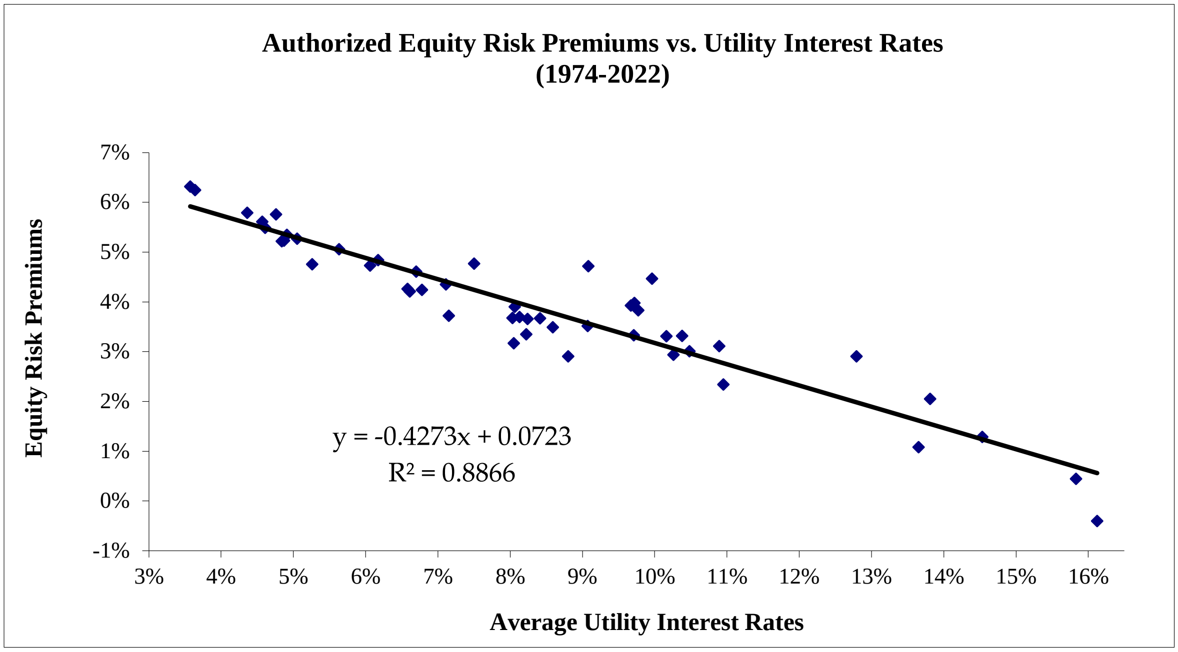
AUTHORIZED RETURNS

Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium	Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%	1999	10.72%	7.55%	3.17%
1975	13.20%	9.88%	3.32%	2000	11.58%	8.09%	3.49%
1976	13.10%	9.17%	3.93%	2001	11.07%	7.72%	3.35%
1977	13.30%	8.58%	4.72%	2002	11.21%	7.53%	3.68%
1978	13.20%	9.22%	3.98%	2003	10.96%	6.61%	4.35%
1979	13.50%	10.39%	3.11%	2004	10.81%	6.20%	4.61%
1980	14.23%	13.15%	1.08%	2005	10.51%	5.67%	4.84%
1981	15.22%	15.62%	-0.40%	2006	10.34%	6.08%	4.26%
1982	15.78%	15.33%	0.45%	2007	10.32%	6.11%	4.21%
1983	15.36%	13.31%	2.05%	2008	10.37%	6.65%	3.72%
1984	15.32%	14.03%	1.29%	2009	10.52%	6.28%	4.24%
1985	15.20%	12.29%	2.91%	2010	10.29%	5.56%	4.73%
1986	13.93%	9.46%	4.47%	2011	10.19%	5.13%	5.06%
1987	12.99%	9.98%	3.01%	2012	10.02%	4.26%	5.76%
1988	12.79%	10.45%	2.34%	2013	9.82%	4.55%	5.27%
1989	12.97%	9.66%	3.31%	2014	9.76%	4.41%	5.35%
1990	12.70%	9.76%	2.94%	2015	9.60%	4.37%	5.23%
1991	12.54%	9.21%	3.33%	2016	9.60%	4.11%	5.49%
1992	12.09%	8.57%	3.52%	2017	9.68%	4.07%	5.61%
1993	11.46%	7.56%	3.90%	2018	9.56%	4.34%	5.22%
1994	11.21%	8.30%	2.91%	2019	9.65%	3.86%	5.79%
1995	11.58%	7.91%	3.67%	2020	9.39%	3.07%	6.32%
1996	11.40%	7.74%	3.66%	2021	9.39%	3.14%	6.25%
1997	11.33%	7.63%	3.70%	2022	9.52%	4.75%	4.77%
1998	11.77%	7.00%	4.77%	**Average**	**11.72%**	**7.83%**	**3.89%**

(a) S&P Global Market Intelligence, *Major Rate Case Decisions*, RRA Regulatory Focus; *UtilityScope Regulatory Service*, Argus. Data for "general" rate cases (excluding limited-issue rider cases) beginning in 2006 (the first year such data presented by RRA).

(b) Moody's Investors Service.

REGRESSION RESULTS



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.941588
R Square	0.886588
Adjusted R Square	0.884175
Standard Error	0.004801
Observations	49

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.008469	0.008469	367.418596	0.000000
Residual	47	0.001083	0.000023		
Total	48	0.009552			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.072337	0.001875	38.582107	0.000000	0.068565	0.076109	0.068565	0.076109
X Variable 1	-0.427257	0.022290	-19.168166	0.000000	-0.472099	-0.382416	-0.472099	-0.382416

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI TESTIMONY

EXHIBIT NO. 16

EXPECTED EARNINGS APPROACH | **Exhibit 16**

ELECTRIC GROUP

		(a)	(b)	(c)
	Company	**Expected Return on Common Equity**	**Adjustment Factor**	**Adjusted Return on Common Equity**
1	ALLETE	9.0%	1.0246	9.2%
2	Ameren Corp.	10.0%	1.0296	10.3%
3	Avista Corp.	8.0%	1.0305	8.2%
4	Black Hills Corp.	9.5%	1.0297	9.8%
5	CMS Energy Corp.	14.0%	1.0105	14.1%
6	Dominion Energy	12.0%	1.0392	12.5%
7	DTE Energy Co.	12.5%	1.0192	12.7%
8	Duke Energy Corp.	9.0%	1.0133	9.1%
9	Entergy Corp.	9.0%	1.0289	9.3%
10	Exelon Corp.	10.0%	0.9820	9.8%
11	Hawaiian Elec.	12.5%	1.0209	12.8%
12	IDACORP, Inc.	9.5%	1.0238	9.7%
13	NorthWestern Corp.	8.0%	1.0277	8.2%
14	OGE Energy Corp.	13.0%	1.0091	13.1%
15	Otter Tail Corp.	11.5%	1.0195	11.7%
16	Pinnacle West Capital	9.0%	1.0172	9.2%
17	Portland General Elec.	9.5%	1.0316	9.8%
18	Pub Sv Enterprise Grp.	13.5%	1.0151	13.7%
19	Sempra Energy	11.0%	1.0224	11.2%
20	Southern Company	14.5%	1.0216	14.8%
	Average (d)	**10.8%**		**11.0%**

(a) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).
(b) Adjustment to convert year-end return to an average rate of return from Exhibit 12.
(c) (a) x (b).
(d) Excludes highlighted values.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI
TESTIMONY

EXHIBIT NO. 17

FLOTATION COST STUDY **Exhibit 17**

Page 1 of 1

VALUE LINE UTILITIES

No.	Sym	Company	(1) Date	(2) Shares Issued	(3) Offering Price	(4) Underwriting Discount (per share)	(5) Underwriting Discount	(6) Offering Expense	(7) Total Flotation Costs	(8) Gross Proceeds Before Flot. Costs	(9) Flotation Cost (%)
1	ALE	ALLETE	4/1/2022	3,200,000	$63.00	$2.20500	$7,056,000	$700,000	$7,756,000	$201,600,000	3.847%
2	LNT	Alliant Energy	11/14/2019	3,717,502	$52.63	$0.39500	$1,468,413	$500,000	$1,968,413	$195,652,130	1.006%
3	AEE	Ameren Corp.	8/5/2019	7,549,205	$74.30	$0.12000	$905,905	$750,000	$1,655,905	$560,905,932	0.295%
4	AEP	American Elec Pwr	4/2/2009	69,000,000	$24.50	$0.73500	$50,715,000	$400,000	$51,115,000	$1,690,500,000	3.024%
5	AGR	Avangrid, Inc.					N/A				
6	AVA	Avista Corp.	12/13/2006	3,162,500	$25.05	$0.48000	$1,518,000	$300,000	$1,818,000	$79,220,625	2.295%
7	BKH	Black Hills Corp.	2/25/2020	1,222,942	$81.77	$0.73590	$899,963	$230,000	$1,129,963	$99,999,967	1.130%
8	CNP	CenterPoint Energy	9/27/2018	60,550,459	$27.25	$0.75000	$45,412,844	$1,000,000	$46,412,844	$1,650,000,008	2.813%
9	CMS	CMS Energy Corp.	3/31/2005	23,000,000	$12.25	$0.42880	$9,862,400	$325,000	$10,187,400	$281,750,000	3.616%
10	ED	Consolidated Edison (a)	6/17/2021	10,100,000	$76.92	$0.83000	$8,383,000	$450,000	$8,833,000	$776,892,000	1.137%
11	D	Dominion Energy (a)	3/29/2018	20,000,000	$67.33	$1.89420	$37,884,000	$450,000	$38,334,000	$1,346,516,000	2.847%
12	DTE	DTE Energy Co.	10/29/2019	2,400,000	$126.00	$3.15000	$7,560,000	$300,000	$7,860,000	$302,400,000	2.599%
13	DUK	Duke Energy Corp. (a)	11/18/2019	25,000,000	$85.99	$2.66000	$66,500,000	$592,000	$67,092,000	$2,149,750,000	3.121%
14	EIX	Edison International	5/13/2020	14,181,882	$56.41	$0.98718	$14,000,000	$1,000,000	$15,000,000	$799,999,964	1.875%
15	ETR	Entergy Corp.	6/8/2018	13,289,037	$75.25	$0.80000	$10,631,230	$650,000	$11,281,230	$1,000,000,034	1.128%
16	EVRG	Evergy Inc.					N/A				
17	ES	Eversource Energy	6/12/2020	6,000,000	$84.91	$1.35000	$8,100,000	$600,000	$8,700,000	$509,460,000	1.708%
18	EXC	Exelon Corp. (a)	8/8/2022	11,300,000	$43.32	$0.99000	$11,187,000	$900,000	$12,087,000	$489,516,000	2.469%
19	FE	FirstEnergy Corp.	9/15/2003	32,200,000	$30.00	$0.97500	$31,395,000	$423,000	$31,818,000	$966,000,000	3.294%
20	HE	Hawaiian Elec.	3/20/2013	7,000,000	$26.75	$1.00312	$7,021,840	$450,000	$7,471,840	$187,250,000	3.990%
21	IDA	IDACORP, Inc.	12/10/2004	4,025,000	$30.00	$1.20000	$4,830,000	$300,000	$5,130,000	$120,750,000	4.248%
22	NEE	NextEra Energy, Inc. (a)	11/3/2016	13,800,000	$124.00	$1.89000	$26,082,000	$750,000	$26,832,000	$1,711,200,000	1.568%
23	NWE	NorthWestern Corp.	11/18/2021	6,074,767	$53.50	$1.60500	$9,750,001	$900,000	$10,650,001	$325,000,035	3.277%
24	OGE	OGE Energy Corp.	8/22/2003	5,324,074	$21.60	$0.79000	$4,206,018	$325,000	$4,531,018	$114,999,998	3.940%
25	OTTR	Otter Tail Corp.					N/A				
26	PNW	Pinnacle West Capital	4/9/2010	6,900,000	$38.00	$1.33000	$9,177,000	$190,000	$9,367,000	$262,200,000	3.572%
27	PNM	PNM Resources	1/7/2020	5,375,000	$47.21	$1.99000	$10,696,250	$750,000	$11,446,250	$253,753,750	4.511%
28	POR	Portland General Elec.	10/27/2022	10,100,000	$43.00	$1.23625	$12,486,125	$515,000	$13,001,125	$434,300,000	2.994%
29	PPL	PPL Corp.	5/10/2018	55,000,000	$27.00	$0.29430	$16,186,500	$1,000,000	$17,186,500	$1,485,000,000	1.157%
30	PEG	Pub Sv Enterprise Grp.	10/2/2003	9,487,500	$41.75	$1.25250	$11,883,094	$350,000	$12,233,094	$396,103,125	3.088%
31	SRE	Sempra Energy	1/5/2018	26,869,158	$107.00	$1.92600	$51,749,998	$1,500,000	$53,249,998	$2,874,999,906	1.852%
32	SO	Southern Company (a)	8/18/2016	32,500,000	$49.30	$1.66000	$53,950,000	$557,000	$54,507,000	$1,602,250,000	3.402%
33	WEC	WEC Energy Group					N/A				
34	XEL	Xcel Energy Inc. (a)	10/30/2019	10,300,000	$62.69	$0.63000	$6,489,000	$650,000	$7,139,000	$645,707,000	1.106%
		Average - Electric									**2.564%**
1	ATO	Atmos Energy Corp.	11/30/2018	7,008,087	$92.75	$0.97690	$6,846,200	$1,000,000	$7,846,200	$650,000,069	1.207%
2	CPK	Chesapeake Utilities	9/23/2016	960,488	$62.26	$2.33000	$2,237,937	$162,046	$2,399,983	$59,799,983	4.013%
3	NJR	New Jersey Resources	12/4/2019	5,700,000	$41.25	$1.23750	$7,053,750	$500,000	$7,553,750	$235,125,000	3.213%
4	NI	NiSource Inc.	5/3/2017	N/A	N/A	N/A	$10,000,000	$57,950	$10,057,950	$500,000,000	2.012%
5	NWN	Northwest Nat. Holding Co.	3/30/2022	2,500,000	$50.00	$1.62500	$4,062,500	$450,000	$4,512,500	$125,000,000	3.610%
6	OGS	ONE Gas, Inc.					N/A				
7	SWX	Southwest Gas	3/9/2023	3,576,180	$60.12	$2.02910	$7,256,427	$538,000	$7,794,427	$214,999,942	3.625%
8	SR	Spire Inc.	5/9/2018	2,000,000	$63.05	$2.10938	$4,218,760	$325,000	$4,543,760	$126,100,000	3.603%
		Average - Gas									**3.040%**
		Average - Electric & Gas									**2.654%**

Column Notes:
(1-4) SEC Form 424B for each company (through April 10, 2023).
(5) Column (2) * Column (4)
(6) SEC Form 424B for each company (through April 10, 2023).
(7) Column (5) + Column (6)
(8) Column (2) * Column (3)
(9) Column (7) / Column (8)
Note (a): Underwriting discount computed as the difference between the current market price and the price offered to the issuing company by the underwriters.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

MCKENZIE, DI TESTIMONY

EXHIBIT NO. 18

DCF MODEL - NON-UTILITY GROUP

DIVIDEND YIELD

	Company	Industry Group	(a) Price	(b) Dividends	Yield
1	3M Company	Diversified Co.	$106.36	$ 6.00	5.6%
2	Abbott Labs.	Med Supp Non-Invasive	$100.29	$ 2.04	2.0%
3	Air Products & Chem.	Chemical (Diversified)	$281.14	$ 7.00	2.5%
4	Allstate Corp.	Insurance (Prop/Cas.)	$120.44	$ 3.56	3.0%
5	Amdocs Ltd.	IT Services	$92.79	$ 1.74	1.9%
6	Amgen	Biotechnology	$234.21	$ 8.52	3.6%
7	Archer Daniels Midl'd	Food Processing	$79.03	$ 1.80	2.3%
8	Becton, Dickinson	Med Supp Invasive	$237.50	$ 3.68	1.5%
9	Bristol-Myers Squibb	Drug	$68.51	$ 2.31	3.4%
10	Brown & Brown	Financial Svcs. (Div.)	$55.82	$ 0.46	0.8%
11	Brown-Forman 'B'	Beverage	$63.90	$ 0.82	1.3%
12	Church & Dwight	Household Products	$84.48	$ 1.09	1.3%
13	Cisco Systems	Telecom. Equipment	$49.51	$ 1.56	3.2%
14	Coca-Cola	Beverage	$60.07	$ 1.84	3.1%
15	Colgate-Palmolive	Household Products	$72.99	$ 1.92	2.6%
16	Comcast Corp.	Cable TV	$36.81	$ 1.16	3.2%
17	Costco Wholesale	Retail Store	$488.50	$ 3.75	0.8%
18	Danaher Corp.	Diversified Co.	$247.94	$ 1.08	0.4%
19	Gen'l Mills	Food Processing	$80.16	$ 2.17	2.7%
20	Gilead Sciences	Drug	$80.65	$ 3.00	3.7%
21	Hershey Co.	Food Processing	$241.73	$ 4.27	1.8%
22	Home Depot	Retail Building Supply	$292.87	$ 8.36	2.9%
23	Hormel Foods	Food Processing	$41.24	$ 1.10	2.7%
24	Intercontinental Exch.	Brokers & Exchanges	$100.99	$ 1.68	1.7%
25	Johnson & Johnson	Med Supp Non-Invasive	$154.32	$ 4.52	2.9%
26	Kimberly-Clark	Household Products	$126.71	$ 4.72	3.7%
27	Lilly (Eli)	Drug	$325.23	$ 4.52	1.4%
28	Lockheed Martin	Aerospace/Defense	$475.63	$ 12.20	2.6%
29	Marsh & McLennan	Financial Svcs. (Div.)	$161.25	$ 2.48	1.5%
30	McCormick & Co.	Food Processing	$73.91	$ 1.56	2.1%
31	McDonald's Corp.	Restaurant	$267.83	$ 6.20	2.3%
32	McKesson Corp.	Med Supp Non-Invasive	$348.20	$ 2.28	0.7%
33	Merck & Co.	Drug	$107.28	$ 2.92	2.7%
34	Microsoft Corp.	Computer Software	$262.00	$ 2.73	1.0%
35	Mondelez Int'l	Food Processing	$66.46	$ 1.54	2.3%
36	NewMarket Corp.	Chemical (Specialty)	$347.55	$ 8.40	2.4%
37	Northrop Grumman	Aerospace/Defense	$461.03	$ 6.92	1.5%
38	Oracle Corp.	Computer Software	$87.33	$ 1.60	1.8%
39	PepsiCo, Inc.	Beverage	$175.49	$ 4.60	2.6%
40	Pfizer, Inc.	Drug	$40.85	$ 1.64	4.0%
41	Procter & Gamble	Household Products	$140.96	$ 3.65	2.6%
42	Progressive Corp.	Insurance (Prop/Cas.)	$141.53	$ 0.40	0.3%
43	Republic Services	Environmental	$129.80	$ 1.98	1.5%
44	Sherwin-Williams	Retail Building Supply	$219.55	$ 2.42	1.1%
45	Smucker (J.M.)	Food Processing	$150.87	$ 4.14	2.7%
46	Texas Instruments	Semiconductor	$174.94	$ 4.96	2.8%
47	Thermo Fisher Sci.	Precision Instrument	$551.89	$ 1.40	0.3%
48	Travelers Cos.	Insurance (Prop/Cas.)	$176.47	$ 3.72	2.1%
49	Verizon Communic.	Telecom. Services	$38.05	$ 2.64	6.9%
50	Walmart Inc.	Retail Store	$141.28	$ 2.32	1.6%
51	Waste Management	Environmental	$152.25	$ 2.80	1.8%
	Average				**2.3%**

(a) Average of closing prices for 30 trading days ended Mar. 29, 2023.
(b) The Value Line Investment Survey, *Summary & Index* (Mar. 31, 2023).

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth		
	Company	**V Line**	**IBES**	**Zacks**
1	3M Company	7.50%	0.09%	9.50%
2	Abbott Labs.	6.50%	8.30%	5.09%
3	Air Products & Chem.	11.50%	8.79%	11.68%
4	Allstate Corp.	3.50%	-2.19%	7.00%
5	Amdocs Ltd.	7.50%	11.07%	11.00%
6	Amgen	4.50%	4.12%	7.00%
7	Archer Daniels Midl'd	13.00%	-2.80%	6.39%
8	Becton, Dickinson	5.00%	6.30%	7.77%
9	Bristol-Myers Squibb	n/a	4.06%	5.70%
10	Brown & Brown	8.00%	13.22%	n/a
11	Brown-Forman 'B'	14.50%	8.85%	n/a
12	Church & Dwight	6.00%	7.81%	7.64%
13	Cisco Systems	8.50%	7.32%	6.50%
14	Coca-Cola	8.00%	6.06%	6.66%
15	Colgate-Palmolive	6.00%	6.02%	6.21%
16	Comcast Corp.	8.50%	6.40%	12.64%
17	Costco Wholesale	10.50%	9.90%	9.24%
18	Danaher Corp.	16.00%	3.31%	12.00%
19	Gen'l Mills	4.50%	7.04%	7.50%
20	Gilead Sciences	12.00%	2.52%	12.26%
21	Hershey Co.	9.00%	9.64%	7.67%
22	Home Depot	9.00%	2.22%	11.22%
23	Hormel Foods	7.50%	3.30%	5.83%
24	Intercontinental Exch.	7.00%	5.86%	5.40%
25	Johnson & Johnson	8.00%	3.94%	5.53%
26	Kimberly-Clark	7.00%	9.61%	9.86%
27	Lilly (Eli)	11.50%	22.87%	20.62%
28	Lockheed Martin	7.00%	9.55%	6.86%
29	Marsh & McLennan	10.50%	9.08%	8.46%
30	McCormick & Co.	4.50%	3.51%	6.92%
31	McDonald's Corp.	9.00%	7.75%	8.07%
32	McKesson Corp.	10.00%	11.87%	10.36%
33	Merck & Co.	8.50%	10.47%	8.01%
34	Microsoft Corp.	15.00%	11.90%	11.66%
35	Mondelez Int'l	7.50%	6.45%	7.14%
36	NewMarket Corp.	1.00%	7.70%	n/a
37	Northrop Grumman	9.50%	3.00%	3.45%
38	Oracle Corp.	10.00%	9.06%	8.00%
39	PepsiCo, Inc.	6.50%	7.55%	7.63%
40	Pfizer, Inc.	2.00%	-8.00%	9.00%
41	Procter & Gamble	5.50%	5.07%	6.14%
42	Progressive Corp.	6.50%	28.64%	23.89%
43	Republic Services	12.50%	8.97%	9.11%
44	Sherwin-Williams	7.00%	9.07%	10.30%
45	Smucker (J.M.)	4.00%	3.79%	4.00%
46	Texas Instruments	4.50%	10.00%	9.33%
47	Thermo Fisher Sci.	11.00%	7.77%	12.50%
48	Travelers Cos.	7.50%	8.83%	10.71%
49	Verizon Communic.	2.50%	0.13%	4.15%
50	Walmart Inc.	7.50%	5.09%	5.50%
51	Waste Management	6.50%	8.75%	10.88%

(a) The Value Line Investment Survey (various editions as of Mar. 31, 2023).
(b) www.finance.yahoo.com (retrieved Mar. 30, 2023).
(c) www.zacks.com (retrieved Mar. 30, 2023).

DCF MODEL - NON-UTILITY GROUP **Exhibit 18**

DCF COST OF EQUITY ESTIMATES

		(a)	(b)	(c)
			Earnings Growth	
	Company	**V Line**	**IBES**	**Zacks**
1	3M Company	13.1%	5.7%	15.1%
2	Abbott Labs.	8.5%	10.3%	7.1%
3	Air Products & Chem.	14.0%	11.3%	14.2%
4	Allstate Corp.	6.5%	0.8%	10.0%
5	Amdocs Ltd.	9.4%	12.9%	12.9%
6	Amgen	8.1%	7.8%	10.6%
7	Archer Daniels Midl'd	15.3%	-0.5%	8.7%
8	Becton, Dickinson	6.5%	7.8%	9.3%
9	Bristol-Myers Squibb	n/a	7.4%	9.1%
10	Brown & Brown	8.8%	14.0%	n/a
11	Brown-Forman 'B'	15.8%	10.1%	n/a
12	Church & Dwight	7.3%	9.1%	8.9%
13	Cisco Systems	11.7%	10.5%	9.7%
14	Coca-Cola	11.1%	9.1%	9.7%
15	Colgate-Palmolive	8.6%	8.7%	8.8%
16	Comcast Corp.	11.7%	9.6%	15.8%
17	Costco Wholesale	11.3%	10.7%	10.0%
18	Danaher Corp.	16.4%	3.7%	12.4%
19	Gen'l Mills	7.2%	9.7%	10.2%
20	Gilead Sciences	15.7%	6.2%	16.0%
21	Hershey Co.	10.8%	11.4%	9.4%
22	Home Depot	11.9%	5.1%	14.1%
23	Hormel Foods	10.2%	6.0%	8.5%
24	Intercontinental Exch.	8.7%	7.5%	7.1%
25	Johnson & Johnson	10.9%	6.9%	8.5%
26	Kimberly-Clark	10.7%	13.3%	13.6%
27	Lilly (Eli)	12.9%	24.3%	22.0%
28	Lockheed Martin	9.6%	12.1%	9.4%
29	Marsh & McLennan	12.0%	10.6%	10.0%
30	McCormick & Co.	6.6%	5.6%	9.0%
31	McDonald's Corp.	11.3%	10.1%	10.4%
32	McKesson Corp.	10.7%	12.5%	11.0%
33	Merck & Co.	11.2%	13.2%	10.7%
34	Microsoft Corp.	16.0%	12.9%	12.7%
35	Mondelez Int'l	9.8%	8.8%	9.5%
36	NewMarket Corp.	3.4%	10.1%	n/a
37	Northrop Grumman	11.0%	4.5%	5.0%
38	Oracle Corp.	11.8%	10.9%	9.8%
39	PepsiCo, Inc.	9.1%	10.2%	10.3%
40	Pfizer, Inc.	6.0%	-4.0%	13.0%
41	Procter & Gamble	8.1%	7.7%	8.7%
42	Progressive Corp.	6.8%	28.9%	24.2%
43	Republic Services	14.0%	10.5%	10.6%
44	Sherwin-Williams	8.1%	10.2%	11.4%
45	Smucker (J.M.)	6.7%	6.5%	6.7%
46	Texas Instruments	7.3%	12.8%	12.2%
47	Thermo Fisher Sci.	11.3%	8.0%	12.8%
48	Travelers Cos.	9.6%	10.9%	12.8%
49	Verizon Communic.	9.4%	7.1%	11.1%
50	Walmart Inc.	9.1%	6.7%	7.1%
51	Waste Management	8.3%	10.6%	12.7%
	Average (b)	**10.9%**	**10.4%**	**10.9%**

(a) Sum of dividend yield (p. 1) and respective growth rate (p. 2).

(b) Excludes highlighted figures.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

BRIAN R. BUCKHAM

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Brian Buckham. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as Senior Vice President and Chief Financial Officer ("CFO").

Q. Please describe your educational background.

A. I received a Bachelor of Science in Mining Engineering from the University of Idaho, a Master of Business Administration from Gonzaga University, and a Juris Doctor from the University of Idaho College of Law.

Q. Please describe your work experience with Idaho Power.

A. I was hired in 2010 as an attorney in Idaho Power's Legal Department, where I focused predominately on securities compliance and external reporting, capital markets transactions, corporate governance, and commercial transactions, among other areas. In 2016, I was appointed as IDACORP's and Idaho Power's Vice President & General Counsel, and in 2017 as Senior Vice President & General Counsel, where in both roles I was responsible for leadership of the legal, corporate governance, compliance, risk management, and physical and cyber security functions at IDACORP and Idaho Power. In 2022, I was appointed as

IDACORP’s Senior Vice President and Chief Financial Officer, where I oversee the companies’ finance, accounting, investor relations, treasury, tax, Sarbanes-Oxley compliance, internal audit, compliance, risk management, and physical and cyber security functions.

Q. What are your duties as Senior Vice President and Chief Financial Officer of Idaho Power as they relate to this proceeding?

A. I oversee the direct financial planning, procurement, and investment of funds for Idaho Power, as well as supervise corporate liquidity management. I also have oversight and responsibility for our financial reporting, both internal and external, and our investor relations function, and for our capital markets transactions and associated relationships with stakeholders in that forum.

My duties and responsibilities include various aspects of all the Company’s capital markets transactions, treasury management, and other financial matters. With respect to long-term financings, sale of bonds, and sale of equity, my duties include development of financial plans with senior officers, meeting with representatives of current and prospective investment banking firms that underwrite Idaho Power securities, discussions with credit rating agencies, assisting in preparation of financial material (including registration statements and prospectuses filed with the U.S. Securities and Exchange Commission), representing the Company in meetings with investment banking firms, reviewing information relative to the Company's financings, meeting with current and prospective debt and equity investors, meeting with investment analysts, and recommending disposition of net proceeds. With respect to short-term financing, these duties and responsibilities include negotiation of credit facilities and term loans with commercial banks and overseeing the purchase and sale of commercial paper, and establishing and maintaining the relationships that help facilitate those transactions.

Q. Do your responsibilities include communicating with members of the financial community?

A. Yes. I am in regular contact with individuals representing investment and commercial banking firms, credit rating agencies, insurance companies, institutional investment firms, pension funds, infrastructure funds, and other organizations interested in publicly traded securities, who follow IDACORP and Idaho Power. Along with the Company's Vice President, Chief Accounting Officer and Treasurer and the Company's Investor Relations and Treasury Director, my responsibilities include keeping these representatives of the financial community informed of the

Company's financial condition, arranging and participating in meetings with these individuals and IDACORP's and Idaho Power's other senior executive management, and visiting with financial representatives in their respective offices or virtually. Some of these members of the investment community have followed the electric utility industry for an extended period of time and have a great deal of expertise in the specific financial risks and prospects of utilities.

Through my contact with the financial community and review of investment banking analytical reports and publications issued by these firms and the rating agencies, I keep informed on trends, interest rates, financing costs, security ratings, and other financial developments in the public utility industry.

Q. Are you a member of any professional societies or associations?

A. Yes. I am a current member of the Idaho State Bar, the Oregon State Bar, the Arizona State Bar (inactive), and the Governing Council of the Business & Corporate Law Section of the Idaho State Bar, in addition to serving on various non-profit boards. Further, I was previously an adjunct professor of law at the University of Idaho College of Law, where I taught the securities regulation course.

I also attend numerous conferences and seminars of these and other utility business, law, and finance professional groups, such as the Edison Electric Institute and Western Energy Institute, and an investor-owned utility CFO forum, on a regular basis. Through participation in these groups and events, I gain additional information and insights into the financial developments affecting IDACORP and Idaho Power, as well as the electric utility industry.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring testimony discussing financial risk factors generally and risk factors unique to Idaho Power that justify a return on equity ("ROE") figure supported in the Direct Testimony of Company Witness Mr. Adrien McKenzie as the minimum acceptable ROE for Idaho Power, the use of a forecasted year end 2023 capital structure, the embedded cost of long-term debt, and the resultant overall cost of capital used to compute the Company's revenue requirement.

Q. What Exhibits are you sponsoring?

A. I am sponsoring Exhibit Nos. 19-21.

I. **COST OF EQUITY POINT ESTIMATE**

Q. What ROE is the Company requesting in this proceeding?

A. The Company requests 10.4 percent as the point estimate to be used for the cost of equity.

Q. Does that point estimate align with the recommendations made by the Company’s outside expert regarding the Company’s cost of capital?

A. No, it is lower. As the Company evaluated its request and the broader economic conditions, the Company decided to apply an ROE that is lower than the 10.6 percent point estimate provided by our outside expert. My recommendation is on the lower end of the range suggested by Mr. McKenzie. The Company believes this recommendation is the minimum required ROE necessary to not weaken the Company’s ability to attract capital at favorable and customer-beneficial rates in the currently uncertain and volatile financial markets.

Q. How did you arrive at your recommendation?

A. While I believe the discussion of risk factors later in my testimony justifies an ROE in excess of 10.4 percent, as supported by Mr. McKenzie, I have taken into account the economic impact of historically high inflation on our customers and selected a rate below the midpoint of the recommended range, while at the same time recognizing that high inflation also biases toward a higher ROE. As discussed in the Direct Testimony of Company Witness Ms. Lisa Grow, Idaho Power has adopted a conservative approach in this rate filing, utilizing several factors to mitigate the overall rate impact on customers of its request. In light of this conservative approach, the Company is requesting a minimum level of ROE at 10.4 percent.

Q. Did you consider other recent decisions in Idaho-jurisdiction electric utility general rate cases ("GRC")?

A. Yes. However, I note that most of the recent electric utility GRC have been settled through negotiated settlement agreements, which may not fully reflect the breadth of issues that a regulator might consider when making an ROE determination. The two most recent electric utility cases that were reviewed in regard to this filing were Avista Corporation's ("Avista") GRC, which was settled in August 2021, and the PacifiCorp (dba Rocky Mountain Power) GRC, which was settled in December 2021. In both cases settlement agreements were reached. More recently, Intermountain Gas Company, a subsidiary of MDU Resources, entered into a settlement in its natural gas retail rate case in Idaho, but the proceedings in that case have not concluded.

In the Avista case, the Commission's final order approved a 9.4 percent ROE, as proposed in the settlement agreement. Notably, the Commission's order cites testimony stating, "the parties reached a compromise among differing points of view, with concessions made by all Parties." To that end, the Company believes the stated ROE is not indicative of the result from a fully contested case. Order No. 35156, Case No. AVU–E-21-01.

In the PacifiCorp case, the settlement agreement and the Commission's final order approving the settlement were silent as to PacifiCorp's authorized ROE. Order No. 35277, Case No. PAC-E-21-07. Regardless, PacifiCorp is a much larger, multi-jurisdictional utility with a higher credit rating and ownership by a substantial utility holding company, which would justify an authorized ROE lower for PacifiCorp than for Idaho Power. Intermountain Gas Company is similarly situated structurally to PacifiCorp, and a distributor of natural gas rather than electric service.

Q. Have financial market conditions changed since these rate cases were filed?

A. Yes. Interest rates have gone up in the last 21 months, since the date Avista's case referenced above was filed, with the 10-year United States ("US") Treasury rate increasing over 200 percent over that period, from less than 1.2 percent to around 3.7 percent as of May 22, 2023 (source: Yahoo Finance). As interest rates increase, investors expect a higher ROE given the higher risk compared to their alternative investment in debt instruments. When the interest rate was at 1.2 percent, a 9.4 percent to 9.6 percent ROE may have been reasonable, but in today’s market the ROE needs to be higher to appropriately reflect the increase in debt cost and prevailing interest rates, given investors’ available options and expectations. The number of basis points should increase even further in light of volatile market conditions, and other factors I discuss in this testimony. Indeed, typical money market deposit account rates currently exceed even the 10-year Treasury rate from 21 months ago, meaning investors have existing nearly risk-free options with relatively high interest rates, thus driving up required ROEs to attract investment.

Moreover, in my conversations with current and prospective investors and with equity analysts, the topic of authorized ROEs is frequently raised. Based on those conversations, it is my impression that an ROE of the level the Company has requested in this case, assuming it also includes recovery of prudent expenditures and a return on and of investment, would be sufficient to meet the expectations of those investors and thus maintain IDACORP’s reasonable access to equity capital. The authorized ROE is one of the primary factors participants in the equity capital markets will review when assessing the adequacy of the outcome of a general rate case for purposes of making an investment decision, and an authorized ROE lower than Idaho Power’s request could increase the Company’s cost of equity issuances. With IDACORP anticipating an equity issuance in 2024, or possibly sooner, an authorized ROE that meets investor expectations will benefit customers through greater value in issued equity financing. Mr. McKenzie addresses this important intersection of utility regulation and the investment markets in his testimony.

Q. Why is Idaho Power's requested 10.4 percent ROE justified in this case?

A. Notable changes in the economy, particularly inflation levels not seen since the 1980s, market volatility and uncertainty, and the interest rate increases noted above, have taken place in the past few years, and exacerbated recently. In his testimony, Mr. McKenzie also discusses these changes and their implications on capital costs and ROE.

Q. What other risks impact your selection of a 10.4 percent ROE?

A. Over the last few years, the utility risk landscape has been shifting dramatically, increasing several risks that the Company must address. I highlight in the next section of my testimony several of these heightened risks, including power supply costs, liquidity challenges, wildfires, cybersecurity, and physical security. I will also discuss other specific risks Idaho Power continues to face.

Idaho Power must remain prepared to respond to unforeseen events that may materialize in the future, some of which are outlined in my discussion below. Recent economic challenges and financial market disruption and uncertainty highlight the importance of maintaining Idaho Power's financial strength in attracting the capital needed to ensure reliable service to customers at a lower cost, and to weather continued volatile and uncertain economic conditions and circumstances.

Q. You mentioned the impact of interest rate increases. How do interest rates affect the required ROE?

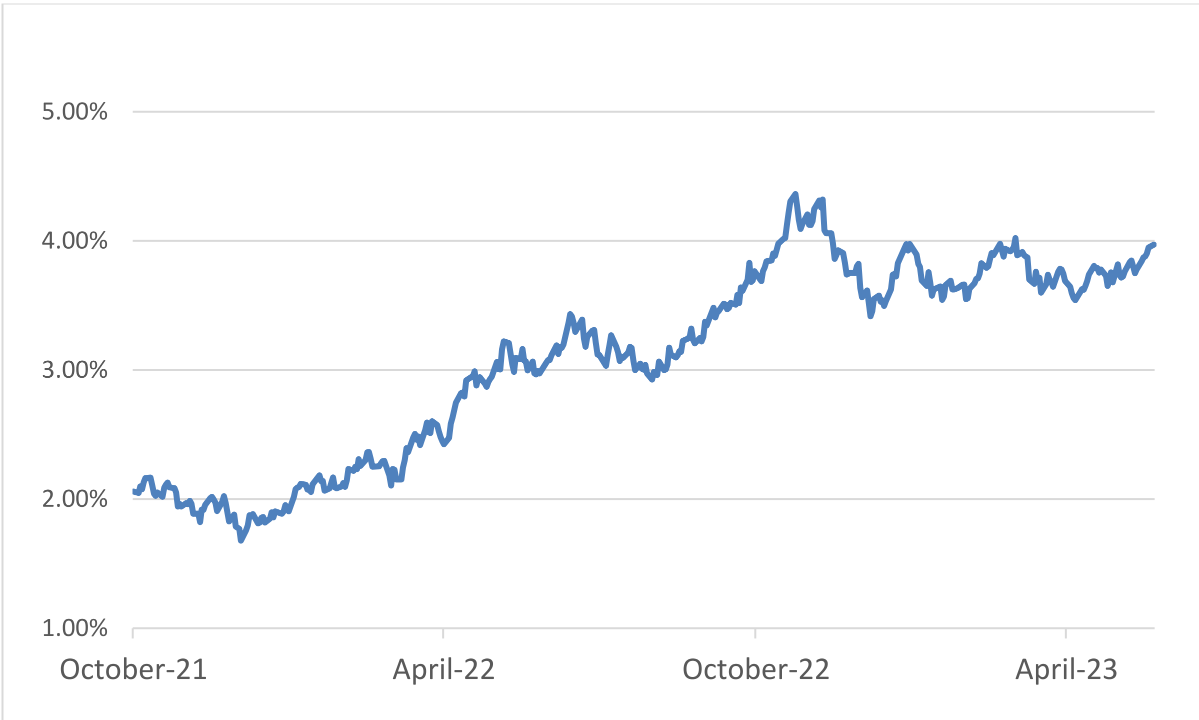
A. As Idaho Power competes with other investments (both stocks and bonds) in the capital markets, to attract capital at reasonable costs the Company must provide a return that adequately compensates its investors relative to the risk of other investments. With rising interest rates, investors can obtain relatively higher returns on debt instruments while retaining a much lower risk profile relative to stocks. To compete as an investment, utilities must then provide the opportunity for a higher return commensurate with their higher relative risk level.

Q. Can you quantify the recent increases in interest rates?

A. Certainly. As seen in the chart below (based on data from Yahoo Finance as of May 22, 2023), 30-year US

Treasury bond yields have risen from around 1.8 percent near the start of 2022 to as high as 4.36 percent in late 2022, and have recently been between 3.6 to 4.0 percent, a 100 percent increase over that period.

FIGURE 1
30-Year Treasury Bond



Q. How do higher levels of inflation impact ROE?

A. As noted in Mr. McKenzie's testimony, an investor's required return is intended to compensate the investor for the loss of purchasing power due to rising prices. An investor adds an inflation premium to the real rate of return (pure risk-free rate plus risk premium) to determine the investor's nominal required return. As a result, higher inflation expectations lead to an increase in the cost of equity capital. The expectations for the required return, and thus the cost of equity capital, increase during inflationary periods when there is regulatory lag in the recovery of those increasing costs, which occurs where a historic test year is applied in the ratemaking process.

II. **RISK FACTORS**

Q. Could you briefly outline the risks confronting the Company that form the basis for your recommendation of a 10.4 percent ROE as the minimum acceptable authorized return?

A. Yes. I will summarize them here and discuss each in greater detail later in my testimony. I believe that, at a minimum, a 10.4 percent ROE is required to properly account for the risks confronting Idaho Power for the following reasons:

(1) The general decline in the Company's credit quality, in conjunction with the growing need for access to debt and equity capital to fund the Company's growing capital expenditures in response to recent and expected future economic growth in its service territory. The Company forecasts capital expenditures of approximately $3.1 billion from 2023 to 2027 to reliably serve customer needs.

(2) Energy market volatility and liquidity challenges.

(3) Large and growing Public Utility Regulatory Policies Act of 1978 ("PURPA") project and Power Purchase Agreement ("PPA") expenditures, and more recently, energy storage agreement expenditures.

(4) Risks related to wildfires from a financial, reliability, insurability, and operational standpoint.

(5) The renewal of federal licenses for the Company's hydroelectric projects, primarily the Hells Canyon Complex, which provides 36 percent of the Company's total generating nameplate capacity, and particularly the costs associated with the relicensing of that project.

(6) Increased risks related to power reliability, as well as execution risk associated with infrastructure projects intended to maintain reliability.

(7) Environmental risks and uncertainties related to new or proposed legislation and requirements and impacts on the Company's operations.

(8) The increasing risks of cyber and physical security attacks on Idaho Power's and other utilities' infrastructure.

(9) The impacts of climate change on the Company, including the perceived risk in the financial community associated with the variability of the Company’s hydroelectric generating base, variances in sales, impacts on operations, reputational concerns, application of investment policies, and other factors associated with changes in the climate.

(10) The Company’s small size in terms of market capitalization and concentrated geographic and associated regulatory risk (i.e., 95 percent of the Company’s business is in Idaho).

(11) The financial impact of a lag in the recovery of costs associated with higher capital expenditures, including the higher costs of financing those capital expenditures.

(12) Heightened scrutiny by equity investors and analysts of authorized ROEs and regulatory outcomes, and the disproportionate impact it has on the success of equity financing, particularly as the Company approaches the need for equity issuances.

I address several of those risks below in my testimony.

Q. Are there other risks, less specific to Idaho

Power, that also impact your recommendation?

A. Yes. There are general financial risks such as increased volatility in the financial markets and what I view as a heightened sensitivity to risk exposure. Other risks are industry-wide, such as unknown costs relative to carbon emissions, a need for infrastructure improvements, and increased capital investment, as well as inflationary pressures that increase costs of both operating expenses and capital outlays. Interest rate uncertainty fuels the fear that future borrowing costs could rise dramatically. Recently, the Federal Reserve has been attempting to control inflation by raising interest rates, which creates expectations for continued rising debt costs in the near future. These factors combine to make a challenging environment in which the Company must compete with others in the electric utility industry, as well as all other industries, for both resources and capital, to serve the needs of its customers. While I do not intend to elaborate further on more general risks, they are factors worthy of note that point to increased risks for the Company.

Many of the risks associated with the Company, and that factor into its equity and debt valuations, are included in the Annual Report on Form 10-K that the Company files with the US Securities and Exchange Commission, under the heading "Risk Factors." For the Form 10-K filed in

February 2023, that section of the document was approximately 13 pages in length.[1]

Credit Ratings and Capital Market Expectations

Q. What is the status of Idaho Power's credit ratings?

A. Idaho Power's credit ratings as of May 31, 2023, are as follows:

TABLE 1
Idaho Power Credit Ratings as of May 31, 2023

	Standard and Poor's Rating Services (S&P)	**Moody's Investors Service (Moody's)**
Corporate Credit Rating	BBB	Baa 1
Senior Secured Debt	A-	A2
Senior Unsecured Debt	BBB	Baa 1
Commercial Paper	A-2	P-2
Rating Outlook	Stable	Stable

Q. Have there been any recent changes in the Company's credit ratings?

A. Yes. In July 2022, Moody's long-term issuer rating for Idaho Power was downgraded from A3 to Baa1. In addition, Moody's ratings for First Mortgage Bonds and Senior Secured Debt were downgraded to A2 from A1. Also, in February 2023, S&P downgraded its liquidity assessment of the Company from "strong" to "adequate." The downgrades occurred despite the expectation by the rating agencies

[1] The Company's 10-K is available at: https://d18rn0p25nwr6d.cloudfront.net/CIK-0000049648/e858bcab-7dd5-4c28-b5ba-56d347339652.pdf

that the Company planned to file this rate case and that by 2024 the Company expected to have an increase in cash flow from collections from customers.

Q. What is the Company's assessment of the impact of these downgrades?

A. Following the recent Moody's credit ratings changes, the Company's credit ratings remained investment grade. However, Moody's new rates move the Company closer to being below investment grade, referred to as "junk bond" status.

The Company's first opportunity to test the bond market after the 2022 downgrade was in December 2022. While Idaho Power was able to issue some long-term debt, buyer interest in the transaction was less than we anticipated, the buyers were limited, and we were not able to issue the volume of debt that we had originally intended to issue. We believe that fixed-income investors that had not been actively following the Company previous to our marketing of the debt instruments likely were concerned when they noticed the recent downgrade. This softened demand likely led to a higher cost of debt associated with these instruments than would have occurred with a backdrop of a more stable credit rating outcome.

Further ratings downgrades would cause additional harm to the risk perception of the Company in the debt markets. If, for example, Idaho Power's credit ratings were to fall below investment grade, which would be below Baa3 for Moody's and below BBB- for S&P, Idaho Power's cost of borrowing would increase substantially. A change below investment grade will also trigger significant increases in collateral-related deposits as well as significant cost increases for the Company's credit facility, which will increase costs to customers. That downgrade would also negatively impact IDACORP's stock price, decreasing the value the Company would receive for issuances in the equity markets.

A downgrade in the short-term debt rating could make it difficult for the Company to issue commercial paper under reasonable terms, if at all, which is the instrument Idaho Power relied upon recently during volatile power and fuel markets for its liquidity and to meet margin requirements. Additionally in tight markets such as a recession, liquidity for companies that are below investment grade becomes extremely limited, resulting in lack of cash on reasonable terms to finance the business, which could result in the inability of the Company to fund needed capital projects to reliably serve customers.

Q. How did Moody's describe the reasons for its downgrade?

A. In July 2022, Moody's noted financial metrics and need for more timely rate relief as reasons:

> Idaho Power Company's (IPC) credit profile reflects lower financial metrics over the last several years that are no longer supportive of an A3 rating, the major driver for the utility's recent downgrade to Baa1. These metrics include a ratio of cash flow from operations before changes in working capital (CFO pre-WC) to debt of between 12% and 13% over the last two years. We expect the ratio to be around 13% over the medium-term, which is weak for its new Baa1 rating.

and

> … without the benefit of more incremental and timelier rate relief through riders or cost tracking mechanisms, more frequent base rate increases and lower imputed debt from pension obligations, IPC's credit metrics will not improve materially and the utility will have limited financial cushion at its current rating level to manage unforeseen events.

Q. How did S&P characterize its February 2023 change?

A. S&P cited Idaho Power's reliability and economic growth-driven capital spending needs as reflecting its liquidity downgrade, as it perceived "elevated capital spending that will result in modest weakening of the Company's liquidity throughout the forecast period."

Q. Do you believe that the current credit ratings of Idaho Power are adequate?

A. Stronger credit ratings would be beneficial, but Idaho Power is still able to raise capital in today's markets with its current ratings. However, new debt/bond issues are at a higher cost than if Idaho Power's credit ratings were higher (i.e., the higher the credit rating, the lower the debt financing cost). Stronger credit ratings also result in more liquidity in all market conditions.

Q. How else can credit ratings impact the Company?

A. Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. If Idaho Power experiences a reduction in its credit rating on its unsecured debt to below investment grade, Idaho Power could be subject to requests by its wholesale counterparties to post additional performance assurance collateral. Likewise, counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. For example, on March 31, 2023, the amount of collateral that could be requested by counterparties upon a downgrade to below investment grade was $44.6 million. The costs to finance the cash needed to meet these margin requirements would increase costs to customers.

Q. What factors could lead to a credit rating upgrade or downgrade?

A. Per Moody’s in July 2022, factors that could lead to an upgrade include:

> The rating of IPC could be upgraded if key credit metrics improve such that the CFO pre-WC to debt ratio increases to 16% or above on a sustained basis. An upgrade could also occur if the utility's regulatory construct improves materially, including authorization of trackers and rider mechanisms that would result in faster cost recovery, reducing regulatory lag.

Factors that could lead to a downgrade include:

> IPC's rating could be downgraded if financial metrics weaken further including a CFO pre-WC to debt ratio of 13% or below on a sustained basis. The rating could also come under pressure if the utility were to experience a decline in the credit supportiveness of its regulator including either higher cost recovery risks or lower returns.

Per S&P in May 2022, factors that could lead to an upgrade include:

> We could raise ratings if the company’s business risk profile strengthened through a more robust management of regulatory relationships and improved operating efficiency, combined with stronger cash flow measures, including FFO [funds from operations] to debt consistently exceeding 20%.

Factors that could lead to a downgrade include:

> We could lower ratings if business risk increased because of unsupported recovery of operating expenses, including higher-than-average reliance on purchased power or unsupported capital investments through the regulatory process or if the company materially expanded its nonregulated segments, which are currently negligible. We could also lower ratings if financial measures consistently underperformed our base case forecast, leading to an FFO-to-debt measure that is consistently less than 14%.

Q. Are there any other considerations mentioned by the rating agencies that could point to future downgrade risks?

A. Yes. Moody's pointed to regulatory lag on material investments that, in its view, overshadows regulatory mechanisms that are in place in Idaho. Specifically, Moody's stated in July 2022 that:

> … the utility's financial profile has historically lagged peers due to certain regulatory constructs, such as flow-through tax accounting and long-lived depreciation due to its hydro asset base. Since Idaho lacks the suite of investment and operating cost recovery mechanisms seen in other states, Idaho Power's cash flow growth is primarily dependent on general rate case filings, which it has not benefited from for several years.
>
> IPC's last general rate increase was in 2011 and the company carries approximately $709 million in regulatory assets on its balance sheet, net of regulatory liabilities, as of 31 March 2022. Some of the most sizable unrecovered asset balances are associated with Idaho Power's Hells Canyon Complex

hydro-fueled generation facility, the relicensing of which has been repeatedly delayed in a lengthy permitting and approval process since originally filed in 2003. The lack of rate cases and delayed cash recovery of these investments has eroded the timeliness of rate relief for the company.

Q. What are Idaho Power's expected near-term capital needs?

A. Over the five-year period from 2023-2027, Idaho Power anticipates spending between $2.95 and $3.2 billion, and approximately $1.5 billion in 2023-2024, on new property, plant, and equipment to serve customers. For comparison, Idaho Power's annual capital expenditures have averaged about $325 million over the five-year period from 2018-2022. This significant increase in capital expenditures will increase the Company's need for debt and equity financing.

Q. Do you believe the relief requested in this case will serve to stabilize or improve the Company's credit ratings going forward?

A. I believe it will stabilize the current credit ratings but not improve them, particularly with the decline in Idaho Power's debt-to-equity ratio from 55 percent in 2022 to what the Company expects to be 51 percent by the end of 2023. The credit rating agencies have built their models and assumptions, in part, based on forecasts Idaho

Power has discussed with them over the past few years. Those forecasts have contemplated the rate relief requested in this case. In addition, this case requests additional return of and return on rate base that has been placed into service since the last general rate case, and that substantial investment has carried regulatory lag from a cash flow perspective over several years. Finally, the credit rating agencies will view as positive the Company's requests in this case to begin to address needed cash collections related to regulatory deferrals, such as those related to wildfire mitigation and pension expenses, though those collections have also been assumptions included in their modeling.

Q. Aside from credit ratings, have equity analysts changed their ratings on IDACORP recently, and for what reasons?

A. Yes. IDACORP's equity ratings by two of its equity analysts declined relatively recently. Mizuho Securities USA LLC downgraded IDACORP from a "Buy" to a "Neutral" rating on April 4, 2023, generally citing risks associated with higher capital expenditures and the impact on financial results, along with regulatory uncertainty. BofA Securities downgraded IDACORP from a "Buy" to a "Neutral" rating on November 7, 2022, citing regulatory uncertainty, growing O&M, and broad inflationary pressures and their impact on small- and mid-capitalization utilities, and a growing trepidation toward smaller companies due to heightened risks.

Energy Market Volatility and Liquidity Challenges

Q. How have recent events in the energy markets impacted the Company?

A. Higher and more volatile prices in the electricity and natural gas markets have created additional risks for the Company in two particular ways. First, by increasing power supply costs. The power cost adjustment mechanism ("PCA") partially mitigates the effects of energy market price volatility on financial results, but the volatility levels can result in the Company absorbing significant amounts of power supply costs. For example, for the Company's April 2022-March 2023 PCA year, total actual power supply costs were $721.8 million, compared to base power supply costs of $305.7 million. After jurisdictionalization, the PCA mechanism's 95 percent/5 percent sharing applied to most of the variance resulted in $14.6 million of increased power supply costs being absorbed by the Company. While this GRC will establish new base power supply costs that will help mitigate some of this impact, continued volatility will likely continue to negatively impact the Company, and thus the return expected by investors.

Second, the higher prices and volatility of power and fuel impact the Company's liquidity. While the PCA mechanism mitigates in-part the potential adverse earnings impacts to Idaho Power of fluctuations in power supply costs, collection from customers of most of the difference between actual power supply costs compared with those included in retail rates is deferred to a subsequent period, which can affect Idaho Power's operating cash flow and liquidity until those costs are recovered from customers. In the Company's recent PCA filing, the total power supply costs that the Company had paid pending future recovery from customers was $190 million, which was a significant strain on operating cash flows. For the first quarter of 2023, Idaho Power's operating cash flows were negative $93 million, reflective of Idaho Power absorbing the cash flow impact of adverse lag in the PCA mechanism. This negative cash flow was particularly alarming.

Further, wholesale commodity contracts often require performance assurance collateral be posted with counterparties. During recent energy market price spikes, the Company was required to post very large amounts of cash collateral, significantly straining its available liquidity. To give an order of magnitude, as of March 31, 2023, Idaho Power had posted $63 million of cash performance assurance collateral related to its energy market contracts.

PURPA and PPA Expenditures and Associated Credit and Equity Impacts

Q. What is the significance of PURPA and PPA expenditures?

A. The Company has significant amounts of financial commitments related to PURPA facilities and other PPAs. Idaho Power has entered into a number of PPAs and PURPA contracts since 2010, the last full year before the Company's last GRC. In Idaho Power's Annual Report on Form 10-K, it cites contractual obligations associated with these contracts of over $4.2 billion. Additional contracts signed in 2023 and awaiting Commission approval push that total to nearly $4.9 billion.

The base rate regulatory treatment of PURPA qualifying facility ("QF") contracts provides for a one-for-one recovery of dollars expended, while PPA recovery is generally subject to the PCA mechanism's 95/5 sharing provision. Neither provides for any return to compensate the Company for its long-term purchase obligation under the applicable contract, despite it being a debt-like obligation and long-term capital commitment. The Company is, in effect, buying and selling energy (pursuant to a legal mandate in the case of QFs) without any compensation for providing this service. The mere dollar-for-dollar recovery of QF expenditures and the significant size of the obligation, with no return for the use of the Company's general and administrative resources, balance sheet, and liquidity in managing QF programs and PPAs, is viewed as a long-term contractual and debt-like obligation, and thus a risk, by the rating agencies. The rating agencies are not making a judgment related to the appropriateness of QF or PPA-based energy purchase programs, but merely pointing out the cost of the financial risk(s) arising from a QF or PPA transaction, and that this risk should be reflected in a higher ROE to recognize the impact of the Company's QF and PPA contracts.

Q. Do the rating agencies recognize the financial costs of QF and PPA transactions beyond the contract price?

A. Yes. Like other electric utilities, when the Company adds to its rate base, it must use some portion of shareholder equity to fund the investment. The Company must maintain its proportion of equity to debt above a certain level as it continues this investment process. If it does not, the debt level increases and the Company will face the threat of a ratings downgrade. Conversely, when the Company enters into a QF or PPA contract for purchased power, an obligation is generally not reflected in the Company's financial statements; however, the rating agencies add to the financial statement an imputed debt for the QF or PPA contract, resulting in an increase in total debt and a need to increase equity in order to maintain credit quality.

Unless an equity component is provided to offset the debt-like obligation of long-term purchased power contracts, the Company faces off-balance sheet financial risk that threatens a reduction in credit ratings. For financial commitments that are not presented on the balance sheet, rating agency analysts impute the debt and interest equivalents on the financial statements of the Company to achieve a more accurate picture of the risk associated with the investment and the Company's related commitment. The added equity needed to offset this imputed debt and interest represents the effect that long-term purchased power commitments have on the cost of capital. An increase in the long-term obligation of a utility related to its capacity and energy resources will have to be backed by an appropriate amount of equity in the eyes of the ratings agencies.

In reviewing its evaluation of the credit implications of QF-related expenditures, in November of 2013, as stated below, S&P noted that it viewed such agreements as creating "fixed debt-like financial obligations" that must be considered in evaluating a utility's credit risks.

> We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates.
>
> …Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers,

Q. How material are QF- and PPA-related expenditures?

A. As of the end of 2022, Idaho Power had 133 signed cogeneration/small power production ("CSPP")-related contracts with QFs representing 1,212 megawatts ("MW") of capacity, as well as 596 MW of non-QF PPAs. 129 QF projects with a nameplate capacity of 1,137 MW were online at the end of 2022. In 2022, the Company incurred approximately $189 million of expense related to QF projects and $45 million related to PPA projects. As of December 31, 2022, the Company is obligated to pay approximately $4.2 billion to QF and PPA developers over the remaining life of these contracts. To provide context on how significant the $4.2 billion liability is to Idaho Power, the Company's total projected long-term debt obligation at year-end 2022 is only $2.2 billion. The QF and PPA obligations are over 160 percent of the debt financing for all assets the Company owns to serve customers.

Q. Are QF and PPA expenses increasing?

A. Yes. Idaho Power has been engaged in resource procurement activities that the Company expects will result in several new, large PPAs and Battery Storage Agreements ("BSA") to meet future resource needs. Currently, Idaho Power has 340 MW of signed solar PPAs and 150 MW of BSAs in development, with an additional substantial resource procurement in the competitive bidding process. The 150-MW BSA signed in April 2023, for example, contributes an additional $440 million on top of the total contracted obligation noted above. The substantial and increasing obligations of PURPA QF and PPA agreements create a material risk factor for Idaho Power and increase costs to customers.

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Wildfire Risks, Insurability, and Insurance Costs

Q. Please describe the increased risks associated with wildfires.

A. Since the 1980s, wildfire activity in the United States in terms of acres burned has more than tripled and, according to the National Interagency Fire Center, western states account for upwards of 95 percent of the acres burned in recent years. While Idaho Power has not experienced catastrophic wildfires within its service area at the same level experienced in other western states, such as California and Oregon, millions of acres of rangeland and southern Idaho forests have burned in the last 30 years.

A variety of factors have contributed to more destructive wildfires, including climate change, increased human encroachment in wildland areas, historical land management practices, and changes in wildland and forest health, among other factors.

Specific to Idaho Power, wildfires have the potential to damage or destroy the Company’s facilities, impact personnel, and cause significant harm to Idaho Power’s customers and the communities in which the Company serves. Company Witness Mr. Mitch Colburn provides a more detailed discussion of wildfire risk in his testimony.

Q. Have Idaho Power’s overall insurance premium costs increased in recent years?

A. Yes. While Idaho Power undertakes significant efforts to manage the cost of insurance and obtain the greatest insurance value possible for its customers, the Company is to some degree a price-taker in the insurance market. In that regard, despite annual assessment of its insurance portfolio to identify the best value and the retention of an experienced insurance broker, the Company is subject to price increases as insurers raise premiums due to losses, either pertaining to Idaho Power or to insurers’ overall insured base.

As noted in the memo from Idaho Power's insurance broker that was provided with the Company’s 2021 wildfire mitigation cost deferral Application in Case No. IPC-E-21-02 (and included as Exhibit No. 19 to my testimony), much of the increases in premiums is attributable to the frequency and magnitude of Western-state wildfires in recent years, as well as insurance providers’ perceptions of Idaho Power's specific wildfire risk. The sizeable increase in Idaho Power's premiums became particularly prominent in 2021 due in part to a new "wildfire load" charge of approximately $1 million that is being added annually to electric utilities, such as Idaho Power, that insurers have determined operate in high-risk zones for wildfire.

To help manage the costs of insurance, Idaho Power has taken actions such as marketing of its programs as needed, formation of a captive insurance program to access the reinsurance market, reviewing and adjusting of self-insured retentions, meeting regularly with insurers to provide details on risk-mitigation practices, and regularly assessing the adequacy of overall coverage. While these efforts have resulted in benefits, costs of insurance for the Company, and for the industry as a whole, have increased notably in recent years.

Q. Does Idaho Power anticipate these premium increases will continue?

A. Because insurance markets continue to be volatile, premium increases are difficult to forecast. Idaho Power anticipates that, notwithstanding its efforts to negotiate favorable rates and coverage, premiums for insurance will continue to increase for the foreseeable future. This trend has been echoed by Idaho Power's third-party insurance broker, who has explained that insurance premiums will continue to increase due to prior losses incurred by insurance providers and projected increased risks of losses by insurers from wildfires.

Q. Aside from insurance premium increases, which are representative of third-party assessments of Idaho Power's wildfire risk, does wildfire risk impact the cost of capital?

A. Yes, it does. In recent years, credit rating agencies have inquired about Idaho Power's wildfire risk and the efforts it undertakes to mitigate the risk. Investment analysts and current and prospective debt and equity investors also frequently inquire about wildfire risk and mitigation efforts. This was elevated by the Pacific Gas & Electric bankruptcy that resulted in large part from wildfire liability associated with numerous California wildfires ignited by the utility.

Credit rating agencies, analysts, and investors have inquired about operating practices, financial exposure, insurance coverage, and other topics relevant to wildfire liability, and the exposure the Company has to wildfires factors. They then incorporate this information into their decision about whether to purchase debt and equity securities and in credit ratings, and thus ultimately the cost of capital, in much the same way that exposure influences insurance premiums.

Hydroelectric Facility Relicensing Risks and Costs

Q. What risks are associated with the Company's relicensing efforts for its hydroelectric facilities?

A. Relicensing of the Company’s hydroelectric facilities will create additional obligations. It involves large capital expenditures, increased operating costs, and reduced hydropower generation, all of which can negatively affect Idaho Power's results of operations and financial condition. For the last several years, Idaho Power has been engaged in an effort to renew its federal license for its largest hydropower generation source, the Hells Canyon Complex (“HCC”). Idaho Power is also in the process of relicensing the American Falls hydroelectric facility.

Relicensing and ongoing permitting requirements include an extensive public review process that involves numerous natural resource issues and environmental conditions. For instance, the existence of endangered and threatened species in the watershed may result in major operational changes to the region’s hydropower projects, which may be reflected in hydropower licenses, including for the HCC and the American Falls facilities.

In addition, new interpretations of existing laws and regulations could be adopted or become applicable to hydropower facilities, which could further increase required expenditures for endangered species protection and other environmental compliance obligations and reduce the amount of hydropower generation available to meet Idaho Power’s generation requirements. Idaho Power cannot predict the requirements that might be imposed during the relicensing and permitting process, or the financial or operational impact of those requirements.

Q. Are there other hydroelectric relicensing-based financial risks considered by the investment community?

A. Yes. For any particular generating facility, the worst possible outcome would be the loss of the license to a competing party. Along with the uncertainty as to the eventual receipt of licenses and the costs involved in preparing for the license applications, costs of protection, mitigation and enhancement ("PM&E") related to these projects are also difficult to quantify. The potential financial magnitude of these PM&E costs and their effect on the Company's low-cost hydro generation resources threaten the financial stability of a company the size of Idaho Power and the ultimate rates it must charge its customers. These amounts will vary among facilities; however, in all cases, they can be significant due to lost generation capacity, generation at a higher cost, and the decreased ability of the Company to time and control water releases. If the Company cannot generate when it is most advantageous for the system, then some of the economic value of the generation will be lost even if the amount of total generation does not change.

Q. What will occur when the Company receives a new license for the Hells Canyon facilities?

A. The amounts in construction work in progress ("CWIP"), net of the accrued balance in the regulatory liability account for pre-collected amounts received relative to the allowance for funds used during construction ("AFUDC"), will be transferred to plant in service and the accumulation of AFUDC will cease and the amortization of the relicensing costs will start. The result will be an increase in rate base with earnings of the Company declining substantially until this additional amount is included in rate base and reflected in rates, since there will be no ongoing contribution to earnings from AFUDC. This is a notable risk to the Company's financial condition. Because this is a relicense of an existing hydro facility, there will be no increase (and potentially a decrease due to operational changes) in the generation of power and thus no increase in sales revenues.

An investor's perspective of the risk, upon receipt of the license, includes the following: (1) the Company's earnings will immediately decrease (no continuing AFUDC and an increase in amortization expense of the relicensing costs), (2) the Company's plant in-service will increase (transfer from CWIP), and (3) no additional sales revenues (same plant but new license) will result. If the completion of relicensing is not aligned perfectly with the allowance of new effective rates that recognize the transfer of previously deferred relicensing costs into rate base, the Company will be financially harmed. For the period of time the new rate base is under review by the Commission, the Company will earn no return on over $200 million of net investment. This potential regulatory lag, combined with investors' potential expectation that there could be some amount of cost disallowance, is a significant risk factor based upon the size of the investment the Company has made in relicensing the HCC.

Q. What is Idaho Power's current HCC relicensing cost in CWIP?

A. Relicensing costs of $432 million for the HCC were included in CWIP as of March 31, 2023. As of March 31, 2023, Idaho Power's regulatory liability for collected AFUDC relating to the HCC was $213 million.

Q. What other risks does the relicensing process create?

A. As Idaho Power's largest single generating resource, continued operation of the HCC and failure to renew a federal license for HCC could have a dramatic operational impact. Further, imposition of onerous conditions in the relicensing and permitting processes could result in Idaho Power incurring significant additional capital expenditures, increase operating costs (including power purchase costs), and reduce hydropower generation, which could negatively affect the financial condition of the Company and the prices its customers pay for electricity.

Reliability Risk and Execution Risk on Infrastructure

Q. What issues with reliability are creating additional risk?

A. The transition to intermittent renewable energy resources in the region, transmission constraints, retirement of baseload fossil fuel plants, aging infrastructure, demand growth, weather conditions and wildfires, and other factors have all impacted the Company’s ability to reliably provide energy. As noted in Ms. Grow’s testimony, the Company is making a concerted effort to maintain reliability using a variety of programs. However, the aforementioned items do subject the Company to greater reliability risks than existed in the past.

Q. Besides the risk of not being able to deliver energy, what other risks does reliability entail?

A. Idaho Power could be subject to regulatory penalties, reputational harm, legal claims, and operational changes if it violates mandatory reliability and security requirements. The obligation to provide reliable service also entails a significant commitment of capital, both for operating and maintenance expenses and for capital improvements. As I noted previously, Idaho Power is in a stage of significant capital investment, constructing the resources needed to reliably serve customers. The capital needed to maintain reliability introduces two elements of risk: the ability of the Company to attract that required capital, and the recovery of the investments on a deferred basis and subject to the uncertainty of the regulatory process.

There are also significant efforts at the national level to reshape energy policy, and that can put upward pressure on that spending and the associated need to attract capital. New federal energy policies are evolving and could introduce new spending requirements to meet reliability standards and regulatory requirements.

Q. Are there other risks associated with Idaho Power's build-out of infrastructure to address reliability?

A. Yes. There are several considerable risks. These risks include, as examples:

- the ability to timely obtain labor or materials at reasonable costs;
- defaults and delays by suppliers and contractors, including delays for specialty equipment that require significant lead times;
- increases in price and limitations on

availability of commodities, materials, and equipment;

- imposition of tariffs on commodities, materials, and equipment sourced by foreign providers;
- equipment, engineering, and design failures;
- credit quality of counterparties and suppliers and their ability to meet financial and operational commitments;
- unexpected environmental and geological problems;
- the effects of adverse weather conditions;
- catastrophic events, natural disasters, epidemics, pandemics and other public health or disruptive events that could result in supply chain disruptions, as well as permitting and construction delays;
- availability of financing;
- the ability to obtain approval from local, state, or federal regulatory and governmental bodies and to comply with permits and land use rights, and environmental constraints; and
- delays and costs associated with disputes and litigation with third parties.

The occurrence of any of these risks could cause Idaho Power to operate at reduced capacity levels, increase expenses, incur penalties, and adversely affect Idaho Power’s financial condition.

Environmental Issues and Risks

Q. Please describe the Company’s increasing risks related to environmental issues.

A. Idaho Power's operations are subject to numerous federal, state, and local environmental statutes, rules, and regulations relating to climate change, air and water quality, natural resources, endangered species and wildlife, renewable energy, and health and safety. Compliance with environmental regulations can significantly increase capital spending, operating costs, and plant availability and can negatively affect the affordability of Idaho Power's services for customers.

Q. What are the costs associated with environmental compliance?

A. Idaho Power’s current estimated compliance expenditures for the three-year period from 2023 to 2025 are $156 million of capital expenditures and $99 million of operating expenses, based on current environmental laws and regulations. Idaho Power anticipates that finalization, implementation, or modification of federal and state rulemakings and other proceedings could result in substantial changes in operating and compliance costs. Idaho Power is unable to estimate the changes in costs that could result, given the uncertainty associated with existing and potential future regulations, but Idaho Power expects the expenditures will remain substantial regardless.

Q. What other impacts could environmental compliance requirements have?

A. In some cases, the costs to obtain permits and ensure facilities are in compliance may be prohibitively expensive. In other instances, the permitting process might substantially delay the Company's ability to acquire resources in accordance with its resource planning process. Furthermore, Idaho Power may not be able to obtain or maintain all environmental regulatory approvals necessary for operation of its existing infrastructure or construction of new infrastructure.

Q. What would be the impact of prohibitively expensive compliance costs or inability to acquire regulatory approval to operate facilities?

A. If new regulations render generating facilities uneconomical or impossible to maintain or operate, Idaho Power would need to identify alternative resources for power, potentially in the form of new generation and transmission facilities, market power purchases, demand-side management programs, or a combination of these and other methods.

Q. What impact do lengthy permitting processes have on the ability to operate facilities and the Company's financial condition?

A. Idaho Power's resource procurement and planning process, its Integrated Resource Plan ("IRP"), assumes the ability of the Company to timely plan and procure the necessary resources to serve load. Lengthy permitting processes impact the Company's ability to execute on its lowest-cost, least-risk resource portfolios.

For example, the Boardman to Hemingway ("B2H") transmission project was first identified in the preferred portfolio of the Company's 2009 IRP, with an estimated in-service date of 2015. Since that time, B2H has remained in subsequent IRP preferred portfolios, and the Company has continued to work to obtain the permits and approvals necessary for construction of B2H, but the process has significantly delayed construction and commercial operation of the project. As of March 31, 2023, the Company has $58 million in CWIP for future recovery. Similar to the HCC relicensing, the prolonged B2H permitting process negatively impacts liquidity and recovery of the costs is subject to regulatory lag.

Physical Security and Cyber Security Risks

Q. What risks do physical security and cybersecurity pose?

A. Idaho Power operates in an industry that requires the continuous use and operation of sophisticated information technology and increasingly complex operational technology systems and network infrastructure. In addition to those cyber assets, Idaho Power's generation and transmission facilities and its grid operations are potential targets for terrorist acts and threats, acts of war, social unrest, cyber and physical security attacks, and other disruptive activities of individuals or groups, including by nation states or nation state-sponsored groups.

Q. Have there been recent examples of such attacks?

A. Yes. There have been recent cyber and physical attacks within the energy industry on infrastructure such as electric substations and fuel pipelines, with notable reports in the media of electric industry infrastructure specifically being targeted for and impacted by physical attacks more recently. Unfortunately, there will be additional attacks in the future. Idaho Power and its vendors have been subject to, and will likely continue to be subject to, continuous attempts to gain unauthorized access to systems and confidential information, and efforts to disrupt operations.

Q. Besides attempts to damage utility infrastructure, are there other cybersecurity risks?

A. Yes. In the normal course of business, Idaho Power or its vendors collect and store sensitive and confidential customer and employee information and proprietary information of Idaho Power. Idaho Power’s technology systems are dependent upon connectivity to the internet and third-party vendors to host, maintain, modify, and update its systems, which may experience significant system failures or cyberattacks that could compromise the security of Idaho Power’s assets and information. All information technology systems are vulnerable to disability, unauthorized access, unintentional defects, user error, errors in system changes, and cybersecurity incidents.

Idaho Power is in the process of pursuing complex business system upgrades, and these significant changes increase the risk of system interruption. Any data security breaches, such as misappropriation, misuse, leakage, falsification, or accidental release or loss of information maintained in Idaho Power's information technology systems or on third-party systems, including customer or employee data, could result in violations of privacy and other laws and associated litigation and liability for damages, fines, and penalties; financial loss to Idaho Power or to its customers; customer dissatisfaction or diminished customer confidence; and damage to Idaho Power’s reputation, all of which could materially affect Idaho Power's financial condition and results of operations.

No security measures can completely shield Idaho Power's systems, infrastructure, and data from vulnerabilities to cyberattacks, human error, intrusions, or other events that could result in their failure or reduced functionality, and ultimately the potential loss of sensitive information or the loss of Idaho Power's ability to fulfill critical business functions and provide reliable electric power to customers. Despite the steps Idaho Power may take to detect, mitigate, or eliminate threats and respond to security incidents, the techniques used by those who seek to obtain unauthorized access, and possibly disable or sabotage systems or abscond with information and data, change frequently and Idaho Power may not be able to protect against all such actions.

Although Idaho Power continues to make investments in its cyber and physical security programs, including personnel, technologies, and training of personnel, there can be no assurance that these systems or their expected functionality will be implemented, maintained, or expanded effectively; nor can security measures completely eliminate the possibility of a cyber or physical security breach or incident. Further, the implementation of security guidelines and measures has resulted in, and Idaho Power expects to continue to result in, increased costs.

Climate Change Risks

Q. Are changes in weather conditions and climate concerns creating increased risk for the Company?

A. Yes, in a number of ways, including the following:

- Due to regulations and associated costs originating from climate change concerns, Idaho Power is retiring fossil fuel generating units that have provided reliable and affordable generation and replacing it with intermittent resources and utility-scale batteries that fit within the confines of federal regulation and infrastructure development risks. This transition creates reliability issues, as discussed above, and additional uncertainty regarding resource costs and impacts on wholesale energy markets, particularly as other utilities make the same transition away from fossil fuel generating plants and baseload energy sources. If new greenhouse gas ("GHG") emissions reduction rules were to become effective, they could result in significant additional compliance costs that could negatively impact Idaho Power's future financial position, results of operations, and cash flows if such costs are not timely recovered through regulated rates. Moreover, the possibility exists that stricter laws, regulations, or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary.

- The price of power in the wholesale energy markets tends to be higher during periods of high regional demand that often occur with weather extremes, which may cause Idaho Power to purchase power in the wholesale market during peak price periods, increasing power supply costs. The PCA helps mitigate the effects of energy market price volatility, but the volatility levels can result in the Company absorbing significant amounts of power supply costs. As described above, the Company's April 2022-March 2023 PCA year, total actual power supply costs were $721.8 million, compared to base power supply costs of $305.7 million, and a large part of this variance resulted from high market prices.

- The Company's hydroelectric generating base depends on water conditions in the Snake River Basin. Warmer temperatures and changes in precipitation levels and sustained drought conditions can adversely affect the amount of energy generated by its hydroelectric generation facilities. Low water conditions in the Snake River Basin, as well as in other areas, can increase wholesale market prices due to a lack of hydroelectric generation in the region and a reliance on more costly energy sources. This can result in power supply cost variances that are absorbed by the Company, as noted previously in my testimony.

- The increased frequency and severity of storms, lightning, high winds, icing events, droughts, heat waves, fires, floods, snow loading, and other extreme weather events can damage transmission, distribution, and generation facilities, causing service interruptions and extended or mass outages, which increases costs and impairs Idaho Power's ability to meet customer energy demand.
- The costs of repairing and replacing infrastructure or any costs related to Idaho Power’s liability for personal injury, loss of life, and property damage from utility equipment that fails, including as a result of significant weather and weather-related events and fires, is not covered in full by insurance.
- Customers' energy use could increase or decrease based on variable weather conditions, impacting the

predictability of revenues and earnings.

- Stakeholder actions and increased regulatory activity related to climate change and reducing GHG emissions, could negatively impact the Company in capital markets transactions. Idaho Power has seen a rise in certain stakeholders, including investors and lenders, placing increasing importance on the impact and social cost associated with climate change. GHG emissions, including, most significantly carbon dioxide, could be further restricted in the future in response to stakeholder expectations with respect to environmental and climate change issues. The increasing focus on climate change and associated stricter regulatory and legal requirements may result in Idaho Power facing adverse reputational risks associated with certain of its operations that produce GHG emissions or that mine coal. If Idaho Power is unable to satisfy the increasing climate-related expectations of certain stakeholders, IDACORP and Idaho Power may suffer reputational harm. This could cause IDACORP's stock price to decrease or cause certain investors and financial institutions not to purchase the companies' debt securities or otherwise provide the companies with capital or credit on favorable terms, which may cause IDACORP's and Idaho

Power's cost of capital to increase.

Company Size and Geographic Concentration

Q. Does IDACORP's size have an impact on investors' perceived level of risk?

A. Yes, IDACORP's relatively small market capitalization compared to its peers is a factor that makes IDACORP riskier than the average electric utility holding company. IDACORP's $5.7 billion market capitalization is much smaller than the $22.8 billion average market cap of the electric utilities used by Mr. McKenzie to estimate the range of acceptable ROEs. There is well-documented evidence that investors in smaller companies expect higher rates of return than larger companies but also face higher risk. Idaho Power does not have a corporate parent with a large balance sheet and strong credit ratings to rely on during times of financial stress given the fact that Idaho Power is the primary subsidiary of IDACORP.

Also, the Company faces a concentrated regulatory risk compared to many of its peers because 95 percent of its retail revenues come from one jurisdiction. Both equity analysts and the credit agencies consistently identify regulatory risk as one of the chief risk factors for the Company. This risk from lack of diversification, combined with the relatively small size, gravitates toward a higher required return from investors compared to many of Idaho

Power's peers.

Growth and Regulatory Lag

Q. What will prevent the Company from earning its authorized or allowed ROE, absent approval of this rate request?

A. In light of the substantial infrastructure development Idaho Power is undertaking, and will be undertaking for the foreseeable future, in my opinion, the reliance on historical test year information is a primary reason the Company may have difficulty earning its authorized or allowed ROE going forward. Idaho Power is in a position of applying to recover its costs on a historical basis when its costs are constantly increasing on a prospective basis. As a result, there is and will continue to be a consistent recovery lag.

Q. What effect does growth have on the use of historical data?

A. Growth inherently worsens the effects. Separate from rising operation & maintenance costs that must accommodate that growth, the allowed rate of return is applied to a rate base from a prior historical period, and thus new plant additions suffer some period of 0 percent return awaiting eventual rate base treatment.

III. CAPITAL STRUCTURE

Q. Would you please describe Exhibit No. 21?

A. Exhibit No. 21 details the forecasted year-end 2023 capital structure for long-term debt and common equity prepared under my direction, the resulting recommended overall rate of return, and the calculation of the Company’s weighted average cost of long-term debt.

Q. The capital structure presented on Exhibit No. 21 incorporates changes to the Company’s financial reporting of its capital structure. Could you please discuss the rationale for the variance?

A. For financial reporting purposes, the American Falls Bond Guarantee is included in the long-term debt portion of the capital structure. For ratemaking purposes, it is excluded as the interest costs associated with the American Falls debt securities are treated as operation and maintenance expenses.

Q. What is the rationale for proposing a capital structure of 51 percent equity and 49 percent debt?

A. This is the projected actual capital structure as of the end of 2023. Idaho Power believes a higher equity proportion than the typical 50/50 split is needed to help support the Company's credit ratings, particularly with the significant QF and PPA debt-like obligations I referred to above, which are not included in the debt component of the ratio. The equity portion of the projected capital structure is lower than the 55 percent year-end equity average over the past six years because of new debt issuances in 2023 to support increased capital spending.

Q. Has the higher equity ratio over the past six years help the Company's credit rating?

A. Yes. The Company began increasing the equity ratio immediately following the last GRC. In fact, the year-end 2012 equity ratio was 53 percent and it grew from that level to 55 percent at year-end 2022. The increased equity ratio has had a significant positive impact to the Company's credit ratings, partially offsetting some of the lower ratios the rating agencies use for calculating applicable ratings.

Another factor to consider in the capital structure is the amount of imputed debt due to QF and PPA contractual obligations the rating agencies consider when evaluating the creditworthiness of the Company, as I have discussed previously in my testimony. Although neither Moody's nor S&P currently publish a specific amount of imputed debt for Idaho Power, S&P published a white paper detailing how they calculate imputed debt for PPAs.[2] Using that methodology, a conservative estimate would be almost $600 million of

[2] *Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements*. Attached as Exhibit No. 20.

imputed debt, which is not reflected in the Company's financial reporting of debt and is not included in the Company's cost of capital exhibit. After incorporating even that conservative imputation of debt, the ratio biases more heavily to debt.

Q. What is the Company's proposed cost of debt?

A. As shown on page 2 of Exhibit No. 21, which details the calculation of the cost of debt used in the estimated year-end 2023 capital structure, the Company's proposed cost of debt is 4.895 percent.

Q. What was the Company's cost of debt in its GRC filed in 2011?

A. In that case, the Company filed a cost of debt of 5.728 percent.

Q. Has there been any significant refinancing since the last GRC?

A. Yes. Idaho Power has taken advantage of the low interest rate environment since the last GRC to lower the overall cost of debt by approximately 83 basis points. At the same time, Idaho Power was able to lengthen its weighted average maturity on the debt portfolio from 15.3 years at the end of 2011 to 19.3 years at the end of 2023. The Company's efforts over the past decade provide a significant savings to customers.

Q. What method did the Company use for calculating its cost of debt in this case?

A. Idaho Power applied a debt calculation method to fully consider the effect of discounts, premiums, and expense of issue on the annual cost of each bond, adopting the bond yield to maturity method.

Q. Please explain the cost of debt calculation on page 2 of Exhibit No. 21.

A. The calculation takes the settlement date, maturity date, coupon rate, and net proceeds at the issuance date for each debt issue to produce a bond yield to maturity. The bond yield was then multiplied by the principal amount outstanding for each debt issue, resulting in an annualized cost of each debt issuance in column 12. The total in column 12 for all the debt issuances produces a total annual effective cost of debt in line 32. This total was divided by the total in column 6, line 32 to produce the weighted average cost for all long-term debt in column 11, line 32. This method is appropriate because the expense of issuance associated with a bond is essentially prepaid interest, and the net proceeds, not the principal amount of the bond, are all that is available to be invested in property, plant, and equipment (rate base).

Q. Does the Company use variable rate securities in its long-term capitalization?

A. No. The Company retired its only variable rate security, the Port of Morrow (Boardman) Pollution Control Revenue Bonds, in 2022 upon the demolition of the Boardman plant and its pollution control equipment, and previously repaid in full its variable-rate term loan entered into in March 2022.

IV. OVERALL COST OF CAPITAL

Q. What is the overall cost of capital for Idaho Power?

A. As shown on page 1 of Exhibit No. 21, using the Company's projected year-end 2023 capital structure, the Company's cost of debt as presented in my testimony, and incorporating the recommended 10.4 percent cost of equity, the resulting overall cost of capital for Idaho Power is 7.702 percent. This is an appropriate rate of return to be utilized by the Commission when deriving the Company's revenue requirement.

Q. How does that compare to the cost of capital approved in Idaho Power's 2011 GRC request?

A. It represents a decrease. The overall cost of capital for Idaho Power approved in the prior GRC was 7.86 percent.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

DECLARATION OF BRIAN BUCKHAM

I, Brian Buckham, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Brian Buckham. I am employed by Idaho Power Company as Senior Vice President and Chief Financial Officer.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 19 through 21 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: ____________________
Brian R. Buckham

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BUCKHAM, DI TESTIMONY

EXHIBIT NO. 19

Greg Miller

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Jeff Pleimann
Insurance & Risk Administrator
Idaho Power
1221 West Idaho St.
Boise, ID 83702

December 21st, 2020

Subject: Wildfire / Excess Liability and Property Premiums

Dear Jeff,

This letter summarizes information regarding insurance premiums paid by Idaho Power for coverage for liability related to wildfire currently, as well as information on what Idaho Power should expect to pay in the future assuming maintenance of existing levels of coverage.

ALLOCATION OF CURRENT PREMIUMS TO WILDFIRES

Coverage for Idaho Power's liability for wildfire is provided within your excess liability insurance tower, with three separate insurers. Generally, insurers are reluctant to attribute how much of a policy is related to a specific risk. With regard to wildfire risk, however, it is understood that a significant portion of Idaho Power's excess liability policies are related to wildfires. Additionally, the latest excess liability policy was purchased expressly to cover Idaho Power's exposure to wildfire-related risk. As a result, the full premium in this layer is due to wildfire liability risk, since Idaho Power would not have purchased this layer but for the desire for additional protection for wildfire-related risk.

FUTURE PREMIUM INCREASE EXPECTATIONS

The mutual insurance company that provides Idaho Power's primary excess liability policy, has advised all policyholders that they should expect excess liability premiums for 2021 to increase, on average, at least 15% over 2020 levels. In addition, they have advised that utilities in wildfire prone areas will be charged a "wildfire load" in addition to their base premium. The load varies depending on the relative exposure. For Idaho Power, we have been informed that the load will be up to $1 million beginning in 2021, with the potential to increase annually thereafter.

The insurance company that provides Idaho Power's second layer of excess liability coverage has not formally advised policyholders of anticipated increases for 2021. For most renewals in 2020 from the insurance company, the premiums are increasing between 10 and 15%. We anticipate the same range will apply in 2021 for most utilities, including Idaho Power.

For the third layer of excess liability coverage, this is placed in the commercial market and is therefore subject to general market conditions. For 2020, the commercial market for excess liability for electric utilities has seen rate increases generally falling between 20% and 50%. We anticipate Idaho Power will be at the higher end of this range.

For 2022 and beyond, we anticipate the liability insurance market to temper and annual rate of premium growth should decrease in magnitude after the significant recent and near-term adjustments; however we do not have significant clarity to future market conditions and future increases could continue to be notable. Our expectation is subject to change based on wildfire losses in the western U.S.

With regard to insurance premiums in general, losses from natural disasters, including wildfires (whether natural or human-caused), and the various causes of losses across numerous forms of coverage, are a concern to underwriters and have contributed to the general hardening of the insurance market and associated sizeable increases in premiums.

Please let me know if you have any questions.

Sincerely,

Greg Miller
Managing Director

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BUCKHAM, DI
TESTIMONY

EXHIBIT NO. 20

STANDARD
&POOR'S

RATINGSDIRECT®

May 7, 2007

Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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Table Of Contents

Exhibit No. 20
Case No. IPC-E-23-11
B. Buckham, IPC
Page 1 of 7

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Exhibit No. 20
Case No. IPC-E-23-11
B. Buckham, IPC
Page 2 of 7

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms

Exhibit No. 20
Case No. IPC-E-23-11
B. Buckham, IPC
Page 3 of 7

are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

Exhibit No. 20
Case No. IPC-E-23-11
B. Buckham, IPC
Page 4 of 7

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

Exhibit No. 20
Case No. IPC-E-23-11
B. Buckham, IPC
Page 5 of 7

We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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Exhibit No. 20
Case No. IPC-E-23-11
B. Buckham, IPC
Page 6 of 7

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BUCKHAM, DI TESTIMONY

EXHIBIT NO. 21

IDAHO POWER COMPANY

PRO FORMA COST OF CAPITAL
SUMMARIZED
December 31, 2023 Capitalization
(000's)

Line No	(1)	(2) Capitalization Structure Amount	(3) Capitalization Structure Percent	(4) Embedded Cost	(5) Weighted Cost
1	Long-term Debt	2,601,100	49.0%	4.895%	2.399%
2	Common Equity	2,707,000	51.0%	10.400% *	5.304%
3	Total Capitalization	$5,308,100	100.000%		7.702%

Note:
* Requested Rate of Return

IDAHO POWER COMPANY
PRO FORMA COST OF LONG-TERM DEBT
As of 12/31/2023
(000's)

Line No.	(1) Class and Series	(2) Coupon Rate	(3) Settlement Date	(4) Maturity Date	(5) Principal Amount Issued	(6) Principal Amount Outstanding	(7) Price	(8) Discount/ (Premium)	(9) Issuance Costs	(10) Net Proceeds	(11) Yield To Maturity	(12) Effective Cost
	First Mortgage Bonds:											
1	6.00% Series due 2032	6.00%	11/15/2002	11/15/2032	100,000	100,000	98.706	1,294.0	441.2	98,264.8	6.127%	6,127.1
2	5.5% Series due 2033	5.50%	5/13/2003	4/1/2033	70,000	70,000	99.198	561.4	3,810.2	65,628.4	5.949%	4,164.3
3	5.5% Series due 2034	5.50%	3/26/2004	3/15/2034	50,000	50,000	98.483	758.5	149.4	49,092.1	5.626%	2,813.0
4	5.875% Series due 2034	5.875%	8/16/2004	8/15/2034	55,000	55,000	97.890	1,160.5	173.3	53,666.2	6.051%	3,328.2
5	5.30% Series due 2035	5.30%	8/26/2005	8/15/2035	60,000	60,000	98.569	858.6	3,399.7	55,741.7	5.802%	3,481.3
6	6.30% Series due 2037	6.30%	6/22/2007	6/15/2037	140,000	140,000	99.051	1,328.6	450.0	138,221.4	6.396%	8,953.9
7	6.25% Series due 2037	6.25%	10/18/2007	10/15/2037	100,000	100,000	98.982	1,018.0	477.5	98,504.5	6.362%	6,362.3
8	4.85% Series due 2040	4.85%	8/30/2010	8/15/2040	100,000	100,000	99.080	920.0	534.9	98,545.1	4.943%	4,943.4
9	4.30% Series due 2042	4.30%	4/13/2012	4/1/2042	75,000	75,000	99.184	612.0	1,397.8	72,990.2	4.463%	3,347.2
10	4.00% Series due 2043	4.00%	4/8/2013	4/1/2043	75,000	75,000	98.991	756.8	179.2	74,064.0	4.072%	3,054.3
11	3.65% Series due 2045	3.65%	3/6/2015	3/1/2045	250,000	250,000	98.564	3,590.0	19,137.5	227,272.5	4.185%	10,462.3
12	4.05% Series due 2046	4.05%	3/10/2016	3/1/2046	120,000	120,000	98.992	1,209.6	14,689.4	104,101.0	4.898%	5,877.1
13	4.20% Series due 2048	4.20%	3/16/2018	3/1/2048	220,000	220,000	98.880	2,464.0	5,532.0	212,004.0	4.420%	9,723.8
14	4.20% Series due 2048	4.20%	4/3/2020	3/1/2048	230,000	230,000	113.013	-29,929.9	621.1	259,308.8	3.482%	8,009.4
15	1.90% Series due 2030	1.90%	6/22/2020	7/15/2030	80,000	80,000	98.940	848.0	3,925.3	75,226.7	2.577%	2,061.4
16	4.99% Series due 2032	4.99%	12/22/2022	12/22/2032	23,000	23,000	99.500	115.0	85.0	22,800.0	5.102%	1,173.5
17	5.06% Series due 2042	5.06%	12/22/2022	12/22/2042	25,000	25,000	99.500	125.0	93.0	24,782.0	5.130%	1,282.6
18	5.06% Series due 2043	5.06%	3/8/2023	3/8/2043	60,000	60,000	99.500	300.0	222.0	59,478.0	5.130%	3,078.0
19	5.20% Series due 2053	5.20%	3/8/2023	3/8/2053	62,000	62,000	99.500	310.0	229.0	61,461.0	5.258%	3,259.9
20	5.50% Series due 2053	5.50%	3/14/2023	3/15/2053	400,000	400,000	98.182	7,272.0	1,480.0	391,248.0	5.652%	22,609.0
21	5.60% Series due 2053	5.60%	10/16/2023	10/15/2053	140,000	140,000	99.000	1,400.0	520.0	138,080.0	5.696%	7,974.2
22												
23	Total First Mortgage Bonds				2,435,000	2,435,000		(3,027.9)	57,547.5	2,380,480.4	5.014%	122,086.2
24												
25	Pollution Control Revenue Bonds:											
26	Humboldt 1.45% Series 2003, due 2024	1.45%	8/21/2019	12/1/2024	49,800	49,800	99.200	398.4	4,352.9	45,048.7	3.442%	1,714.1
27	Sweetwater 1.70% Series 2006, due 2026	1.70%	8/21/2019	7/15/2026	116,300	116,300	99.200	930.4	8,612.9	106,756.7	3.027%	3,519.8
28												
29	Total Pollution Control Revenue Bonds				166,100	166,100		1,329	12,966	151,805	3.151%	5,234
30												
31												
32	TOTAL DEBT CAPITAL				2,601,100	2,601,100		(1,699)	70,513	2,532,286	4.895%	127,320

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF IDAHO POWER COMPANY FOR	)	
AUTHORITY TO INCREASE ITS RATES	)	CASE NO. IPC-E-23-11
AND CHARGES FOR ELECTRIC SERVICE	)	
IN THE STATE OF IDAHO AND FOR	)	
ASSOCIATED REGULATORY ACCOUNTING	)	
TREATMENT.	)	
	)	

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

PAULA JEPPSEN

Q. Please state your name, business address, and present occupation.

A. My name is Paula Jeppsen, and my business address is 1221 West Idaho Street, Boise, Idaho. I am employed by Idaho Power Company (“Idaho Power” or “Company”) as the Forecasting and Planning Director within the Finance department.

Q. Please describe your educational background.

A. I graduated in 1999 from Boise State University, receiving a Bachelor of Arts degree in Finance. In 2010, I earned a Master of Business Administration degree from Colorado State University. In 2021, I attended the Energy Executive Course through the University of Idaho.

Q. Please describe your work experience with Idaho Power.

A. In 2007, I was hired as a Financial Analyst in the Finance department. In 2010, I was promoted to Finance Team Leader. My primary responsibilities included leading a team of financial analysts, supporting and facilitating budgeting, advising on proper accounting treatment, and preparing and reviewing financial analyses. In 2016, I was promoted to Business Unit Finance Director; in 2019, my duties were broadened, and my title was changed to Financial Accounting and Reporting Director. In these roles, I provided oversight and direction to the Business Unit Finance Support teams, Property Accounting department, Financial Accounting and Reporting department, and Financial Planning and Analysis department. In 2022 my role changed slightly, and my title changed to Forecasting and Planning Director. In this role I continued to be responsible for overseeing the Business Unit Finance Support teams and Financial Planning and Analysis department. I also added oversight of the Load Research and Forecasting team when I moved into this role.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is two-fold. First, I will present the Company’s historical actual audited financial information for the 12-month period ended December 31, 2022. Second, my testimony will discuss the quantification of certain adjustments to operating expenses and rate base consistent with previous Idaho Public Utilities Commission (“Commission”) directives regarding regulatory treatment that result in an adjusted historical actual 12-month period ended December 2022 (“2022 Base”). Finally, I will discuss the quantification of certain adjustments to operating expenses and rate base associated with the Boardman Power Plant (“Boardman”), the Jim Bridger Power Plant (“Bridger”), the North Valmy Generating Station

("Valmy) and Idaho Power's Wildfire Mitigation Plan ("WMP").

Q. Please describe the manner in which the 2022 financial data is presented.

A. Actual 2022 financial data is presented using the account names from the Commission-approved Uniform System of Accounts ("USA"). This data has been fully audited and was filed with the U.S. Securities and Exchange Commission and the Federal Energy Regulatory Commission ("FERC") in the Company's Form 10-K and FERC Form 1, respectively. The components of the 2022 financial data include the following items: (1) other operating revenues; (2) other revenues and expenses;(3) operation and maintenance ("O&M") expenses;(4) property insurance expenses;(5) regulatory commission expenses;(6) depreciation and amortization expense;(7) electric plant/regulatory assets - amortizations, adjustments, gains, and losses;(8) regulatory debits and credits;(9) taxes other than income taxes;(10) Idaho Energy Resources Company's ("IERCo") statement of income and rate base components;(11) allowance for funds used during construction ("AFUDC") related to the Hells Canyon relicensing;(12) electric plant in service and related items;(13) materials and supplies;(14) other deferred programs;(15) Plant Held for Future Use;(16) accumulated deferred income taxes;(17) customer advances for construction; and (18) certain deductions from O&M expenses.

Q. Please describe the rationale for quantifying adjustments to the 2022 actual financial data ("2022 Actuals").

A. Several of the adjustments to 2022 Actuals that I have quantified are in conformance with prior Commission orders and thus have become, in the opinion of the Company, standard regulatory adjustments. The adjustments that are not the result of prior orders are the adjustments to Plant Held for Future Use, adjustments to remove Bridger coal-related expenses, Valmy expenses, Transmission of Electricity by Others ("Third Party Transmission") expenses that are included in normalized net power supply expenses ("NPSE"), Oregon COVID-related expenses, regulatory expenses and intervenor funding, an adjustment to include WMP-related expenses that were deferred in 2022 and a few other minor adjustments to O&M expenses. I will discuss the rationale for these adjustments later in my testimony.

The Company has made adjustments to remove expenses as previously directed by the Commission. These adjustments include the removal of certain general advertising expenses, specific memberships and contributions, certain management expenses, and other exclusions that, although justified for business purposes, may be viewed as more appropriately funded by shareholders than customers and are therefore not recoverable through the Company’s rates.

The following have also been removed from 2022 Actuals:(1) all 2022 incentive compensation; (2) the financial impacts of both the Idaho and Oregon Energy Efficiency Rider revenues and expenses; (3) Bridger coal-related expenses; (4) Valmy expenses; (5) Boardman, Bridger coal-related and Valmy plant, depreciation expense and accumulated depreciation; (6) Third Party Transmission actual 2022 expense that is included in normalized NPSE, and, finally, (7) certain Oregon COVID-related expenses, regulatory expenses, and intervenor funding amounts.

Q. How has the Company treated prepayments in this case?

A. Prepayments have been removed in their entirety, consistent with previous Commission orders. This adjustment is reflected in Company Witness Ms. Kelley Noe’s Exhibit No. 34.

Q. Please describe the Company’s proposed adjustment to Plant Held for Future Use.

A. The Company is proposing Plant Held for Future Use as of December 31, 2022, be included in rate base but adjusted to remove structures and specific properties for which the future use is uncertain (e.g., subject to being divided for partial use or removed due to the possible change in need for the property). The rationale for inclusion of Plant Held for Future Use and the adjustments will be discussed in more detail later in my testimony.

Q. Are you sponsoring exhibits that contain the 2022 Actuals and 2022 adjustments by the components you have just identified?

A. Yes. I am sponsoring Exhibit Nos. 22 through 24 which detail 2022 Actuals and the 2022 adjustments by component categories. The additional adjustments to get from the 2022 Base to the 2023 Test Year, which are also contained in my exhibits, are addressed in the Direct Testimony of Company Witness Mr. Matthew Larkin.

Q. Please describe Exhibit No. 22.

A. Exhibit No. 22 is a compilation of the Company’s supporting schedules for the adjusted historical actual data for the 12-month period ended December 31, 2022.

Q. Please describe pages 1 through 13 of Exhibit No. 22.

A. Page 1 of Exhibit No. 22 reflects the detail for Other Operating Revenues, Accounts 451, 454, and 456. Page 2 reflects the detail of Other Revenues and Expenses, Accounts 415 and 416. Pages 3 through 6 reflect the O&M

expenses by USA account. Page 7 reflects the detail of Property Insurance Expense, Account 924. Page 8 reflects the detail of Regulatory Commission Expenses, Account 928. Page 9 includes Depreciation and Amortization Expense, Accounts 403 and 404. Page 10, Electric Plant/Regulatory Assets – Amortizations, Adjustments, Gains, and Losses, Account 406, presents the Asset Exchange acquisition adjustment amortization. Page 11 reflects Regulatory Debits and Credits, Accounts 407.3 and 407.4, respectively. Page 12 shows the detail of Taxes Other Than Income Taxes.

Q. Please explain the adjustment you have made on page 1 of Exhibit No. 22, Other Operating Revenues, to arrive at the 2022 Base.

A. The adjustment on line 21, column 4 to the 2022 Actuals removes the impact of the Energy Efficiency Rider revenues as directed in Commission Order No. 30189.

Q. Please describe the adjustments quantified on Pages 3 through 6 of Exhibit No. 22, O&M expenses.

A. Pages 3 through 6 include the standard regulatory adjustments that I will discuss in more detail later in my testimony. Pages 3 through 6 also include adjustments related to Bridger, Valmy, Third Party Transmission expenses, Oregon COVID-related expenses, Oregon regulatory expenses and Oregon intervenor funding, WMP-related expenses, and a couple of other minor adjustments to O&M expenses. I will discuss each of these adjustments individually.

Q. Please describe the Company-proposed adjustment to O&M expenses related to Bridger.

A. On June 1, 2022, the Commission authorized the Company to establish a balancing account, with the necessary regulatory accounting, to track the incremental costs and benefits associated with the Company's cessation of coal-fired operations at Bridger as part of the Bridger coal-related levelized revenue requirement mechanism.[1] In this case the Company proposes to include as part of the Bridger coal-related levelized revenue requirement, all coal-related non-fuel O&M expenses, as compared to the previous methodology that included only the variances between actual coal-related non-fuel O&M expenses and coal-related non-fuel O&M expenses included in 2011 base rates as part of the mechanism.

The Company's update to the Bridger related levelized revenue requirement reflects cost recovery at current levels, with the exception of collection related to previously deferred revenue requirement amounts. It also allows for the presentment of Bridger coal-related non-fuel

[1] *In the Matter of Idaho Power Company's Application for Authority to Increase Its Rates for Electric Service to Recover Costs Associated with the Jim Bridger Power Plant,* Case No. IPC-E-21-17 Order No. 35423(June 1, 2022).

O&M expenses to align with the presentment of Bridger coal-related plant-related investments in the Bridger levelized revenue requirement. To avoid double counting Bridger coal-related non-fuel O&M expenses, an adjustment was made to remove actual 2022 Bridger O&M ("Bridger O&M Adjustment"). The Bridger coal-related levelized revenue requirement mechanism will be discussed more fully in Mr. Larkin's testimony.

Q. How was the Bridger O&M Adjustment calculated?

A. The Bridger O&M Adjustment, a reduction of $30,338,732, consists of the removal of 2022 actual O&M totaling $30,474,476, partially offset by $135,744 related to a negative entry recorded in 2022 to Account 557.007. The 2022 reduction to actual O&M was calculated using the sum of non-fuel O&M charged to Bridger-related accounts in 2022 including 500.001, 502.001, 506.001, 507.001, 510.001, 512.001, 513.001, 514.001, and 557.007. Table 1 below presents the amounts charged to each account:

TABLE 1

2022 Bridger O&M Accounts

Table 1 2022 Bridger O&M Accounts	O&M $s
500.001	$ 231,676
502.001	6,046,168
506.001	7,284,754
507.001	229,461
510.001	12,403
512.001	6,756,285
513.001	2,177,957
514.001	9,322,817
Subtotal	32,061,521
Idaho Allocation Factor	95.05%
Subtotal Idaho Bridger Allocated	30,474,476
557.007	(135,744)
Total Bridger O&M Adjustment	$ 30,338,732

The Idaho jurisdictional allocation was computed using the allocation factors approved in the Company's last general rate case.[2] The subtotal, including the allocated 2022 Bridger O&M expense, results in a reduction of $30,474,476. These adjustments are included on page 3, lines 1 through 14, column 5. The negative amount of $135,744 was added back to zero out the 557.007 account. This adjustment is on page 4, line 12, column 5. The 557.007 account is specific to Idaho, so the jurisdictional allocation factor was not applied to this account.

[2] *In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service in Idaho,* Case No. IPC-E-11-08, Order No. 32426 (Dec. 30, 2011).

Q. Please describe the Company’s proposed adjustment to O&M expenses related to Valmy.

A. On May 31, 2017, the Commission authorized the Company to establish a balancing account, with the necessary regulatory accounting, to track the incremental costs and benefits associated with the accelerated Valmy end-of-life as part of the Valmy levelized revenue requirement mechanism.[3] In this case, like the proposed change to the Bridger coal-related levelized revenue requirement, the Company proposes to include as part of the Valmy levelized revenue requirement all non-fuel in O&M expenses, as compared to the previous methodology, that included only the variances between actual non-fuel O&M expenses and the non-fuel O&M expense included in 2011 base rates as part of the mechanism. This modification does not reflect an increase in overall collection, but rather an update to the base from which variances are tracked. It also allows for the presentment of Valmy non-fuel O&M expenses to align with the presentment of Valmy plant-related investments in the Valmy levelized revenue requirement. To avoid double counting non-fuel O&M expenses, an adjustment was made to remove actual 2022

[3] *In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates for Electric Service to Recover Costs Associated with the North Valmy Plant,* Case No. IPC-E-16-24 Order No. 33771 (May 31, 2017).

Valmy O&M ("Valmy O&M Adjustment").

Q. How was the Valmy O&M Adjustment calculated?

A. The Valmy O&M Adjustment, a reduction of $10,614,592, was calculated using the sum of O&M charged to Valmy-related accounts in 2022 including 500.003, 502.003, 505.003, 506.003, 511.003, 512.003, 513.003, and 514.003. Table 2 below presents the amounts charged to each account:

TABLE 2
2022 Valmy O&M Accounts

Table 2 2022 Valmy O&M Accounts		**O&M $s**
500.003	$	531,405
502.003		3,250,319
505.003		1,128,466
506.003		1,301,526
511.003		2,540,009
512.003		2,017,796
513.003		128,562
514.003		269,294
2022 Total Valmy O&M		11,167,377
Idaho Allocation Factor		95.05%
Total Valmy O&M Adjustment	$	10,614,592

The Idaho jurisdictional allocation was computed using the allocation factors approved in the Company's last general rate case. The Idaho jurisdictional allocated 2022 Valmy O&M expense results in a reduction to O&M of $10,614,592, which is included on page 3, lines 1 through 14, column 5.

Q. Please describe the adjustment related to Third Party Transmission expense, Account 565.

A. The test year third Party Transmission expense is included in normalized NPSE that is more fully discussed in the Direct Testimony of Company Witness Ms. Jessica Brady. Therefore, an adjustment was made to remove actual 2022 Third Party Transmission expenses of $11,322,964 from O&M. This adjustment is shown on page 5, line 6, column 5, Account 565.

Q. Please describe the adjustment related to the WMP-related expenses.

A. On June 17, 2021, the Commission authorized Idaho Power to defer its Idaho-jurisdictional incremental O&M expenses, incremental insurance expenses, and depreciation expenses for its capital expenditures related to its WMP for recovery in a future rate proceeding.[4] Incremental O&M and insurance expenses are measured from a 2019 base. In 2022, Idaho Power deferred $21,003,203 of Idaho jurisdictional WMP-related expenses. In this case, the Company proposes to continue to defer certain incremental WMP-related expenses. This request is discussed

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[4] *In the Matter of Idaho Power Company's Application for an Accounting Order Authorizing the Deferral of Incremental Wildfire Mitigation and Insurance Costs,* Case No. IPC-E-21-02, Order No. 35077 (June 17, 2021); *In the Matter of Idaho Power Company's Application for Review of the Company's Current Wildfire Mitigation Plan and Authorization to Defer Newly Identified Incremental Wildfire Mitigation Costs,* Case No. IPC-E-22-27, Order No. 35717 (Mar. 23, 2023).

more fully in Mr. Tatum’s testimony.

To set a new 2022 base year that will be used to track incremental WMP-related expenses going forward, an adjustment was made to add the amounts deferred in 2022 to O&M, thus resetting 2022 actual WMP-related O&M to what it would have been absent the deferrals (“WMP O&M Adjustment”).

Q. How was the WMP O&M Adjustment calculated?

A. The WMP O&M Adjustment, an increase of $20,229,304, was calculated by identifying the amounts by O&M account that were deferred in 2022, with certain adjustments for labor, depreciation, and amortization expense to avoid double counting of test year amounts. Table 3 below presents the amounts adjusted to each account in detail:

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TABLE 3
2022 WMP O&M Accounts

Table 3 2022 WMP O&M Accounts	2022 Deferral	Adjustments		Net Adjustment to 2022 O&M
571.000	$ 930,096	$ (124,562)	.)	$ 805,534
580.000	3,922			3,922
583.000	105,035			105,035
584.000	4,282			4,282
593.000	13,204,749	(502,437)	.)	12,702,312
594.000	18,123			18,123
596.000	3,043			3,043
924.000	1,277,597			1,277,597
925.000	5,309,456			5,309,456
403.290	141,418	(141,418)	.)	(0)
404.290	5,482	(5,482)	.)	(0)
	$ 21,003,203	$ (773,899)		$ 20,229,304

1.) Remove 2022 actual labor included in O&M labor forecast.

2.) Remove depreciation & amortization expense included in depreciation & amortization expense forecast.

The Idaho-jurisdictional WMP O&M Adjustment results in an increase to O&M of $20,229,304, which is included on page 5, lines 13, 18, 21, 22, 32, 33, and 35, column 5 and page 6, lines 20 and 21, column 5.

Q. Please describe the adjustment for Oregon COVID-related expenses.

A. There are two adjustments for Oregon COVID-related expenses. The first adjustment removes $354,610 of amortization expense recorded to Account 904.002 in 2022 for the deferred incremental costs and savings through December 31, 2021, related to the COVID-19 Arrearage Management Program that is being collected in Oregon rates pursuant to Public Utility Commission of Oregon ("OPUC") Order No. 22-192. The second adjustment is related to a reserve recorded in 2021 for COVID-19 Arrearage Management Program costs. After the OPUC authorized collection of the deferred 2021 COVID-19 Arrearage Management Program costs on May 31, 2022, the reserve was reversed, resulting in a negative $552,743 being recorded to Account 904.003. Idaho Power made an adjustment to add this amount back, effectively zeroing out the recording of the reserve in 2021 and the reversal of the reserve in 2022. The net of these two adjustments is $198,133 which can be seen on page 6, line 4, column 5, Account 904.

Q. Please describe the adjustments for Oregon regulatory expenses and intervenor funding.

A. An adjustment was made to remove $28,878 in amortization expense for deferred Oregon annual regulatory expenses and $36,197 in amortization expense for the Oregon Citizens' Utility Board ("CUB") intervenor funding being collected in Oregon rates pursuant to OPUC Order Nos. 21-166 and 22-192. These amounts were recorded to Account 928.303 in 2022. The total adjustment is $65,075, which can be seen on page 6, line 27, column 5, Account 928.

Q. Were there any other adjustments to O&M on page 3 through 6 of Exhibit No. 22?

A. Yes. In addition to the standard regulatory adjustments there were two other adjustments to O&M. The first was a $124,942 adjustment to Account 537 Hydraulic Expenses related to an Idaho Department of Fish and Game invoice that was under accrued at year-end 2022. This adjustment is included on page 3, line 18, column 5, Account 537. The second was a $9,801 adjustment to Account 536 Water Leases to correct for an error that occurred at the beginning of 2022. This adjustment zeroes out this account as there were no water leases in 2022 and none expected in 2023. This adjustment can be seen on page 3, line 17, column 5, Account 536.

Q. Please describe the adjustment quantified on page 7 of Exhibit No. 22, Property Insurance.

A. The amount included on line 6 of page 7 represents the adjustment to Account 924 for deferred WMP-related property insurance as seen in Table 3 above.

Q. Please describe the adjustment quantified on page 8 of Exhibit No. 22, Regulatory Commission Expenses.

A. The amount included on line 14 of page 8 represents the adjustment to Account 928.303 for Oregon annual regulatory expenses and Oregon CUB intervenor funding described in this testimony above.

Q. Please describe the adjustments quantified on page 9 of Exhibit No. 22, Depreciation and Amortization Expense.

A. The amount on line 2, column 4 of page 9 removes Bridger coal-related and Valmy depreciation expense. The adjustment for 2022 Bridger coal-related electric plant depreciation expense is $5,100,316. The adjustment for 2022 Valmy electric plant depreciation expense is $19,484,573. The sum of these two adjustments is a $24,584,889 reduction to depreciation expense.

Q. Please describe the adjustments quantified on page 11 of Exhibit No. 22, Regulatory Debits and Credits.

A. On June 25, 2020, the Commission authorized the Company to record expenses associated with cloud computing arrangements to a regulatory asset. Further, the Commission directed that amortization begins when the asset is placed in service and becomes used and useful.[5] Idaho Power has recorded a regulatory asset for the Idaho-only portion of prepaid licensing costs for the Zycus procurement tool cloud computing agreement. The amount on line 3, column 4 of page 11 reduces cloud computing amortization by $173,640 to only the amount associated with

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[5] *In the Matter of Idaho Power Company's Application for an Accounting Order for Costs Associated with Cloud Computing Arrangements,* Case No. IPC-E-20-11, Order No. 34707, pg. 3 (June 25, 2020).

the Zycus procurement tool that is currently used and useful which is $201,265.

Q. Please describe the adjustments quantified on page 12 of Exhibit No. 22, Taxes Other Than Income Taxes, to arrive at the adjusted 2022 Base.

A. The amounts included on lines 1, 2, 20 and 21 of page 12, column 4 in Exhibit No. 22 are eliminated by the state and federal payroll loading reversal on line 25, column 4. These amounts represent federal unemployment, Social Security, and state unemployment taxes, respectively. The state and federal payroll loading reversal effectively removes these amounts from Taxes Other Than Income Taxes and spreads them over all accounts that receive labor charges. Therefore, the adjustments in column 4, page 12 eliminate these expenses in their entirety in order to demonstrate that these amounts are not double counted when determining the Company’s revenue requirement. The amounts included on lines 8 and 9 of Exhibit No. 22 represent the removal of property taxes related to Bridger and Valmy, respectively.

Q. Please describe pages 13 and 14 of Exhibit No. 22.

A. Page 13 of Exhibit No. 22 reflects the net earnings of IERCo that are added to operating income for ratemaking purposes and page 14 reflects AFUDC related to the Hells Canyon relicensing that is currently being collected from customers.

Q. How does the Company treat IERCo's earnings and investment for ratemaking purposes?

A. The primary purpose of IERCo is to mine the coal that fuels the Bridger plant in Wyoming. Consistent with prior Commission orders, the Company treats IERCo's coal operations as a part of its utility operations and, accordingly, adds the current year IERCo earnings to electric operating income and the investment in IERCo to the net electric rate base. Accordingly, the interest expense net of tax (line 13, page 13 of Exhibit No. 22) on notes payable to Idaho Power has been added back to IERCo's Net Income from Operations. Additionally, the notes payable (column 3, page 23 of Exhibit No. 22) to Idaho Power have been added to IERCo's rate base in determining the Company's net investment in IERCo to be included in total system rate base.

Q. Please describe the adjustments to IERCo's net earnings and rate base in this proceeding.

A. Adjustments were made to increase IERCo's rate base for notes payable to Idaho Power in the amount of $5,101,864 (column 3, line 14, page 23 of Exhibit No. 22) and the associated interest expense adjustment net of income tax of $77,939 (column 3, line 13, page 13 of

Exhibit No. 22) in order for IERCo's rate base and earnings to reflect only the cash required to fund IERCo operations for the year 2022. If IERCo were to use these funds to make a distribution of earnings to the Company, or if the Company were to actually fold IERCo into its own operations, the result would be the same as presented herein.

Q. Please describe the data contained on pages 15 through 23 of Exhibit No. 22

A. Pages 15 through 23 of Exhibit No. 22 reflect the development of all components applicable to the combined system rate base of the Company for 2022 as directed by Mr. Larkin. Page 15 reflects the balance by month and the thirteen-month average of Electric Plant in Service, Account 101. Page 16 reflects the balance by month and the thirteen-month average of Accumulated Provision for Depreciation, Account 108. Page 17 reflects the balance by month and the thirteen-month average of Accumulated Provision for Amortization, Account 111. Page 18 reflects the balance by month and the thirteen-month average of Materials and Supplies, Accounts 154 and 163. Page 19 of Exhibit No. 22 reflects the balance of the Company's Other Deferred Programs. For these programs, the Company has included the December 31, 2022, ending balance in rate base, consistent with previous orders. Page 20 reflects the year-end balance of Plant Held for Future Use, Account 105. Page 21 reflects the balance at the end of 2022 and the average balance for Accumulated Deferred Income Taxes, Accounts 190, 282, and 283. Page 22 reflects the balance by month and the thirteen-month average balance of Customer Advances for Construction, Account 252. Page 23 reflects the balance by month and thirteen-month average of the rate base components for IERCo, consistent with prior Commission orders.

Q. Please describe the adjustment on page 15 of Exhibit No. 22.

A. The adjustment in column 4, page 15 is to remove the Electric Plant in Service associated with Bridger coal-related plant and Valmy plant using the respective average plant balance of the thirteen-month period between December 2021 and December 2022. Additionally, Idaho Power removed Electric Plant in Service for Boardman using the average of the thirteen-month period between December 2021 and December 2022. The only remaining Boardman asset in Idaho Power's Electric Plant in Service accounts as of December 31, 2022, is land. There is no associated depreciation expense or accumulated depreciation because land does not depreciate.

On February 15, 2012, the Commission authorized the Company's request to establish regulatory accounting, a cost recovery plan, and a balancing account to track the costs and benefits associated with the early shut-down of Boardman.[6] Boardman ceased operations on October 15, 2020, and the Company is currently in the process of decommissioning the plant.

Using the thirteen-month average of the period between December 2021 and December 2022, the adjustment for Bridger coal-related Electric Plant in Service results in a reduction of $479,890,777 to total Electric Plant in Service. Using the same period average for Valmy plant, the adjustment results in a reduction of $257,496,723 to total Electric Plant in Service. The Boardman adjustment results in a reduction in Electric Plant in Service of $106,610 associated with land owned in fee. The sum of the thirteen-month average adjustments to Total Electric Plant in Service, $737,494,110 is presented on line 14, Column 4, page 15.

Q. Please describe the adjustment on page 16, Accumulated Provision for Depreciation of Exhibit No. 22.

A. The adjustment in column 4, page 16 is to remove the accumulated depreciation related to Bridger coal-related plant and Valmy plant, using a thirteen-month average of December 2021 through December 2022. The

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[6] *In the Matter of Idaho Power Company's Request for Acceptance of Its Regulatory Plan Regarding the Early Shutdown of the Boardman Power Plant,* Case No. IPC-E-11-18, Order No. 32457 (Feb. 15, 2012).

adjustment to accumulated depreciation attributable to Bridger coal-related plant results in a reduction of $281,445,851. The adjustment to accumulated depreciation related to Valmy plant results in a reduction of $202,576,957. The sum of the thirteen-month average adjustments to Total Accumulated Depreciation, a reduction of $484,022,808 is presented on row 14, column 4, page 16.

Q. Please describe the adjustment on page 18, Materials and Supplies of Exhibit No. 22.

A. The adjustment in column 4, page 18 of $967,717 is to remove the Boardman inventory balance, using a thirteen-month average of December 2021 through December 2022.

Q. Please describe in more detail Other Deferred Programs on page 19 of Exhibit No. 22.

A. Previous Commission-approved programs included on page 19 of Exhibit No. 22 are the American Falls bond refinancing costs (Commission Order No. 25880), the Idaho Siemens Long-Term Program ("LTP") (Order No. 33420), Cloud Computing (Order No. 34707), and Wildfire Mitigation (Order No. 35077). The American Falls bond refinancing is being amortized over the life of the American Falls bond and will be fully amortized in 2025.

Also included on Exhibit No. 22 is the CUB 2021-2025 Fund Grant (OPUC Order No. 20-493), the Oregon Siemens LTP

(OPUC Order No. 15-387), the Statement of Financial Accounting Standards 87 capitalized pension costs (OPUC Order No. 10-064), Oregon regulatory liabilities associated with Reconnect Fees for Remote Meters (OPUC ADV 16-09) and the Jim Bridger Plant End-of-Life Depreciation (OPUC Order No. 12-296).

Q. Please describe in more detail Plant Held for Future Use, Account 105, on page 20 of Exhibit No. 22.

A. Consistent with treatment approved in the 2011 Idaho general rate case, Case No. IPC-E-11-08, the Company has included portions of Plant Held for Future Use in rate base. Idaho Code § 61-502A allows the Commission to set rates for utilities that include a rate of return on property held for future use if the Commission makes an explicit finding that such a return is in the public interest. In preparing this case, the Company performed a review and identified those parcels of land included in Account 105, Plant Held for Future Use, that are anticipated to be used in their entirety for operating property in the future. As a result of this review, the year-end 2022 Actuals balance of $7,129,775 (page 20, column 3, line 34) has been reduced by $501,610 (page 20, column 4, line 34) by those properties or facilities for which the use is uncertain, may be split, or for structures that will be razed prior to the start of construction to arrive at an adjusted 2022 Base of $6,628,165 (page 20, column 5, line 34).

Q. Please describe Exhibit No. 23.

A. Exhibit No. 23 reflects the detailed support of deductions from the O&M expenses of the Company for general advertising expenses, certain memberships and contributions, certain senior management expenses, and miscellaneous other expenses. This screening process is consistent with previous Idaho general rate case filings.

Q. Please describe in more detail pages 2 through 9 of Exhibit No. 23.

A. The Company has put processes in place to review and screen its accounting records to identify memberships and contributions in an effort to properly identify, account for, and share the costs of each. All contributions, and either 33 percent or 100 percent of certain memberships, have been removed. This screening process is consistent with previous Idaho general rate case filings.

Additionally, officer expenses have been reviewed and adjusted by (1) removing 100 percent of all charges to the Arid Club and Oregon jurisdiction direct charges, (2) removing one-third of Edison Electric Institute expenses, and (3) allocating the balance of expense account charges of officers between Idaho Power and IDACORP on the basis of how their payroll is charged. Six officers had no further allocation based on payroll because they either incurred no expenses, their management responsibilities are solely incurred on behalf of Idaho Power, or their expenses are reviewed monthly for proper allocation between IDACORP and Idaho Power, thus not requiring further allocation.

Lastly, the Company has reviewed all expense account charges to O&M in an effort to identify and exclude charges from regulatory recovery based on prior concerns expressed in other filings based on the nature of the business establishment. While many of these expense account charges are legitimate business expenses, out of an abundance of caution, they were removed.

Q. Please describe Exhibit No. 24.

A. Exhibit No. 24 was developed to identify and include or exclude specific rate base, revenue, and expense adjustments which have not been provided for elsewhere. These and/or similar adjustments have been made in previous general rate cases.

Q. Please describe the adjustments you have included in Exhibit No. 24.

A. Lines 1 through 3 reflect the Electric Plant Acquisition Adjustment associated with the exchange of certain transmission assets with PacifiCorp approved by Commission Order No. 33313.

Line 4 reflects the unamortized portion of the regulatory asset associated with the Cloud Computing Zycus procurement tool authorized by Commission Order No. 34707.

Line 5 reflects the unamortized portion of certain deferred Wildfire Mitigation expenses approved by Commission Order No. 35077 for which the Company will request amortization in this case.

Lines 6 and 7 reflect the unamortized portions of the Idaho and Oregon Siemens LTPs, respectively (Commission Order No. 33420 and OPUC Order No. 15-387).

Line 8 reflects increases due to forecasted pension expense amortization that is discussed in Company Witness Mr. Timothy Tatum’s testimony.

Lines 9, 10, 11 and 12 remove the income statement impact of the Idaho and Oregon Energy Efficiency Riders accounting affecting Other Electric Revenues, Account 456, and Customer Assistance Expenses, Account 908, in accordance with Commission Order No. 30189. While the purpose of these entries is to demonstrate that the Energy Efficiency Rider revenues and expenses have been excluded from the revenue requirement, leaving these amounts in the income statement would have had no impact to the revenue requirement because they are a net zero adjustment.

Line 13 shows the Idaho Energy Efficiency Rider funded labor to be included in O&M.

Lines 14 through 17 reflect one year of amortization for the Cloud Computing, Wildfire Mitigation, Idaho Siemens LTP and Oregon Siemens LTP regulatory assets described in this testimony above.

Line 18 removes all 2022 incentives included in Administrative and General Salaries, Account 920. 2023 Test Year incentive expense for which the Company seeks recovery is addressed in Mr. Larkin’s testimony.

Line 19 shows one year of amortization for the Asset Exchange Acquisition Adjustment described above.

Lines 20 through 50 include the 2023 projected Idaho intervenor funding amortization.

Lines 51 and 52 remove the 2022 amortization of Oregon CUB intervenor funding and Oregon annual regulatory expenses that are being recovered in Oregon rates.

Q. Are all the data and associated adjustments made to your exhibits and supporting schedules calculated on a total system basis?

A. Yes, except for the Bridger, Valmy, and WMP adjustments to O&M that are presented on an Idaho-allocated basis.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

DECLARATION OF PAULA JEPPSEN

I, Paula Jeppsen, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Paula Jeppsen. I am employed by Idaho Power Company as Forecasting and Planning Director.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 22 through 24 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: ______________________
PAULA JEPPSEN

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

JEPPSEN, DI TESTIMONY

EXHIBIT NO. 22

IDAHO POWER COMPANY
OTHER OPERATING REVENUES
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line No	Description	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
1	Miscellaneous service revenues (451)	$ 4,936,204	$ -	$ 4,936,204		$ 1,271,884	$ 1,271,884		$ 6,208,088	$ -	$ 6,208,088
	Rent from electric property (454):										
2	Substation equipment	3,215,758	-	3,215,758	YES	-	-		3,215,758	-	3,215,758
3	Transformer & distribution rentals	17,330	-	17,330	YES	-	-		17,330	-	17,330
4	Station and line rentals	-	-	-	YES	-	-		-	-	-
5	Cogeneration and small power production	1,832,348	-	1,832,348		60,186	60,186		1,892,534	-	1,892,534
6	Real estate rents	257,813	-	257,813	YES	-	-		257,813	-	257,813
7	Dark fiber rents	400,000	-	400,000		(400,000)	(400,000)		-	-	-
8	Joint pole attachments	1,634,179	-	1,634,179	YES	-	-		1,634,179	-	1,634,179
9	Facilities charges	10,470,031	-	10,470,031		(189,692)	(189,692)		10,280,339	-	10,280,339
10	Overnight park rents	814,189	-	814,189	YES	-	-		814,189	-	814,189
11	Water District payments	185,425	-	185,425		(101,177)	(101,177)		84,248	-	84,248
12	Miscellaneous	-	-	-		-	-		-	-	-
13	Total rent from electric property	18,827,073	-	18,827,073		(630,683)	(630,683)		18,196,390	-	18,196,390
	Other electric revenue (456):										
14	Network Service	11,130,006	-	11,130,006		743,001	743,001		11,873,007	-	11,873,007
15	Point - to - Point and other services	49,667,827	-	49,667,827		(1,334,489)	(1,334,489)		48,333,338	-	48,333,338
16	Photovoltaic	-	-	-	YES	-	-		-	-	-
17	Antelope	-	-	-	YES	-	-		-	-	-
18	Conservation recovery - Oregon	-	-	-	YES	-	-		-	-	-
19	Sierra Pacific Power Company sales	51,764	-	51,764	YES	-	-		51,764	-	51,764
20	Stand-by service	759,997	-	759,997	YES	-	-		759,997	-	759,997
21	Energy efficiency rider	33,197,113	(33,197,113)	-	YES	-			-	-	-
22	Miscellaneous	1,663	-	1,663	YES	-	-		1,663	-	1,663
23	Total other electric revenue	94,808,370	(33,197,113)	61,611,257		(591,488)	(591,488)		61,019,769	-	61,019,769
24	Total other operating revenues	$ 118,571,647	$ (33,197,113)	$ 85,374,534		$ 49,713	$ 49,713	A	$ 85,424,247	$ -	$ 85,424,247

IDAHO POWER COMPANY
OTHER REVENUES AND EXPENSES
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line No	Program	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
	Other Revenues (Acct 415):										
1	Power Solutions	$ (11,623)	$ -	$ (11,623)		$ 30,623	$ 30,623		$ 19,000	$ -	$ 19,000
2	Hydro Services	3,803	-	3,803	YES	-	-		3,803	-	3,803
3	Water Management Services	641	-	641	YES	-	-		641	-	641
4	Qualified Reporting Entity Svcs	6,600	-	6,600	YES	-	-		6,600	-	6,600
5	Operating Agreements	3,295,495	-	3,295,495	YES	-	-		3,295,495	-	3,295,495
6	Joint Use (Pole) - Idaho	606,267	-	606,267	YES	-	-		606,267	-	606,267
7	Joint Use (Pole) - Oregon	10,632	-	10,632	YES	-	-		10,632	-	10,632
8	Total	$ 3,911,815	$ -	$ 3,911,815		$ 30,623	$ 30,623	**B**	$ 3,942,438	$ -	$ 3,942,438
	Other Expenses (Acct 416):										
9	Power Solutions	$ 49,615	$ -	$ 49,615	YES	$ -	$ -		$ 49,615	$ -	$ 49,615
10	Hydro Services	11,599	-	11,599	YES	-	-		11,599	-	11,599
11	Water Management Services	10,097	-	10,097	YES	-	-		10,097	-	10,097
12	Qualified Reporting Entity Svcs	1,804	-	1,804	YES	-	-		1,804	-	1,804
13	Operating Agreements	3,295,495	-	3,295,495	YES	-	-		3,295,495	-	3,295,495
14	Joint Use - Idaho	1,333,265	-	1,333,265	YES	-	-		1,333,265	-	1,333,265
15	Joint Use - Oregon	-	-	-	YES	-	-		-	-	-
16	Total	$ 4,701,875	$ -	$ 4,701,875		$ -	$ -	**C**	$ 4,701,875	$ -	$ 4,701,875

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2023

(1) LINE NO	(2) FERC ACCOUNT NUMBER	(3) DESCRIPTION	(4) 2022 Actuals	(5) 2022 Adjustments	(6) 2022 Base	(7) Forecast Methodology 2022 Base	(8) Forecast Methodology Other	(9) Forecast Adjustment	Ref No	(10) 2023 Unadjusted Test Year	(11) Annualizing	(12) 2023 Test Year
		Power production expenses:										
		Steam power generation -										
		Operation -										
1	500	Oper and supv engineering	$ 632,248	$ (725,308)	$ (93,060)		$ 10,451	$ 10,451		$ (82,609)	$ 6,114	$ (76,495)
2	501	Fuel	-	-	-		-	-		-	-	-
3	502	Steam expenses	9,298,487	(8,836,311)	462,176		-	-		462,176	-	462,176
4	505	Electric expenses	1,128,466	(1,072,607)	55,859		-	-		55,859	-	55,859
5	506	Misc steam power expenses	8,586,280	(8,161,259)	425,021		13	13		425,034	7	425,041
6	507	Rents	229,461	(218,103)	11,358		-	-		11,358	-	11,358
7		Total operation	19,874,943	(19,013,588)	861,355		10,463	10,463		871,818	6,121	877,940
		Maintenance -										
8	510	Main supv and engineering	(238,936)	(11,789)	(250,724)		-	-		(250,724)	-	(250,724)
9	511	Main of structures	2,540,010	(2,414,279)	125,730		-	-		125,730	-	125,730
10	512	Main of boiler plant	8,774,081	(8,339,764)	434,317		-	-		434,317	-	434,317
11	513	Main of electric plant	2,306,519	(2,192,346)	114,173		-	-		114,173	-	114,173
12	514	Main of misc steam plant	9,592,111	(9,117,301)	474,809		-	-		474,809	-	474,809
13		Total maintenance	22,973,785	(22,075,479)	898,305		-	-		898,305	-	898,305
14		Total steam power generation	42,848,728	(41,089,067)	1,759,660		10,463	10,463		1,770,124	6,121	1,776,245
		Hydraulic power generation -										
		Operation -										
15	535	Oper supv and engineering	5,758,397	-	5,758,397		455,619	455,619		6,214,017	262,711	6,476,728
16	536	Water for power/Cloud seeding	6,637,301	-	6,637,301		(210,258)	(210,258)		6,427,044	54,646	6,481,690
17	536	Water leases	(9,801)	9,801	-		-	-		-	-	-
18	537	Hydraulic expenses	18,433,658	124,562	18,558,220		1,237,383	1,237,383		19,795,603	394,497	20,190,100
19	538	Electric expenses	1,959,732	-	1,959,732		180,701	180,701		2,140,433	95,472	2,235,905
20	539	Misc hydro pwr gen exp	5,131,195	(227)	5,130,968		386,324	386,324		5,517,292	213,191	5,730,483
21	540	Rents	303,402	-	303,402		-	-		303,402	-	303,402
22		Total operation	38,213,885	134,136	38,348,022		2,049,769	2,049,769		40,397,791	1,020,517	41,418,308
		Maintenance -										
23	541	Main supv and engineering	110,982	-	110,982		9,442	9,442		120,425	5,514	125,939
24	542	Main of structures	932,291	-	932,291		64,830	64,830		997,121	36,545	1,033,666
25	543	Main of res,dams,waterwys	454,092	-	454,092		38,359	38,359		492,451	16,036	508,487
26	544	Main of electric plant	2,611,843	-	2,611,843		198,915	198,915		2,810,758	111,584	2,922,342
27	545	Main of misc hydro plant	3,919,209	(108)	3,919,101		252,325	252,325		4,171,425	138,826	4,310,252
28		Total maintenance	8,028,417	(108)	8,028,309		563,871	563,871		8,592,180	308,505	8,900,685
29		Total hydraulic power generation	46,242,302	134,028	46,376,331		2,613,640	2,613,640		48,989,970	1,329,023	50,318,993
		Other power generation -										
		Operation -										
30	546	Oper supv and engineering	627,106	-	627,106		55,260	55,260		682,366	32,326	714,692
31	547.000	Fuel - Salmon diesel	10,499	-	10,499		-	-		10,499	-	10,499
32	547	Fuel	-	-	-		-	-		-	-	-
33	548	Generation expenses	4,902,489	-	4,902,489		343,492	343,492		5,245,982	198,160	5,444,142
34	549	Misc other pwr gen exp	9,124	-	9,124		43,934	43,934		53,058	22,895	75,953
35	550	Rents	-	-	-		-	-		-	-	-
36		Total operation	5,549,218	-	5,549,218		442,687	442,687		5,991,905	253,381	6,245,286

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2023

(1) LINE NO	(2) FERC ACCOUNT NUMBER	(3) DESCRIPTION	(4) 2022 Actuals	(5) 2022 Adjustments	(6) 2022 Base	(7) Forecast Methodology 2022 Base	(8) Forecast Methodology Other	(9) Forecast Adjustment	Ref No	(10) 2023 Unadjusted Test Year	(11) Annualizing	(12) 2023 Test Year
		Other power generation - (continued)										
		Maintenance -										
1	551	Main supv and engineering	$ -	$ -	$ -		$ -	$ -		$ -	$ -	$ -
2	552	Main of structures	159,030	-	159,030		5,316	5,316		164,346	2,832	167,178
3	553	Main of gen and elec plt	927,810	-	927,810		6,648	6,648		934,458	3,674	938,131
4	554	Main misc oth pwr gen plt	6,730,628	-	6,730,628		(3,372,657)	(3,372,657)		3,357,971	29,364	3,387,334
							-					
5		Total maintenance	7,817,467	-	7,817,467		(3,360,693)	(3,360,693)		4,456,775	35,869	4,492,643
6		Total other power generation	13,366,686	-	13,366,686		(2,918,006)	(2,918,006)		10,448,680	289,250	10,737,929
		Other power supply expenses -										
7	555.050	Purchased power - transmission losses	-	-	-		-	-		-	-	-
8	555	Purchased power	-	-	-		-	-		-	-	-
9	556	System cont and load disp	-	-	-		-	-		-	-	-
10	557	Other expenses - other power production	6,279,434	-	6,279,434		473,536	473,536		6,752,969	277,021	7,029,990
11	557	Other expenses - PCA, EPC and PCAM	-	-	-		-	-		-	-	-
12	557	Other expenses - Bridger GAAP Adj	(135,744)	135,744	-		-	-		-	-	-
13		Total other power supply expenses	6,143,689	135,744	6,279,434		473,536	473,536		6,752,969	277,021	7,029,990
14		Total power production expenses	108,601,405	(40,819,295)	67,782,110		179,632	179,632		67,961,743	1,901,415	69,863,157

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2023

(1) LINE NO	(2) FERC ACCOUNT NUMBER	(3) DESCRIPTION	(4) 2022 Actuals	(5) 2022 Adjustments	(6) 2022 Base	(7) Forecast Methodology 2022 Base	(8) Forecast Methodology Other	(9) Forecast Adjustment	Ref No	(10) 2023 Unadjusted Test Year	(11) Annualizing	(12) 2023 Test Year
		Transmission expenses:										
		Operation -										
1	560	Oper supv and engineering	$ 3,193,933	$ (6)	$ 3,193,927		$ 251,886	$ 251,886		$ 3,445,814	$ 147,211	$ 3,593,025
2	561	Load dispatching	5,375,576	-	5,375,576		454,303	454,303		5,829,880	187,405	6,017,285
3	562	Station expenses	2,788,678	(1,453)	2,787,225		214,444	214,444		3,001,669	120,418	3,122,087
4	563	Overhead line expenses	1,121,678	-	1,121,678		57,232	57,232		1,178,910	26,779	1,205,690
5	564	Underground line expenses	-	-	-		-	-		-	-	-
6	565	Trans of elec by others	11,322,964	(11,322,964)	(0)		-	-		(0)	-	(0)
7	566	Misc trans expenses	8	-	8		0	0		8	-	8
8	567	Rents	4,855,402	-	4,855,402		-	-		4,855,402	-	4,855,402
9		Total operation	28,658,239	(11,324,423)	17,333,816		977,866	977,866		18,311,682	481,814	18,793,496
		Maintenance -										
10	568	Main supv and engineering	206,814	-	206,814		9,586	9,586		216,400	5,608	222,008
11	569	Main of structures	1,907,634	-	1,907,634		151,682	151,682		2,059,316	88,601	2,147,917
12	570	Main of station equip	2,611,391	(489)	2,610,902		297,615	297,615		2,908,517	144,194	3,052,711
13	571	Main of overhead lines	2,274,243	805,534	3,079,777		116,824	116,824		3,196,601	55,564	3,252,166
14	573	Main of misc trans plant	5,113	-	5,113		442	442		5,555	226	5,781
15	575	Admin-EIM	686,880	-	686,880		-	-		686,880	-	686,880
16		Total maintenance	7,692,075	805,045	8,497,120		576,149	576,149		9,073,269	294,193	9,367,462
17		Total transmission expenses	36,350,314	(10,519,378)	25,830,936		1,554,015	1,554,015		27,384,951	776,007	28,160,958
		Distribution expenses:										
		Operation -										
18	580	Oper supv and engineering	5,911,141	3,912	5,915,054		326,853	326,853		6,241,907	186,671	6,428,578
19	581	Load dispatching	5,170,071	-	5,170,071		488,757	488,757		5,658,828	285,943	5,944,770
20	582	Station expenses	1,862,473	(7)	1,862,466		114,459	114,459		1,976,925	60,977	2,037,902
21	583	Overhead line expenses	5,421,238	104,989	5,526,227		477,721	477,721		6,003,948	214,267	6,218,215
22	584	Underground line expenses	4,717,552	4,282	4,721,834		167,229	167,229		4,889,062	82,237	4,971,299
23	585	St light and sgnl sys exp	44,756	-	44,756		2,724	2,724		47,479	1,309	48,788
24	586	Meter expenses	5,719,569	(73)	5,719,496		535,125	535,125		6,254,621	256,699	6,511,320
25	587	Customer install expenses	1,095,297	-	1,095,297		88,874	88,874		1,184,170	45,823	1,229,993
26	588	Misc distribution exp	4,687,904	(1,010)	4,686,894		323,082	323,082		5,009,975	181,825	5,191,800
27	589	Rents	741,341	-	741,341		-	-		741,341	-	741,341
28		Total operation	35,371,341	112,093	35,483,435		2,524,822	2,524,822		38,008,257	1,315,749	39,324,006
		Maintenance -										
29	590	Main supv and engineering	11,968	-	11,968		997	997		12,965	583	13,548
30	591	Main of structures	-	-	-		-	-		-	-	-
31	592	Main of station equip	4,120,742	(351)	4,120,391		328,264	328,264		4,448,655	167,728	4,616,383
32	593	Main of overhead lines	21,931,803	12,695,311	34,627,115		684,800	684,800		35,311,914	330,675	35,642,590
33	594	Main of underground lines	751,577	18,123	769,700		45,008	45,008		814,708	22,649	837,357
34	595	Main of line transformers	94,087	-	94,087		2,717	2,717		96,804	1,557	98,361
35	596	Main of st lght-sgnl sys	204,924	3,043	207,967		16,003	16,003		223,970	7,856	231,826
36	597	Main of meters	862,000	-	862,000		77,162	77,162		939,163	42,167	981,330
37	598	Main of misc dist plant	123,765	-	123,765		10,116	10,116		133,880	5,037	138,917
38		Total maintenance	28,100,867	12,716,126	40,816,993		1,165,066	1,165,066		41,982,059	578,252	42,560,311
39		Total distribution expenses	63,472,208	12,828,219	76,300,428		3,689,888	3,689,888		79,990,316	1,894,002	81,884,317

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)	(11)	(12)
	FERC					Forecast Methodology				2023		
LINE	ACCOUNT		2022	2022	2022	2022		Forecast	Ref	Unadjusted		2023
NO	NUMBER	DESCRIPTION	Actuals	Adjustments	Base	Base	Other	Adjustment	No	Test Year	Annualizing	Test Year
	Customer accounts expenses:											
	Operation -											
1	901	Supervision	$ 845,854	$ -	$ 845,854		$ 75,609	$ 75,609		$ 921,463	$ 44,217	$ 965,680
2	902	Meter reading expenses	1,819,788	-	1,819,788		142,617	142,617		1,962,406	79,111	2,041,516
3	903	Cust records - collect exp.	15,041,848	-	15,041,848		997,289	997,289		16,039,137	569,230	16,608,368
4	904	Uncollectible accounts	3,069,311	198,133	3,267,444		2,514,638	2,514,638		5,782,082	-	5,782,082
5	905	Misc customer accts exp.	(3,031)	-	(3,031)		-	-		(3,031)	-	(3,031)
6		Total customer accounts expenses	20,773,771	198,133	20,971,903		3,730,154	3,730,154		24,702,057	692,558	25,394,615
	Customer service and informational expenses:											
	Operation -											
7	907	Supervision	1,009,780	(15,995)	993,785		87,883	87,883		1,081,669	51,408	1,133,077
8	908	Customer assistance exp.	7,286,059	(835)	7,285,224		4,110,142	4,110,142		11,395,366	291,521	11,686,886
9	908	Energy efficiency rider - Idaho	31,673,550	(31,673,550)	-		-	-		-	-	-
10	908	Energy efficiency rider - Oregon	1,523,563	(1,523,563)	-		-	-		-	-	-
11	909	Info and instruct adv exp.	295,103	-	295,103		10	10		295,112	-	295,112
12	910	Misc cust svc and inf exp.	746,645	(3,166)	743,479		33,938	33,938		777,417	19,452	796,869
13	912	Demo and selling exp.	-	-	-		-	-		-	-	-
14		Total customer service and informational expenses	42,534,700	(33,217,109)	9,317,591		4,231,973	4,231,973		13,549,564	362,381	13,911,945
	Administrative and general expenses:											
	Operation -											
15	920	Admin and gen salaries	69,192,001	-	69,192,001		6,557,156	6,557,156		75,749,157	3,836,202	79,585,359
16	920	Incentive	26,598,671	(26,598,671)	-		10,040,205	10,040,205		10,040,205	-	10,040,205
17	921	Office supplies and exp.	15,137,531	(28,774)	15,108,757		50,701	50,701		15,159,457	15,816	15,175,273
18	922	Admin exp transf - cr.	(35,131,943)	-	(35,131,943)		(3,326,773)	(3,326,773)		(38,458,716)	(1,946,297)	(40,405,013)
19	923	Outside services employed	8,733,229	-	8,733,229		5	5		8,733,233	-	8,733,233
20	924	Property insurance	3,925,608	1,277,597	5,203,205		40,547	40,547		5,243,752	98,991	5,342,742
21	925	Injuries and damages	6,544,597	5,309,456	11,854,054		14,295	14,295		11,868,349	8,363	11,876,713
22	926	Emp pensions and benefits	36,409,743	(16,837)	36,392,906		3,281,778	3,281,778		39,674,684	1,919,922	41,594,606
23	926.OR	Emp pensions and benefits - Oregon	880,053	-	880,053		-	-		880,053	-	880,053
24	926.204	Emp pensions and benefits - Idaho	17,153,713	-	17,153,713		18,028,665	18,028,665		35,182,378	-	35,182,378
25	926.205	Emp pensions and benefits - FERC	-	-	-		-	-		-	-	-
26	927	Franchise requirements	-	-	-		-	-		-	-	-
27	928	Reg commission expenses	6,545,806	(65,075)	6,480,731		296,576	296,576		6,777,307	-	6,777,307
28	929	Duplicate charges - cr.	-	-	-		-	-		-	-	-
29	930.1	General advertising exp.	491,473	(491,473)	-		-	-		-	-	-
30	930.2	Misc general expenses	4,378,924	(365,067)	4,013,857		20,958	20,958		4,034,815	12,261	4,047,076
31	931	Rents	-	-	-		-	-		-	-	-
32		Total operation	160,859,406	(20,978,844)	139,880,562		35,004,113	35,004,113		174,884,675	3,945,258	178,829,933
	Maintenance -											
33	935	Main of general plant	7,877,237	(826)	7,876,411		132,761	132,761		8,009,172	65,032	8,074,204
34		Total maintenance	7,877,237	(826)	7,876,411		132,761	132,761		8,009,172	65,032	8,074,204
35		Total administrative and general expenses	168,736,643	(20,979,670)	147,756,973		35,136,874	35,136,874		182,893,847	4,010,290	186,904,137
36		Total electric operation and maintenance expenses	$ 440,469,041	$ (92,509,099)	$ 347,959,942		$ 48,522,536	$ 48,522,536	D	$ 396,482,478	$ 9,636,652	$ 406,119,130

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
PROPERTY INSURANCE - ACCOUNT 924
For Twelve Months Ended December 31, 2023

(1) Line No	(2) Description	(3) 2022 Actuals	(4) 2022 Adjustments	(5) 2022 Base	(6) Forecast Methodology 2022 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2023 Unadjusted Test Year	(10) Annualizing	(11) 2023 Test Year
	Production - steam:										
1	Bridger plant	$ 333,083	$ -	$ 333,083	YES	$ -	$ -		$ 333,083	$ -	$ 333,083
2	Boardman plant	19,354	-	19,354	YES	-	-		19,354	-	19,354
3	Valmy plant	60,158	-	60,158	YES	-	-		60,158	-	60,158
4	Total production - steam	412,595	-	412,595		-	-		412,595	-	412,595
	All risk:										
5	Blanket fidelity bond	62,870	-	62,870	YES	-	-		62,870	-	62,870
6	Property "all risk"	2,933,239	1,277,597	4,210,836		-	-		4,210,836	75,269	4,286,105
7	Other miscellaneous	67,077	-	67,077	YES	-	-		67,077	-	67,077
8	Total all risk	3,063,186	1,277,597	4,340,783		-	-		4,340,783	75,269	4,416,052
9	Total property insurance	$ 3,475,781	$ 1,277,597	$ 4,753,378		$ -	$ -	**D**	$ 4,753,378	$ 75,269	$ 4,828,647

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
REGULATORY COMMISSION EXPENSES - ACCOUNT 928
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line No	Description	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
	FERC administrative assessments and securities (928.101)										
1	Capacity..	$ 2,826,830	$ -	$ 2,826,830	YES		$ -		$ 2,826,830	$ -	$ 2,826,830
2	Generation..	963,911	-	963,911	YES		-		963,911	-	963,911
3	Ferc Order #472 - Sales for resale..	963,867	-	963,867	YES		-		963,867	-	963,867
4	Miscellaneous Other..	109,055	-	109,055	YES		-		109,055	-	109,055
5	Total (928.101)...	4,863,663	-	4,863,663		-	-		4,863,663	-	4,863,663
6	FERC - Rate Case (928.102)..	-	-	-		-	-		-	-	-
7	FERC - Oregon Hydro (928.104)...	271,717	-	271,717	YES		-		271,717	-	271,717
8	Total FERC expense..	5,135,380	-	5,135,380		-	-		5,135,380	-	5,135,380
	Idaho Public Utilities Commission expense:										
9	Rate case (928.202)...	-	-	-		-	-		-	-	-
10	Other (928.203)..	36,197	-	36,197		296,576	296,576		332,773	-	332,773
11	Total IPUC expense..	36,197	-	36,197		296,576	296,576		332,773	-	332,773
	Oregon Public Utility Commission expense:										
12	Filing Fees (928.301)...	-	-	-		-	-		-	-	-
13	Rate case (928.302)..	-	-	-		-	-		-	-	-
14	Other (928.303)..	1,374,230	(65,075)	1,309,155	YES		-		1,309,155	-	1,309,155
15	Total OPUC expense...	1,374,230	(65,075)	1,309,155		-	-		1,309,155	-	1,309,155
	Nevada Public Service Commission expense:										
16	Other (928.403)..	-	-	-		-	-		-	-	-
17	Total NPSC expense..	-	-	-		-	-		-	-	-
18	Total regulatory commission expenses...	$ 6,545,806	$ (65,075)	$ 6,480,731		$ 296,576	$ 296,576	D	$ 6,777,307	$ -	$ 6,777,307

IDAHO POWER COMPANY
DEPRECIATION AND AMORTIZATION EXPENSE
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line No	Description	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
	Accounts 403 and 404:										
1	Amortization expense..	$ 5,266,930 1.)	$ -	$ 5,266,930		$ 618,646	$ 618,646		$ 5,885,576	$ 95,740	$ 5,981,316
2	Depreciation expense...	163,581,418 2.)	(24,584,889)	138,996,530		9,845,191	9,845,191		148,841,721	8,884,245	157,725,966
3	Total..	$ 168,848,348	$ (24,584,889)	$ 144,263,460		$ 10,463,837	$ 10,463,837	E	$ 154,727,297	$ 8,979,985	$ 163,707,282

IDAHO POWER COMPANY
ELECTRIC PLANT/REGULATORY ASSETS - AMORT.,ADJUST.,GAINS & LOSSES
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)	(11)	(12)
						Forecast Methodology						
Line No		Description	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	2023 Unadjusted Test Year	Annualizing	2023 Test Year
1	406	Amortization of Electric Plant Acquisition Adjustment - Asset Exchange (IPUC Order No. 33313, OPUC Order No. 15-184, FERC Order No. 20150617-3060)......	$ 15,018	$ -	$ 15,018	YES	$ -	$ -		$ 15,018	$ -	$ 15,018
2		Total...	$ 15,018	$ -	$ 15,018		$ -	$ -	F	$ 15,018	$ -	$ 15,018

IDAHO POWER COMPANY
REGULATORY DEBITS AND CREDITS
For Twelve Months Ended December 31, 2023

(1) Line No	(2) Description	(3) 2022 Actuals	(4) 2022 Adjustments	(5) 2022 Base	(6) Forecast Methodology 2022 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2023 Unadjusted Test Year	(10) Annualizing	(11) 2023 Test Year
	Regulatory Debits/Credits (Acct 407.3/407.4):										
	Idaho										
1	Siemens LTP Amort - Idaho	$ 643,866	$ -	$ 643,866	YES	$ -	$ -		$ 643,866	$ -	$ 643,866
2	Siemens LTP Amort - Idaho Deferred RB	$ 431,488	$ -	$ 431,488	YES	$ -	$ -		$ 431,488	$ -	$ 431,488
3	Cloud computing	$ 374,905	$ (173,640)	$ 201,265	YES	$ -	$ -		$ 201,265	$ -	$ 201,265
4	Wildfire Mitigation	$ -	$ -	$ -		$ 1,865,167	$ 1,865,167		$ 1,865,167	$ -	$ 1,865,167
5	Subtotal Idaho	$ 1,450,259	$ (173,640)	$ 1,276,619		$ 1,865,167	$ 1,865,167		$ 3,141,786	$ -	$ 3,141,786
	Oregon										
6	Deferred Pension - Oregon	$ 219,697	$ -	$ 219,697	YES	$ -	$ -		$ 219,697	$ -	$ 219,697
7	Siemens LTP Amort - Oregon	$ 39,316	$ -	$ 39,316	YES	$ -	$ -		$ 39,316	$ -	$ 39,316
8	Siemens LTP Amort - Oregon Deferred RB	$ 44,046	$ -	$ 44,046	YES	$ -	$ -		$ 44,046	$ -	$ 44,046
9	Subtotal Oregon	$ 303,059	$ -	$ 303,059	YES	$ -	$ -		$ 303,059	$ -	$ 303,059
10	Total	$ 1,753,318	$ (173,640)	$ 1,579,678		$ 1,865,167	$ 1,865,167	**G**	$ 3,444,845	$ -	$ 3,444,845

IDAHO POWER COMPANY
TAXES OTHER THAN INCOME TAXES
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line No	Description	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
	Federal taxes:										
1	Unemployment	$ 94,333	$ (94,333)	$ -	YES	$ -	$ -		$ -	$ -	$ -
2	Social Security	18,219,357	(18,219,357)	-	YES	-	-		-	-	-
3	Total federal taxes	18,313,691	(18,313,691)	-		-	-		-	-	-
	State, county and local taxes:										
	Real and personal property:										
4	Idaho	16,447,825	-	16,447,825		2,709,059	2,709,059		19,156,884	482,288	19,639,172
5	Oregon	5,007,521	-	5,007,521		585,570	585,570		5,593,091	-	5,593,091
6	Montana	473,595	-	473,595		46,111	46,111		519,706	-	519,706
7	Washington	4,069	-	4,069		(109)	(109)		3,960	-	3,960
8	Wyoming	1,391,819	(1,282,348)	109,471		1,204	1,204		110,675	15,946	126,621
9	Nevada	321,605	(314,445)	7,160		(1,824)	(1,824)		5,336	-	5,336
10	Shoshone-Bannock	91,431	-	91,431		5,851	5,851		97,282	-	97,282
11	Total real and personal property	23,737,866	(1,596,793)	22,141,073		3,345,862	3,345,862		25,486,935	498,234	25,985,169
12	Kilowatt-hour tax - Idaho	1,162,897	-	1,162,897		1,055,305	1,055,305		2,218,202	-	2,218,202
	Licenses:										
13	Wyoming	4,090	-	4,090	YES	-	-		4,090	-	4,090
14	Shoshone-Bannock	150	-	150	YES	-	-		150	-	150
15	Total licenses	4,240	-	4,240		-	-		4,240	-	4,240
	Regulatory commission:										
16	Idaho	2,616,251	-	2,616,251	YES	-	-		2,616,251	-	2,616,251
17	Oregon	290,260	-	290,260		95,251	95,251		385,511	-	385,511
18	Total regulatory commission	2,906,511	-	2,906,511		95,251	95,251		3,001,762	-	3,001,762
	Franchise:										
19	Oregon total franchise	890,161	-	890,161		62,839	62,839		953,000	-	953,000
										-	
	Unemployment:										
20	Idaho	199,146	(199,146)	-	YES	-	-		-	-	-
21	Oregon	45,401	(45,401)	-	YES	-	-		-	-	-
22	Total unemployment	244,547	(244,547)	-		-	-		-	-	-
23	Total state, county and local taxes	28,946,224	(1,841,340)	27,104,883		4,559,257	4,559,257		31,664,140	498,234	32,162,374
24	Total other taxes	47,259,914	(20,155,031)	27,104,883		4,559,257	4,559,257		31,664,140	498,234	32,162,374
25	Less: State & Fed P/R Loading Reversal	(18,558,238)	18,558,238	-		-	-		-	-	-
26	Net other taxes	$ 28,701,676	$ (1,596,793)	$ 27,104,883		$ 4,559,257	$ 4,559,257	H	$ 31,664,140	$ 498,234	$ 32,162,374

IDAHO POWER COMPANY
STATEMENT OF INCOME
FOR IDAHO ENERGY RESOURCES COMPANY
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line No	Description	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
	Income:										
1	Bridger Coal Company - joint venture	$10,211,212	$ -	$ 10,211,212		$ (7,211,212)	$ (7,211,212)		$ 3,000,000	$ -	$ 3,000,000
2	Bridger Coal Company - overriding royalties	247,311	-	247,311		(14,817)	(14,817)		232,494	-	232,494
3	Interest and dividend income	3,248	-	3,248		(3,248)	(3,248)		-	-	-
4	Taxes Other than Income Taxes	-	-	-		-	-		-	-	-
5	Total income	10,461,771	-	10,461,771		(7,229,277)	(7,229,277)		3,232,494	-	3,232,494
	Expenses:										
6	Operation expense	247,311	-	247,311		(14,817)	(14,817)		232,494	-	232,494
7	Income taxes	1,330,515	-	1,330,515		(841,104)	(841,104)		489,411	-	489,411
8	Provision for deferred income taxes	-	-	-		-	-		-	-	-
9	Intercompany interest expense	101,905	-	101,905		567,568	567,568		669,473	-	669,473
10	Interest expense	-	-	-		-	-		-	-	-
11	Total expenses	1,679,731	-	1,679,731		(288,353)	(288,353)		1,391,378	-	1,391,378
12	Net income from operations	8,782,040	-	8,782,040		(6,940,924)	(6,940,924)		1,841,116	-	1,841,116
13	Add: Interest expense from notes payable to parent (Net of Tax)	77,939	-	77,939		450,945	450,945		528,884	-	528,884
14	Net income (earnings to Idaho Power Company)	$ 8,859,979	$ -	$ 8,859,979		$ (6,489,979)	$ (6,489,979)	I	$ 2,370,000	$ -	$ 2,370,000

IDAHO POWER COMPANY
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC) RELATED TO HELLS CANYON RELICENSING COLLECTED FROM CUSTOMERS
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line No	Description	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
1	AFUDC related to Hells Canyon relicensing collected...	$ 6,815,472		$ 6,815,472	YES	$ -	$ -		$ 6,815,472	$ -	$ 6,815,472
2	Total AFUDC related to Hells Canyon Relicensing Collected..........................	6,815,472	-	6,815,472		-	-	**J**	6,815,472	-	6,815,472

IDAHO POWER COMPANY
ELECTRIC PLANT IN SERVICE (Excluding ARO Entries)
For The Thirteen Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line No	Month	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
1	December, 2021....................................	$ 6,482,321,388	$ (734,727,907)	$ 5,747,593,482		$ 314,837,327	$ 314,837,327		$ 6,062,430,809	$ -	$ 6,062,430,809
2	January, 2022..	6,491,936,129	(735,611,485)	5,756,324,644		312,179,468	312,179,468		6,068,504,113	-	6,068,504,113
3	February..	6,504,930,241	(735,561,109)	5,769,369,131		312,714,759	312,714,759		6,082,083,890	-	6,082,083,890
4	March...	6,540,209,581	(735,792,019)	5,804,417,562		305,764,751	305,764,751		6,110,182,313	-	6,110,182,313
5	April..	6,551,240,968	(736,164,064)	5,815,076,904		310,534,335	310,534,335		6,125,611,239	-	6,125,611,239
6	May..	6,571,566,813	(737,340,034)	5,834,226,779		311,925,031	311,925,031		6,146,151,809	-	6,146,151,809
7	June...	6,654,009,072	(737,630,520)	5,916,378,552		287,963,459	287,963,459		6,204,342,012	-	6,204,342,012
8	July..	6,652,494,874	(739,045,575)	5,913,449,300		397,088,528	397,088,528		6,310,537,828	-	6,310,537,828
9	August..	6,668,313,271	(739,117,974)	5,929,195,297		414,237,100	414,237,100		6,343,432,397	-	6,343,432,397
10	September...	6,708,499,049	(739,254,042)	5,969,245,007		405,616,489	405,616,489		6,374,861,496	-	6,374,861,496
11	October..	6,712,869,047	(739,384,738)	5,973,484,308		477,790,493	477,790,493		6,451,274,802	-	6,451,274,802
12	November..	6,730,682,438	(738,680,228)	5,992,002,210		479,755,721	479,755,721		6,471,757,931	-	6,471,757,931
13	December..	6,801,544,542	(739,113,733)	6,062,430,809		490,306,909	490,306,909		6,552,737,718	-	6,552,737,718
14	Average..	$ 6,620,816,724	$ (737,494,110)	$ 5,883,322,614		$ 370,824,182	$ 370,824,182	K	$ 6,254,146,797	$ -	$ 6,254,146,797

IDAHO POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION (Excluding ARO Entries)
For The Thirteen Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line No	Month	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
1	December, 2021	$ 2,429,210,499	$ (442,763,625)	$ 1,986,446,874		$ 69,821,495	$ 69,821,495		$ 2,056,268,369	$ -	$ 2,056,268,369
2	January, 2022	2,440,296,309	(445,400,489)	1,994,895,820		67,474,788	67,474,788		2,062,370,608	-	2,062,370,608
3	February	2,451,056,338	(448,022,265)	2,003,034,072		67,428,582	67,428,582		2,070,462,655	-	2,070,462,655
4	March	2,456,151,466	(450,637,944)	2,005,513,522		67,710,802	67,710,802		2,073,224,324	-	2,073,224,324
5	April	2,467,251,838	(453,262,972)	2,013,988,866		65,681,174	65,681,174		2,079,670,040	-	2,079,670,040
6	May	2,470,981,025	(455,720,952)	2,015,260,073		70,904,786	70,904,786		2,086,164,859	-	2,086,164,859
7	June	2,519,553,447	(499,093,335)	2,020,460,112		51,478,083	51,478,083		2,071,938,195	-	2,071,938,195
8	July	2,530,068,705	(503,801,575)	2,026,267,130		52,617,855	52,617,855		2,078,884,985	-	2,078,884,985
9	August	2,536,953,490	(508,746,243)	2,028,207,247		58,732,949	58,732,949		2,086,940,196	-	2,086,940,196
10	September	2,550,267,830	(513,755,725)	2,036,512,105		53,392,441	53,392,441		2,089,904,546	-	2,089,904,546
11	October	2,563,961,938	(518,619,342)	2,045,342,596		52,252,303	52,252,303		2,097,594,900	-	2,097,594,900
12	November	2,575,189,654	(523,684,763)	2,051,504,890		52,638,408	52,638,408		2,104,143,298	-	2,104,143,298
13	December	2,585,055,649	(528,787,280)	2,056,268,369		42,146,361	42,146,361		2,098,414,730	-	2,098,414,730
14	Average	$ 2,505,846,014	$ (484,022,808)	$ 2,021,823,206		$ 59,406,156	$ 59,406,156	L	$ 2,081,229,362	$ -	$ 2,081,229,362

IDAHO POWER COMPANY
ACCUMULATED PROVISION FOR AMORTIZATION (Excluding ARO Entries)
OF ELECTRIC UTILITY PLANT
For The Thirteen Months Ended December 31, 2023

(1) Line No	(2) Month	(3) 2022 Actuals	(4) 2022 Adjustments	(5) 2022 Base	(6) Forecast Methodology 2022 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2023 Unadjusted Test Year	(10) Normalizing	(11) 2023 Test Year
1	December, 2021	$ 39,195,698	$ -	$ 39,195,698		$ 133,443	$ 133,443		$ 39,329,141	$ -	$ 39,329,141
2	January, 2022	39,539,156	-	39,539,156		266,799	266,799		39,805,955	-	39,805,955
3	February	39,932,735	-	39,932,735		353,826	353,826		40,286,561	-	40,286,561
4	March	40,250,549	-	40,250,549		518,643	518,643		40,769,192	-	40,769,192
5	April	40,255,052	-	40,255,052		797,459	797,459		41,052,512	-	41,052,512
6	May	40,551,163	-	40,551,163		874,968	874,968		41,426,131	-	41,426,131
7	June	40,903,109	-	40,903,109		1,011,003	1,011,003		41,914,112	-	41,914,112
8	July	41,314,481	-	41,314,481		957,143	957,143		42,271,624	-	42,271,624
9	August	41,773,810	-	41,773,810		990,683	990,683		42,764,493	-	42,764,493
10	September	42,233,979	-	42,233,979		1,024,920	1,024,920		43,258,899	-	43,258,899
11	October	38,724,789	-	38,724,789		4,647,280	4,647,280		43,372,069	-	43,372,069
12	November	38,933,163	-	38,933,163		4,934,313	4,934,313		43,867,476	-	43,867,476
13	December	39,329,141	-	39,329,141		4,831,972	4,831,972		44,161,114	-	44,161,114
14	Average	$ 40,225,910	$ -	$ 40,225,910		$ 1,641,727	$ 1,641,727	**M**	$ 41,867,637	$ -	$ 41,867,637

IDAHO POWER COMPANY
MATERIALS AND SUPPLIES
For The Thirteen Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)	(11)	(12)	(13)	(14)
					Forecast Methodology									
Line No	Description - Account 154 & 163	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	3 Period CAGR	Other	Forecast Adjustment	Ref No	2023 Unadjusted Test Year	Normalizing	Annualizing	Known and Measurable	2023 Test Year
1	December, 2021	$ 77,551,656	$ (967,717)	$ 76,583,939	$ -	$ 9,542,885	$ -	$ 9,542,885		$ 86,126,824	$ -	$ -	$ -	$ 86,126,824
2	January, 2022	77,145,002	(967,717)	76,177,285	-	9,481,028	-	9,481,028		85,658,313	-	-	-	85,658,313
3	February	79,201,267	(967,717)	78,233,550	-	9,742,347	-	9,742,347		87,975,897	-	-	-	87,975,897
4	March	80,202,921	(967,717)	79,235,204	-	9,951,432	-	9,951,432		89,186,636	-	-	-	89,186,636
5	April	79,260,605	(967,717)	78,292,888	-	9,843,058	-	9,843,058		88,135,946	-	-	-	88,135,946
6	May	80,563,116	(967,717)	79,595,399	-	10,000,244	-	10,000,244		89,595,643	-	-	-	89,595,643
7	June	78,715,131	(967,717)	77,747,414	-	9,842,988	-	9,842,988		87,590,402	-	-	-	87,590,402
8	July	78,765,724	(967,717)	77,798,007	-	9,870,834	-	9,870,834		87,668,840	-	-	-	87,668,840
9	August	81,908,238	(967,717)	80,940,521	-	10,237,728	-	10,237,728		91,178,249	-	-	-	91,178,249
10	September	82,698,968	(967,717)	81,731,251	-	10,361,718	-	10,361,718		92,092,968	-	-	-	92,092,968
11	October	83,983,658	(967,717)	83,015,941	-	10,556,157	-	10,556,157		93,572,099	-	-	-	93,572,099
12	November	85,846,436	(967,717)	84,878,719	-	10,794,269	-	10,794,269		95,672,988	-	-	-	95,672,988
13	December	92,460,894	(967,717)	91,493,177	-	11,664,349	-	11,664,349		103,157,526	-	-	-	103,157,526
14	Average	$ 81,407,970	$ (967,717)	$ 80,440,254	$ -	$ 10,145,311	$ -	$ 10,145,311	N	$ 90,585,564	$ -	$ -	$ -	$ 90,585,564

IDAHO POWER COMPANY
OTHER DEFERRED PROGRAMS
At December 31, 2023

(1) Line No	(2) Description	(3) 2022 Actuals	(4) 2022 Adjustments	(5) 2022 Base	(6) Forecast Methodology 2022 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2023 Unadjusted Test Year	(10) Annualizing	(11) 2023 Test Year
	Idaho Public Utilities Commission:										
	Account 186										
1	American Falls Bond Refinancing - (IPUC Order 25880)..	$ 135,528	$ -	$ 135,528		$ (62,551)	(62,551)		$ 72,977	$ -	$ 72,977
	Account 182										
2	Siemens LTP Rate Base - (IPUC Order 33420)..	12,851,571	-	12,851,571		(643,866)	(643,866)		12,207,705	-	12,207,705
3	Siemens LTP Deferred Rate Base - (IPUC Order 33420)..	8,612,494	-	8,612,494		(431,488)	(431,488)		8,181,006	-	8,181,006
4	Cloud Computing - (IPUC Order 34707)...	1,616,918	(409,326)	1,207,592		(201,265)	(201,265)		1,006,327	-	1,006,327
5	Wildfire Mitigation - (IPUC Order 35077)..	27,078,227	(14,022,056)	13,056,171	YES		-		13,056,171	-	13,056,171
	Oregon Public Utilities Commission:										
	Account 182										
6	CUB Fund Grant - (OPUC Order 21-166, 22-192)..	37,154	-	37,154		(37,154)	(37,154)		-	-	-
7	Siemens LTP Rate Base - (OPUC Order 15-387)..	511,105	-	511,105		(39,316)	(39,316)		471,789	-	471,789
8	Siemens LTP Deferred Rate Base - (OPUC Order 15-387)..	138,550	-	138,550		(44,046)	(44,046)		94,504	-	94,504
9	SFAS 87 Capitalized Pension - (OPUC Order 10-064)..	7,000,878	-	7,000,878		(219,697)	(219,697)		6,781,181	-	6,781,181
	Account 254										
10	Reconnect Fees (Remote Meters) - (OPUC ADV 16-09)...	(14,711)	-	(14,711)	YES	-	-		(14,711)	-	(14,711)
11	Jim Bridger Plant End-of-Life Depreciation - (OPUC Order 12-296)............................	(3,285,386)	-	(3,285,386)	YES	-	-		(3,285,386)	-	(3,285,386)
12	Total...	$ 54,682,328	$ (14,431,382)	$ 40,250,946		$ (1,679,383)	$ (1,679,383)	O	$ 38,571,563	$ -	$ 38,571,563

IDAHO POWER COMPANY
PLANT HELD FOR FUTURE USE
At December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
					Forecast Methodology				2023		
Line No	Description	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
	Power Production:										
1	American Falls Power Plant...	$ 104,155	$ (104,155)	$ -	YES	$ -	$ -		$ -	$ -	$ -
2	Total Power Production...	104,155	(104,155)	-		-	-		-	-	-
	Distribution:										
3	Amity Substation...	153,751	-	153,751	YES	-	-		153,751	-	153,751
4	Beacon Light Substation..	204,511	(204,511)	-	YES	-	-		-	-	-
5	Dist. Lines, Blaine, ID..	443,545	-	443,545	YES	-	-		443,545	-	443,545
6	Dist. Lines, Canyon, ID..	25,581	-	25,581	YES	-	-		25,581	-	25,581
7	Farmway Station...	934,174	-	934,174	YES	-	-		934,174	-	934,174
8	Filer Substation...	27,813	-	27,813	YES	-	-		27,813	-	27,813
9	Highland Substation..	64,224	-	64,224	YES	-	-		64,224	-	64,224
10	Jump Substation...	67,722	(67,722)	-	YES	-	-		-	-	-
11	Lakeshore Substation..	188,565	-	188,565	YES	-	-		188,565	-	188,565
	McDermott Substation...	1,330,604	-	1,330,604	YES	-	-		1,330,604	-	1,330,604
12	Melba Substation...	29,321	-	29,321	YES	-	-		29,321	-	29,321
13	Notch Butte Substation..	15,665	-	15,665	YES	-	-		15,665	-	15,665
14	Pillar Falls Substation..	209,434	-	209,434	YES	-	-		209,434	-	209,434
15	State Substation..	117,597	-	117,597	YES	-	-		117,597	-	117,597
16	Ustick Substation...	19,670	(19,670)	-	YES	-	-		-	-	-
17	Wagner Substation..	91,452	-	91,452	YES	-	-		91,452	-	91,452
18	Ward Substation..	243,933	-	243,933	YES	-	-		243,933	-	243,933
19	Greenleaf Substation...	-	-	-		250,000	250,000		250,000	-	250,000
20	Northside Substation...	-	-	-		1,372,140	1,372,140		1,372,140	-	1,372,140
21	Total Distribution...	4,167,562	(291,903)	3,875,659		1,622,140	1,622,140		5,497,799	-	5,497,799
	Transmission:										
22	Boise Bench Transmission Station..	179,904	-	179,904	YES	-	-		179,904	-	179,904
23	Donnelly McCall Transmission Land R/W....................................	68,592	-	68,592	YES	-	-		68,592	-	68,592
24	Dry Creek Transmission Station..	26,671	-	26,671	YES	-	-		26,671	-	26,671
25	Line #853 500KV...	332,748	-	332,748	YES	-	-		332,748	-	332,748
26	Line #854 500KV...	308,066	-	308,066	YES	-	-		308,066	-	308,066
27	Long Valley Transmission Station..	22,377	(22,377)	-	YES	-	-		-	-	-
28	Mayfield Transmission Station...	220,052	-	220,052	YES	-	-		220,052	-	220,052
29	Midpoint Transmission Station...	851,271	(73,257)	778,014	YES	-	-		778,014	-	778,014
30	Pallette Junction Substation..	748,482	-	748,482	YES	-	-		748,482	-	748,482
31	Sage Transmission Station..	89,977	-	89,977	YES	-	-		89,977	-	89,977
32	Shellrock Transmission Station..	9,918	(9,918)	-	YES	-	-		-	-	-
33	Total Transmission..	2,858,058	(105,552)	2,752,506		-	-		2,752,506	-	2,752,506
34	Total Plant Held for Future Use	$ 7,129,775	$ (501,610)	$ 6,628,165		$ 1,622,140	$ 1,622,140	P	$ 8,250,305	$ -	$ 8,250,305

IDAHO POWER COMPANY
2023 RATE CASE
DEFERRED INCOME TAX BALANCES

	Balance Dec 31, 2022	2023 Change	Balance Dec 31, 2023	Average 2022-2023
ACCOUNT 190 - ACCUM DEF INC TAXES:				
004003-CONSTRUCTION ADVANCES	2,563,899	(1,514,441)	1,049,458	1,806,678
005010-POSTEMPLOYMENT BENEFITS	396,050	23,244	419,294	407,672
005026-USBR AMERICAN FALLS O&M COSTS	28,489	(8,996)	19,492	23,991
005033-NON VEBA PENSION AND BENEFITS	(804,568)	(56,450)	(861,018)	(832,793)
005047-OTHER EMPLOYEE'S LT DEFERRED COMP	90,889	149,356	240,245	165,567
005053-STOCK BASED COMPENSATION	3,184,240	810,433	3,994,673	3,589,457
005064-BRIDGER REVENUE DEFERRAL	1,114,435	(57,435)	1,057,000	1,085,717
005073-OR RECONNECT FEES ADV	3,262	525	3,787	3,524
005531-RATE CASE DISALLOWANCES AMORTIZATION	963,150	(76,267)	886,883	925,016
008001-VEBA POST-RETIREMENT BENEFITS	12,042,335	800,015	12,842,350	12,442,343
008013-ANNUALIZED BOOK DEPRECIATION	0	596,171	596,171	298,086
TOTAL 190	19,582,181	666,153	20,248,333	19,915,258
ACCOUNT 282 - ACCUM DEF INC TAXES - OTHER PROPERTY:				
LIBERALIZED DEPR - ELECTRIC PLANT	(404,092,568)	16,604,189	(387,488,379)	(395,790,474)
TOTAL 282	(404,092,568)	16,604,189	(387,488,379)	(395,790,474)
ACCOUNT 283 - ACCUM DEF INC TAXES - OTHER:				
004501-ROYALTY INCOME	(247,446)	63,658	(183,788)	(215,617)
005008-GAIN/LOSS ON REACQUIRED DEBT	(212,169)	70,330	(141,839)	(177,004)
005045-WILDFIRE MITIGATION 35077 DEFERRAL	(5,940,336)	480,094	(5,460,242)	(5,700,289)
005057-INTERVENOR FUNDING ORDERS	(88,723)	(1,148)	(89,871)	(89,297)
008081-SIEMENS LTP CONTRACT	(127,703)	(17,214)	(144,916)	(136,310)
008083-SIEMENS OR DRB INTEREST RESERVE	49,647	7,161	56,808	53,228
TOTAL 283	(6,566,729)	602,881	(5,963,848)	(6,265,289)
TOTAL DEFERRED TAX BALANCES	**(391,077,117)**	**17,873,223**	**(373,203,894)**	**(382,140,505)**

Deferred Tax Expense without ITC - 410 / 411	(17,873,223)
ITC Deferred Tax Expense - 411.4	25,014,178
Total Deferred Tax Expense	7,140,954

IDAHO POWER COMPANY
CUSTOMER ADVANCES FOR CONSTRUCTION
For The Thirteen Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line No	Month	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
1	December, 2021	$ 8,350,901	$ -	$ 8,350,901		$ (591,838)	$ (591,838)		$ 7,759,063	$ -	$ 7,759,063
2	January, 2022	8,592,890	-	8,592,890		(987,155)	(987,155)		7,605,735	-	7,605,735
3	February	8,538,803	-	8,538,803		(898,797)	(898,797)		7,640,006	-	7,640,006
4	March	10,213,241	-	10,213,241		(2,483,500)	(2,483,500)		7,729,741	-	7,729,741
5	April	10,679,989	-	10,679,989		(3,239,939)	(3,239,939)		7,440,050	-	7,440,050
6	May	11,148,661	-	11,148,661		(3,995,622)	(3,995,622)		7,153,039	-	7,153,039
7	June	11,932,802	-	11,932,802		(5,269,772)	(5,269,772)		6,663,030	-	6,663,030
8	July	14,999,118	-	14,999,118		(7,501,216)	(7,501,216)		7,497,902	-	7,497,902
9	August	15,495,033	-	15,495,033		(8,135,695)	(8,135,695)		7,359,338	-	7,359,338
10	September	16,087,930	-	16,087,930		(9,104,261)	(9,104,261)		6,983,669	-	6,983,669
11	October	18,048,874	-	18,048,874		(10,742,365)	(10,742,365)		7,306,509	-	7,306,509
12	November	17,611,152	-	17,611,152		(10,027,295)	(10,027,295)		7,583,857	-	7,583,857
13	December	19,112,288	-	19,112,288		(11,088,683)	(11,088,683)		8,023,605	-	8,023,605
14	Average	$ 13,139,360	$ -	$ 13,139,360		$ (5,697,395)	$ (5,697,395)	Q	$ 7,441,965	$ -	$ 7,441,965

IDAHO POWER COMPANY
IERCo - SUBSIDIARY RATE BASE COMPONENTS
For The Thirteen Months Ended December 31, 2023

Line No	Month	(1) 2022 Investment	Change	2023 Investment	(2) 2022 Advance Coal Royalties	Change	2023 Advance Coal Royalties	(3) 2022 Notes Receivable from Subsidiary	Change	2023 Notes Receivable from Subsidiary	Ref No	(4) 2022 Total	Change	2023 Total
1	December, 2021	$ 27,909,477	$ (13,217,958)	$ 14,691,519	$ 961,328	$ (247,311)	$ 714,017	$ 6,169,545	$ 8,333,213	$ 14,502,758		$ 35,040,351	$ (5,132,056)	$ 29,908,294
2	January, 2022	28,761,648	(13,873,414)	14,888,234	940,660	(246,017)	694,643	5,869,705	6,542,689	12,412,394		35,572,013	(7,576,742)	27,995,271
3	February	29,321,846	(14,303,661)	15,018,185	920,340	(245,072)	675,268	1,869,799	9,529,108	11,398,907		32,111,986	(5,019,626)	27,092,360
4	March	29,868,676	(14,709,423)	15,159,253	895,180	(239,286)	655,894	769,870	11,170,222	11,940,093		31,533,727	(3,778,487)	27,755,239
5	April	23,299,816	(8,034,515)	15,265,301	873,183	(236,664)	636,519	6,294,076	9,477,055	15,771,131		30,467,075	1,205,877	31,672,951
6	May	23,705,051	(8,347,313)	15,357,738	852,741	(235,596)	617,145	1,996,857	14,682,645	16,679,502		26,554,648	6,099,737	32,654,384
7	June	24,274,225	(8,804,613)	15,469,612	832,823	(235,053)	597,770	2,476,672	15,300,115	17,776,787		27,583,719	6,260,449	33,844,169
8	July	25,078,116	(9,414,845)	15,663,271	813,730	(235,335)	578,396	2,280,171	14,226,231	16,506,402		28,172,018	4,576,051	32,748,069
9	August	25,941,338	(10,082,906)	15,858,432	794,481	(235,460)	559,021	584,225	17,092,958	17,677,183		27,320,045	6,774,592	34,094,636
10	September	27,468,901	(11,448,670)	16,020,231	772,589	(232,942)	539,647	(1,674,522)	18,212,397	16,537,875		26,566,968	6,530,785	33,097,753
11	October	13,288,889	2,918,075	16,206,964	748,223	(227,951)	520,272	11,622,230	4,736,156	16,358,387		25,659,343	7,426,280	33,085,623
12	November	14,024,236	2,356,277	16,380,513	733,392	(232,494)	500,898	13,562,845	1,840,634	15,403,478		28,320,472	3,964,417	32,284,889
13	December	14,691,519	1,841,115	16,532,634	714,017	(232,494)	481,523	14,502,758	69,301	14,572,059		29,908,294	1,677,922	31,586,217
14	Average	$ 23,664,134	$ (8,086,296)	$ 15,577,837	$ 834,822	$ (237,052)	$ 597,770	$ 5,101,864	$ 10,093,286	$ 15,195,150	R	$ 29,600,820	$ 1,769,938	$ 31,370,758

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

JEPPSEN, DI
TESTIMONY

EXHIBIT NO. 23

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
GENERAL ADVERTISING EXPENSE (ACCOUNT 930.1)
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
Line		2022	2022	2022	2022		Forecast	Ref	Unadjusted		2023
No	Description	Actuals	Adjustments	Base	Base	Other	Adjustment	No	Test Year	Annualizing	Test Year
1	General Advertising Expense..	$ 491,473	$ (491,473)	$ -		$ -	$ -		$ -	$ -	$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
MEMBERSHIPS AND CONTRIBUTIONS
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)	(15)
				Actual					Forecast Methodology				2023		
Line	Acct		Contributions	Memberships		2022	2022	2022	2022		Forecast	Ref	Unadjusted		2023
No	No	Organization	100%	33.33%	100%	Actuals	Adjustments	Base	Base	Other	Adjustment	No	Test Year	Annualizing	Test Year
1	537	Oregon Department of Agriculture		$ 41		$ 41	$ (41)	$ -	YES	$ -	$ -		$ -	$ -	$ -
2	537	Southern Idaho Water Quality Coalition		333		333	(333)	-	YES	-	-		-	-	-
3	539	American Concrete Institute		37		37	(37)	-	YES	-	-		-	-	-
4	539	American Society of Civil Engineers		24		24	(24)	-	YES	-	-		-	-	-
5	539	North American Weather Modification Council		166		166	(166)	-	YES	-	-		-	-	-
6	545	Greater Pine Valley Rangeland Fire Protection Association		25		25	(25)	-	YES	-	-		-	-	-
7	545	Weiser River Rangeland Fire Protection Association		83		83	(83)	-	YES	-	-		-	-	-
8	562	Utilities Technology Council		1,446		1,446	(1,446)	-	YES	-	-		-	-	-
9	570	Utilities Technology Council		482		482	(482)	-	YES	-	-		-	-	-
10	588	The Electrical Apparatus Service Association		683		683	(683)	-	YES	-	-		-	-	-
11	592	Utilities Technology Council		344		344	(344)	-	YES	-	-		-	-	-
12	593	Donation	7,000			7,000	(7,000)	-	YES	-	-		-	-	-
13	907	Chartwell		15,995		15,995	(15,995)	-	YES	-	-		-	-	-
14	908	Donation	(488)			(488)	488	-	YES	-	-		-	-	-
15	908	Forth		833		833	(833)	-	YES	-	-		-	-	-
16	908	Kiwanis Club Capital City		240		240	(240)	-	YES	-	-		-	-	-
17	908	Rotary Club Boise Metro		250		250	(250)	-	YES	-	-		-	-	-
18	910	Chartwell		3,166		3,166	(3,166)	-	YES	-	-		-	-	-
19	921	American Welding Society		85		85	(85)	-	YES	-	-		-	-	-
20	921	Americas' SAP Users' Group		945		945	(945)	-	YES	-	-		-	-	-
21	921	Arid Club			300	300	(300)	-	YES	-	-		-	-	-
22	921	Chamber of Commerce Pocatello		1,000		1,000	(1,000)	-	YES	-	-		-	-	-
23	921	Chamber of Commerce Boise Metro		650		650	(650)	-	YES	-	-		-	-	-
24	921	Crane Creek			2,100	2,100	(2,100)	-	YES	-	-		-	-	-
25	921	DirectEmployers Association		5,000		5,000	(5,000)	-	YES	-	-		-	-	-
26	921	Donation	500			500	(500)	-	YES	-	-		-	-	-
27	921	Hillcrest Country Club			600	600	(600)	-	YES	-	-		-	-	-
28	921	Idaho Business for Education		1,667		1,667	(1,667)	-	YES	-	-		-	-	-
29	921	Industrial Asset Management Council		583		583	(583)	-	YES	-	-		-	-	-
30	921	Lions Club Twin Falls		133		133	(133)	-	YES	-	-		-	-	-
31	921	Lions Twin Falls		42		42	(42)	-	YES	-	-		-	-	-
32	921	National Association of Property Tax Representatives - Transportation Energy Communications			50	50	(50)	-	YES	-	-		-	-	-
33	921	Northwest Public Power Association		504		504	(504)	-	YES	-	-		-	-	-
34	921	Risk Management Society		255		255	(255)	-	YES	-	-		-	-	-
35	921	Rotary Blue Lakes		68		68	(68)	-	YES	-	-		-	-	-
36	921	Rotary Club Blue Lakes		206		206	(206)	-	YES	-	-		-	-	-
37	921	Rotary Club Gooding		184		184	(184)	-	YES	-	-		-	-	-
38	921	Rotary Club Jerome		225		225	(225)	-	YES	-	-		-	-	-
39	921	Rotary Club Ketchum		177		177	(177)	-	YES	-	-		-	-	-
40	921	Rotary Club Nampa		367		367	(367)	-	YES	-	-		-	-	-
41	921	Rotary Club Twin Falls		73		73	(73)	-	YES	-	-		-	-	-
42	921	Urban Land Institute		164		164	(164)	-	YES	-	-		-	-	-
43	921	Western Energy Institute		533		533	(533)	-	YES	-	-		-	-	-
44	921	Western States Association of Tax Representatives			50	50	(50)	-	YES	-	-		-	-	-
45	930	Associated Taxpayers of Idaho			24,000	24,000	(24,000)	-	YES	-	-		-	-	-
46	930	Association of Idaho Cities		833		833	(833)	-	YES	-	-		-	-	-
47	930	Avian Power Line Interaction Committee		833		833	(833)	-	YES	-	-		-	-	-
48	930	Bannock Development		2,667		2,667	(2,667)	-	YES	-	-		-	-	-
49	930	Boise Valley Economic Partnership		5,833		5,833	(5,833)	-	YES	-	-		-	-	-
50	930	BusinessPlus		1,667		1,667	(1,667)	-	YES	-	-		-	-	-
51	930	Cambridge Commercial Club		13		13	(13)	-	YES	-	-		-	-	-
52	930	Centre for Energy Advancement through Technological Innovation		19,717		19,717	(19,717)	-	YES	-	-		-	-	-
53	930	Chamber of Commerce Baker City		359		359	(359)	-	YES	-	-		-	-	-
54	930	Chamber of Commerce Blackfoot		-		-	-	-	YES	-	-		-	-	-
55	930	Chamber of Commerce Boise Metro		9,521		9,521	(9,521)	-	YES	-	-		-	-	-
56	930	Chamber of Commerce Buhl		208		208	(208)	-	YES	-	-		-	-	-
57	930	Chamber of Commerce Caldwell		644		644	(644)	-	YES	-	-		-	-	-
58	930	Chamber of Commerce Donnelly		17		17	(17)	-	YES	-	-		-	-	-
59	930	Chamber of Commerce Eagle		158		158	(158)	-	YES	-	-		-	-	-
60	930	Chamber of Commerce Emmett		167		167	(167)	-	YES	-	-		-	-	-
61	930	Chamber of Commerce Fruitland		167		167	(167)	-	YES	-	-		-	-	-

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
MEMBERSHIPS AND CONTRIBUTIONS
For Twelve Months Ended December 31, 2023

(1) Line No	(2) Acct No	(3) Organization	(4) Actual Contributions 100%	(5) Actual Memberships 33.33%	(6) Actual Memberships 100%	(7) 2022 Actuals	(8) 2022 Adjustments	(9) 2022 Base	(10) Forecast Methodology 2022 Base	(11) Forecast Methodology Other	(12) Forecast Adjustment	Ref No	(13) 2023 Unadjusted Test Year	(14) Annualizing	(15) 2023 Test Year
62	930	Chamber of Commerce Garden City		83		83	(83)	-	YES	-	-		-	-	-
63	930	Chamber of Commerce Garden Valley		33		33	(33)	-	YES	-	-		-	-	-
64	930	Chamber of Commerce Gooding		48		48	(48)	-	YES	-	-		-	-	-
65	930	Chamber of Commerce Hagerman		65		65	(65)	-	YES	-	-		-	-	-
66	930	Chamber of Commerce Halfway		27		27	(27)	-	YES	-	-		-	-	-
67	930	Chamber of Commerce Heyburn		128		128	(128)	-	YES	-	-		-	-	-
68	930	Chamber of Commerce Horseshoe Bend		67		67	(67)	-	YES	-	-		-	-	-
69	930	Chamber of Commerce Jerome		200		200	(200)	-	YES	-	-		-	-	-
70	930	Chamber of Commerce Kuna		333		333	(333)	-	YES	-	-		-	-	-
71	930	Chamber of Commerce Meridian		333		333	(333)	-	YES	-	-		-	-	-
72	930	Chamber of Commerce Mountain Home		183		183	(183)	-	YES	-	-		-	-	-
73	930	Chamber of Commerce Nampa		1,483		1,483	(1,483)	-	YES	-	-		-	-	-
74	930	Chamber of Commerce Nyssa		50		50	(50)	-	YES	-	-		-	-	-
75	930	Chamber of Commerce Ontario		105		105	(105)	-	YES	-	-		-	-	-
76	930	Chamber of Commerce Payette		92		92	(92)	-	YES	-	-		-	-	-
77	930	Chamber of Commerce Pocatello		781		781	(781)	-	YES	-	-		-	-	-
78	930	Chamber of Commerce Riggins		42		42	(42)	-	YES	-	-		-	-	-
79	930	Chamber of Commerce Star		33		33	(33)	-	YES	-	-		-	-	-
80	930	Chamber of Commerce Twin Falls		780		780	(780)	-	YES	-	-		-	-	-
81	930	Chamber of Commerce Weiser		100		100	(100)	-	YES	-	-		-	-	-
82	930	Chartwell		18,329		18,329	(18,329)	-	YES	-	-		-	-	-
83	930	City Club Boise		183		183	(183)	-	YES	-	-		-	-	-
84	930	E Source		6,409		6,409	(6,409)	-	YES	-	-		-	-	-
85	930	Eastern Oregon Vistor Association		500		500	(500)	-	YES	-	-		-	-	-
86	930	Edison Electric Institute		193,785		193,785	(193,785)	-	YES	-	-		-	-	-
87	930	Electric Power Research Institute		6,667		6,667	(6,667)	-	YES	-	-		-	-	-
88	930	Great Rift Business Development		750		750	(750)	-	YES	-	-		-	-	-
89	930	Grid Forward		2,500		2,500	(2,500)	-	YES	-	-		-	-	-
90	930	Idaho Association of Counties		1,000		1,000	(1,000)	-	YES	-	-		-	-	-
91	930	Idaho Manufacturing Alliance		333		333	(333)	-	YES	-	-		-	-	-
92	930	Jerome 20/20		1,666		1,666	(1,666)	-	YES	-	-		-	-	-
93	930	National Hydropower Association		15,774		15,774	(15,774)	-	YES	-	-		-	-	-
94	930	North American Energy Standards Board		2,667		2,667	(2,667)	-	YES	-	-		-	-	-
95	930	Oregon State University Foundation		5,000		5,000	(5,000)	-	YES	-	-		-	-	-
96	930	Pacific Northwest Utilities Conference Committee		18,058		18,058	(18,058)	-	YES	-	-		-	-	-
97	930	Regional Economic Development Eastern Idaho		667		667	(667)	-	YES	-	-		-	-	-
98	930	Rotary Club Twin Falls		146		146	(146)	-	YES	-	-		-	-	-
99	930	Snake River Economic Development Alliance		1,000		1,000	(1,000)	-	YES	-	-		-	-	-
100	930	Southern Idaho Economic Development		1,667		1,667	(1,667)	-	YES	-	-		-	-	-
101	930	Southern Idaho Livestock Hall of Fame		100		100	(100)	-	YES	-	-		-	-	-
102	930	Sun Valley Economic Development		833		833	(833)	-	YES	-	-		-	-	-
103	930	Western Alliance for Economic Development		1,000		1,000	(1,000)	-	YES	-	-		-	-	-
104	930	Western Energy Institute		10,335		10,335	(10,335)	-	YES	-	-		-	-	-
105	930	Wyoming Taxpayers Association			1,600	1,600	(1,600)	-	YES	-	-		-	-	-
106	935	Utilities Technology Council		826		826	(826)	-	YES	-	-		-	-	-
		Total	$ 7,012	$ 374,974	$ 28,700	$ 410,686	$ (410,686)	$ -		$ -	$ -		$ -	$ -	$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
No	Name	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
1	**Ryan Adelman**										
2	Total Expenses	$ 7,461									
3	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
4	Arid Club..	-									
5	EEI..	-									
6	Oregon Direct Charges...	-									
7	Total..	7,461									
8	Payroll Percentage Allocated to IDACORP..................................	0.00%									
9	Net IDACORP Exclusions	-									
10	Other Exclusions:										
11	Arid Club (100% Per IPUC Order 29505)......................................	-									
12	Oregon - Direct Allocation (100%)..	-									
13	EEI (1/3 Per IPUC Order 29505)..	-									
14	Total Exclusions	$ -	$ -	$ -	YES	$ -	$ -		$ -	$ -	$ -
15	**Brian Buckham**										
16	Total Expenses	$ 22,621									
17	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
18	Arid Club..	-									
19	EEI..	(3,367)									
20	Oregon Direct Charges...	-									
21	Total..	19,254									
22	Payroll Percentage Allocated to IDACORP..................................	1.00%									
23	Net IDACORP Exclusions	193									
24	Other Exclusions:										
25	Arid Club (100% Per IPUC Order 29505)......................................	-									
26	Oregon - Direct Allocation (100%)..	-									
27	EEI (1/3 Per IPUC Order 29505)..	1,124									
28	Total Exclusions	$ 1,317	$ (1,317)	$ -	YES	$ -	$ -		$ -	$ -	$ -
29	**Mitch Colburn**										
30	Total Expenses	$ 3,055									
31	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
32	Arid Club..	-									
33	EEI..	(49)									
34	Oregon Direct Charges...	-									
35	Total..	3,006									
36	Payroll Percentage Allocated to IDACORP..................................	0.00%									
37	Net IDACORP Exclusions	-									
38	Other Exclusions:										
39	Arid Club (100% Per IPUC Order 29505)......................................	-									
40	Oregon - Direct Allocation (100%)..	-									
41	EEI (1/3 Per IPUC Order 29505)..	16									
42	Total Exclusions	$ 16	$ (16)	$ -	YES	$ -	$ -		$ -	$ -	$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
No	Name	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
43	**Sarah Griffin**										
44	Total Expenses	$ 2,515									
45	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
46	Arid Club..	-									
47	EEI..	(272)									
48	Oregon Direct Charges..	-									
49	Total...	2,243									
50	Payroll Percentage Allocated to IDACORP.................................	0.62%									
51	Net IDACORP Exclusions	14									
52	Other Exclusions:										
53	Arid Club (100% Per IPUC Order 29505)....................................	-									
54	Oregon - Direct Allocation (100%)..	-									
55	EEI (1/3 Per IPUC Order 29505)..	90									
56	Total Exclusions	$ 104	$ (104)	$ -	YES	$ -	$ -		$ -	$ -	$ -
57	**Lisa Grow**										
58	Total Expenses	$ 33,568									
59	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
60	Arid Club..	(84)									
61	EEI..	(5,872)									
62	Oregon Direct Charges..	-									
63	Total...	27,612									
64	Payroll Percentage Allocated to IDACORP.................................	1.00%									
65	Net IDACORP Exclusions	276									
66	Other Exclusions:										
67	Arid Club (100% Per IPUC Order 29505)....................................	84									
68	Oregon - Direct Allocation (100%)..	-									
69	EEI (1/3 Per IPUC Order 29505)..	1,959									
70	Total Exclusions	$ 2,319	$ (2,319)	$ -	YES	$ -	$ -		$ -	$ -	$ -
71	**Bo Hanchey**										
72	Total Expenses	$ 6,503									
73	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
74	Arid Club..	-									
75	EEI..	-									
76	Oregon Direct Charges..	-									
77	Total...	6,503									
78	Payroll Percentage Allocated to IDACORP.................................	0.00%									
79	Net IDACORP Exclusions	-									
80	Other Exclusions:										
81	Arid Club (100% Per IPUC Order 29505)....................................	-									
82	Oregon - Direct Allocation (100%)..	-									
83	EEI (1/3 Per IPUC Order 29505)..	-									
84	Total Exclusions	$ -	$ -	$ -	YES	$ -	$ -		$ -	$ -	$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2023

(1) No	(2) Name	(3) 2022 Actuals	(4) 2022 Adjustments	(5) 2022 Base	(6) Forecast Methodology 2022 Base	(7) Forecast Methodology Other	(8) Forecast Adjustment	Ref No	(9) 2023 Unadjusted Test Year	(10) Annualizing	(11) 2023 Test Year
85	**Patrick Harrington**										
86	Total Expenses	$ 20,908									
87	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
88	Arid Club......	-									
89	EEI......	(4,046)									
90	Oregon Direct Charges......	-									
91	Total......	16,862									
92	Payroll Percentage Allocated to IDACORP......	0.95%									
93	Net IDACORP Exclusions	160									
94	Other Exclusions:										
95	Arid Club (100% Per IPUC Order 29505)......	1,385									
96	Oregon - Direct Allocation (100%)......	-									
97	EEI (1/3 Per IPUC Order 29505)......	1,350									
98	Total Exclusions	$ 2,895	$ (2,895)	$ -	YES	$ -	$ -		$ -	$ -	$ -
99	**Jason Huszar**										
100	Total Expenses	$ 1,450									
101	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
102	Arid Club......	-									
103	EEI......	-									
104	Oregon Direct Charges......	-									
105	Total......	1,450									
106	Payroll Percentage Allocated to IDACORP......	0.00%									
107	Net IDACORP Exclusions	-									
108	Other Exclusions:										
109	Arid Club (100% Per IPUC Order 29505)......	-									
110	Oregon - Direct Allocation (100%)......	-									
111	EEI (1/3 Per IPUC Order 29505)......	-									
112	Total Exclusions	$ -	$ -	$ -	YES	$ -	$ -		$ -	$ -	$ -
113	**Steve Keen**										
114	Total Expenses	$ 1,461									
115	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
116	Arid Club......	-									
117	EEI......	-									
118	Oregon Direct Charges......	-									
119	Total......	1,461									
120	Payroll Percentage Allocated to IDACORP......	1.35%									
121	Net IDACORP Exclusions	20									
122	Other Exclusions:										
123	Arid Club (100% Per IPUC Order 29505)......	-									
124	Oregon - Direct Allocation (100%)......	-									
125	EEI (1/3 Per IPUC Order 29505)......	-									
126	Total Exclusions	$ 20	$ (20)	$ -	YES	$ -	$ -		$ -	$ -	$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
		2022	2022	2022	2022		Forecast	Ref	Unadjusted		2023
No	Name	Actuals	Adjustments	Base	Base	Other	Adjustment	No	Test Year	Annualizing	Test Year
127	**Debra Leithauser**										
128	Total Expenses	$ 1,283									
129	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
130	Arid Club..	-									
131	EEI...	-									
132	Oregon Direct Charges...	-									
133	Total..	1,283									
134	Payroll Percentage Allocated to IDACORP..................................	1.00%									
135	Net IDACORP Exclusions	13									
136	Other Exclusions:										
137	Arid Club (100% Per IPUC Order 29505).....................................	-									
138	Oregon - Direct Allocation (100%)..	-									
139	EEI (1/3 Per IPUC Order 29505)...	-									
140	Total Exclusions	$ 13	$ (13)	$ -	YES	$ -	$ -		$ -	$ -	$ -
141	**Jeff Malmen**										
142	Total Expenses	$ 8,363									
143	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
144	Arid Club..	-									
145	EEI...	-									
146	Oregon Direct Charges...	-									
147	Total..	8,363									
148	Payroll Percentage Allocated to IDACORP..................................	25.00%									
149	Net IDACORP Exclusions	2,091									
150	Other Exclusions:										
151	Arid Club (100% Per IPUC Order 29505).....................................	-									
152	Oregon - Direct Allocation (100%)..	-									
153	EEI (1/3 Per IPUC Order 29505)...	-									
154	Total Exclusions	$ 2,091	$ (2,091)	$ -	YES	$ -	$ -		$ -	$ -	$ -
155	**Ken Petersen**										
156	Total Expenses	$ 443									
157	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
158	Arid Club..	-									
159	EEI...	-									
160	Oregon Direct Charges...	-									
161	Total..	443									
162	Payroll Percentage Allocated to IDACORP..................................	0.13%									
163	Net IDACORP Exclusions	1									
164	Other Exclusions:										
165	Arid Club (100% Per IPUC Order 29505).....................................	-									
166	Oregon - Direct Allocation (100%)..	-									
167	EEI (1/3 Per IPUC Order 29505)...	-									
168	Total Exclusions	$ 1	$ (1)	$ -	YES	$ -	$ -		$ -	$ -	$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
No	Name	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustment	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
169	**Adam Richins**										
170	Total Expenses	$ 22,450									
171	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
172	Arid Club..	-									
173	EEI..	-									
174	Oregon Direct Charges...	-									
175	Total..	22,450									
176	Payroll Percentage Allocated to IDACORP................................	0.00%									
177	Net IDACORP Exclusions	-									
178	Other Exclusions:										
179	Arid Club (100% Per IPUC Order 29505)....................................	-									
180	Oregon - Direct Allocation (100%)..	-									
181	EEI (1/3 Per IPUC Order 29505)..	-									
182	Total Exclusions	$ -	$ -	$ -	YES	$ -	$ -		$ -	$ -	$ -
183	**Tim Tatum**										
184	Total Expenses	$ 6,230									
185	IDACORP Exclusions Requiring Special Treatment (Listed Below):										
186	Arid Club..	-									
187	EEI..	-									
188	Oregon Direct Charges...	-									
189	Total..	6,230									
190	Payroll Percentage Allocated to IDACORP................................	0.00%									
191	Net IDACORP Exclusions	-									
192	Other Exclusions:										
193	Arid Club (100% Per IPUC Order 29505)....................................	-									
194	Oregon - Direct Allocation (100%)..	-									
195	EEI (1/3 Per IPUC Order 29505)..	-									
196	Total Exclusions	$ -	$ -	$ -	YES	$ -	$ -		$ -	$ -	$ -
197	Total Reduction to Officer's Expenses	$ 8,775	$ (8,775)	$ -		$ -	$ -		$ -	$ -	$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
OTHER EXCLUSIONS
For Twelve Months Ended December 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)
					Forecast Methodology				2023		
	Account	2022 Actuals	2022 Adjustments	2022 Base	2022 Base	Other	Forecast Adjustmen	Ref No	Unadjusted Test Year	Annualizing	2023 Test Year
1	537	$ 6	$ (6)	$ -	YES	$ -	$ -		$ -	$ -	$ -
2	562	7	(7)	-	YES	-	-		-	-	-
3	570	7	(7)	-	YES	-	-		-	-	-
4	582	7	(7)	-	YES	-	-		-	-	-
5	583	46	(46)	-	YES	-	-		-	-	-
6	586	73	(73)	-	YES	-	-		-	-	-
7	588	327	(327)	-	YES	-	-		-	-	-
8	592	7	(7)	-	YES	-	-		-	-	-
9	921	5,897	(5,897)	-	YES	-	-		-	-	-
10	926	16,822	(16,822)	-	YES	-	-		-	-	-
11	Total	$ 23,199	$ (23,199)	$ -		$ -	$ -		$ -	$ -	$ -

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

JEPPSEN, DI
TESTIMONY

EXHIBIT NO. 24

Idaho Power Company
DETAIL OF ADDITIONAL RATE BASE, REVENUE AND EXPENSE ADJUSTMENTS
FOR THE YEARS 2022 AND 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			2022			2023		
Line No.	Description	Account No.	Ratebase	Revenue	Expense	Ratebase	Revenue	Expense
1	Asset Exchange Acquisition Adjustment (IPUC Order No. 33313, OPUC Order No. 15-184, FERC Order No. 20150617-3060)	114	$ 750,893			$ 750,893		
2	Asset Exchange Acquisition Adjustment Accumulated Amortization	115	$ (107,628)			$ (122,646)		
3	Net Asset Exchange Acquisition Adjustment		$ 643,265			$ 628,247		
4	Cloud Computing - (IPUC Order 34707)	182	$ 1,207,592			$ 1,006,327		
5	Wildfire Mitigation - (IPUC Order 35077)	182	$ 13,056,171			$ 13,056,171		
6	Siemens LTP Deferred Rate Base - (IPUC Order 33420)	182	$ 8,612,494			$ 8,181,006		
7	Siemens LTP Deferred Rate Base - (OPUC Order 15-387)	182	$ 138,550			$ 94,504		
8	Pension Expense Amortization (IPUC Order No. 32426)	926						$ 18,028,665
9	Energy Efficiency Rider (IPUC Order No. 30189)	456		$ (31,673,550)				
10	Energy Efficiency Rider (IPUC Order No. 30189)	908			$ (31,673,550)			
11	Energy Efficiency Rider (Oregon)	456		$ (1,523,563)				
12	Energy Efficiency Rider (Oregon)	908			$ (1,523,563)			
13	Energy Efficiency Rider Labor - Idaho	908						$ 3,474,555
14	Cloud Computing - (IPUC Order 34707)	407			$ 201,265			$ 201,265
15	Wildfire Mitigation - (IPUC Order 35077)	407			$ -			$ 1,865,167
16	Siemens LTP Deferred Rate Base Amortization - Idaho	407			$ 431,488			$ 431,488
17	Siemens LTP Deferred Rate Base Amortization - Oregon	407			$ 44,046			$ 44,046
18	2022 Incentive	920			$ (26,598,671)			
19	Asset Exchange Acquisition Adjustment Amortization (IPUC Order No. 33313, OPUC Order No. 15-184, FERC Order No. 20150617-3060)	406			$ 15,018			$ 15,018
20	Intervenor Funding CAPAI (IPUC Order No. 32788)	928						$ 3,574
21	Intervenor Funding Sierra Club (IPUC Ord No 33872)	928						$ 16,267
22	Intervenor Funding CAP (IPUC Order 33908)	928						$ 1,089
23	Intervenor Funding ICL (IPUC Order 32697)	928						$ 6,583
24	Intervenor Funding CAPAI (IPUC Order 32245)	928						$ 2,428
25	Intervenor Funding ICL (IPUC Order 32245)	928						$ 4,901
26	Intervenor Funding NW Energy (IPUC Order 32505)	928						$ 809
27	Intervenor Funding ICEA (IPUC Order 32846)	928						$ 11,191
28	Intervenor Funding ICL (IPUC Order 32846)	928						$ 13,287
29	Intervenor Funding ICL (IPUC Order 32505 32537)	928						$ 7,742
30	Intervenor Funding ICL (IPUC Order 32426)	928						$ 16,482
31	Intervenor Funding CAPAI (IPUC Order 32426)	928						$ 14,943
32	Intervenor Funding IIPA (IPUC Order 32426)	928						$ 14,943
33	Intervenor Funding SRA (IPUC Order 32956)	928						$ 18,709
34	Intervenor Funding IIPA (IPUC Order 33357)	928						$ 14,152
35	Intervenor Funding SRA (IPUC Order 33357)	928						$ 4,190
36	Intervenor Funding REC (IPUC Order 33357)	928						$ 6,616
37	Intervenor Funding ICL (IPUC Order 33357)	928						$ 6,871
38	Intervenor Funding ICEA (IPUC Order 34046)	928						$ 11,969
39	Intervenor Funding Sierra Club (IPUC Order 34046)	928						$ 11,969
40	Intervenor Funding SRA (IPUC Order 34046)	928						$ 7,617
41	Intervenor Funding IIPA (IPUC Order 34046)	928						$ 11,969
42	Intervenor Funding ICL (IPUC Order 34546)	928						$ 11,631
43	Intervenor Funding ICEA (IPUC Order 34546)	928						$ 19,032
44	Intervenor Funding IIPA (IPUC Order 34546)	928						$ 5,287
45	Intervenor Funding Idaho Sierra Club (IPUC Order 34546)	928						$ 6,344
46	Intervenor Funding ICL (IPUC Order 34608)	928						$ 6,745
47	Intervenor Funding ICEA (IPUC Order 34608)	928						$ 8,431
48	Intervenor Funding Idaho Sierra Club (IPUC Order 34608)	928						$ 7,248
49	Intervenor Funding IIPA (IPUC Order 34608)	928						$ 19,730
50	Intervenor Funding Idaho Sierra Club (IPUC Order 34892)	928						$ 3,825
51	OR CUB Funding OPUC Order 21-166 22-192	928			$ (36,197)			
52	OR Annual Reg Expense OPUC Order 21-166 22-192	928			$ (28,878)			

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MATTHEW T. LARKIN

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Matthew T. Larkin. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Revenue Requirement Senior Manager in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. I received a Bachelor of Business Administration degree in Finance from the University of Oregon in 2007. In 2008, I earned a Master of Business Administration degree from the University of Oregon. I have also attended electric utility ratemaking courses, including the *Electric Rates Advanced Course*, offered by the Edison Electric Institute, and *Estimation of Electricity Marginal Costs and Application to Pricing*, presented by National Economic Research Associates, Inc.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power as a Regulatory Analyst in January 2009. As a Regulatory Analyst, I provided support for the Company's regulatory activities, including compliance reporting, financial analysis, and the development of revenue forecasts for regulatory filings.

In January 2014, I was promoted to Senior Regulatory Analyst where my responsibilities expanded to include the development of complex cost-related studies and the analysis of strategic regulatory issues.

Since becoming the Revenue Requirement Senior Manager in March 2016, I have overseen the Company's regulatory activities related to revenue requirement, such as power supply expense modeling, jurisdictional separation studies, and Idaho Power's Open Access Transmission Tariff formula rate.

I. OVERVIEW

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the forecast methodologies that were applied to the Company's 2022 financial data to arrive at the 2023 forecasted financial levels. Further, my testimony will describe the instructions that I provided to Company Witnesses Ms. Jessica G. Brady, Ms. Kelley Noe, and Ms. Paula Jeppsen with regard to the normalizing, annualizing, and other regulatory adjustments required to arrive at the 2023 test year revenue requirement.

Q. How is your testimony organized?

A. My testimony begins with an overview of direction I received from Vice President of Regulatory

Affairs Mr. Timothy E. Tatum regarding the development of the Company's 2023 Test Year ("2023 Test Year" or "Test Year"). I then detail two specific adjustments to the Company's 2023 Test Year regarding the recovery of costs related to Idaho Power's defined benefit pension plan and the recovery of non-fuel coal-related costs. Next, I discuss the broader methodologies utilized by the Company to forecast the remainder of the test year components. My testimony concludes with a summary of the direction I gave to other Company witnesses in developing the 2023 Test Year, and a quantification of the Company's requested Idaho jurisdictional revenue requirement.

Q. Did you consult with Mr. Tatum, Vice President of Regulatory Affairs, regarding the development of the 2023 Test Year?

A. Yes. The 2023 Test Year development methodology presented in my testimony is a direct result of numerous discussions with Mr. Tatum.

Q. Did Mr. Tatum provide you with any specific instructions or guidance regarding the development of the test year presented in this proceeding?

A. Yes. Mr. Tatum instructed me to develop a 2023 Test Year based on 2022 actual financial data in a manner similar to that presented to the Idaho Public Utilities Commission ("Commission") in the Company's last general rate case, IPC-E-11-08 ("2011 Rate Case"). However, Mr. Tatum instructed me to deviate from the methodology used in the 2011 Rate Case in a number of specific areas.

First, Mr. Tatum instructed me to set the recovery of 2023 Test Year pension expense at approximately $35 million, an increase above the level currently reflected in rates of $17 million. Second, Mr. Tatum directed me to maintain the North Valmy Power Plant ("Valmy") and the Jim Bridger Power Plant ("Bridger") non-fuel coal-related cost recovery at current levels, with the exception of collection related to previously deferred revenue requirement amounts. Third, Mr. Tatum directed me to update base net power supply expenses ("NPSE") to be included in base rates and tracked through the Power Cost Adjustment ("PCA") on a going forward basis. Fourth, Mr. Tatum instructed me to hold non-labor operations and maintenance ("O&M") expense at 2022 levels with specific adjustments for known and measurable changes. Fifth, Mr. Tatum instructed me to hold test year levels of wildfire mitigation costs to 2022 actual costs, and include amortization into rates of previously deferred wildfire mitigation costs, excluding deferred vegetation management costs, over a seven-year amortization period.

Prior to discussing the broader methodology utilized to develop the 2023 Test Year, I will first address the Company's methodologies related to pension and non-fuel coal-related costs at Bridger and Valmy.

II. PENSION COST RECOVERY

Q. Please provide an overview of the regulatory treatment for the Company's defined benefit pension plan expense in Idaho rate proceedings.

A. In Order No. 30333 issued in 2007, the Commission authorized Idaho Power to account for its defined benefit pension expense on a cash basis and to defer and account for accrued Statement of Financial Accounting Standards ("SFAS") 87 / Accounting Standards Codification ("ASC") 715 pension expense as a regulatory asset. Then in 2010, the Commission determined in Order No. 31003 that the previously authorized regulatory asset could be considered a balancing account to track, on a cumulative basis, the difference between the cash amounts contributed to the pension plan and the amounts included in rates. Additionally, the Commission determined that recovery of deferred cash contributions and ASC 715 expense and the associated amortization period were to be evaluated during a revenue requirement proceeding.

Q. Do customers benefit under the current regulatory treatment for pension expense?

A. Yes. The balancing account established by Order No. 31003 provides for a greater level of cost tracking that assures customers pay no more than the actual cost as well as providing a better opportunity to match costs with revenues. The balancing account is also an effective tool to mitigate financial market volatility as well as discount rate volatility. The balancing account results in the Company addressing both market and discount rate volatility while the customer impact of the volatility is mitigated. The balancing account also provides the Commission with the opportunity to determine an appropriate amortization period for rate recovery.

Q. What is the Company’s current annual level of pension expense recovery?

A. In Order No. 32248 issued in 2011 in Case No. IPC-E-11-04, the Commission authorized recovery of $17,153,713 per year.

Q. Aside from the current level of base rate recovery, have there been any other reductions to the balancing account?

A. Yes. Due to the Company’s revenue sharing mechanism,[1] from 2011 to 2014 the pension balancing account

[1] Case No. IPC-E-09-30, Order No. 30978. This ADITC/Revenue Sharing mechanism was subsequently extended, and percentages, thresholds, and accounting were modified by the Commission in Order Nos. 32424, 33149, and 34071.

was reduced by approximately $68 million, as earnings above a 10.5 percent return on equity were used to offset future rate increases associated with pension deferrals.

Q. What is the current balance in the pension balancing account?

A. As of December 31, 2022, the balance was $221 million.

Q. What is the Company's requested level of pension expense recovery in the 2023 Test Year?

A. At Mr. Tatum's direction, the Company is requesting $35 million of pension amortization, reflecting an approximate increase of $18 million compared to the amount currently in rates.

Q. Is there a risk to customers of over-recovery if assumptions regarding pension costs or funding levels change?

A. No. The existing balancing account methodology ensures that customers never pay more than actual pension costs. If future contributions are less than $35 million the balance in the account will be reduced sooner. If contributions continue to be higher than the recovery of $35 million, the pension balancing account will grow but will not impact customers without future rate approvals, as has been illustrated over the period since Idaho Power's last general rate case.

III. NON-FUEL COAL-RELATED COST RECOVERY

Q. How are non-fuel coal-related costs generally recovered in rates?

A. On May 31, 2017, the Commission authorized the Company in Order No. 33771 to establish a balancing account, with the necessary regulatory accounting, to track the incremental costs and benefits associated with the accelerated Valmy end-of-life as part of the Valmy levelized revenue requirement mechanism.[2] Similarly, on June 1, 2022, the Commission authorized the Company in Order No. 35423 to establish a balancing account, with the necessary regulatory accounting, to track the incremental costs and benefits associated with the Company's cessation of coal-fired operations at Bridger as part of the Bridger coal-related levelized revenue requirement mechanism.[3] The recovery of these amounts is embedded in the Company's currently-approved base rates.

Q. What direction did you receive from Mr. Tatum with regard to the inclusion of non-fuel coal-related costs in the 2023 Test Year?

A. Mr. Tatum directed me to maintain the Valmy and Bridger non-fuel coal-related cost recovery at current

[2] Case No. IPC-E-16-24, Order No. 33771.
[3] Case No. IPC-E-21-17, Order No. 35423.

levels, with the exception of collection related to previously deferred revenue requirement amounts.

Q. How did the Company achieve this directive?

A. This directive was achieved as reflected in Ms. Jeppsen's testimony and exhibits, through the removal of these costs from 2022 actuals. As discussed by Ms. Jeppsen, actual non-fuel coal-related costs at Bridger and Valmy were adjusted out of actual costs in all pertinent cost categories, including non-fuel O&M, electric plant-in-service, and property taxes.

Q. How is Idaho Power accounting for the existing cost recovery through these coal mechanisms in its presentment of the 2023 Test Year?

A. With regard to revenues, the Company's existing base rates already reflect the amount of current recovery of these levelized amounts, therefore the 2023 Test Year retail revenues calculated by Ms. Brady and provided to Ms. Noe reflect revenues the Company is currently receiving related to these levelized revenue requirements. With regard to costs, Idaho Power has quantified the current level of authorized cost recovery for both the Bridger coal-related and Valmy levelized revenue requirement mechanisms. Because coal-related Bridger and Valmy costs were removed from actual 2022 financials by Ms. Jeppsen, the Company has added the currently authorized Idaho jurisdictional recovery levels to the 2023 Test Year revenue requirement, as detailed in the jurisdictional separation study ("JSS") prepared by Ms. Noe. As described in the Direct Testimony of Mr. Tatum, these amounts also include the total incremental annual Bridger-related cost recovery associated with previously deferred revenue requirement amounts.

IV. TEST YEAR METHODS

Q. Will you briefly summarize how the Company developed its 2023 Test Year?

A. Yes. The development of the 2023 Test Year began with 2022 actual financial data ("2022 Actuals"). 2022 Actuals were compiled and adjusted by Ms. Jeppsen to reflect standard ratemaking adjustments and to arrive at 2022 adjusted actual financial information ("2022 Base"). The 2022 Base was then adjusted to reach 2023 forecasted financial levels ("2023 Unadjusted Test Year"). Finally, annualizing adjustments were made to the 2023 Unadjusted Test Year to reach the Company's 2023 Test Year.

Q. Which forecast methodologies were used to adjust the 2022 Base to the 2023 Unadjusted Test Year?

A. There were two primary methods developed and applied to the 2022 Base Year to forecast the 2023 Unadjusted Test Year. First, the Company used the unchanged 2022 Base Year financial data when the Company believed that certain amounts would continue to remain at 2022 levels or if account balances were relatively small. Alternatively, “Other Adjustments” were applied based upon known or probable factors for 2023 that relate to a particular account. Examples of these factors include, but are not limited to, new billing and volume contract terms, discontinued services, anticipated levels of economic activity, and existing regulatory commission orders.

Q. Have you prepared exhibits that list all accounts and identify the specific method used to forecast the 2023 Unadjusted Test Year?

A. Yes. I directed the preparation of Exhibit No. 25 to present a summarized list of all accounts to which the two previously discussed methods were applied. Each methodology is described in more detail within the Forecast Methodology Manual, provided as Exhibit No. 26, which was also prepared at my direction. To develop the Forecast Methodology Manual, the Company performed a review of each group of accounts included within the test year. Based upon specific knowledge and analysis of each account grouping, the Company either used 2022 Actuals or applied an Other Adjustment methodology to that account to represent an appropriate level of anticipated spending.

Q. Have the data and the associated adjustments made to your exhibits and supporting schedules been calculated on a total system basis?

A. Yes. Ms. Noe will address the determination of the Idaho jurisdictional test year values in her testimony.

Q. What are the major areas or groupings of financial accounts addressed by the methodologies included in the Forecast Methodology Manual (Exhibit No. 26)?

A. The major areas or groupings of financial accounts addressed in Exhibit No. 26 include Other Operating Revenues (Accounts 451, 454, and 456), Operation and Maintenance Expenses (Accounts 500 through 935), Depreciation and Amortization Expense (Accounts 403 and 404), and Electric Plant in Service (Account 101). A detailed discussion of the individual accounts and methods used is provided in Exhibit No. 26.

Q. Which methodology was used to forecast 2023 Other Operating Revenues (Accounts 447, 451, 454, and 456)?

A. Consistent with Mr. Tatum's directive, Surplus Sales Revenues (Account 447) were included in the Company's quantification of base NPSE as further detailed in Ms. Brady's testimony. The remaining Other Operating Revenues (Accounts 451, 454, and 456) were kept at year-end 2022 Actuals, with the exception of six items: 1) miscellaneous service revenues, 2) cogeneration and small power production, 3) revenues from dark fiber rents, 4) payments to water districts, 5) facilities charges, and 6) third-party transmission revenues.

Account 451 contains Miscellaneous Service Revenues, and was forecast based on proposed changes to Schedule 66 (the Miscellaneous Charges tariff that governs these offerings) that are further discussed in the Direct Testimony of Company Witness Mr. Riley Maloney. Cogeneration and small power production revenues were determined by applying a five-year compound average growth rate ("CAGR"), as the Company believes this method reflects a reasonable expectation for the 2023 timeframe. Revenues from dark fiber rents will cease in February 2023, therefore they were removed as a forecast adjustment. Payments from water districts were calculated based on a five-year average, as these payments fluctuate based on demand for water and availability. Expected facilities charge revenues were based on the Company's proposed facilities charge rate filed in this case applied to expected applicable investment in the 2023 Test Year, as further addressed by Mr. Maloney. Network services and other long-term firm and point-to-point transmission revenues were projected based on information more reflective of current circumstances and an anticipated Open Access Transmission Tariff rate update in October 2023.

Q. Which methodology was used to forecast 2023 O&M Expenses (Accounts 500 through 935)?

A. Based on the instructions I received from Mr. Tatum, the general process to determine 2023 Test Year O&M began with the separation of the majority of O&M components into two elements: labor and non-labor. Each element was then forecast separately and allocated to the individual Federal Energy Regulatory Commission ("FERC") accounts.

Based upon the instructions I received from Mr. Tatum, there were several O&M accounts that were determined separately from this process. First, the base NPSE accounts tracked through the PCA were updated by Ms. Brady primarily utilizing the AURORA model. The PCA expense accounts include Fuel Expense (Accounts 501 and 547), Water for Power Expense (Account 536.003), Purchased Power Expense (Account 555), and Transmission of Electricity by Others (Account 565).

The Idaho Energy Efficiency Rider Expense (Account 908) was removed in its entirety from the 2023 Test Year, while the labor component was added back to this account, as discussed in the Direct Testimony of Mr. Tatum.

Incentive Expense (included in Account 920) was forecasted for 2023 to include only the normalized incentive components that are attributable to Customer Satisfaction and Reliability, consistent with the method approved in Case No. IPC-E-08-10 ("2008 Rate Case"), Order No. 30722, and filed in the Company's 2011 Rate Case. Incentive expense represents the "at-risk" portion of employees' total compensation package.

Pension Expense (Account 926) for the Idaho jurisdiction was increased to reflect $35 million in annual collection, as discussed previously in my testimony.

Regulatory Commission Expenses (Account 928) were adjusted to include known changes in amortizations for recovery of Commission-ordered intervenor funding.

Q. What methodology was used to forecast 2023 O&M labor expense?

A. The 2023 labor expense was forecasted by applying historical monthly labor cost relationships to the first two calendar months of 2023 actual labor costs. More specifically, the 2023 O&M labor forecast was developed by first calculating the three-year historical average of February year-to-date actual O&M labor costs as a percentage of the total year actual O&M labor costs. The resulting percentage was determined to be 16.0 percent. This percentage was then applied to the actual February 2023 year-to-date O&M labor to estimate the total 2023 O&M labor costs. The February amount was first reduced by pension expense and incentive expense. The resulting 2023 labor projection of $188.8 million was then allocated to the applicable FERC accounts based on 2022 actual labor charges to those same accounts.

This method is similar to that utilized by Commission Staff ("Staff") in the 2008 Rate Case to validate the Company's labor forecast as additional actual labor cost data became available throughout the test period, and mirrors the Company's filed approach in the 2011 Rate Case. A more detailed discussion of the labor-related O&M adjustment is provided in Exhibit No. 26, pages 5 and 6.

Q. Did Idaho Power make any adjustments to expected labor costs related to the Energy Efficiency Rider ("Rider")?

A. Yes. As described in the Direct Testimony of Mr. Tatum, in this case Idaho Power is proposing to transfer approximately $3.5 million in Rider-funded labor costs into base rates. As discussed later in my testimony, the movement of these labor costs from the Rider to base rate recovery is one of two rate neutral transfer adjustments the Company is proposing in this case.

Q. What methodology was used to forecast 2023 non-labor O&M expenses?

A. 2023 non-labor O&M expenses, excluding the accounts mentioned above, were projected to be equal to the 2022 actual expense level with adjustments only for relatively large known changes. At my direction, the O&M expenses were reviewed by subject matter experts to identify and adjust those areas, based on specific knowledge, where expense levels are expected to be materially different than those included in the 2022 Base. The review identified specific increases or decreases to the 2022 non-labor actual levels in the following categories:

- Idaho Fish and Game's Projected Hatchery Expense Increases
- Fleet Adjustment
- Water for Power Adjustment
- Langley and Bennett Mountain Plant Maintenance
- Western Resource Adequacy Program ("WRAP")[4] Costs
- Uncollectible / Bad Debt Expense
- Solar Payback Calculator

Actual 2022 non-labor O&M, excluding these items listed for known changes, equaled $157.6 million. Following the adjustments for significant known changes, non-labor O&M is projected to increase by $339,424, to $157.9 million. This reflects a non-labor O&M amount for the 2023 Test Year that has increased by less than 0.25 percent. A more detailed discussion of the non-labor O&M

[4] The WRAP and its associated benefits are currently the subject of an open case before the Commission (Case No. IPC-E-23-08).

adjustments is provided in Exhibit No. 26, pages 6 through 16.

Q. Is there any specific regulatory accounting treatment that the Company is seeking related to the list of known and measurable adjustments you just identified?

A. Yes. The Company requests specific regulatory accounting authority related to the known and measurable adjustment item "Langley and Bennett Mountain Plant Maintenance." As can be seen on pages 7 and 8 of Exhibit No. 26, Langley and Bennett Mountain Plant Maintenance — Account 554 was decreased from the 2022 Base by $3,423,030. For this non-labor component, this account was projected to be equal to the 5-year average. The 2022 base included cyclical plant maintenance related to Langley and Bennett Mountain major overhaul and inspections that do not occur on an annual basis.

Consistent with the accounting authority previously granted in Order No. 32426,[5] the Company requests the Commission authorize the deferral and amortization of annual differences between actual costs and the annual recovery amount authorized in this case to allow for a

[5] Order No. 32426 issued in Case No. IPC-E-11-08 approved a settlement stipulation containing the following ¶ 6(b) Amortization provision: "The Signing Parties agree to a deferral of $299,546 in expenses associated with the Bennett Mountain combustor inspection with a four-year period beginning on the date that the Company's new base rates become effective."

proper matching of cost and revenue for this periodic cost. The Company further recommends this treatment be allowed until new rates become effective in a future general rate case or are otherwise modified by the Commission.

Q. What accounting will the Company use to track the annual differences between actual costs and the annual authorized recovery amount?

A. Idaho Power will defer the difference between actual costs and the annual recovery amount to Account 182.3 Other Regulatory Assets with an offsetting entry to Account 554 Maintenance of Miscellaneous Other Power Generation Plant.

Q. What methodology was used to forecast 2023 Depreciation and Amortization Expense (Accounts 403 and 404)?

A. The 2023 depreciation expense, amortization expense, and related reserve accounts were calculated based on the monthly estimated 2023 plant balances. Depreciation rates authorized by Commission Order No. 35272 were used for the entire 2023 Test Year. The determination of the Depreciation and Amortization Expense adjustments is detailed in Exhibit No. 26, pages 16 and 17.

Q. Which methodology was used to forecast 2023 Electric Plant in Service (Account 101)?

A. Electric Plant in Service ("EPIS") is a function of multiple components, including actual year-end 2022 EPIS and construction work in progress ("CWIP") balances, estimated 2023 spending, expected 2023 closings of CWIP, and estimated retirements. Therefore, it was necessary to use several methodologies to develop the 2023 Unadjusted Test Year EPIS balances, which are detailed in Exhibit No. 26, pages 21 through 22.

To project 2023 construction expenditures and 2023 closings of CWIP to EPIS, at Mr. Tatum's instruction, the Company first bifurcated into two separate and distinct parts, those projects in excess of $8 million and those under $8 million.

Projects in excess of $8 million were reviewed by the individual project managers, who estimated the costs to complete and the in-service date of each project. The investment in projects under $8 million (excluding vehicles) closing to EPIS as a group, were forecast based on the five-year average of the percent of similar-sized projects to the previous year's CWIP balance multiplied by the year-end 2022 CWIP balance.

Q. Which methodology was used to forecast AFUDC associated with Hells Canyon relicensing CWIP?

A. While AFUDC continues to increase relating to the Hells Canyon relicensing efforts, the Company is requesting recovery of the same amount ($6,815,472) previously included in the 2011 Rate Case and subsequently approved in Order No. 32426. This adjustment is explained in greater detail in Exhibit No. 26, page 20.

V. <u>ADDITIONAL ADJUSTMENTS</u>

Q. In Ms. Jeppsen's testimony, she describes the various adjustments that were made to 2022 Actuals to arrive at the 2022 Base Year. Do these same adjustments need to be made in 2023?

A. No. These adjustments are standard ratemaking adjustments based on prior Commission orders and are adjustments to charges included in the 2022 Actuals. By removing them from 2022 Actuals prior to applying the various methodologies to arrive at the Company's proposed 2023 Unadjusted Test Year, the same adjustments are already accounted for.

Q. What were your instructions to Ms. Brady with regard to the determination of the test year retail sales revenues?

A. I instructed Ms. Brady to determine the 2023 Test Year retail sales revenues using the same methodology approved by the Commission in the 2008 Rate Case, Order No. 30722, and applied in the Company's 2011 Rate Case. That is, my instructions were to develop the test year retail sales revenues based upon forecasted billing determinants under normal weather and precipitation assumptions. As Ms. Brady will cover in greater detail in her testimony, the 2023 Test Year billing determinants were developed based on the Company's energy sales and customer count forecasts prepared for this case. To derive the demand-related billing determinants, historical demand-to-energy relationships were applied to the energy sales forecast. The forecasted billing determinants were then applied to the rates in effect at the time of the filing to determine the 2023 Test Year retail sales revenues.

Q. Was the customer, sales, and load forecast prepared at your direction?

A. Yes. The customer, sales, and load forecast for the 2023 Test Year was prepared at my direction. This forecast was utilized to determine the billing components for the 2023 retail sales revenue forecast, as well as the allocation factors utilized by Ms. Noe and Mr. Goralski as well.

Q. Did you direct Ms. Brady to make any adjustments to the 2023 retail sales revenues relative to the methodology utilized in the 2011 Rate Case?

A. Yes. Due to the Commission's approval of a revised special contract for electric service ("Special Contract") with Micron Technologies ("Micron") on March 9, 2022,[6] I directed Ms. Brady to exclude the component of Micron's retail revenues that will be offset by generation from the Black Mesa Solar Facility ("Black Mesa").

Q. Can you describe the mechanics of Micron's revised Special Contract and how it pertains to the 2023 retail sales revenue calculation?

A. Per the terms of the revised Special Contact, a portion of Micron's retail sales will be offset by generation from Black Mesa. Functionally, that means Micron will pay Idaho Power for 100 percent of the output from Black Mesa, which will offset the retail energy rates Micron would otherwise pay. Consequently, the portion of Micron's sales offset by Black Mesa must be separately calculated from other retail revenues to ensure these contract components are appropriately accounted for throughout the various steps in the rate development process.

Q. Did you have any additional instructions for Ms. Brady?

A. Yes. In addition to the development of 2023 Test Year retail revenues, Ms. Brady is also the Company's expert with regard to the modeling of base NPSE. As mentioned earlier in my testimony, Mr. Tatum directed me to update the PCA expense accounts to expected 2023 normalized

[6] Case No. IPC-E-22-06, Order Nos. 35482, 35607 and 35735.

levels. Consistent with this directive, Ms. Brady updated base NPSE as provided in Exhibit No. 30 to her testimony.

Q. When was base NPSE last updated in customer rates?

A. Idaho Power last updated base NPSE in customer rates through Order No. 33000 issued in Case No. IPC-E-13-20, which became effective June 1, 2014 ("2013 NPSE Update").

Q. Did you direct Ms. Brady to make any methodological changes to the determination of base NPSE relative to the method utilized in the 2013 NPSE Update?

A. Yes. Due to the aforementioned Black Mesa component of Micron's revised Special Contract, I directed Ms. Brady to include the generation from the Black Mesa project in the Company's resource stack, but exclude the corresponding costs from Account 555, as these costs will be directly paid for by Micron. Further, due to changes in conditions since the filing of the 2011 Rate Case, I also directed Ms. Brady to modify the treatment of Account 447.050, which reflects revenues received due to third-party transmission wheeling losses. Lastly, given current and expected changes in the Company's resource stack, I directed Ms. Brady to include in the 2023 Test Year the availability of gas-fired generation at Bridger units 1 and 2.

Q. What methodology adjustment was made related to Account 447.050, revenues from wheeling losses?

A. Account 447.050 reflects financial payments made to Idaho Power as compensation for the Company generating electricity to offset transmission losses to third parties wheeling through Idaho Power's transmission system. In past determinations of base NPSE, Idaho Power did not include 447.050 revenues in these quantifications, nor did it include any costs associated with the additional generation required to serve third party losses. In the current case, however, Idaho Power is proposing to include in its base NPSE determination both the cost of serving third party losses as well as the offsetting revenues received through Account 447.050. Therefore, Idaho Power added 36 average megawatts ("aMW") to its load forecast utilized for AURORA modeling purposes to account for this load service requirement, and Ms. Brady determined an offsetting revenue amount to include in Account 447.050.

Q. Why is Idaho Power proposing to make this methodological change?

A. Theoretically, the inclusion or exclusion of Account 447.050 and the corresponding cost to serve third party losses would ultimately yield the same result; the exclusion of these components would have no impact on revenue requirement because they would be entirely removed from the quantification, while the inclusion of these components would net to zero.

Additionally, when the 2013 NPSE Update was performed, third party wheeling customers had the option to account for wheeling losses in two ways: 1) financially – meaning the customer would pay Idaho Power to generate the additional energy to account for the losses, or 2) physically – meaning the customer would generate or acquire additional physical energy to account for the losses themselves, resulting in no additional payment to Idaho Power. However, with the advent of the energy imbalance market ("EIM"), nearly all wheeling customers now settle their losses financially, meaning they pay Idaho Power to generate the physical energy to account for wheeling losses through the Company's system. Because of this, the Company is proposing to modify the base NPSE methodology to include both the cost to serve third-party wheeling losses and the offsetting revenues received by the Company.

Q. Given this change, is the Company proposing that Account 447.050 would be included in the PCA as well?

A. Yes. Under the Company's proposal, Account 447.050 would become part of base NPSE utilized in PCA calculations as of the effective date of rates resulting from this case.

Q. What direction did you give Ms. Brady with regard to the Company’s resource stack?

A. The timing of Idaho Power’s 2023 Test Year corresponds with changes in the Company’s resource stack, resulting in the need for an adjustment to assumed resource availability. Under current operations, the Jim Bridger Power Plant consists of four coal-fired units. However, the Company will cease coal-fired operations at units 1 and 2 at year-end 2023, converting these units to natural gas, with an expected online date of summer 2024. Because of this timing, I directed Ms. Brady to model the availability of two gas units and two coal units at Bridger, which better aligns with expectations on a going forward basis.

Because the Company’s requested effective date in this case is January 1, 2024, and because the PCA will capture differences between actual NPSE and base NPSE on a going forward basis until base NPSE are reset in a future proceeding, Idaho Power believes the modeling of gas-fired generation at Bridger units 1 and 2 is preferable to the modeling of four coal-fired units at Bridger, which would be immediately outdated as of the day rates go into effect.

Q. Are there any additional adjustments that need to be made to properly determine the 2023 Test Year?

A. Yes. It is necessary for the Company to make additional annualizing and known and measurable adjustments.

Q. Which other annualizing adjustments were made under your direction to the 2023 Test Year?

A. I instructed Ms. Noe to make annualizing adjustments to certain expense and rate base items to reflect them as though they have been in existence for the entire 2023 Test Year; that is, at year-end 2023 levels. These include operating payroll, depreciation expense and reserve, and plant placed in service during 2023 in excess of $8 million with the associated estimated property taxes and insurance premiums. Such adjustments are appropriate to reflect conditions that will be in effect at the time rates are placed in effect. Ms. Noe provides additional detail regarding the annualizing adjustments in her testimony.

Q. Has an exhibit been prepared that details each of the adjustments that were made to move from the 2022 Actuals to the 2023 Test Year?

A. Yes. Ms. Noe’s Exhibit No. 34 summarizes the adjustments that were made to each FERC Account to: 1) move from the 2022 Actuals to the 2022 Base, 2) move from the 2022 Base to the 2023 Unadjusted Test Year, and 3) move from the 2023 Unadjusted Test Year to the 2023 Test Year.

Q. How did you direct Ms. Noe to reflect the costs and revenues associated with Black Mesa and the Micron Special Contract?

A. Due to the offsetting nature of these costs and revenues, I directed Ms. Noe to exclude both components from the Idaho jurisdictional revenue requirement.

Q. Did you direct Ms. Noe to make any additional adjustments prior to quantifying the Company's requested revenue requirement in this case?

A. Yes. As previously discussed, in order to determine an accurate revenue requirement change, Ms. Noe had to first include the currently authorized recovery for non-fuel coal-related costs. I directed Ms. Noe to include the requested Bridger and Valmy levelized revenue requirements as separate lines in the JSS. Further, as discussed in Mr. Tatum's testimony, Idaho Power is proposing to offset the revenue requirement increase stemming from the battery projects to be installed in 2023 through the acceleration of accumulated deferred investment tax credits ("ADITC"). I directed Ms. Noe to incorporate this proposed rate mitigation into the quantification of the Company's request as well. Lastly, I directed Ms. Noe to reflect two transfer adjustments in the body of the JSS.

Q. What is meant by transfer adjustment?

A. Two of the Company's proposed updates in this case will have corresponding offsetting impacts on other rate mechanisms, thus reducing the net increase to customer bills. The term "transfer adjustment" is in reference to the fact that the recovery of these components of revenue requirement is already reflected in customer rates, and the Company's request in this case merely reflects the transfer of this recovery to base rates rather than a true increase to customer bills.

Q. What comprises the transfer adjustments?

A. The transfer adjustments are comprised of the aforementioned Rider labor adjustment and an update to PCA-related items.

Q. Please describe the transfer adjustment related to the Rider.

A. The Rider labor adjustment is simply the movement of labor-related costs out of the Rider and into base rates. As discussed by Mr. Tatum, the Company is proposing a corresponding reduction in the Rider percentage, thus resulting in no material impact to customer bills.

Q. What comprises the PCA-related transfer adjustment?

A. The PCA transfer adjustment is comprised of two subcomponents: 1) the reduction to the PCA due to an update to base NPSE, and 2) removal of EIM-related revenue requirement from PCA recovery.

Q. How will the PCA be reduced as a result of the base NPSE update?

A. A primary component of PCA rates contained in Schedule 55 is the difference between base NPSE and the forecast of NPSE for the PCA year. Therefore, when base NPSE are updated— and in this case, increased— the difference between base NPSE and the forecast established in the PCA is reduced, necessitating a reduction in Schedule 55 PCA rates. Consequently, the increase in NPSE proposed to be included in base rates is mostly offset by a corresponding reduction in the PCA rate. The only net impact to customers stems from the difference between full recovery in base rates of base NPSE, as compared to 95 percent recovery of deviations between base NPSE and forecast NPSE for certain accounts through the PCA. Ms. Brady quantifies this component of the PCA transfer adjustment in her testimony.

Q. Please explain the component of the PCA-related transfer adjustment stemming from EIM costs.

A. In accordance with Order No. 33706, which approved Idaho Power’s entrance into the EIM, the Company currently collects actual EIM-related costs through the PCA balancing adjustment. Order No. 34100 authorized Idaho

Power to recover its actual EIM-related costs on a backward-looking basis, as benefits in the form of reduced NPSE also flow through the PCA balancing adjustment via actual realized NPSE. This method of cost recovery was intended to capture these costs until they could be included in the Company's base rates as Idaho Power is proposing in this case. Therefore, to recognize that the Company's 2023 Test Year includes EIM-related costs that are currently collected through the balancing adjustment, Idaho Power has included a transfer adjustment in its quantification of the 2023 revenue requirement computation.

Q. What is the total amount of the transfer adjustments reflected in the presentment of the Company's 2023 revenue requirement computation?

A. The three transfer adjustments are listed in the following table on an Idaho jurisdictional basis:

Table 1: Transfer Adjustments by Component

Component	**Amount**
Rider Labor Transfer	$3,474,555
PCA Transfer – EIM	$2,456,681
PCA Transfer – Base Update	$170,912,271
Total	**$176,843,507**

Q. What direction did you provide Ms. Noe with regard to the inclusion of the transfer adjustments?

A. To recognize that these costs are already reflected in customer rates, I directed Ms. Noe to include these transfer adjustments in 2023 Test Year operating revenues.

Q. According to Ms. Noe’s analysis using the 2023 Test Year and incorporating the adjustments she made at your direction, what is the Company’s revenue requirement on an Idaho jurisdictional basis?

A. Using the 2023 Test Year financial information, Ms. Noe has calculated the Company’s revenue requirement to be $1,404.3 million on an Idaho jurisdictional basis. Ms. Noe calculated the Company’s annual revenue deficiency, the amount that the test year revenue requirement exceeds the test year retail sales revenue, to be $111.3 million on an Idaho jurisdictional basis, which would result in an overall average increase to customer rates of 8.61 percent.

Q. Is it appropriate for the Commission to determine the Company’s Idaho-jurisdictional revenue requirement to be $1,404.3 million, its revenue deficiency to be $111.3 million, and therefore, approve an overall 8.61 percent increase to customer rates?

A. Yes. The $1,404.3 million figure is a reasonable determination of the Company’s annual Idaho-jurisdictional revenue requirement. The $111.3 million quantification of revenue deficiency is also reasonable. It is in the best interest of the Company and its customers for the Commission to approve a rate increase to provide an 8.61 percent increase to the Company's Idaho jurisdictional revenues.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF MATTHEW T. LARKIN

I, Matthew T. Larkin, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Matthew T. Larkin. I am employed by Idaho Power Company as the Revenue Requirement Senior Manager.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 25 through 26 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: ____________________
MATTHEW T. LARKIN

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

LARKIN, DI
TESTIMONY

EXHIBIT NO. 25

IDAHO POWER COMPANY
Methodology Summary - Larkin Exhibit No. 25
2023 Idaho Test Year

- 2022 Base
- Other Methodology
- Normalized
- Removed in its Entirety

LINE NO	Description	(1) FERC ACCOUNT NUMBER	(2) Methodology
	Cost of Service Components		
	Other Operating Revenues		
1	Miscellaneous Service Revenues	451	Other Methodology
	Rent from Electric Property		
2	Substation equipment	454	2022 Base
3	Transformer & distribution rentals	454	2022 Base
4	Station and line rentals	454	2022 Base
5	Cogeneration and small power production	454	Other Methodology
6	Real estate rents	454	2022 Base
7	Dark fiber rents	454	Removed in its entirety
8	Joint pole attachments	454	2022 Base
9	Facilities charges	454	Other Methodology
10	Overnight park rents	454	2022 Base
11	Water district payments	454	Other Methodology
12	Miscellaneous	454	2022 Base
	Other Electric Revenues		
13	Network Service	456	Other Methodology
14	Point-to-Point and other services	456	Other Methodology
15	Photovoltaic	456	2022 Base
16	Antelope	456	2022 Base
17	Conservation recovery - Oregon	456	2022 Base
18	Sierra Pacific Power Company sales	456	2022 Base
19	Stand-by service	456	2022 Base
20	Energy Efficiency Rider	456	Removed in its entirety
21	Miscellaneous	456	2022 Base
	Other Revenues and Expenses		
	Other Revenues		
22	Power Solutions	415	Other Methodology
23	Hydro Services	415	2022 Base
24	Water Management Services	415	2022 Base
25	Qualified Reporting Entity Svcs	415	2022 Base
26	Operating Agreements	415	2022 Base
27	Joint Use (Pole) - Idaho	415	2022 Base
28	Joint Use (Pole) - Oregon	415	2022 Base
	Other Expenses		
29	Power Solutions	416	2022 Base
30	Hydro Services	416	2022 Base
31	Water Management Services	416	2022 Base
32	Qualified Reporting Entity Svcs	416	2022 Base
33	Operating Agreements	416	2022 Base
34	Joint Use (Pole) - Idaho	416	2022 Base
35	Joint Use (Pole) - Oregon	416	2022 Base

IDAHO POWER COMPANY
Methodology Summary - Larkin Exhibit No. 25
2023 Idaho Test Year

(cyan)	**- 2022 Base**
(yellow)	**- Other Methodology**
(green)	**- Normalized**
(red)	**- Removed in its Entirety**

LINE NO	Description	(1) FERC ACCOUNT NUMBER	(2) Methodology
	Operations and Maintenance Expenses		
	Power production expenses		
36	Steam power generation(excluding account 501)	500-514	Other Methodology
37	Fuel expense	501	Normalized
38	Hydraulic power generation	535-545	Other Methodology
39	Other power generation(excluding 547.1)	546-554	Other Methodology
40	Fuel expense	547	Normalized
	Other power supply expenses		
41	Purchased power (including 555.050)	555	Normalized
42	System control and load dispatch	556	2022 Base
43	Other expenses	557.000	Other Methodology
44	Other expenses	557.007	2022 Base
45	Other expenses - PCA, EPC and PCAM (excluding 557.050)	557	Removed in its entirety
46	Transmission expenses	560-575	Other Methodology
47	Distribution expenses	580-598	Other Methodology
48	Customer account, service and information expenses (excluding acct 908.1)	901-912	Other Methodology
49	Energy Efficiency Rider expenses	908.1	Removed in its entirety
50	Administrative & general expenses(excluding accts 920.1 and 930.1)	920-935	Other Methodology
51	Incentive	920.1	Removed in its entirety
52	General advertising expenses	930.1	Removed in its entirety
	Depreciation and Amortization Expense		
53	Depreciation	403	Other Methodology
54	Amortization	404	Other Methodology
	Electric Plant/Regulatory Assets - Amort, Adj, Gains & Losses		
55	Amortization of electric plant acquisition adjustment-Asset Exchange	406	2022 Base
	Regulatory Debits and Credits		
56	Siemens LTP amort - Idaho	407.3/407.4	2022 Base
57	Siemens LTP amort - Idaho deferred RB	407.3/407.4	2022 Base
58	Cloud computing	407.3/407.4	2022 Base
59	Wildfire Mitigation	407.3/407.4	Other Methodology
60	Deferred pension - Oregon	407.3/407.4	2022 Base
61	Siemens LTP amort - Oregon	407.3/407.4	2022 Base
62	Siemens LTP amort - Oregon deferred RB	407.3/407.4	2022 Base
	Taxes Other Than Income		
63	Real and personal property	600, 601	Other Methodology
64	Kilowatt-hour tax - Idaho	601.3	Normalized
	Licenses		
65	Wyoming	601	2022 Base
66	Shoshone-Bannock	602	2022 Base
	Regulatory commission		
67	Idaho	601	2022 Base
68	Oregon	601, 602	Other Methodology
69	Franchise tax - Oregon	602	Other Methodology
70	**Idaho Energy Resources Statement of Income**	418.1/419	Other Methodology
71	**Allowance for Funds Used During Construction (AFUDC) Related to Hells Canyon Relicensing**	440-444	2022 Base

IDAHO POWER COMPANY
Methodology Summary - Larkin Exhibit No. 25
2023 Idaho Test Year

- **- 2022 Base** (light blue)
- **- Other Methodology** (yellow)
- **- Normalized** (green)
- **- Removed in its Entirety** (pink)

LINE NO	Description	(1) FERC ACCOUNT NUMBER	(2) Methodology
	Rate Base Components		
	Electric Plant-In-Service		
72	Projects > $8 million	101	Other Methodology
73	Projects < $8 million	101	Other Methodology
	Accumulated Reserve for Depreciation and Amortization		
74	Depreciation reserve	108	Other Methodology
75	Amortization reserve	111	Other Methodology
	Materials and Supplies		
76	Plant materials and operating supplies	154	Other Methodology
77	Stores expense undistributed	163	Other Methodology
78	**Other Deferred Programs (excluding accts 182.310 and 254)**	182/186	Other Methodology
79	Wildfire Mitigation, OR Remote Meters, OR Bridger Depreciation	182.310/254	2022 Base
80	**Plant Held for Future Use(excluding Greenleaf and Northside Substations)**	105	2022 Base
81	Greenleaf Substation	105	Other Methodology
82	Northside Substation	105	Other Methodology
83	**Deferred Income Taxes**	190/282/283	Other Methodology
84	**Customer Advances For Construction**	252	Other Methodology
85	**IERCO-Subsidiary Rate Base Components**	123.1/186/145	Other Methodology

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

LARKIN, DI
TESTIMONY

EXHIBIT NO. 26

IDAHO POWER
An IDACORP Company

Forecast Methodology Manual

2023 Rate Case

Proprietary

TABLE OF CONTENTS

CROSS-REFERENCE LIST OF TABLES

Provided in Ms. Noe’s Exhibits

INTRODUCTION

The Forecast Methodology Manual is a reference document that provides supporting detail for the methodologies that have been used to set the values contained in Idaho Power Company's ("Idaho Power" or "Company") proposed 2023 test year. These values were provided to Idaho Power witness Ms. Kelley Noe for appropriate application to the Uniform System of Accounts for determination of revenue requirement in the 2023 test year. The manual is organized in three sections and includes:

- **Forecast Methods.** Forecast Methods includes a description of the forecast methodologies used to develop the 2023 unadjusted test year from the 2022 actual financial data.

- **Cost of Service Components.** Cost of Service Components includes a description of the three-digit account number specified in the Uniform System of Accounts adopted by the Idaho Public Utilities Commission ("IPUC" or "Commission") and the Federal Energy Regulatory Commission ("FERC") and the forecast method for each major account or account group.

- **Rate Base Components.** Rate Base Components includes a description of the three-digit account number specified in the Uniform System of Accounts adopted by the Commission and FERC and the forecast method applied for each major account or account group that comprises rate base.

FORECAST METHODS

Updates to the 2022 actual financial data to Idaho Power's proposed 2023 unadjusted test year were developed using one of the following two forecast methods:

(1) **2022 Base.** 2022 actual financial data was used when Idaho Power believed that certain amounts would continue to remain at 2022 levels or if account balances relatively very small.

(2) **Other Adjustments.** Other Adjustments are based on known or probable factors for 2023 that relate to a particular account. Examples of these factors include but are not limited to new billing and volume contract terms, discontinued services, anticipated levels of economic activity, and existing regulatory commission orders.

COST OF SERVICE COMPONENTS

Forecast Adjustment A—Other Operating Revenues

Table 4—FERC Accounts 451–456

Description

Account 451 includes revenues for all miscellaneous services and charges billed to customers that are not specifically provided for in other accounts. Miscellaneous service revenues include continuous service reversion charges (Idaho only), field visit charges, return trip charges, returned check fees, service connection charges, service establishment charges, and application and processing fees collected for new permits, new leases, or requests for easement relinquishments. Account 454 includes rents received for the use by others of land, buildings, and other property devoted to electric operations by Idaho Power such as joint pole attachments, facilities charges, and line and substation rents. Account 456 includes revenues derived from electric operations not includable in other revenue accounts. For example, compensation for minor services provided for others, such as engineering and revenues from transmission of electricity of others over transmission facilities of Idaho Power, including network and point-to-point wheeling.

Forecast Methodology

Forecast Adjustment A increases Other Operating Revenue (Accounts 451–456) by $49,713 above the 2022 Base. Accounts 451 through 456 used a combination of the methods for projecting 2023 amounts as described below.

Account 451—Miscellaneous Service Revenues. Miscellaneous Service Revenues were projected to increase by $1,271,884 for 2023 due to proposed changes to Schedule 66 Service Establishment, Connection and Field Visit charges.

Account 454—Rent from Electric Property. Rent from Electric Property was projected based on either the 12 months actual ended December 2022 balance, 2017-2022 Period compound average growth rate ("CAGR"), five- year average or a specifically identified change depending on the type of 2022 rental income to be projected as described below:

Substation equipment, transformer and distribution rentals, real estate rents, joint pole attachments, and overnight park rents were forecasted at 12 months actual ended December 2022, as this was the most reasonable expectation for these revenues.

Cogeneration and small power production was determined by applying the 2017-2022 CAGR to 2022 Actual amounts resulting in an increase of 3.28%, as this was determined to be a reasonable expectation for these amounts. Revenues from Dark Fiber Rents will cease February 2023 and have not been included in the test year. Facilities charges were projected to decrease by $189,692 due to proposed changes to Facilities Charge rates applied to January 2023 Facilities Investment Reports, which contain facilities on the Company's system subject to the Facilities Charge. Payments from Water Districts were determined by using the five-year historical average based on the 2018-2022 time period. These payments fluctuate based on demand for water and availability.

Account 456—Other Electric Revenues. Other Electric Revenues were projected based on using either the carry-forward of the 2022 Base or the Other Adjustment methodology depending on the type of 2023 revenue to be projected as described below:

Revenues related to the Sierra Pacific Power Company sales, stand-by service, and miscellaneous were projected for 2023 to be the same as the 2022 Base, as this was the most reasonable expectation for these revenues.

The 2023 point-to-point ("PTP") wheeling revenues were calculated based on nine months of the 2023 equivalent kilowatt-hours ("kWh") multiplied by the forecasted FERC formula-based transmission rate (effective 10/1/22-9/30/23), and three months of the 2023 equivalent kWh times the forecasted transmission rate (effective 10/1/23-9/30/24). The 2023 equivalent kWh used to calculate the 3rd party non-firm and short-term firm transmission wheeling revenue was based on the average of 2021 and 2022 equivalent kWh. The 3rd party long-term firm PTP wheeling revenue was based on 2022 actual megawatt ("MW") demand.

The 2023 Network Transmission Customer revenues were calculated based on nine months of the network transmission customers' average load ratio share times the forecasted FERC formula-based transmission revenue requirement and three months of the network transmission customers' average load ratio share times the forecasted FERC transmission revenue requirement. The timing for the Transmission Revenue Requirement is the same as the point-to-point wheeling rate described above. The 2023 estimated network customer MW demand used to calculate the Network Transmission Customer revenue was calculated by taking 2022 MW demand and escalating it using a 1.1% annual growth factor.

Forecast Adjustment B & C—Other Revenues and Other Expenses

Tables 4&5—FERC Accounts 415–416 (excluding 415.002 and 416.002)

Description

Accounts 415 through 416 include, respectively, all revenues derived from the sale of merchandise and jobbing or contract work and all expenses incurred in such activities. For Idaho Power, jobbing and contract work revenues and expenses include activities related to Idaho Power Solutions service agreements, hydro services, water management services, qualified reporting entity services, Joint Ownership and Operating Agreements with PacifiCorp and joint pole use.

Forecast Methodology

Forecast Adjustment B for Other Revenues (Account 415) reflects an increase of $30,623 from 2022 Base. Forecast Adjustment C for Other Expenses (Account 416) is not adjusted; therefore 2023 forecast remains the same as the 2022 Base.

Account 415 (Other Revenues) and account 416 (Other Expenses) used a combination of the methods for projecting described below:

Account 415. Power Solutions was projected based on 2022 actual amounts, excluding disbursements made to Howard Industries that are not expected to repeat in future years.

Hydro services, water management services, qualified reporting entity services, operating agreements, joint use (pole) – Idaho, and joint use (pole) – Oregon were forecasted at 12 months actual ended December 2022, as this was the most reasonable expectation for these revenues.

Account 416. Power Solutions, hydro services, water management services, qualified reporting entity services, operating agreements, joint use (pole) – Idaho, and joint use (pole) – Oregon were forecasted at 12 months actual ended December 2022, as this was the most reasonable expectation for these revenues.

Forecast Adjustment D—Operations and Maintenance Expenses (“O&M”)

Table 5—FERC Accounts 500–935

Overview

Forecast Adjustment D increases Operations and Maintenance Expenses (“O&M”) (Accounts 500–935) by $48,522,536 above the 2022 Base. Excluded from Adjustment D is any increase in normalized accounts 501-Fuel, 547-Fuel, 555-Purchased Power and 565-Transmission of Electricity by Others.

In developing the 2023 forecast, Idaho Power split O&M historical actuals into two elements (Labor and Non-Labor) and forecasted each element separately and then allocated each separately to the individual FERC accounts. Excluded from this process were the normalized accounts described above, 908.131, 908.132 (Idaho and Oregon Energy Efficiency Riders), 920.001 (Incentive), 926.203, 926.204, 926.303, 926.320 and 926.350 (Pension Expense), and 930.100 (Advertising Expense) as these were handled separately.

Labor

Idaho Power calculated the projected 2023 O&M labor by first calculating the average three-year historical February year-to-date actual O&M labor costs as a percentage of the total year actual O&M labor costs which was determined to be 16.0%. This percentage was then applied to the actual February 2023 year-to-date O&M labor of $30,154,755 to estimate the total 2023 O&M labor costs of $188,779,193 (the February amount was first reduced by 920 incentive expense and 926 pension expense accounts). The 2023 labor projection was then allocated to FERC accounts based on 2022 actual labor charges to those same accounts.

The table below details the 2023 estimated labor amount:

2023 O&M Labor Expenses	Total
February YTD O&M Labor Excluding Incentive & Pension	$30,154,755
Divided by the Historical February YTD as a Percentage of Total Year Labor	16.0%
2023 O&M Labor Expense Excluding Incentive and Pension	$188,779,193

Demand-Side Management ("DSM") Labor- Idaho Only

Idaho Power calculated the projected 2023 Idaho DSM Rider funded labor to be included in O&M by first calculating the average three-year historical February year-to-date actual DSM labor costs as a percentage of the total year actual DSM labor costs which was determined to be 16.7%. This percentage was then applied to the actual February 2023 year-to-date O&M labor of $578,654 to estimate the total 2023 DSM labor costs of $3,474,555. The 2023 labor projection was then directly assigned to FERC account 908.

The table below details the 2023 estimated labor amount:

2023 DSM Labor Expenses	Total
February YTD DSM Labor Excluding Incentive & Pension	$578,654
Divided by the Historical February YTD as a Percentage of Total Year Labor	16.7%
2023 DSM Labor Expense Excluding Incentive and Pension	$3,474,555

Non-Labor

Idaho Power calculated the projected 2023 non-labor O&M expenses by utilizing 2022 non-payroll actual expenses with adjustments for relatively large known changes. Idaho Power reviewed the O&M expenses to identify and adjust those areas, based on specific knowledge, where expense levels are expected to be materially different than those included in the 2022 actuals.

The table below identifies significant specific increases or decreases to the 2022 nonlabor actual:

2023 O&M Non-Labor Expenses	Total	Allocated	Direct Assignment
2022 O&M Non-Labor Actuals	$157,617,663	$0	$157,617,663
2023 Identified Significant Known Adjustments			
Idaho Department of Fish and Game	471,796	—	471,796
Fleet Adjustment	831,379	831,379	—
Water for Power Adjustment	(307,335)	—	(307,335)
Langley and Bennett Mountain Plant Maintenance	(3,423,030)	—	(3,423,030)
Western Resource Adequacy Program	133,975	—	133,975
Uncollectible/Bad-Debt Expense	2,514,638	—	2,514,638
Solar Payback Calculator	118,000	—	118,000
Subtotal 2023 Identified Significant Known Adjustments	339,424	831,379	(491,955)
Total 2023 O&M Non-Payroll Expenses	$157,957,087	$831,379	$157,125,708

The following adjustment to the 2022 Base included in the table above have been allocated to FERC account balances rather than directly assigned:

> **Fleet Adjustment**—The 2023 forecast adjustment for O&M accounts associated with fleet expense was developed by adjusting the 2022 fleet expense base for known cost increases. Fleet clearing expense notably increased in 2022 mostly due to significant increases in fuel costs. To estimate the 2023 fleet expense, Idaho Power used January 2023 through March 2023 actual expenses and annualized these costs based on a 3-year average of the proportional cost incurred in January through March. Subsequently, these costs were allocated to individual O&M accounts proportionately based upon actual 2022 O&M fleet expenses.

The following adjustments to the 2022 Base included in the table above have been directly assigned to one or more FERC accounts:

- **Idaho Fish & Game Adjustment**—Account 537 was increased by $471,796 above 2022 Base due to a 9.9% increase from the Idaho Department of Fish and Game for the cost of hatchery operations. The increase is primarily related to the increase in employee compensation and related labor costs.

- **Water for Power Adjustment**—Account 536 was decreased from the 2022 Base by $307,335 to reflect the 3-year average. For this non-labor component, this account was projected to be equal to the 3-year average to smooth variations from year to year.

- **Langley and Bennett Mountain Plant Maintenance**—Account 554 was decreased from the 2022 Base by $3,423,030. For this non-labor component, this account was projected to be equal to the 5-year average. The 2022 base included cyclical plant maintenance related to Langley and Bennett Mountain major overhaul and inspections that do not occur on an annual basis.

- **Western Resource Adequacy Program—**Account 561 was projected to be equal to the 2022 Base with an increase of $133,975 related to increased Western Resource Adequacy Program ("WRAP") participation.

- **Uncollectible/Bad-Debt Expense—**Bad debt expense as a percentage of revenues was evaluated over a 10-year period (2013 – 2022). The 10-year average percentage of bad debt expense compared to revenues was 0.351%. Applying this percentage to 2023 forecasted sales of $1,641,862,697 results in forecasted 2023 bad debt expense of $5,770,879. Comparing this amount to actual 2022 bad debt expense of $3,256,241 results in an adjustment of $2,514,638 over the 2022 Base.

- **Solar Payback Calculator—**Account 908 was projected to be equal to the 2022 Base with an increase of $118,000 related to development and maintenance of a Solar Payback Calculator to aid in Idaho Power customers' decision-making when considering the benefits of a solar installation.

Once O&M labor and non-labor increases or decreases were determined for each FERC account, the results were combined to reflect the total forecast adjustment.

FERC Account Development

Because Idaho Power does not forecast by individual FERC accounts, the following two methods (Direct Assignment and Allocation) were used to assign both labor and non-labor to the appropriate FERC accounts.

Direct Assignment Method—The forecast adjustments listed in the direct assignment column in the non-labor expenses above are charges that would occur in specific accounts and therefore were directly assigned to those accounts listed below.

- Account 536—Water for Power Adjustment
- Account 537—Idaho Fish & Game Adjustment
- Account 554—Langley and Bennett Mountain Plant Maintenance
- Account 561—Western Resource Adequacy Program Adjustment
- Account 904—Uncollectible/Bad Debt Expense
- Account 908—Solar Payback Calculator

Allocation Method—This method was used to allocate the forecast amounts when the identification of specific accounts was impossible or when the impact would be to all accounts. The O&M labor forecast was allocated to individual FERC accounts based on the percentage of 2022 actual O&M labor charges incurred within each account to total O&M labor charges incurred in 2022. The DSM labor forecast was directly assigned to account 908. The O&M non-labor forecast (not directly assigned) was allocated based on 2022 actual non-labor charges included in each FERC account to total O&M non-labor charges incurred in 2022.

Exceptions to the O&M Methodology Described Above

FERC Accounts 501, 547, 555, 555.050, 557, 565, 908.131, 908.132, 920.001, 926.204, 928.203

As stated earlier, the following were forecasted separately from the labor and non-labor O&M forecast described above and directly assigned to the FERC accounts they impact:

- **Account 501—Fuel Expense.** This account is forecasted using the AURORAxmp® Model.
- **Account 547—Fuel Expense (Excluding 547.000—Salmon Diesel).** This account is forecasted for the test year using the AURORAxmp® Model.
- **Account 555—Purchased Power (Including 555.050).** This account is forecasted for the test year using the AURORAxmp® Model.
- **Account 557—Other Expense (Excluding 557.000).** The amounts in these accounts have been removed in their entirety from the test year.
- **Account 565—Transmission of Electricity by Others.** This account is forecasted for the test year using the AURORAxmp® Model
- **Account 908.131 and 908.132—Idaho and Oregon Energy Efficiency Rider Expenses.** The amounts in these accounts have been removed from the 2022 Base in their entirety per IPUC Order No. 30189. The DSM labor forecast was added back and directly assigned to account 908.
- **Account 920.001—Incentive Expense.** The entire actual 2022 incentive expense of $26,598,671 was removed from the 2022 Base and replaced with the projected 2023 incentive of $10,040,205 that includes only elements related to Customer Satisfaction and Reliability. This resulted in a net reduction for incentive expense of $16,558,466.
- **Accounts 926.204—Pension Expense.** In the Idaho jurisdiction, per IPUC Order No. 32426, Idaho Power is currently recovering $17,153,713 of its cash contributions to its defined benefit pension plan. Idaho Power's actual 2022 Base pension expense (SFAS 87) was $30,182,378 (Idaho portion) Therefore, Idaho Power has included in its forecast adjustment an additional $18,028,665 in pension expense for 2023 to cover its SFAS 87 pension expense and provide $5,000,000 per year in pension balancing account amortization.

- **Accounts 928.203—Regulatory Commission Expense.** Intervenor Funding was estimated to increase $296,576 by assuming a one-year amortization period, per the following Orders:

  - IPUC Order No. 32788—CAPAI for $3,574.
  - IPUC Order No. 33872—Sierra Club for $16,267.
  - IPUC Order No. 33908—CAP for $1,089.
  - IPUC Order No. 32697—ICL for $6,583.
  - IPUC Order Nos. 32245—CAPAI for $2,428, ICL for $4,901.
  - IPUC Order No. 32505—NW Energy for $809.
  - IPUC Order Nos. 32846—ICEA for $11,191, ICL for $13,287.
  - IPUC Order No. 32505_32537—ICL for $7,742.
  - IPUC Order Nos. 32426—ICL for $16,482, CAPAI for $14,944, IIPA for $14,944.
  - IPUC Order No. 32956—SRA for $18,709.
  - IPUC Order Nos. 33357—IIPA for $14,152, SRA for $4,190, REC for $6,616, ICL for $6,871.
  - IPUC Order Nos. 34046—ICEA for $11,969, Sierra Club for $11,969, SRA for $7,617, IIPA for $11,969.
  - IPUC Order Nos. 34546—ICL for $11,631, ICEA for $19,032, IIPA for $5,287, Idaho Sierra Club for $6,344.
  - IPUC Order Nos. 34608—ICL for $6,745, ICEA for $8,431, Idaho Sierra Club for $7,248, IIPA for $19,730.
  - IPUC Order No. 34892—Idaho Sierra Club for $3,825.

The following O&M discussion has been organized by functional account groups. Within each account group, a general description of the accounts has been provided.

Steam Power Generation

FERC Accounts 500–514

Description

Accounts 500 through 514 include the labor, materials, and expenses incurred to operate and maintain prime movers, generators, and their auxiliary apparatus, switch gear, and other electric equipment used in steam power generation. Additionally, the labor and expenses incurred in the general supervision and direction of maintenance of steam generation facilities are included in these accounts.

Forecast Methodology

Accounts 500–514—Excluding Account 501, Fuel Expense.

Bridger Power Plant - Coal-related capital investment, O&M and property taxes associated with the Bridger Power Plant were removed from Idaho Power's 2022 Actuals as these costs are separately captured in the Bridger balancing account mechanism established and approved by IPUC Order No. 35423.

The Bridger annual levelized revenue requirement with a proposed effective date of January 1, 2024, is a $19,784,734 increase from the annual levelized revenue requirement included in Idaho Power-E-21-17 due to the following factors:

- Change in methodology effective January 1, 2024, to remove Bridger O&M from Idaho Power base rates and incorporate the full O&M amount into the balancing account mechanism as opposed to tracking only the O&M variance from previous base rates in the mechanism.

- Add into the mechanism the difference between the levelized payment calculated and the levelized payment authorized to be collected from customers from June 2022 through December 2023 per Idaho Power-E-21-17, resulting in a forecasted Idaho-level uncollected regulatory asset balance of $12,553,081 as of Dec 31, 2023, amortized over the life of the mechanism through 2030.

Valmy Power Plant - Coal-related capital investment, O&M and property taxes associated with the Valmy Power Plant were removed from Idaho Power's 2022 Actuals as these costs are separately captured in the Valmy balancing account mechanism established and approved and updated through IPUC Order Nos. 34349 and 35494.

The Valmy annual levelized revenue requirement with a proposed effective date of January 1, 2024, is a $7,059,079 increase from the annual levelized revenue requirement included in Idaho Power-E-22-05 due to the change in methodology effective January 1, 2024, to remove Valmy O&M from Idaho Power base rates and incorporate the full O&M amount into the balancing account mechanism as opposed to tracking only the O&M variance from previous base rates in the mechanism.

Account 501—Fuel Expense. Fuel expense is forecasted for the test year using the AURORAxmp® Model.

Hydraulic Power Generation

FERC Accounts 535–545

Description

Accounts 535 through 545 include the labor, materials used, and expenses incurred to operate and maintain hydraulic works including structures, reservoirs, dams, waterways, generators, roads and bridges, and expenses directly related to the hydroelectric development outside the generating station, including fish and wildlife and recreational facilities. These accounts also include the labor and expenses incurred in the general supervision and direction of maintenance of hydraulic power generating stations, rents of property of others used, occupied, or operated in connection with hydraulic power generation, including amounts payable to the United States for the occupancy of public lands and reservations for reservoirs, dams, flumes, forebays, penstocks, and power houses.

Forecast Methodology

Accounts 535–545—The projection of accounts 535–545 was developed using both methods described under FERC Account Development above. For labor, these accounts received their allocated portion of the total 2023 O&M labor projection based on actual 2022 labor. For non-labor, these accounts were projected to be equal to the 2022 Base adjusted by a decrease in account 536 of $307,335 to reflect the 3-year average to smooth variations from year to year, an increase in account 537 for Idaho Fish & Game's projected increases of $471,796, and by each account's allocated portion of the $831,379 non-direct adjustment to non-labor O&M.

Other Power Generation

FERC Accounts 546–557

Description

Accounts 546 through 554 include the operation labor, materials used, and expenses incurred in operating and maintaining prime movers, generators, and electric equipment in other power generating stations. Labor and expenses incurred in the general supervision and direction of maintenance of other power generating stations are also included in these accounts. Account 556 includes labor and expenses incurred in load dispatching activities for system control. System control activities include the production and dispatching of electricity. Account 557 includes production expenses incurred directly in connection with the purchase of electricity which is not specifically provided for in other production expense accounts.

Forecast Methodology

Accounts 546–557—Excluding Account 547, Fuel Expense; Account 555, Purchased Power; and Account 557, Other Expense. The projection of accounts 546–557 was developed using both methods described under FERC Account Development above. For labor, these accounts received their allocated portion of the total 2023 O&M labor projection based on actual 2022 labor. For non-labor, these accounts were projected to be equal to the 2022 Base and adjusted by a $3,423,030 decrease (in account 554) for the 2023 Langley and Bennett Mountain Plant Maintenance adjustment and by each account's allocated portion of the $831,379 non-direct adjustment to non-labor O&M.

Account 547—Fuel Expense and Account 555—Purchased Power. Fuel and purchased power were forecasted for the test year using the AURORAxmp® Model.

Account 557, Other Expense (Excluding 557.000—Other Power Production Expense). These expenses are removed entirely from the test year.

Transmission Expenses

FERC Accounts 560–573

Description

Accounts 560 through 573 include the operation labor, materials used, and expenses incurred in the system planning, operation, executing the reliability coordination function, monitoring, assessing, and operating the power system and individual transmission facilities in real-time to maintain safe and reliable operation of the transmission system specified. Additional activities include: processing the hourly, daily, weekly, and monthly transmission service requests using an automated system such as an Open Access Same-Time Information System ("OASIS"); billing to transmission owners for system control and dispatching service; and conducting transmission services studies for proposed transmission interconnections and generation interconnection with the transmission system. These accounts include the labor, materials used, and expenses incurred in the operation of transmission substations, switching stations, and transmission lines. The use of transmission facilities owned by others and rents of property used, occupied, or operated in connection with the transmission system are also part of this account. The accounts also include the labor, materials used, and expenses incurred in the maintenance of structures, computer hardware and software, communication equipment, miscellaneous transmission plant, station equipment, and transmission plant serving the transmission function.

Forecast Methodology

Accounts 560–573—Excluding Account 565.000, Transmission of Electricity by Others (3rd-Party Transmission). The projection of accounts 560–573 was developed using both methods described under FERC Account Development above. For labor, these accounts received their allocated portion of the total 2023 O&M labor projection based on actual 2022 labor. For non-labor, these accounts were projected to be equal to the 2022 Base and adjusted by $133,975 increase (in account 561) for costs associated with participation in the Western Resource Adequacy Program, and by each account's allocated portion of the $831,379 non-direct adjustment to non-labor O&M.

- **Account 565—Transmission of Electricity by Others.** This account was projected using the AURORAxmp® Model.

Distribution Expenses

FERC Accounts 580–598

Description

Accounts 580 through 598 include labor, materials used, and expenses incurred in the general supervision and direction of the operation of the distribution system such as station operation, overhead and underground line operation, meter department operation of customer meters and associated equipment, load dispatching operations, work on customer installations, and inspecting premises. Also included in these accounts are the labor, materials used, and expenses incurred in the general supervision and direction of the maintenance of the distribution system, including maintenance of structures, distribution plant, overhead distribution line facilities, underground distribution line facilities, distribution line transformers, meters, and meter testing equipment.

Forecast Methodology

Accounts 580–598. The projection of accounts 580–598 was developed using both methods described under FERC Account Development above. Each of the accounts received their allocated portion of the total 2023 O&M labor projection based on actual 2022 labor. For non-labor, these accounts were projected to be equal to the 2022 Base adjusted by each account's allocated portion of the $831,379 non-direct adjustment to non-labor O&M.

Customer Accounting and Customer Services and Information Expenses

FERC Accounts 901–905 and 907–912

Description

Accounts 901 through 905 include the labor, materials used, and expenses incurred in the general direction and supervision of customer accounting and collecting activities, including reading customer meters, work on customer applications, contracts, orders, credit investigations, billing and accounting, collections, and complaints. These accounts also include the accounting for losses from uncollectible utility revenues. Accounts 907 through 912 include the labor and expenses incurred in customer service and informational activities to encourage safe and efficient use of the utility's service, to encourage conservation of the utility's service, and answer specific inquiries as to proper use of the service and equipment utilizing the service.

Forecast Methodology

Accounts 901–905 and 907–912—Excluding Account 908.131 and 908.132, Idaho and Oregon Energy Efficiency Rider. The projection of accounts 901–905 and 907–912, excluding the Idaho and Oregon Energy Efficiency Rider (energy efficiency expenses), was developed using both methods described under FERC Account Development above. For labor, these accounts received their allocated portion of the total 2023 O&M labor projection based on actual 2022 labor. The DSM labor projection was directly assigned to account 908. For non-labor, these accounts were projected to be equal to the 2022 Base and adjusted for an increase in Uncollectible/Bad Debt Expense of $2,514,638 (in account 904), an increase of $118,000 for implementation of a Solar Payback Calculator for customers (in account 908), and by each account's allocated portion of the $831,379 non-direct adjustment to non-labor O&M.

Account 908.131 and 908.132—Idaho and Oregon Energy Efficiency Rider. The expenses associated with the Idaho and Oregon Energy Efficiency Riders have been excluded from the 2023 test year in their entirety (IPUC Order No. 30189). The DSM labor projection was added back and directly assigned to account 908.

Administration and General Expenses ("A&G")

FERC Accounts 920–935

Description

Accounts 920 through 935 include activities undertaken in connection with the utility's general and administrative operations that are assignable to specific administrative or general departments and are not specifically provided for in other accounts. A&G accounts include: (1) compensation of officers, executives, and other employees of the utility which are properly chargeable to utility operations but not chargeable directly to a particular operating function, (2) office supplies and expenses, (3) fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function, (4) insurance or reserve accruals to protect the utility against losses and damages to owned or leased property used in its utility operations, (5) payments for employee accident, sickness, hospital, and death benefits or insurance, (6) payments to municipal or other governmental authorities, (7) the cost of materials, supplies, and services furnished to such authorities without reimbursement in compliance with franchise, ordinance, or similar requirements, (8) expenses incurred by the utility in connection with formal cases before regulatory commissions or other regulatory bodies, (9) regulatory fees assessed against the utility, (10) commission expenses, (11) payments made to the United States for the administration of the Federal Power Act, (12) materials used and expenses incurred in advertising and related activities, (13) rents properly includable in operating expenses for the property of others used, occupied, or operated in connection with customer accounts, customer service, and informational sales and general and administrative functions of the utility, and (14) operation and maintenance of transportation equipment and the maintenance of utility property which is not chargeable directly to a particular operating function.

Forecast Methodology

Accounts 920–935—Excluding Account 920.001, Incentive Expense, 926.203, 926.204, 926.303, 926320 and 926350, Pension Expense and part of 928.203, Regulatory Commission Expenses. The projection of accounts 920–935, excluding incentive, was developed using both methods described under FERC Account Development above. For labor, these accounts received their allocated portion of the total 2023 O&M labor projection based on actual 2022 labor. For non-labor, these accounts were projected to be equal to the 2022 Base. These accounts also received each account's allocated portion of the $831,379 non-direct adjustment to non-labor O&M.

Account 920.001—Incentive Expense. In the 2008 Idaho General Rate case order (IPUC Order No. 30722) the Commission directed Idaho Power to only include a normalized incentive that "is directly related to improving service or reducing costs to customers." Idaho Power, therefore, included in its projection only the normalized level of incentive attributable to Customer Satisfaction and Reliability. As a result, for the 2023 test year, Idaho Power removed its entire 2022 actual incentive expense of $26,598,671 from its 2022 Base and replaced that amount with its projected 2023 normalized incentive of $10,040,205 that includes only those elements related to Customer Satisfaction and Reliability. This resulted in a net reduction for incentive expense of $16,558,466.

Accounts 926.203, 926.204, and 926.303—Pension Expense. For the Oregon jurisdiction the accounts were projected to be equal to 2022 Base of $880,053.

In the Idaho jurisdiction, per IPUC Order No. 32426, Idaho Power is currently recovering $17,153,713 of its cash contributions to its defined benefit pension plan. Idaho Power has included in its forecast adjustment an additional $18,028,665 in expense for 2023.

Account 928—Regulatory Commission Expenses. This account was increased for intervenor funding by $296,576 that was directed in IPUC Order Nos. 32788, 33872, 33908, 32697, 32245, 32505, 32846, 32537, 32426, 32956, 33357, 34046, 34546, 34608, and 34892. Idaho Power has assumed a one-year amortization for intervenor funding. Account 928 also received its allocated portion of the $831,379 non-direct adjustment to non-labor O&M.

Forecast Adjustment E—Depreciation and Amortization Expense

Table 6—FERC Accounts 403 and 404

Description

Account 403 includes depreciation expense for all classes of depreciable electric plant in service except such depreciation expense as is chargeable to clearing accounts or to account 416, Costs and Expenses of Merchandising, Jobbing and Contract Work. Account 404 includes amortization charges applicable to amounts included in the electric plant accounts for limited-term franchises, licenses, patent rights, limited-term interest in land, and expenditures on leased property where the service life of the improvements is terminable by action of the lease. The charges to this account are such as to distribute the book cost of each investment as evenly as may be over the period of its benefit to the utility.

Forecast Methodology

Forecast Adjustment E increases Depreciation and Amortization Expense (accounts 403 and 404) by $10,463,837 above the 2022 Base.

Depreciation and amortization rates were applied to the monthly estimated plant balances (see the Electric Plant in Service discussion in the Rate Base Components section). The depreciation rates updated by IPUC Order No. 35272 were used for the entire 2023 test year. Several FERC plant accounts have sub-accounts, for which the individual sub-account data was used to calculate a composite rate and applied at the major account level.

For plant accounts 392, Transportation Equipment; 396, Power Operated Equipment; and 312, Boiler Plant Equipment, either all or part of the depreciation expense is recorded to other accounts and not account 403.

Forecast Adjustment F—Electric Plant/Regulatory Assets—Amortization, Adjustments, Gains and Losses

Table 6—FERC Accounts 406, 411.6, and 411.7

Description

Account 406 is debited or credited with amounts includable in operating expenses, pursuant to approval or order of the Commission, for the purpose of providing for the extinguishment of the amount in account 114, Electric Plant Acquisition Adjustments. Accounts 411.6 and 411.7 include, as approved by the Commission, amounts relating to gains and losses from the disposition of future use utility plant, including amounts which were previously recorded in and transferred from account 105, Electric Plant Held for Future Use.

Forecast Methodology

Forecast Adjustment F is $0, resulting in the Amortization of Electric Plant Acquisition Adjustments (account 406) and Gains and Losses from Disposition of Utility Plant (account 411.6 and 411.7) remaining the same as the 2022 Base.

Account 406 is projected for 2023 to remain the same as the 2022 Base. Included in this account is the amortization of the Exchange of Certain Transmission Assets with PacifiCorp (approved by IPUC Order No. 33313, OPUC Order No. 15-184 and FERC Order No. 20150617-3060) acquisition adjustment of account 114 over 50 years at $15,018 per year. The amount in account 114 will be fully amortized in October 2065.

Accounts 411.6 and 411.7 do not have a forecast since there is no plan to sell utility plant in 2023.

Forecast Adjustment G—Regulatory Debits and Credits

Table 8—FERC Account 407.3

Description

Account 407.3 is debited, when appropriate, with the amounts credited to account 254, Other Regulatory Liabilities, to record regulatory liabilities imposed on the utility by the ratemaking actions of regulatory agencies. This account is also debited, when appropriate, with the amounts credited to account 182.3, Other Regulatory Assets, concurrent with the recovery of such amounts in rates.

Forecast Methodology

Forecast Adjustment G increases Regulatory Debits (account 407.3) by $1,865,167 above the 2022 Base.

Idaho Power has recorded a regulatory asset in account 182.310 for deferred incremental wildfire mitigation expenses as authorized by IPUC Order No. 35077. Idaho Power is forecasting amortization of $13,056,171 of expenses deferred as of December 31, 2022, over 7 years.

Forecast Adjustment H—Taxes Other than Income Taxes

Table 7—FERC Account 600-602

Description

Accounts 600, 601 and 602 includes those taxes other than income taxes which relate to utility operating income. This account is maintained to allow ready identification of the various classes of taxes relating to utility operation, plant leased to others, and other operating income.

Forecast Methodology

Forecast Adjustment H increases Taxes Other Than Income (Accounts 600-602) by $4,559,257 above the 2022 Base.

The 2023 forecast methodology for Taxes Other Than Income Taxes was based on a combination of known adjustments arising from specifics of the particular account activity and a carry forward of the 2022 Base amounts.

Real and Personal Property Taxes

The methodology used to project Idaho property taxes for the 2023 test year is estimating Idaho Power's 2023 ad valorem value and levy. For the ad valorem value methodology, tax is based on the assessed value of the property. For the tax levy methodology, the state's historical levy data and local government budget policy is used to estimate levies. For all other states the 3-year CAGR was used.

Idaho kWh Taxes

Test year 2023 kWh taxes were projected based on normalized hydro conditions and normalized consumption.

Regulatory Commission Fees

The 2023 Idaho regulatory fee was forecast by using the 2022 actual payment as an estimate. The Oregon regulatory fee consists of two fees, Oregon PUC fee and Oregon Department of

Energy fee. For the 2023 test year, the Oregon PUC fee was the actual 2023 fee and for the Oregon Department of Energy fee, the 2023 estimate was based upon the prior year's tax rate applied to the actual Oregon gross operating revenue.

Licenses

The 2023 Wyoming and Shoshone–Bannock licenses fee was estimated using the prior year's actual amount.

Franchises

The Oregon franchise tax is based upon a rate (established by each city) multiplied by the electric revenue within the city. The test year taxes were established using forecasted Oregon revenue compared to 2022. That percent of change was applied to each city's gross revenue and the appropriate tax rate was applied.

Forecast Adjustment I—Idaho Energy Resources Co. ("IERCO") Cost of Service Components

Net Income Summary—FERC Accounts 418.1 and 419

Description

Account 418.1 includes the utility's equity in the earnings or losses of subsidiary companies for the year. Account 419 includes interest revenues on securities, loans, notes, advances, special deposits, tax refunds, all other interest-bearing assets, and dividends on stocks of other companies, whether the securities on which the interest and dividends are received are carried as investments or included in sinking or other special fund accounts.

Forecast Methodology

Forecast Adjustment I decreases Idaho Energy Resources Co. ("IERCO") Cost of Service Components (Accounts 418.1 and 419) by $6,489,979 below the 2022 actual amount of $8,859,979 for a projected 2023 net income of $2,370,000. The estimate incorporates PacifiCorp's projected activity for the Bridger Coal Company ("BCC") mine and a $3,000,000 earnings margin calculated utilizing the most recent long-term forecast to estimate IERCo rate base and the Weighted Average Cost of Capital as approved in the 2011 Idaho General Rate Case.

Idaho Power owns 100% of IERCO, which has a one-third joint venture interest in BCC, a mine that supplies coal to the Jim Bridger plant. PacifiCorp, Inc. owns the remaining two-thirds interest and is the mine's operating partner. As a one-third owner in BCC, IERCO is entitled to 33% of the BCC net income and cash flows.

IERCO overriding royalties are determined by the location and lease under which BCC is mining. The three leases are with BLM, Union Pacific Railroad, and State of Wyoming, and each lease pays at a different rate. The overriding royalty was granted to BCC from IERCO, who in turn received them from Idaho Power as advance royalties in the past. Coal royalty payments have no impact on IERCO's net income as revenue is recognized when paid by BCC, and expense recognized when remitted to Idaho Power.

Income taxes are calculated at the federal tax rate of 21% as Wyoming has no state income tax. Taxes are accrued and paid during the calendar year.

As discussed in the Rate Base Components section that follows, IERCO maintains an intercompany note with Idaho Power that accrues interest monthly at Idaho Power's short-term borrowing rate, which is projected to be 0.45% per month (Annual Rate 5.39%) in 2023. For purposes of the Cost of Service Component of IERCO, the intercompany interest expense net of income tax is added back to increase IERCO's net income.

Forecast Adjustment J—Allowance for Funds Used During Construction ("AFUDC") Related to Hells Canyon Relicensing

Revenue Requirement Summary—FERC Accounts 107

Description

Account 107 (Construction Work in Progress) includes the total of the balances of work orders for electric plant in process of construction. Work orders shall be cleared from this account as soon as practicable after completion of the job. Expenditures on research, development, and demonstration projects for construction of utility facilities are to be included in a separate subdivision in this account. Also included in this account is an Allowance for Funds Used During Construction ("AFUDC"). AFUDC includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission. The rates shall be determined annually.

Forecast Methodology

Forecast Adjustment J is $0, resulting in the AFUDC related to Hells Canyon Relicensing (Account 107) remaining the same as the 2022 Base.

Idaho Power began incurring Hells Canyon relicensing costs in 1999. These relicensing efforts are financed from internally generated funds and from outside sources including short-term debt, long-term debt and new equity. Idaho Power accrues and capitalizes these financing costs to account 107 as AFUDC during the construction phase of the project. AFUDC is calculated monthly using a rate determined by a FERC formula. In the 2011, Idaho General Rate Case Order (IPUC Order No. 32426), Idaho Power requested and was granted the inclusion of the AFUDC related to Hells Canyon Relicensing in the revenue requirement.

While AFUDC continues to increase relating to the Hells Canyon Relicensing efforts, Idaho Power is requesting recovery of the same amount ($6,815,472) previously included the 2011 General Rate Case and subsequently approved in IPUC Order No. 32426.

RATE BASE COMPONENTS

Forecast Adjustment K—Electric Plant in Service

Table 1—FERC Account 101

Description

This account includes the original cost of electric plant that is included in accounts 301 to 399 (referred to herein as plant accounts). It is described as being owned and used by the utility in its electric utility operations and having an expectation of life in service of more than one year from date of installation, including such property owned by the utility but held by nominees. The cost of additions to and improvements of property leased from others, which are includable in this account, are recorded in subdivisions separate and distinct from those relating to owned property.

Forecast Methodology

Forecast Adjustment K increases Electric Plant In Service (Account 101) by $370,824,182 above the 2022 Base. Electric Plant In Service has been presented using a thirteen-month average.

The methodologies used for plant additions and retirements are described below.

Plant Additions to Electric Plant In Service

Projected 2023 plant additions to Electric Plant In Service were developed based on actual project closings as a percentage of Construction Work in Process ("CWIP") projects as of year-end 2022 plus the expected 2023 capital expenditures. These capital projects were segregated into pools of greater than and less than $8 million. Capital projects greater than $8 million were considered to be known and measurable. For capital projects less than $8 million, an historical methodology was developed. Once both pools were determined, the results were then combined and allocated to FERC plant accounts 301 through 399 using a five-year historical average.

Projected 2023 Plant Additions

Capital Projects Greater than $8 Million. Large capital projects with total costs in excess of $8 million were determined to be known and measurable adjustments for the 2023 unadjusted test year. Actual capital expenditures in CWIP as of year-end 2022, plus expected 2023 capital expenditures were used in determining the amount that would close to plant by year-end 2023. Allowance for Funds Used During Construction ("AFUDC") was accrued on the CWIP balances prior to their projected close. In addition, these projects' capital account balances, projected expenditures, and the timing of closes to plant were reviewed by business unit managers familiar with the projects.

The total amounts for the plant additions in the pool of over $8 million in capital expenditures were assigned CWIP project types based on the nature of each individual project.

Capital Projects Less Than $8 Million. Anticipated 2023 plant closings were set equal to the five-year historical average of the percent of similar-sized projects to the previous year's CWIP balance times the 2022-year end CWIP balance.

The total amounts for the plant additions in the pool of under $8 million in capital expenditures were then allocated to the CWIP project types based on a five-year historical average.

Allocation to FERC Plant Account

The above CWIP project type pools were combined for final allocation to FERC plant accounts. For this allocation, actual final closings from CWIP account 107 into Electric Plant In Service, account 101 were analyzed for the five-year period 2018 through 2022. Final closing amounts were used to allocate closings to plant accounts rather than preclose amounts. Final closings represent the "as built" property units after construction and individual work orders have been completed and reconciled, whereas pre-closes are based on work order estimates and may not be reflective of the final closing plant account distribution. For each CWIP project type, the percentage allocation to FERC plant accounts 301 through 399 was determined using the ratio from the five-year historical plant account closings for that CWIP project type.

Retirements from Electric Plant In Service

Retirements were analyzed for the previous five-year period 2018 through 2022. Retirements by FERC plant account were determined and compared to the final closings by FERC plant account for the same period. Retirements by FERC plant account were estimated by calculating the historical percentage of retirements to additions for the five-year period.

The following FERC plant accounts have known retirement dates based on vintage layers and were not estimated:

- Account 302— Franchises and consents
- Account 303— Miscellaneous intangible plant
- Account 391— Office furniture and equipment
- Account 393—Stores equipment
- Account 394— Tools, shop, and garage equipment
- Account 395—Laboratory equipment
- Account 397—Communication equipment
- Account 398—Miscellaneous equipment

Forecast Adjustments L & M—Accumulated Provision for Depreciation and Amortization

Table 2—FERC Accounts 108 and 111

Description

Account 108 is credited for amounts charged to account 403, Depreciation Expense, or to clearing accounts for current depreciation expense for electric plant in service. At the time of retirement of depreciable electric utility plant, this account is charged with the book cost of the property retired and cost of removal and then credited with the salvage value and any other amounts recovered such as insurance. When retired, costs of removal and salvage are originally entered in retirement work orders, the net total of such work orders may be included in a separate subaccount hereunder. Upon completion of the work order, the proper distribution to subdivisions of this account shall be made for general ledger and balance sheet purposes as a single composite provision for depreciation. For purposes of analysis, however, each utility shall maintain subsidiary records in which this account is segregated according to the functional classification of electric plant in service. Account 111 is credited with amounts charged to account 404, Amortization of Limited-Term Electric Plant, for the current amortization of limited-term electric plant investments.

Forecast Methodology

Forecast Adjustments L & M increase Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111) by $59,406,156 and $1,641,727 respectively, above the 2022 Base. The accumulated provision for depreciation and amortization has been presented using a thirteen-month average. The 2023 forecast was developed by first determining the 2022 monthly balances and then building upon that to determine the 2023 thirteen-month account balances.

The process began with the year-end 2022 accumulated depreciation and amortization account balances which were rolled forward monthly using the estimated 2023 depreciation and amortization expense accruals, retirements, salvage, and removal costs. See account 403 and 404 in the Cost of Service Components section for discussion with respect to the depreciation and amortization accrual calculation and Electric Plant In Service, account 101 in the Rate Base Components section for discussion of the method of determining retirements. The previous five-year (2018–2022) average salvage, removal costs, and retirements were then calculated by functional area (Steam Production, Hydraulic Production, Other Production, Transmission Plant, Distribution Plant and General Plant). The salvage and removal averages as a percentage of the retirement average were used to estimate monthly salvage and removal costs, allocated to FERC plant accounts utilizing the respective ratio to estimated retirements.

Forecast Adjustment N—Materials and Supplies

Table 3—FERC Accounts 154 and 163

Description

Account 154 includes the cost of materials purchased primarily for use in the utility business for construction, operation, and maintenance purposes. Materials and supplies issued are credited hereto and charged to the appropriate construction, operating expense, or other account on the basis of a unit price determined by the method of inventory accounting. Account 163 includes the cost of supervision, labor, and expenses incurred in the operation of general storerooms, including purchasing, storage, handling, and distribution of materials and supplies. This account is cleared by adding to the cost of materials and supplies issued a suitable loading charge which distributes the expense equitably over stores issues. The balance in the account at the close of the year shall not exceed the amount of stores expenses reasonably attributable to the inventory of materials and supplies.

Forecast Methodology

Forecast Adjustment N reflects a $10,145,311 increase in Materials and Supplies (accounts 154 and 163) above the 2022 Base after removing Boardman inventory balances of ($967,717).

Idaho Power continues to see increases in inventory values. Therefore, a Compound Annual Growth Rate (CAGR) forecast methodology was used. A three-year CAGR of 12.78% and 6.83% was calculated on the thirteen-month average balances of accounts 154 and 163, respectively, excluding Boardman inventory balances. The CAGRs were applied to the thirteen months ending December 2022 to develop the 2023 forecast adjustment.

Forecast Adjustment O—Other Deferred Programs

Table 3—FERC Accounts 182.3 and 186

Description

This account includes the amounts of regulatory assets not includable in other accounts resulting from the ratemaking actions of regulatory agencies.

Forecast Methodology

Forecast Adjustment O decreases Other Deferred Programs (Accounts 182.3 and 186) by $1,679,383 below the 2022 Base.

Accounts 186.722 and 186.770—American Falls Bond Refinancing, IPUC Order No. 25880. These deferred costs are financing costs related to American Falls Bond issuances. The total monthly amortization of these two bonds is $5,212 per month or $62,551 per year. Idaho Power has reduced the 2022 Base for one year of additional amortization for $62,551, resulting in a total deferral of $72,977.

Account 182.310—Wildfire Mitigation, IPUC Order No. 35077. This account includes the unamortized balance of the Idaho-only portion of incremental wildfire mitigation costs associated with Idaho Power's Wildfire Mitigation Plan. Included in the 2022 Base and test year deferral is $13,056,171 associated with the Idaho-only portion of deferred costs for incremental insurance and other wildfire mitigation costs.

Account 182.315—Cloud Computing, IPUC Order No. 34707. This account includes the unamortized balance of the Idaho-only portion of prepaid licensing costs associated with cloud computing arrangements meeting the requirements of IPUC Order No. 34707. Included in the 2022 Base is $1,207,592 associated with the Idaho-only portion of prepaid licensing costs for the Zycus procurement tool cloud computing agreement. Idaho Power has included a reduction to its 2022 Base of $201,265 for one year of additional amortization, bringing the test year deferral balance associated with Zycus to $1,006,327.

Accounts 182.410 and 182.411— Siemens Long-Term Program Contract, IPUC Order Nos. 33391 and 33420. Idaho Power entered into a long-term program contract under which Siemens Energy agrees to maintain the Company's three gas plants. A deferral was set up to account for the sale of the spare parts inventory, initialization fees and associated deferred income taxes. The spare parts inventory currently owned by the Company included two components: 1) assets that were included in the prior test year and are earning a return and 2) assets that have not been included in a test year and are not earning a return. Two regulatory asset accounts were established, one labeled "Rate Based" that includes the initial spare parts currently included in rate base and one labeled "Deferred Rate Base" that includes the initial spare parts that are not currently included in rate base, plus the initialization fees and associated tax expense. The deferral will be amortized over the remaining life of each asset in accordance with IPUC Order Nos. 33391 and 33420. The 2022 Base was reduced by $1,075,354 for one year of additional amortization, resulting in a total deferral of $20,388,711.

Account 182.385—Citizens Utility Board ("CUB") 2022 Funding Grant, OPUC Order No. 22-015, 22-192. Idaho Power was ordered in Docket UM 2126 to fund $33,000 annually to CUB pursuant to the terms of the Intervenor Funding Agreement by and among Idaho Power and CUB and approved by the OPUC in Order no. 20-493. Idaho Power has assumed a one-year amortization period for recovery of these costs through the Power Cost Adjustment Mechanism ("PCAM", Oregon Tariff Schedule 56). This reduced the deferral by the 2022 Base of $37,154 including accrued interest, resulting in a total deferral balance of $0.

Account 182.339—SFAS 87 Capitalized Pension Costs, OPUC Order No. 10-064. The 2022 Base was reduced by $219,697 for one year of additional amortization, resulting in a total deferral of $6,781,181.

Accounts 182.412 and 182.413— Siemens Long-term Program Contract, OPUC Order Nos. 15-387 and 15-388. As part of the long-term program contract with Siemens discussed above, the Company established two Oregon jurisdictional regulatory assets, one labeled "Rate Based" that includes the initial spare parts currently included in rate base and one labeled "Deferred Rate Base" that includes the initial spare parts that were not currently included in rate base, the initialization fees and associated tax expense. The deferral will be amortized over the remaining life of each asset in accordance with OPUC Order Nos. 15-387 and 15-388. The 2022 Base was reduced by $83,362 for one additional year of amortization, resulting in a total deferral of $566,293.

Forecast Adjustment P—Plant Held for Future Use

Table 3—FERC Account 105

Description

This account includes the original cost of electric plant owned and held for future use in electric service under a definite plan for such use and includes property acquired but never used by the utility in electric service but held for such service in the future under a definite plan, and property previously used by the utility in service, but retired from such service and held pending its reuse in the future, under a definite plan, in electric service.

Forecast Methodology

Forecast Adjustment P increases Plant Held for Future Use (Account 105) by $1,622,140 above the 2022 Base

Idaho Power developed its 2022 Base by removing from the 2022 actual Plant Held for Future Use those properties that it either plans to sell, will be possibly split and partially sold, structures or improvements that will be removed prior to construction and properties for which the use is uncertain.

In addition, Idaho Power included in its forecast adjustment $1,622,140 for the acquisition of two additional parcels of land that will be acquired by year-end 2023. These include land purchases for the Greenleaf and Northside substations.

Forecast Adjustment Q—Customer Advances for Construction ("CAC")

Table 3—FERC Account 252

Description

Account 252 includes advances by customers for construction which are to be partially or wholly refunded. When a customer is refunded the entire amount to which he or she is entitled according to the agreement or rule under which the advance was made, any remaining balance is credited to the appropriate plant account.

Forecast Methodology

Forecast Adjustment Q decreases the Customer Advances for Construction (Account 252) 2022 Base by $5,697,395, based on an estimated thirteen-month average balance.

Idaho Power forecast Account 252 using a 5-year (2018-2022) average methodology to determine the estimated balances for unusual conditions, substation allowances, and transmission network upgrades. The tax gross-up portion was excluded from the substation allowances' estimate. For unusual conditions the balance was estimated based on average refund amounts. Please see the analysis in the table below:

2023 Forecast of Customer Advances	**Total**
2018-2022 5-year Average Unusual Conditions Refunds	$4,765,091
2018-2022 5-year Average Substation Allowances (Excluding Tax Gross-up)	1,877,865
2018-2022 5-year Average Transmission Network Upgrades	1,380,649
12/31/23 Forecast for Unusual Conditions Refunds, Substation Allowances, & Network Upgrades (Excluding Tax Gross-up)	**$8,023,605**[1]

[1] This amount represents the estimated year-end balance. Idaho Power has estimated the thirteen-month balance of $7,441,965 based on the shape of the 2022 actual thirteen--month average balance.

Forecast Adjustment R—Idaho Energy Resources Co. ("IERCO") Rate Base

Table 3—FERC Accounts 123.1, 186, and 145

Description

Account 123.1 includes the cost of investments in securities issued or assumed by subsidiary companies and investment advances to such companies, including interest accrued thereon when such interest is not subject to current settlement plus the equity in undistributed earnings or losses of such subsidiary companies since acquisition. This account is credited with any dividends declared by such subsidiaries. This account is maintained in such a manner as to show separately for each subsidiary: (1) the cost of such investments in the securities of the subsidiary at the time of acquisition, (2) the amount of equity in the subsidiary's undistributed net earnings or net losses since acquisition, and (3) advances or loans to such subsidiary. Account 145 represents notes receivable from associated companies. Account 186 includes all debits not elsewhere provided for, such as miscellaneous work in progress, and unusual or extraordinary expenses, not included in other accounts, which are in process or amortization and items the proper final disposition of which is uncertain.

Forecast Methodology

Forecast Adjustment R increases Idaho Energy Resources Co. ("IERCO") projected 2023 Rate Base (Accounts 123.1,186 and 145) by $1,769,938 above the 2022 actual thirteen-month average balance of $29,600,820 to $ 31,370,758.

Idaho Power's projected 2023 investment in IERCO is based on actual activity for 2022 at the BCC mine that supplies coal to the Jim Bridger thermal plant. As a one-third owner in BCC, IERCO is entitled to 33% of the BCC net income and cash flows.

- **Account 123.1—Investment in IERCO.** The 2023 thirteen-month average investment in IERCO balance is projected to decrease $8,086,296 from the 2022 actual thirteen-month average balance of $23,664,134. IERCO's investment in BCC is accounted for using the equity method. BCC income, IERCO income, and IERCO capital contributions to BCC increase the investment balance, while BCC dividend distributions to IERCO reduce the investment balance. The $8.1 million decrease is primarily due to dividends being paid in 2022. No dividend assumptions are made during the forecast test year. Instead, any extra cash remaining after paying operating expenses and capital investment are returned to Idaho Power via the intercompany note (see below for discussion of Account 145 – IERCo Intercompany Note).

- **Account 145—Notes Payable To/Receivable from Subsidiary.** The 2023 thirteen-month average balance is projected to increase $10,093,286 from the 2022 actual thirteen-month average balance of $5,101,864. The IERCO intercompany note is the funding mechanism whereby IERCO not only receives distributions from and makes capital contributions to BBC, but also pays income taxes and dividends to Idaho Power. The intercompany note activity is based on the projected 2023 BCC operating and capital budgets. In 2022, the note payable increased due to funding the dividend payment. Interest on the intercompany note is based on Idaho Power's short-term borrowing rates and accrues monthly. The average interest rate used is 0.45% per month (Annual Rate 5.39%).

- **Account 186—Prepaid Coal Royalties.** The 2023 thirteen-month average balance is projected to decrease $237,052 from the 2022 actual thirteen-month average balance of $834,822. BCC overriding coal royalties are determined by the location and lease under which BCC is mining. The overriding royalty was granted to BCC from IERCO, who in turn received them from Idaho Power as advance royalties in the past. Although coal royalty payments have no impact on IERCO's net income because revenue is recognized when paid by BCC and expense recognized when remitted back to Idaho Power, the payment flow serves to reduce the account 186 balance.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JESSICA G. BRADY

Q. Please state your name, business address, and present position with Idaho Power Company (“Idaho Power” or “Company”).

A. My name is Jessica G. Brady. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as a Regulatory Analyst in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May 2016, I received a Bachelor of Science degree in Economics and a Bachelor of Arts degree in Spanish from the University of Idaho. I have also attended “The Basics: Practical Regulatory Training for the Electric Industry,” an electric utility ratemaking course offered through New Mexico State University’s Center for Public Utilities, and “Electric Utility Fundamentals & Insights,” an electric utility course offered through the Western Energy Institute.

Q. Please describe your work experience with Idaho Power.

A. In September 2021, I accepted my current position at Idaho Power as a Regulatory Analyst in the Regulatory Affairs Department. As a Regulatory Analyst, I am responsible for running the AURORA model (“AURORA”) to calculate net power supply expenses (“NPSE”) for ratemaking purposes, as well as the determination of the marginal cost of energy used in the Company’s marginal cost analyses. My duties also include providing analytical support for other regulatory activities within the Regulatory Affairs Department.

Q. What is the purpose of your testimony in this matter?

A. The purpose of my testimony is to discuss the derivation of the Company’s 2023 retail revenue forecast used for the 2023 test year, detail the proposed energy-related test year billing components, present the quantification of 2023 normalized or “base level” net power supply expenses (“2023 Base Level NPSE”) and inform the Commission of the necessary reduction to the rates contained in Schedule 55, Power Cost Adjustment (“PCA”) resulting from the proposed 2023 Base Level NPSE update.

I. <u>2023 TEST YEAR RETAIL REVENUE DERIVATION</u>

Q. What methodology was used to determine test year retail revenues?

A. Generally speaking, the Company’s retail revenue forecast is derived by applying current base rates to forecasted test year billing components. These billing components are derived by applying historical relationships to the Company’s customer and kilowatt-hour (“kWh”) sales forecast.

Q. Was the 2023 test year retail sales revenue forecast developed using the same methodology applied in the Company's last general rate case, Case No. IPC-E-11-08 ("2011 Rate Case")?

A. Yes. The 2023 test year retail sales revenue forecast was developed using the same methodology applied in the 2011 Rate Case.

Q. Please describe the customer and kWh sales forecast that serves as the basis for the 2023 test year retail revenue forecast.

A. The 2023 test year customer and kWh sales forecast consists of class customer counts and total kWh sales estimates for each month of the test period. It is prepared by the Company's Load Research and Forecasting Department and is further described in workpapers filed by Company Witness Mr. Matthew Larkin.

Q. How were the 2023 test year kWh sales further segmented into the class-specific energy-related billing components?

A. The first step in deriving energy-related billing components for the test year is to develop factors based on the most current complete calendar year of available historical data, which in this case is 2022. These historical factors represent the percentage of total kWh billed in each tier level of a class's rate structure.

To illustrate, Residential Service customers taking service under Schedule 1 are billed according to a three-tiered structure with seasonal rate differentiation. Using the historical month of June 2022 as an example, actual tiered usage was recorded at the following levels for Schedule 1 customers in the Idaho jurisdiction:

Table 1
2022 Actual Tiered Usage

Table 1 2022 Actual Tiered Usage	
Usage Tier	**June 2022 Schedule 1 Billing Components**
Summer, 0-800 kWh	105,736,225
Summer, 801-2000 kWh	26,415,166
Summer, Over 2000 kWh	3,257,841
Non-Summer, 0-800 kWh	168,424,645
Non-Summer, 801-2000 kWh	42,615,564
Non-Summer, Over 2000 kWh	6,376,771
Total Schedule 1 kWh Usage	352,826,211[1]

Based on the data above, historical factors for Schedule 1 customers for the month of June were calculated as shown in Table 2.

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[1] Totals in tables may not tie due to rounding.

Table 2
Historical Weighting Factors

Table 2 Historical Weighting Factors	
Usage Tier	**June 2022 Schedule 1 Weighting Factors**
Summer, 0-800 kWh	30%
Summer, 801-2000 kWh	7%
Summer, Over 2000 kWh	1%
Non-Summer, 0-800 kWh	48%
Non-Summer, 801-2000 kWh	12%
Non-Summer, Over 2000 kWh	2%
Total Schedule 1	100%

This process is used to develop historical factors for all rate classes with tiered structures. Once a complete set of monthly factors has been developed for each applicable rate class, they are applied to monthly forecast kWh totals to derive the energy-related billing component forecast that aligns with each class's current rate structure. Continuing with the illustration of Schedule 1 customers, Table 3 demonstrates the final step in determining test year energy-related billing components.

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Table 3
Billing Component Forcast

Table 3 Billing Component Forecast		
Usage Tier	**Historical June Weighting Factor**	**June 2023 Schedule 1 Billing Component Forecast (kWh)**
Summer, 0-800 kWh	30%	108,107,252
Summer, 801-2000 kWh	7%	27,007,499
Summer, Over 2000 kWh	1%	3,330,895
Non-Summer, 0-800 kWh	48%	172,201,397
Non-Summer, 801-2000 kWh	12%	43,571,175
Non-Summer, Over 2000 kWh	2%	6,519,763
Total	100%	360,737,981

Q. How are demand-related billing components derived based on the kWh sales forecast?

A. The demand-related billing components consist of billing demand and basic load capacity ("BLC") by month for each rate class. Both billing demand and BLC totals are forecasted by applying four-year average load factors to each month in the kWh sales forecast. Historical data from the most currently available four calendar years is used to derive an average load factor by month for each rate class. These average factors are then applied to monthly kWh sales figures to determine total forecasted billing demand and BLC by class for each month of the test period. Once monthly totals have been developed, they are divided into the appropriate tiered rate structure (if applicable) utilizing historical factors in the same manner as kWh charges.

Q. How are customer-related billing components derived based on the customer count forecast?

A. The primary customer-related billing component in the retail revenue forecast is the service charge. Because the customer forecast reflects the expected number of customers under active Utility Service Agreements (“USAs”) at the end of each forecast month, forecast values must be converted to reflect the expected number of service charges received throughout the corresponding month. To convert the USA forecast to an expected service charge count, historical factors are developed reflecting the relationship between the number of USAs at the end of each historical month and the number of service charges received during the corresponding month. These factors are then applied to the monthly customer forecast to develop a forecast of expected service charges by rate class for each month of the test year.

Q. How are test year retail revenues calculated once the billing component forecast has been derived?

A. Once the billing components have been forecasted by rate class, the most currently approved base rates are applied to the test year values to derive monthly revenue estimates for each rate class.

Q. Have you prepared any exhibits that detail the calculations that were made to determine the Company's 2023 test year retail revenues?

A. Yes. Exhibit No. 27 provides a summary of forecasted 2023 test year retail revenues, and Exhibit No. 28 details the calculations that were made to determine these revenues. Input data used in the forecast calculations can be found in my workpapers. As can be seen on page 3 of Exhibit No. 27, the Company's 2023 Idaho jurisdictional retail sales revenues are forecast to be $1.12 billion.

Q. How is the portion of Micron Technology's ("Micron") forecast kWh sales that will be met by Black Mesa Solar treated in the 2023 test year retail revenues?

A. As described in the Direct Testimony of Mr. Matthew Larkin, as part of the new Special Contract with Micron, Black Mesa Solar's generation will be paid for completely by Micron. To account for this, the revenue from the portion of Micron's load that will be met by Black Mesa Solar is not included in the 2023 retail revenue forecast. The treatment of the revenue associated with the portion of Micron's load met by Black Mesa Solar is discussed further in the Direct Testimony of Mr. Paul Goralski.

II. 2023 ENERGY-RELATED BILLING COMPONENTS – PROPOSED RATE STRUCTURE

Q. Please describe the energy-related billing components under the Company's proposed rate structure ("proposed billing components").

A. As described in the Direct Testimony of Ms. Connie Aschenbrenner, the Company's proposed rate structure includes modifying the months considered to be "summer" and "non-summer", as well as the time-of-use periods for certain time variant rate classes. The proposed billing components represent the total forecast kWh billed in each tier within each rate class, under the new proposed rate structure.

Q. How were the proposed billing components calculated?

A. The proposed billing components were calculated using the same methodology as the billing components calculated for the derivation of the 2023 test year retail revenues. However, instead of using 2022 billing data to derive historical factors, 2022 kWh usage data, divided into tiers based on the proposed rate structure for each rate class, was used.

Q. How was the 2022 kWh usage data collected and divided into the proposed tiers?

A. The process for collecting 2022 kWh usage data is described in workpapers filed by Mr. Larkin.

Q. Have you prepared an exhibit that details the Company's 2023 proposed billing determinants?

A. Yes. Exhibit No. 29 provides a summary of the 2023 proposed billing determinants.

III. 2023 BASE NET POWER SUPPLY EXPENSES

Q. How is this section of your testimony organized?

A. First, I provide an overview of the Commission-approved method for quantifying base level NPSE. Next, I describe the update to base level NPSE that occurred in 2013 ("2013 Base Level NPSE"). Lastly, I describe the quantification of the Company's 2023 Base Level NPSE.

Q. How has the Commission historically reviewed and approved Idaho Power's quantification of normal base NPSE?

A. Due to the high variability of power supply expenses, the Commission has historically approved a normalized power supply expense value for setting base rates. The Company has utilized the AURORA model to provide the Commission with a snapshot of "normal" expectations for base NPSE for a given test year.

Q. Please define the term “base NPSE” as the Company and Commission have used the term historically.

A. The Company and Commission have historically defined the term “base NPSE” as the sum of fuel expenses (Federal Energy Regulatory Commission [“FERC”] Accounts 501 and 547) and purchased power expenses (FERC Account 555), including purchases from qualifying facilities under the Public Utility Regulatory Policies Act of 1978 (“PURPA”) and power purchase agreements (“PPA”), minus surplus sales revenues (FERC Account 447). The AURORA model is used to quantify base NPSE components related to fuel and surplus sales, while PURPA and PPA expenses are quantified outside of AURORA; however, energy from these projects is modeled as must-take in the AURORA simulation.

Q. Does the Company include any other categories of expense or revenue in the base level NPSE used for PCA computations?

A. Yes. In addition to the expense and revenue categories described above, the base level NPSE included in the Company’s PCA computations also includes financial payments made by Idaho Power to offset transmission losses associated with market purchases (FERC Account 555), third-party transmission expense required to bring market purchases to the Company’s border (FERC Account 565), water for power expense (FERC Account 536), and demand response ("DR") incentives (FERC Account 555).

Q. Is the Company proposing to include any new categories of expense or revenue in the base level NPSE used for PCA computations?

A. Yes. At the direction of Mr. Larkin, I have included an additional component, FERC Account 447.050, transmission loss revenue, in the 2023 Base Level NPSE. According to the FERC's Uniform System of Accounts, these amounts are recorded to Account 447.

Q. What does the transmission loss revenue component of Account 447 represent?

A. As further discussed in Mr. Larkin's testimony, transmission loss revenue in FERC Account 447 reflects revenues received by Idaho Power from third parties to compensate the Company for physically generating electricity to offset losses associated with wheeling energy through Idaho Power's transmission system.

Q. How does the Company arrive at a "normalized" look at base NPSE for ratemaking purposes?

A. In order to "normalize" base NPSE, the Company uses AURORA to model various water conditions using current loads and current resources. At this time, 37 water conditions have been evaluated to develop an average or normalized NPSE. This general methodology was adopted by the Commission in 1981 and has been used in general rate proceedings ever since.

Q. What is the currently approved base level NPSE amount?

A. The currently approved 2013 Base Level NPSE is $305,684,869. It is comprised of the following components:

Table 4
2013 Bale Level NPSE

Table 4 2013 Base Level NPSE	
95% Accounts (with 95% recovery in PCA)	
Account 501, fuel (coal)	$108,503,180
Account 536, water for power	$2,380,597
Account 547, fuel (gas)	$33,367,563
Account 555, purchased power (non-PURPA)	$62,606,593
Account 565, third-party transmission	$5,455,955
Account 447, surplus sales	($51,735,153)
Net 95% Accounts	$160,578,735
100% Accounts (with 100% recovery in PCA)	
Account 555, purchased power (PURPA)	$133,853,869
Account 555, purchased power (demand response)	$11,252,265
Total	$305,684,869

Q. When was the currently approved base level NPSE established and approved by the Commission?

A. The 2013 Base Level NPSE was established on March 21, 2014, by Order No. 33000 issued in Case No. IPC-E-13-20.

Q. Since the establishment of the 2013 Base Level NPSE, has the Company made any modifications to the AURORA model that was used to develop the 2023 Base Level NPSE?

A. Yes. In order to quantify the 2023 Base Level NPSE, the Company utilized a new AURORA version and database, which reflects updated inputs for the entire Western Electricity Coordinating Counsel ("WECC") footprint. This database was also used in the development of the Company's 2021 Integrated Resource Plan ("IRP"), which was acknowledged by the Commission on November 18, 2022, in Order No. 35603 issued in Case No. IPC-E-21-43. The Company also updated the database to include resource changes, current fuel prices, heat rates, forced outage rates, maintenance schedules, and plant capacities.

Q. Were any adjustments made to the resources included in the 2023 AURORA Model?

A. Yes. Idaho Power updated expected generation from PURPA projects based on current or expected contracts. Additionally, the 2023 AURORA model includes the removal of two resources, Boardman Coal and North Valmy Unit 1, and the addition of six resources. The six resources are listed below.

New Resources included in the 2023 AURORA Model

1. Bridger Gas
2. Jackpot Solar PPA
3. Black Mesa Solar PPA
4. Black Mesa Battery
5. 80-Megawatt ("MW") Grid Battery
6. Demand Response

Q. Please describe the Bridger Gas resource, including how it was modeled for the development of the 2023 Base Level NPSE.

A. The Company's 2021 IRP Action Plan includes the conversion of Bridger units 1 and 2 from coal to natural gas by summer 2024. As discussed further in Mr. Larkin's testimony, I was directed to model Bridger units 1 and 2 as natural gas units online for the entire 2023 test year in order to more closely align 2023 Base Level NPSE with the time period in which rates will take effect.

Q. How were Jackpot Solar and Black Mesa Solar modeled for the development of the 2023 Base Level NPSE?

A. Jackpot Solar, which came online December 2022, is a 120-MW alternating current solar photovoltaic generation facility. It is a 20-year PPA with Jackpot Holdings, LLC.

Black Mesa Solar is a 40-MW alternating current solar photovoltaic facility that is scheduled to come online June 2023. As described previously in my testimony, and further detailed in Mr. Larkin's testimony, Black Mesa Solar is a PPA that was negotiated in conjunction with a new Special Contract with Micron Technology. The Micron Special Contract states that Idaho Power will procure renewable resources to assist Micron in meeting a portion of its annual energy requirements with energy generated by those resources. While Black Mesa Solar will be connected to the Company's system and will not serve Micron directly, Micron will pay for 100 percent of the output through its Special Contract. As a result, the cost of the PPA is excluded from the 2023 Base Level NPSE.

The Company modeled both Jackpot Solar and Black Mesa Solar's generation in AURORA by applying the projects' forecast hourly shape to the monthly forecasted generation amounts. In addition, Black Mesa Solar was modeled as an annualized online resource for the entire test year, in line with the Company's typical practice for resources expected to come online during the test year.

Q. How were the two new battery resources modeled for the development of the 2023 Base Level NPSE?

A. The two new battery resources include a 40-MW battery at Black Mesa Solar and an 80-MW grid battery. The Black Mesa Battery is scheduled to come online September 2023 and the 80-MW grid battery is scheduled to come online June 2023. Similar to Bridger Gas and Black Mesa Solar, both batteries were modeled as annualized online resources for the entire test year.

The 80-MW grid battery is modeled to be charged from the entire grid, while the Black Mesa Battery is modeled to only be charged from Black Mesa Solar.

Q. How was demand response modeled for the development of the 2023 Base Level NPSE?

A. Demand response was modeled according to the parameters of its three programs: A/C Cool Credit, Flex Peak Program, and Irrigation Peak Rewards. Based on actual 2022 participation, Idaho Power assumed the programs would provide a total of 320 MW of peak capacity from June 1 – September 15.

Q. Have there been any changes to the way PURPA is modeled compared to the way it was modeled in the 2013 Base Level NPSE?

A. Yes. In the 2013 normalized NPSE determinations, the Company segmented PURPA generation into two categories, “PURPA Wind” and all “other PURPA”. PURPA Wind was modeled by applying the 2012 hourly actual historical PURPA Wind generation shape to the monthly forecasted generation amounts. All other PURPA resources were modeled on a monthly basis.

For the 2023 Base Level NPSE, the Company segmented PURPA into three categories, “PURPA Wind”, “PURPA Solar”, and all “other PURPA”. PURPA Wind was modeled by applying a 5-year average (2018 – 2022) hourly actual generation shape to the total nameplate capacity of the combined PURPA wind projects. PURPA Solar was modeled by applying the 2022 actual hourly shape to the total monthly forecasted generation amounts. All other PURPA resources were modeled on a monthly basis, as hourly fluctuations do not occur to as great an extent for those resource types. The Company views the modification to be an improvement that more accurately reflects the variable nature of solar into the hourly dispatch modeling in AURORA.

Q. What other AURORA inputs were modified for the development of the 2023 Base Level NPSE?

A. The Company included annualized forecast generation from its Oregon Community Solar Program, which is scheduled to come online November 2023. In addition, the Company included 11 MW of distribution-connected battery storage.

Q. Have you prepared an exhibit that presents the normalization of variable power supply expenses consistent with the changes you have described in your testimony?

A. Yes. Exhibit No. 30 shows the results containing the 37-year average variable power supply generation sources and expenses.

Q. Please summarize the sources and disposition of energy shown on Exhibit No. 30.

A. Hydro generation supplies 8.3 million megawatt-hours ("MWh"), approximately 47 percent (8.3 million MWh / 17.8 million MWh = 47 percent) of the generation mix. Thermal generation supplies 4.1 million MWh (Bridger Coal 1.8, Bridger Gas 0.1, Valmy 0.2, Langley Gulch 1.7, Danskin 0.2, Bennett Mountain 0.1), approximately 23 percent (4.1 million MWh / 17.8 million MWh = 23 percent) of the generation mix. Purchases of power are made up of short-term and long-term market purchases, as well as PURPA generation. Short-term market purchases supply 1.4 million MWh, approximately 8 percent of the generation mix. Long-term market purchases, or PPAs, supply 0.96 million MWh, approximately 5 percent of the generation mix. PURPA purchases reflect normalized and annualized generation levels and account for 3.0 million MWh, approximately 17 percent of the generation mix. Total purchases amount to 5.3 million MWh (1.4 million MWh + 0.96 million MWh + 3.0 million MWh = 5.3 million MWh) or approximately 30 percent of the generation mix. Of the 17.8 million MWh generated by the system, 17.0 million MWh are utilized for system loads while 0.8 million MWh are sold as surplus sales.

Q. Please summarize the expenses associated with each resource shown on Exhibit No. 30.

A. Hydro generation has no assumed fuel expense. Coal expenses of $65.5 million are comprised of Bridger at $57.1 million and Valmy at $8.4 million. Gas expenses of $119.7 million are comprised of Langley Gulch at $78.7 million, Bridger Gas at $6.1 million, Danskin at $13.8 million, and Bennett Mountain at $6.8 million. The fixed capacity charge for gas transportation for all of the gas plants is $14.3 million. Purchased power expenses (*including transmission losses, excluding PURPA*) amount to $99.5 million, and surplus sales revenue (*including transmission losses)* is ($29.0) million. Transmission losses will be discussed in more detail later in my testimony.

Q. How have natural gas prices changed between the time of quantification of the 2013 Base Level NPSE and the 2023 Base Level NPSE quantification?

A. For the 2013 Base Level NPSE, natural gas prices were assumed to be $3.62 per million British thermal units ("MMBtu") for Henry Hub and $3.68 per MMBtu for natural gas delivered to the Company's plants. For the 2023 Base Level NPSE, they are forecasted to be $3.36 per MMBtu for Henry Hub, $4.28 per MMBtu for natural gas delivered to Bridger, and $4.70 per MMBtu for natural gas delivered to Langley, Bennett Mountain, and Danskin.

Q. In general, how has base level NPSE and generation changed from 2013 to 2023?

A. As described earlier in my testimony, since 2013 there have been several changes to Idaho Power's resource mix. These changes were incorporated into the 2023 AURORA model and are reflected in the calculated 2023 Base Level NPSE.

Due to the decrease in coal capacity from the removal of Boardman and North Valmy Unit 1, as well as the conversion of Bridger units 1 and 2 to natural gas, expenses related to coal generation have decreased 40 percent from 2013. In addition, due to the increased reliance on natural gas generation and increase in natural gas price, expenses related to natural gas generation have increased 259 percent.

Next, Non-PUPRA purchased power expense has increased 59 percent since 2013. This is a result of the addition of the Jackpot Solar PPA, as well as the increase in AURORA calculated market purchase volumes and market prices. PURPA expense has increased 60 percent since 2013 as a result of increased PURPA generation and updated PURPA contract values.

Lastly, surplus sales revenue has decreased 44 percent from 2013. As a result of the increase in system load, decrease in coal capacity, and increase in natural gas prices, there are fewer opportunities to make economic off-system sales in the 2023 test year.

Q. How are transmission losses on market purchases (FERC Account 555) accounted for within the Company’s calculation of 2023 Base NPSE?

A. Within the AURORA model, transmission losses are incorporated into the market price paid by the purchasing entity. In other words, the purchase price on all short-term market purchases is grossed up to account for transmission losses. As a result, the non-PURPA purchased power expenses of $99.5 million included in FERC Account 555 include both purchased power and transmission losses on purchased power.

Q. Does the Company propose to update the base level NPSE accounts that are not calculated by AURORA, or partially calculated by AURORA, as part of this request?

A. Yes. The Company’s proposal reflects 2023 test year amounts for the below FERC Accounts.

447.050	Transmission Loss Revenue
565	Third-Party Transmission Expense
536.003	Water for Power
555	Demand Response

Q. How did the Company determine the 2023 Base Level amount for FERC Account 447.050, Transmission Loss Revenue?

A. FERC Account 447.050, Transmission Loss Revenue, was forecasted by multiplying Idaho Power's average hourly marginal price, as calculated by AURORA, by 36 average MW, which is the assumed average MW generated in each hour to serve third-party transmission losses.

Q. How did the Company determine the average hourly MW generated to serve third-party transmission losses?

A. The 36 MW was provided by the Load Research and Forecasting Department and is further described in the workpapers filed by Mr. Larkin.

Q. How did the Company determine the 2023 Base Level amount for FERC Account 565, Third-Party Transmission Expense?

A. The 2023 test year amount for FERC Account 565, Third-Party Transmission Expense, of $10.3 million was calculated by multiplying the Company's historical 3-year average wheeling rate, based on total wheeling expenses and volumes reported in the FERC Form 1, by the AURORA calculated market purchase volumes. Information used in this calculation can be found in my workpapers.

Q. How did the Company determine the 2023 Base Level amounts for FERC Account 536.003, Water for Power and FERC Account 555, Demand Response?

A. FERC Account 536.003, Water for Power, is forecast at 0 for the 2023 test year. Idaho Power did not have water lease expense amounts in 2022 and does not anticipate any for the 2023 test year.

FERC Account 555, Demand Response, was forecast for the 2023 test year based on Idaho-jurisdictionalized forecast costs associated with projected participation in the three programs.

Q. Have you quantified the 2023 Base Level NPSE amounts?

A. Yes. The 2023 Base Level NPSE amounts as proposed by the Company for Commission-approval are as follows:

Table 5
2023 Base Level NPSE

Table 5 2023 Base Level NPSE	
95% Accounts (with 95% recovery in PCA)	
Account 501, fuel (coal)	$65,523,000
Account 536, water for power	$0
Account 547, fuel (gas)	$119,653,675
Account 555, purchased power (non-PURPA)	$99,465,021
Account 565, third-party transmission	$10,263,139
Account 447, surplus sales	($29,035,180)
Net 95% Accounts	$265,869,655
100% Accounts (with 100% recovery in PCA)	
Account 555, purchased power (PURPA)	$214,448,755
Account 555, purchased power (demand response)	$10,240,003
Total	$490,558,413

Q. How do these 2023 Base Level NPSE amounts compare with the 2013 Base Level NPSE amounts?

A. The 2023 Base Level NPSE total is $490,558,413, an increase of $184,873,544 from the 2013 Base Level NPSE of $305,684,869.

Q. Is Idaho Power proposing to update Schedule 55, Power Cost Adjustment, with this filing?

A. Yes. As discussed in Mr. Larkin's testimony, the update in base NPSE will result in a reduction in the variance between base and forecast NPSE embedded in current PCA rates. Therefore, Idaho Power has calculated an updated PCA rate that incorporates the proposed 2023 Base Level NPSE. If approved as filed, the Company's 2023 Base Level NPSE would result in a reduction in PCA revenue collection of $171,516,689 using the June 2023 through May 2024 PCA year. Applying this rate change to 2023 test year sales results in the $170,912,271 detailed in Mr. Larkin's testimony – the only difference due to differing sales between the June 2023 through May 2024 time period and the January 2023 through December 2023 time period. This comprises the majority of the PCA-related transfer adjustment discussed in Mr. Larkin's testimony. The calculations made to determine the updated PCA forecast rate, as well as the decrease in PCA revenue collection as a result of the 2023 Base Level NPSE update are provided in my workpapers.

Q. Have you prepared a revised Schedule 55 that includes the updated PCA rate?

A. Yes. Attachment 1 to Idaho Power’s Application filed concurrently herewith is a revised Schedule 55 and includes the proposed PCA rates in clean and legislative formats.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF JESSICA G. BRADY

I, Jessica G. Brady, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Jessica G. Brady. I am employed by Idaho Power Company as a Regulatory Analyst in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 27 through 30 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: Jessica Brady
JESSICA G. BRADY

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

EXHIBIT NO. 27

IDAHO JURISDICTION

Tariff Description	January	February	March	April	May	June	July	August	September	October	November	December	Total
9S	19,255,806	19,379,168	18,312,689	17,438,189	17,274,189	18,892,979	21,511,585	22,634,444	21,075,381	18,294,341	17,766,240	18,647,900	230,482,910
9P	2,847,710	2,797,128	2,673,968	2,730,602	2,654,158	2,888,200	3,598,743	3,759,083	3,624,338	2,989,855	2,861,018	2,785,731	36,210,534
9T	19,615	18,436	16,813	19,323	21,093	21,097	22,257	18,131	19,404	17,795	20,650	21,615	236,229
Total Rate 9	22,123,131	22,194,732	21,003,470	20,188,114	19,949,439	21,802,275	25,132,585	26,411,659	24,719,123	21,301,992	20,647,907	21,455,245	266,929,672
19S	32,382	31,924	29,108	31,633	30,958	30,257	33,936	36,021	36,347	30,601	32,573	30,812	386,553
19P	9,788,962	10,087,930	9,021,917	9,628,156	9,321,832	9,654,913	11,877,722	12,295,915	12,512,697	9,808,203	10,023,196	9,713,467	123,734,911
19T	136,919	138,278	104,370	112,798	131,207	136,105	151,278	159,264	172,613	130,087	123,520	133,663	1,630,102
Total Rate 19	9,958,263	10,258,132	9,155,395	9,772,588	9,483,997	9,821,275	12,062,937	12,491,200	12,721,657	9,968,892	10,179,289	9,877,942	125,751,566
24S	239,676	234,703	264,214	1,982,667	10,256,227	23,998,633	33,935,281	31,863,690	26,084,365	9,504,531	1,654,254	309,507	140,327,749
24T	0	0	0	0	0	0	0	0	0	0	0	0	0
Total 24	239,676	234,703	264,214	1,982,667	10,256,227	23,998,633	33,935,281	31,863,690	26,084,365	9,504,531	1,654,254	309,507	140,327,749

STATE OF OREGON

Tariff Description	January	February	March	April	May	June	July	August	September	October	November	December	Total
9S	868,590	858,798	783,657	686,941	625,549	617,050	700,902	753,584	746,930	744,550	869,457	837,561	9,093,570
9P	79,203	79,288	75,140	74,720	67,796	72,545	90,624	98,107	89,781	73,042	71,190	73,091	944,527
9T	20,984	19,888	17,705	18,845	15,375	13,880	14,046	15,419	13,326	12,368	15,069	17,011	193,916
Total Rate 9	968,778	957,974	876,503	780,506	708,720	703,475	805,573	867,110	850,037	829,960	955,715	927,663	10,232,013
19S	0	0	0	0	0	0	0	0	0	0	0	0	0
19P	805,762	814,550	761,864	886,325	816,688	821,349	1,021,029	964,055	1,034,910	762,027	805,100	767,224	10,260,882
19T	649,323	299,320	476,115	661,593	503,234	613,486	647,969	622,494	510,390	567,447	618,667	627,932	6,797,970
Total Rate 19	1,455,085	1,113,870	1,237,979	1,547,918	1,319,922	1,434,835	1,668,998	1,586,550	1,545,300	1,329,474	1,423,767	1,395,156	17,058,851
													0
24S	16,658	14,634	14,817	83,503	406,033	1,084,281	1,660,443	1,722,943	1,229,137	250,619	35,595	17,785	6,536,448
24T	0	0	0	0	0	0	0	0	0	0	0	0	0
Total 24	16,658	14,634	14,817	83,503	406,033	1,084,281	1,660,443	1,722,943	1,229,137	250,619	35,595	17,785	6,536,448

IDAHO POWER COMPANY
SUMMARY OF REVENUE FORECAST
IDAHO JURISDICTION
BY MONTH BY RATE
12 MONTHS ENDING DECEMBER 31, 2023

Tariff Description	January	February	March	April	May	June	July	August	September	October	November	December	Total
1 - Residential Serv.	53,158,012	48,971,387	44,396,809	35,487,498	32,106,869	33,384,745	43,584,432	52,153,852	43,060,429	31,951,125	35,429,329	45,908,953	499,593,439
3 - Residential Master Meter	42,645	39,137	35,610	28,652	25,858	26,111	31,946	37,523	32,312	25,870	28,570	36,647	390,879
5 - Residential TOD	160,423	146,570	133,417	107,754	99,275	101,088	124,746	148,054	129,044	100,419	105,983	138,050	1,494,824
6 - Residential On-site Generation	1,440,581	1,144,090	872,781	661,961	587,409	620,389	966,836	1,082,351	856,254	702,623	1,071,531	1,560,564	11,567,368
7 - Small General Serv.	1,593,596	1,540,368	1,370,797	1,214,025	1,120,789	1,193,150	1,434,705	1,539,435	1,371,271	1,172,561	1,175,078	1,376,848	16,102,622
8 - Small General Serv. On-Site Generation	4,798	4,389	3,629	2,560	2,177	1,874	2,967	4,068	4,248	2,762	4,320	5,921	43,713
9 - Large General Serv.	22,123,131	22,194,732	21,003,470	20,188,114	19,949,439	21,802,275	25,132,585	26,411,659	24,719,123	21,301,992	20,647,907	21,455,245	266,929,672
15 - Dusk/Dawn Lighting	105,010	105,442	105,482	105,457	105,447	105,364	105,178	104,885	104,876	104,726	104,945	105,041	1,261,853
19 - Uniform Rate Cont.	9,958,263	10,258,132	9,155,395	9,772,588	9,483,997	9,821,275	12,062,937	12,491,200	12,721,657	9,968,892	10,179,289	9,877,942	125,751,566
24 - Irrigation & Pump.	239,676	234,703	264,214	1,982,667	10,256,227	23,998,633	33,935,281	31,863,690	26,084,365	9,504,531	1,654,254	309,507	140,327,749
40 - Unmetered Gen. Serv.	91,355	92,856	93,320	93,769	94,791	95,315	95,739	96,660	97,237	97,569	97,770	97,907	1,144,288
41 - Municipal St. Light.	309,637	294,498	268,883	311,728	286,073	282,636	282,155	281,011	283,919	285,135	287,859	289,786	3,463,322
42 - Traffic Control Light.	14,399	14,482	12,595	14,482	13,441	13,098	13,722	13,617	14,013	13,719	14,098	13,942	165,609
Total Idaho Rates	89,241,526	85,040,785	77,716,403	69,971,254	74,131,791	91,445,953	117,773,229	126,228,004	109,478,748	75,231,922	70,800,934	81,176,352	1,068,236,903
Special Contracts													
26 - Micron (IPC Energy)	2,377,310	2,190,961	2,284,587	2,233,527	2,453,393	2,547,535	2,638,119	2,673,395	2,553,247	2,421,107	2,434,504	2,546,554	29,354,238
26 - Micron (Embedded Fixed)	9,124	13,682	21,703	26,955	32,083	33,357	34,803	31,865	26,099	19,660	11,024	7,759	268,115
26 - Micron Total	2,386,434	2,204,644	2,306,291	2,260,482	2,485,476	2,580,892	2,672,922	2,705,260	2,579,346	2,440,767	2,445,528	2,554,312	29,622,353
29 - J R Simplot	650,728	686,573	683,513	519,784	629,771	614,308	652,906	644,856	640,294	687,922	683,806	664,908	7,759,368
30 - DOE	1,137,466	1,077,733	1,004,219	862,357	752,934	707,700	643,799	633,233	668,101	943,506	986,909	1,129,751	10,547,708
Total Specials	4,174,628	3,968,950	3,994,023	3,642,623	3,868,180	3,902,900	3,969,627	3,983,349	3,887,741	4,072,195	4,116,242	4,348,971	47,929,429
Total Idaho Firm Sales	93,416,155	89,009,736	81,710,426	73,613,877	77,999,972	95,348,853	121,742,856	130,211,353	113,366,489	79,304,117	74,917,176	85,525,323	1,116,166,332

IDAHO POWER COMPANY

SUMMARY OF REVENUE FORECAST

STATE OF OREGON

BY MONTH BY RATE

12 MONTHS ENDING DECEMBER 31, 2023

Tariff Description	January	February	March	April	May	June	July	August	September	October	November	December	Total
01 - Residential Serv.	2,250,893	2,049,815	1,744,816	1,377,855	1,117,003	1,023,178	1,254,244	1,358,041	1,240,290	988,950	1,301,481	1,846,107	17,552,674
05 - Residential TOD	1,102	1,033	746	579	480	511	767	772	609	465	657	963	8,687
07 - Small General Serv.	212,363	207,026	184,413	155,145	139,723	143,982	181,267	180,318	157,357	128,929	148,102	181,179	2,019,803
09 - Large General Serv.	968,778	957,974	876,503	780,506	708,720	703,475	805,573	867,110	850,037	829,960	955,715	927,663	10,232,013
15 - Dusk/Dawn Lighting	9,000	8,934	8,944	8,970	8,949	8,972	8,927	8,961	8,933	8,944	8,958	8,960	107,451
19 - Uniform Rate Cont.	1,455,085	1,113,870	1,237,979	1,547,918	1,319,922	1,434,835	1,668,998	1,586,550	1,545,300	1,329,474	1,423,767	1,395,156	17,058,851
24 - Irrigation Service	16,658	14,634	14,817	83,503	406,033	1,084,281	1,660,443	1,722,943	1,229,137	250,619	35,595	17,785	6,536,448
40 - Unmetered Gen. Serv.	28	28	28	28	28	28	28	28	28	28	28	28	333
41 - Municipal St. Light.	12,585	12,530	12,489	12,374	12,321	12,270	12,200	12,235	12,334	12,307	12,371	12,433	148,451
42 - Traffic Control Light.	210	205	190	171	168	163	174	165	160	158	161	204	2,130
Total Oregon Firm Sales	4,926,702	4,366,048	4,080,924	3,967,049	3,713,346	4,411,696	5,592,620	5,737,123	5,044,186	3,549,835	3,886,835	4,390,477	53,666,841

IDAHO POWER COMPANY

SUMMARY OF REVENUE FORECAST

TOTAL COMPANY

12 MONTHS ENDING DECEMBER 31, 2023

Tariff Description	January	February	March	April	May	June	July	August	September	October	November	December	Total
1 - Residential Serv.	55,408,906	51,021,201	46,141,625	36,865,353	33,223,872	34,407,923	44,838,676	53,511,892	44,300,719	32,940,075	36,730,810	47,755,060	517,146,113
3 - Residential Master Meter	42,645	39,137	35,610	28,652	25,858	26,111	31,946	37,523	32,312	25,870	28,570	36,647	390,879
5 - Residential TOD	161,525	147,603	134,163	108,332	99,755	101,599	125,514	148,827	129,654	100,884	106,641	139,013	1,503,511
6 - Residential On-site Generation	1,440,581	1,144,090	872,781	661,961	587,409	620,389	966,836	1,082,351	856,254	702,623	1,071,531	1,560,564	11,567,368
7 - Small General Serv.	1,805,959	1,747,394	1,555,210	1,369,170	1,260,512	1,337,132	1,615,972	1,719,753	1,528,628	1,301,489	1,323,179	1,558,027	18,122,425
8 - Small General Serv. On-site Generation	4,798	4,389	3,629	2,560	2,177	1,874	2,967	4,068	4,248	2,762	4,320	5,921	43,713
9 - Large General Serv.	23,091,909	23,152,706	21,879,973	20,968,620	20,658,159	22,505,750	25,938,157	27,278,769	25,569,160	22,131,952	21,603,623	22,382,908	277,161,685
15 - Dusk/Dawn Lighting	114,010	114,376	114,426	114,427	114,396	114,336	114,104	113,846	113,809	113,670	113,903	114,001	1,369,304
19 - Uniform Rate Cont.	11,413,348	11,372,002	10,393,374	11,320,506	10,803,919	11,256,110	13,731,935	14,077,749	14,266,957	11,298,366	11,603,056	11,273,097	142,810,418
24 - Irrigation & Pump.	256,334	249,337	279,031	2,066,170	10,662,261	25,082,914	35,595,724	33,586,634	27,313,502	9,755,150	1,689,849	327,292	146,864,197
40 - Unmetered Gen. Serv.	91,382	92,884	93,347	93,797	94,819	95,343	95,767	96,687	97,265	97,597	97,798	97,935	1,144,620
41 - Municipal St. Light.	322,223	307,028	281,372	324,102	298,394	294,907	294,355	293,246	296,254	297,443	300,230	302,219	3,611,772
42 - Traffic Control Light.	14,609	14,687	12,786	14,653	13,608	13,261	13,897	13,782	14,173	13,878	14,259	14,145	167,739
Total All Rates	94,168,228	89,406,833	81,797,327	73,938,303	77,845,138	95,857,649	123,365,850	131,965,128	114,522,933	78,781,757	74,687,769	85,566,828	1,121,903,744
Special Contracts													
26 - Micron	2,386,434	2,204,644	2,306,291	2,260,482	2,485,476	2,580,892	2,672,922	2,705,260	2,579,346	2,440,767	2,445,528	2,554,312	29,622,353
29 - J R Simplot	650,728	686,573	683,513	519,784	629,771	614,308	652,906	644,856	640,294	687,922	683,806	664,908	7,759,368
30 - DOE	1,137,466	1,077,733	1,004,219	862,357	752,934	707,700	643,799	633,233	668,101	943,506	986,909	1,129,751	10,547,708
Total Specials	4,174,628	3,968,950	3,994,023	3,642,623	3,868,180	3,902,900	3,969,627	3,983,349	3,887,741	4,072,195	4,116,242	4,348,971	47,929,429
Total Firm Retail Sales	98,342,856	93,375,784	85,791,350	77,580,926	81,713,318	99,760,548	127,335,476	135,948,477	118,410,674	82,853,952	78,804,011	89,915,800	1,169,833,173

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BRADY, DI TESTIMONY

EXHIBIT NO. 28

2023 Test Year Revenue Forecast

Rate	State		Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total	Rates As of 6/1/2022
IDAHO																
Rate 01	I	**Bills**	490,124	489,968	489,175	488,869	488,833	490,266	491,169	492,205	492,961	493,490	494,545	496,102	5,897,706	5.000000
		Min Bills	4317.0	5209.0	5532.0	6124.0	6327.0	7040.0	6746.0	6992.0	6196.0	6095.0	5680.0	4607.0	70,865	2.000000
		S 0-800	3,450	(2,569)	301	1,410	(3,970)	108,107,252	292,086,075	291,815,097	167,588,620	1,522,590	15,245	14,115	861,147,615	0.086518
		S 801-2000	(878)	(3,745)	(333)	0	5	27,007,499	124,606,380	186,550,147	95,258,304	488,793	2,744	1,656	433,910,571	0.104033
		S Over 2000	0	(137)	0	0	0	3,330,895	19,864,970	40,624,505	19,517,439	73,921	99	(53)	83,411,640	0.123585
		N 0-800	308,568,702	285,333,690	282,345,964	276,644,799	261,646,571	172,201,397	3,757,357	17,598	106,902,802	278,294,625	275,969,649	273,715,785	2,525,398,940	0.080390
		N 801-2000	181,095,731	163,194,665	144,859,882	96,634,360	80,169,435	43,571,175	1,197,932	19,505	49,563,609	68,157,038	95,452,214	153,557,678	1,077,473,224	0.088627
		N Over 2000	100,278,583	92,816,662	65,240,244	22,687,748	15,398,753	6,519,763	183,180	5,005	7,897,197	8,834,167	23,420,185	79,512,518	422,794,007	0.098154
		Total kWh	589,945,587	541,338,567	492,446,058	395,968,317	357,210,794	360,737,981	441,695,895	519,031,858	446,727,970	357,371,134	394,860,136	506,801,700	5,404,135,997	
		Rev	53,158,012	48,971,387	44,396,809	35,487,498	32,106,869	33,384,745	43,584,432	52,153,852	43,060,429	31,951,125	35,429,329	45,908,953	499,593,439	
Rate 03	I	**Bills**	19	19	19	19	19	19	19	19	19	19	19	19	225	5.000000
		Total kWh	488,670	448,386	407,887	327,969	295,883	298,791	365,801	429,850	370,004	296,021	327,035	419,789	4,476,086	0.087075
		Rev	42,645	39,137	35,610	28,652	25,858	26,111	31,946	37,523	32,312	25,870	28,570	36,647	390,879	
Rate 05	I	**Bills**	991	986	986	986	990	988	986	980	986	985	979	993	11,836	5.000000
		Min Bills	2.0	3.0	2.0	2.0	4.0	3.0	2.0	3.0	3.0	1.0	2.0	2.0	29	2.000000
		S Peak	0	0	0	0	0	104,680	384,616	494,903	325,893	7,746	0	0	1,317,837	0.128910
		S Off Peak	0	0	0	0	0	265,746	925,589	1,073,772	658,873	8,078	0	0	2,932,059	0.073899
		N Peak	732,685	712,772	640,067	519,261	474,648	309,961	6,408	0	156,111	488,436	517,770	648,820	5,206,937	0.095159
		N Off Peak	1,160,259	998,787	914,432	722,694	665,063	453,521	16,505	0	251,020	641,674	701,153	965,411	7,490,517	0.073899
		Total kWh	1,892,943	1,711,559	1,554,498	1,241,955	1,139,711	1,133,908	1,333,117	1,568,675	1,391,896	1,145,934	1,218,922	1,614,231	16,947,350	
		Rev	160,423	146,570	133,417	107,754	99,275	101,088	124,746	148,054	129,044	100,419	105,983	138,050	1,494,824	
Rate 06	I	**Bills**	12,300	12,461	12,646	12,853	12,995	13,158	13,422	13,524	13,716	13,914	14,076	14,388	159,453	5.000000
		Min Bills	79.0	104.0	110.0	100.0	116.0	126.0	110.0	141.0	140.0	160.0	164.0	132.0	1482.0	2.000000
		S 0-800	0	0	0	0	0	1,633,117	6,215,916	6,648,747	3,699,791	37,932	(112)	0	18,235,390	0.086518
		S 801-2000	0	0	0	0	0	460,510	2,206,053	2,935,090	1,430,062	10,015	(597)	0	7,041,132	0.104033
		S Over 2000	0	0	0	0	0	236,234	993,817	1,083,194	523,630	4,007	0	0	2,840,881	0.123585
		N 0-800	7,530,201	6,019,882	5,079,746	4,590,719	4,090,000	2,673,835	68,739	0	2,153,947	5,703,638	7,864,629	8,757,924	54,533,261	0.080390
		N 801-2000	4,526,918	3,571,126	2,629,146	1,578,140	1,387,124	856,949	24,536	0	664,393	1,337,460	2,731,373	4,828,226	24,135,393	0.088627
		N Over 2000	3,793,654	2,864,276	1,711,168	902,479	717,938	459,007	17,243	0	221,789	518,205	1,289,650	3,631,029	16,126,439	0.098154
		Total kWh	15,850,773	12,455,285	9,420,060	7,071,338	6,195,062	6,319,652	9,526,304	10,667,031	8,693,613	7,611,257	11,884,942	17,217,179	122,912,496	
		Rev	1,440,581	1,144,090	872,781	661,961	587,409	620,389	966,836	1,082,351	856,254	702,623	1,071,531	1,560,564	11,567,368	
Rate 07	I	**Bills**	30,369	30,320	30,303	30,329	30,210	30,338	30,348	30,406	30,369	30,571	30,572	30,674	364,810	5.000000
		Min Bills	162.0	202.0	195.0	169.0	208.0	162.0	197.0	156.0	158.0	164.0	189.0	215.0	2177.0	2.000000
		S 0-300	833	(107)	329	0	(130)	2,127,752	5,445,180	4,994,740	2,930,085	28,578	(649)	(126)	15,526,486	0.098633
		S Over	2,828	(446)	0	0	(1,496)	1,837,668	6,199,162	7,613,614	4,027,601	(24,690)	(14,013)	(677)	19,639,552	0.117472
		N 0-300	5,971,026	5,661,411	5,407,777	5,565,716	5,182,326	3,348,322	79,473	189	1,974,388	5,217,804	5,119,586	5,037,758	48,565,776	0.098633
		N Over	8,233,703	8,020,646	6,623,828	4,957,968	4,429,219	2,755,344	91,119	394	2,534,016	4,878,052	5,011,199	7,017,857	54,553,347	0.103486
		kWh Total	14,208,391	13,681,505	12,031,934	10,523,684	9,609,919	10,069,086	11,814,934	12,608,938	11,466,089	10,099,744	10,116,124	12,054,812	138,285,160	
		Rev	1,593,596	1,540,368	1,370,797	1,214,025	1,120,789	1,193,150	1,434,705	1,539,435	1,371,271	1,172,561	1,175,078	1,376,848	16,102,622	
Rate 08	I	**Bills**	82	82	84	85	86	88	89	90	90	90	91	93	1,050	5.000000
		Min Bills	0.0	0.0	1.0	0.0	0.0	0.0	0.0	1.0	0.0	2.0	1.0	1.0	6.0	2.000000
		S 0-300	0	0	0	0	0	3,141	10,048	8,107	5,000	51	0	0	26,347	0.098633
		S Over	0	0	0	0	0	1,099	12,643	23,973	18,119	273	0	0	56,107	0.117472
		N 0-300	13,968	14,066	13,982	14,138	11,432	5,653	198	0	3,414	8,410	17,319	14,716	117,296	0.098633
		N Over	29,086	25,024	17,681	7,146	5,997	4,232	251	0	8,130	13,919	20,810	38,680	170,958	0.103486
		kWh Total	43,055	39,090	31,663	21,284	17,429	14,126	23,140	32,081	34,664	22,653	38,129	53,395	370,708	
		Rev	4,798	4,389	3,629	2,560	2,177	1,874	2,967	4,068	4,248	2,762	4,320	5,921	43,713	
Rate 09S	I	**Bills**	37473.4	37518.3	37564.4	37635.7	37677.7	37704.6	37761.8	37824	37924.9	37975.7	38108.3	37993.2	453162	16.000000
		Min Bills	124.0	155.0	180.0	174.0	138.0	126.0	164.0	132.0	152.0	149.0	158.0	132.0	1784.0	5.000000
		BLC 0-20	533,392	544,937	538,010	544,378	549,234	557,323	544,031	540,507	532,412	543,704	531,004	535,180	6,494,112	0.000000
		BLC Over 20	701,603	716,918	708,596	715,650	718,451	726,582	703,995	702,706	699,081	706,857	708,711	707,404	8,516,555	1.030000
		BLC Total	1,234,995	1,261,854	1,246,605	1,260,028	1,267,685	1,283,905	1,248,027	1,243,213	1,231,494	1,250,562	1,239,715	1,242,584	15,010,667	
		kW 0-20	424,991	435,973	431,269	436,271	454,035	472,744	459,882	457,592	448,945	457,594	438,929	430,970	5,349,195	0.000000
		S kW Over 20	(0)	0	0	0	0	202,621	500,914	541,931	313,328	3,161	148	147	1,562,250	6.060000
		N kW Over 20	451,304	457,962	455,474	445,971	449,595	285,476	8,568	(0)	231,668	515,678	477,424	451,757	4,230,876	4.450000
		kW Total	876,295	893,936	886,742	882,243	903,630	960,841	969,363	999,523	993,941	976,432	916,501	882,874	11,142,321	

		S 0-2000	(1,606)	2,071	1,623	2,078	8,323	22,466,910	55,811,628	55,328,169	32,227,680	310,958	20,553	7,311	166,185,698	0.105250
		S Over	0	0	0	0	3,727	84,106,752	225,752,868	250,290,708	144,179,468	1,338,931	78,638	5,531	705,756,622	0.048716
		N 0-2000	59,089,099	59,939,263	57,030,726	57,220,840	56,660,607	34,394,189	813,745	3,440	22,158,012	55,092,345	55,263,382	57,140,717	514,806,364	0.094742
		N Over	233,654,792	233,567,727	216,098,068	196,669,820	193,699,815	120,415,479	3,591,975	89,013	97,361,138	211,025,546	204,963,241	223,659,319	1,934,795,934	0.044196
		kWh Total	292,742,285	293,509,062	273,130,416	253,892,738	250,372,471	261,383,329	285,970,217	305,711,331	295,926,298	267,767,780	260,325,814	280,812,878	3,321,544,618	
		Rev	19,255,806	19,379,168	18,312,689	17,438,189	17,274,189	18,892,979	21,511,585	22,634,444	21,075,381	18,294,341	17,766,240	18,647,900	230,482,910	
Rate 09P	I	**Bills**	281.4	281.1	279	276.8	280.4	275.7	285.9	279.7	281	280	282.1	278.8	3361.9	285.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	161,070	157,417	160,006	157,428	159,471	167,508	172,468	165,516	154,215	159,557	159,756	160,908	1,935,320	1.300000
		S kW	0	0	0	0	0	0	140,515	142,116	139,062	314	0	(270)	421,737	5.160000
		N kW	122,555	118,748	121,749	118,891	120,018	132,429	2,223	0	0	140,861	128,829	123,437	1,129,739	4.520000
		Total kW	122,555	118,748	121,749	118,891	120,018	132,429	142,738	142,116	139,062	141,174	128,829	123,167	1,551,476	
		On-peak kW	0	0	0	0	0	0	131,493	133,093	130,008	308	0	(340)	394,562	0.970000
		S On-peak kWh	0	0	0	0	0	0	14,883,769	14,575,502	15,978,455	44,404	0	(31,571)	45,450,558	0.049454
		S Mid-peak kWh	0	0	0	0	0	0	22,599,333	25,103,152	23,226,698	65,998	0	(50,568)	70,944,613	0.045633
		S Off-peak kWh	0	0	0	0	0	0	14,746,043	17,050,278	15,069,765	32,804	0	(34,085)	46,864,805	0.043133
		N Mid-peak kWh	30,153,518	28,676,698	28,108,718	29,921,611	28,487,696	29,630,158	465,246	0	0	31,735,636	30,680,676	29,080,242	266,940,199	0.040920
		N Off-peak kWh	19,478,333	20,284,766	17,345,146	17,328,681	16,657,404	19,744,621	201,903	0	0	19,187,253	18,590,374	19,123,381	167,941,864	0.039546
		Total kWh	49,631,851	48,961,464	45,453,864	47,250,292	45,145,100	49,374,779	52,896,294	56,728,933	54,274,918	51,066,095	49,271,050	48,087,399	598,142,039	
		Rev	2,847,710	2,797,128	2,673,968	2,730,602	2,654,158	2,888,200	3,598,743	3,759,083	3,624,338	2,989,855	2,861,018	2,785,731	36,210,534	
Rate 09T	I	**Bills**	4	4	4	4	4	4	4	4	4	4	4	4	48	285.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	1,374	1,288	1,220	1,432	1,490	1,439	1,386	1,339	1,486	1,580	1,501	1,473	17,008	0.690000
		S kW	0	0	0	0	0	0	1,176	990	1,044	0	0	0	3,210	4.840000
		N kW	1,090	994	946	1,208	1,366	1,377	0	0	0	1,189	1,235	1,269	10,676	4.360000
		Total kW	1,090	994	946	1,208	1,366	1,377	1,176	990	1,044	1,189	1,235	1,269	13,886	
		On-peak kW	0	0	0	0	0	0	1,027	832	891	0	0	0	2,749	0.970000
		S On-peak kWh	0	0	0	0	0	0	75,676	54,511	63,328	0	0	0	193,515	0.048664
		S Mid-peak kWh	0	0	0	0	0	0	131,543	106,090	112,994	0	0	0	350,627	0.045000
		S Off-peak kWh	0	0	0	0	0	0	90,851	71,465	74,079	0	0	0	236,395	0.042585
		N Mid-peak kWh	198,448	172,384	157,731	180,772	198,713	187,011	0	0	0	164,046	198,809	203,859	1,661,772	0.040408
		N Off-peak kWh	121,409	130,438	110,656	118,127	126,154	137,935	0	0	0	95,780	129,116	145,218	1,114,834	0.039155
		Total kWh	319,857	302,822	268,387	298,899	324,867	324,946	298,070	232,066	250,401	259,826	327,925	349,077	3,557,143	
		Rev	19,615	18,436	16,813	19,323	21,093	21,097	22,257	18,131	19,404	17,795	20,650	21,615	236,229	
Rate 19S	I	**Bills**	1	1	1	1	1	1	1	1	1	1	1	1	12	39.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	5.000000
		BLC	1,209	1,203	1,176	1,170	1,177	1,213	1,171	1,184	1,188	1,162	1,164	1,150	14,167	0.930000
		S kW	0	0	0	0	0	0	1,067	1,086	1,080	0	0	0	3,233	5.990000
		N kW	1,142	1,127	1,104	1,135	1,152	1,134	0	0	0	1,058	1,134	1,123	10,109	4.300000
		Total kW	1,142	1,127	1,104	1,135	1,152	1,134	1,067	1,086	1,080	1,058	1,134	1,123	13,342	
		On-peak kW	0	0	0	0	0	0	830	895	866	0	0	0	2,591	1.030000
		S On-peak kWh	0	0	0	0	0	26,440	123,837	128,376	145,152	0	0	0	423,806	0.064456
		S Mid-peak kWh	0	0	0	0	0	34,980	164,151	181,679	182,469	0	0	0	563,279	0.051034
		S Off-peak kWh	0	0	0	0	0	40,473	203,224	218,708	202,568	0	0	0	664,973	0.045292
		N Mid-peak kWh	330,465	341,885	314,201	345,614	334,038	237,242	0	0	0	323,206	347,674	319,781	2,894,106	0.047466
		N Off-peak kWh	251,857	229,856	197,116	218,695	213,733	180,910	0	0	0	227,468	238,861	229,968	1,988,464	0.042171
		Total kWh	582,322	571,741	511,317	564,309	547,771	520,046	491,212	528,763	530,190	550,674	586,535	549,749	6,534,628	
		Rev	32,382	31,924	29,108	31,633	30,958	30,257	33,936	36,021	36,347	30,601	32,573	30,812	386,553	
Rate 19P	I	**Bills**	113	113	113	113	113	113	113	113	113	113	113	113	1356	299.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	431,617	440,148	420,070	427,664	439,780	445,858	437,209	444,833	443,608	434,900	436,890	438,634	5,241,211	1.280000
		S kW	0	0	0	0	0	0	391,774	402,402	406,562	0	0	(575)	1,200,164	6.120000
		N kW	378,684	385,302	367,585	369,769	374,451	380,809	0	0	0	400,556	389,446	387,351	3,433,952	4.540000
		Total kW	378,684	385,302	367,585	369,769	374,451	380,809	391,774	402,402	406,562	400,556	389,446	386,777	4,634,116	
		On-peak kW	0	0	0	0	0	0	376,296	386,737	390,330	0	0	(192)	1,153,172	0.970000
		S On-peak kWh	0	0	0	0	0	0	51,578,510	48,552,770	55,642,610	0	0	(31,615)	155,742,275	0.053049
		S Mid-peak kWh	0	0	0	0	0	0	82,749,256	88,978,533	87,097,038	0	0	(47,302)	258,777,524	0.042185
		S Off-peak kWh	0	0	0	0	0	0	60,965,432	67,102,459	64,250,840	0	0	(30,663)	192,288,068	0.037639
		N Mid-peak kWh	114,838,401	114,566,530	105,310,222	116,525,935	110,706,610	109,016,493	0	0	0	114,248,901	117,487,542	111,921,373	1,014,622,007	0.039765
		N Off-peak kWh	82,051,537	89,613,115	72,966,109	76,921,322	73,779,822	84,008,755	0	0	0	80,340,733	84,112,909	82,071,151	725,865,453	0.035550
		Total kWh	196,889,938	204,179,645	178,276,331	193,447,257	184,486,432	193,025,248	195,293,198	204,633,762	206,990,488	194,589,634	201,600,451	193,882,943	2,347,295,327	
		Rev	9,788,962	10,087,930	9,021,917	9,628,156	9,321,832	9,654,913	11,877,722	12,295,915	12,512,697	9,808,203	10,023,196	9,713,467	123,734,911	
Rate 19T	I	**Bills**	2	2	2	2	2	2	2	2	2	2	2	2	24	299.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000

		BLC	5,069	5,130	4,339	4,350	5,393	5,239	4,887	5,131	5,541	5,005	4,679	5,251	60,014	0.710000
		S kW	0	0	0	0	0	0	4,757	5,020	5,412	0	0	0	15,188	5.930000
		N kW	4,997	5,021	4,246	4,295	5,247	5,088	0	0	0	4,876	4,551	5,134	43,455	4.410000
		Total kW	4,997	5,021	4,246	4,295	5,247	5,088	4,757	5,020	5,412	4,876	4,551	5,134	58,643	
		On-peak kW	0	0	0	0	0	0	4,529	4,722	5,186	0	0	0	14,437	0.970000
		S On-peak kWh	0	0	0	0	0	0	641,736	606,088	753,092	0	0	0	2,000,915	0.052447
		S Mid-peak kWh	0	0	0	0	0	0	1,150,166	1,244,475	1,309,729	0	0	0	3,704,369	0.041889
		S Off-peak kWh	0	0	0	0	0	0	876,461	983,033	978,764	0	0	0	2,838,258	0.037394
		N Mid-peak kWh	1,663,670	1,628,866	1,260,363	1,406,203	1,584,213	1,588,199	0	0	0	1,567,059	1,495,850	1,581,008	13,775,429	0.039577
		N Off-peak kWh	1,267,336	1,340,499	906,829	975,484	1,157,090	1,313,963	0	0	0	1,198,742	1,139,770	1,246,993	10,546,708	0.035383
		Total kWh	2,931,006	2,969,365	2,167,192	2,381,687	2,741,303	2,902,162	2,668,363	2,833,595	3,041,585	2,765,801	2,635,620	2,828,001	32,865,680	
		Rev	136,919	138,278	104,370	112,798	131,207	136,105	151,278	159,264	172,613	130,087	123,520	133,663	1,630,102	
Rate 24	I	**In Bills**	0	0	0	0	0	19327.8	19243	19478.2	19621.3	0	0	0	77,670	22.000000
	I	**Out-Bills**	18525	18838.8	18916.6	19284.1	19398	0	0	0	0	19478.4	19081.8	18953.8	152,477	3.500000
		Min Bills	39.9	23.9	62.5	71.2	48.7	22.3	-0.3	0.0	6.9	34.6	44.7	24.3	379	1.500000
		In-kW						1,007,972	1,080,974	1,018,561	957,920				4,065,427	7.060000
		Out-kW			**Out of Season - No Impact**			0	0	0	0		**Out of Season - No Impact**		-	0.000000
		Total kW						1,007,972	1,080,974	1,018,561	957,920				4,065,427	
		In <164 kWh per k\	(451)	(19,150)	0	0	30,276	157,613,372	167,416,604	153,196,402	132,009,262	433,728	7,163	91,152	610,778,359	0.058436
		In >164 kWh per k\	0	(52,764)	0	0	0	129,813,328	290,438,380	282,136,227	194,707,635	449,476	0	256,153	897,748,435	0.055483
		Out-kWh	2,605,766	2,575,541	2,950,218	28,547,278	151,846,820	661,503	(257,707)	(5,393,540)	5,555,976	139,914,453	23,656,636	3,333,035	355,995,978	0.067084
		Total kWh	2,605,316	2,503,627	2,950,218	28,547,278	151,877,097	288,088,203	457,597,276	429,939,089	332,272,872	140,797,657	23,663,799	3,680,340	1,864,522,772	
		Rev	239,676	234,703	264,214	1,982,667	10,256,227	23,998,633	33,935,281	31,863,690	26,084,365	9,504,531	1,654,254	309,507	140,327,749	
Rate 40	I	**In Bills**	1663	1663	1663	1663	1663	1663	1663	1663	1663	1663	1663	1663	19956	0.000000
		Min Bills	70.6	68.8	68.9	70.8	71.5	71.8	67.9	70.9	71.9	72.6	70.9	70.3	846.8	1.500000
		kWh	1,111,671	1,129,997	1,135,643	1,141,087	1,153,527	1,159,902	1,165,140	1,176,306	1,183,323	1,187,351	1,189,839	1,191,515	13,925,301	0.082070
		Intermittent Usage	14	14	14	14	14	14	14	14	14	14	14	14	168	1.000000
		Rev	91,355	92,856	93,320	93,769	94,791	95,315	95,739	96,660	97,237	97,569	97,770	97,907	1,144,288	
Rate 42	I	**Bills**	766	766	766	766	766	766	766	766	766	766	766	766	9192	0.000000
		kWh	247,623	249,052	216,602	249,052	231,141	225,244	235,982	234,167	240,982	235,926	242,437	239,753	2,847,961	0.058150
		Rev	14,399	14,482	12,595	14,482	13,441	13,098	13,722	13,617	14,013	13,719	14,098	13,942	165,609	
Rate 15		1csa	7,515	7,518	7,512	7,495	7,503	7,493	7,470	7,455	7,430	7,438	7,439	7,446	89,714	9.630000
		2csa	769	772	776	774	790	790	795	791	802	789	797	813	9,459	11.500000
		2csf	808	812	807	814	794	793	794	795	794	795	798	796	9,599	13.780000
		4chf	105	104	104	104	100	99	95	92	92	90	90	89	1,164	14.910000
		4csa	139	141	151	152	157	157	151	153	152	150	149	149	1,801	15.570000
		4csf	440	447	445	446	445	447	453	450	454	452	456	453	5,387	16.240000
		1khf	71	79	79	80	80	80	81	80	81	82	83	80	956	23.710000
		Min Bill	34.2	30.8	34.4	35.7	31.8	37.6	42.6	36.2	38.2	39.1	34.3	38.8	433.8	3.000000
		kWh	467,630	460,083	454,542	448,316	445,066	440,449	434,588	434,010	429,419	424,087	418,486	410,747	5,267,423	
		Rev	105,010	105,442	105,482	105,457	105,447	105,364	105,178	104,885	104,876	104,726	104,945	105,041	1,261,853	
Rate 41A	I															
		70 S	36	36	36	36	36	36	36	36	36	36	35	36	431	11.550000
		100 S	15,573	14,950	13,395	16,513	14,949	14,952	14,957	14,804	14,963	14,992	14,994	15,005	180,046	11.010000
		200 S	1,793	1,667	1,565	1,765	1,668	1,670	1,671	1,642	1,671	1,674	1,675	1,676	20,137	14.750000
		250 S	240	238	233	246	238	228	227	228	230	231	230	230	2,799	16.050000
		400 S	119	120	100	144	122	125	126	126	126	126	126	126	1,486	18.300000
		41A Variable Usage	3,624	3,624	3,624	3,624	3,624	3,624	3,624	3,402	3,624	3,624	3,624	3,624	43,270	0.074640
		41A kWh	431,570	391,271	341,515	413,338	356,774	341,204	342,933	334,813	319,578	302,319	295,621	282,208	4,153,143	
		Rev 41A	204,616	195,894	176,821	215,113	195,931	195,888	195,955	193,847	196,074	196,453	196,460	196,597	2,359,648	
		All Rate 41 Bills	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	35,760	
		All Rate 41 kWh	2,294,057	2,126,315	1,939,585	2,126,315	1,927,140	1,868,190	1,866,664	1,879,169	1,904,924	1,904,924	1,951,450	1,971,281	23,760,014	
		Rev All 41	309,637	294,498	268,883	311,728	286,073	282,636	282,155	281,011	283,919	285,135	287,859	289,786	3,463,322	
Rate 41B	29	70 S	0	0	0	0	0	0	0	0	0	0	0	0	0	3.110000
	39	100 S	3,219	3,092	3,008	2,976	2,957	2,060	1,917	1,913	675	661	661	660	23,799	3.480000
	74	200 S	148	127	120	120	117	113	110	110	68	65	64	64	1,226	5.030000
	100	250 S	858	832	826	813	794	749	674	649	574	433	419	418	8,039	6.200000
	157	400 S	127	127	127	125	123	121	122	120	70	70	57	56	1,245	8.760000
		Variable Usage Cha	0	0	0	0	0	0	0	0	0	0	0	0	0	0.074640
		kwh	273,073	256,567	239,127	263,502	241,734	198,240	187,222	185,109	108,196	90,770	86,911	84,537	2,214,987	
		Rev 41B	18,379	17,670	17,305	17,096	16,879	13,441	12,472	12,286	6,863	5,925	5,719	5,701	149,735	

Rate 41BM		100 S	0	0	0	0	0	0	0	0	0	0	0	0	0	1.280000
		200 S	0	0	0	0	0	0	0	0	0	0	0	0	0	1.270000
		250 S	33	33	33	33	33	33	33	33	33	33	33	33	396	1.370000
		400 S	0	0	0	0	0	0	0	0	0	0	0	0	0	1.370000
		Bills	6	6	6	6	6	7	4	4	4	4	4	4	61	3.360000
		kWh	10,274	8,601	7,518	7,717	6,344	5,846	5,160	4,299	4,997	5,114	5,893	6,340	78,103	0.051250
		Rev 41BM	592	506	451	461	390	368	323	279	315	321	361	384	4,750	
Rate 41C		**kWh**	857,989	844,827	805,767	903,470	845,378	873,468	896,048	892,087	951,296	951,591	951,646	930,670	10,704,238	0.052400
		Rev 41C	44,959	44,269	42,222	47,342	44,298	45,770	46,953	46,745	49,848	49,863	49,866	48,767	560,902	
Rate 41CM	**I**	**Bills**	1230	1228	1226	1229	1230	1231	1233	1230	1228	1227	1226	1228	14746	3.360000
		kWh	721,151	625,049	545,658	538,287	476,911	449,432	435,301	462,861	520,856	555,130	611,379	667,526	6,609,543	0.051250
		Rev 41CM	41,092	36,160	32,084	31,717	28,574	27,170	26,452	27,854	30,820	32,573	35,453	38,337	388,286	
																Rates
OREGON			**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**		**As of 06/1/2022**
Rate 01	O	**Bills**	13685.1	13717.1	13686.7	13632.1	13646.2	13682.1	13672.5	13633.4	13699.2	13728.9	13709.3	13750.3	164,243	8.000000
		Min Bills	124.0	110.0	100.0	110.0	147.0	139.0	104.0	187.0	146.0	126.0	125.0	100.0	1,518	3.000000
		0-1000	11,805,082	11,021,784	10,419,412	11,083,899	8,991,286	9,097,914	10,065,869	9,009,830	8,942,630	8,970,207	10,121,329	9,934,042	119,463,283	0.079919
		Over 1000	12,726,917	11,253,020	8,526,271	4,066,509	3,069,297	1,978,853	3,614,255	5,614,894	4,416,336	1,720,009	4,065,347	10,009,519	71,061,228	0.094099
		Total kWh	24,531,999	22,274,803	18,945,683	15,150,408	12,060,582	11,076,767	13,680,124	14,624,725	13,358,966	10,690,217	14,186,675	19,943,561	190,524,510	
		Rev	2,250,893	2,049,815	1,744,816	1,377,855	1,117,003	1,023,178	1,254,244	1,358,041	1,240,290	988,950	1,301,481	1,846,107	17,552,674	
Rate 05	O	**Bills**	4	4	4	4	4	4	4	4	3	4	4	4	47	8.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.000000
		S Peak	0	0	0	0	0	492	1,399	1,582	947	0	0	0	4,420	0.122949
		S Off Peak	0	0	0	0	0	1,535	4,629	4,486	2,569	0	0	0	13,220	0.121709
		N Peak	3,106	3,134	2,339	1,751	1,480	690	0	0	511	1,635	2,185	3,115	19,947	0.075445
		N Off Peak	11,220	10,268	7,219	5,567	4,519	2,416	0	0	1,560	4,160	6,184	9,343	62,457	0.074486
		Total kWh	14,326	13,402	9,558	7,318	6,000	5,133	6,028	6,068	5,587	5,795	8,369	12,459	100,043	
		Rev	1,102	1,033	746	579	480	511	767	772	609	465	657	963	8,687	
Rate 07	O	**1 phase**	2,306.6	2,304.0	2,321.9	2,305.9	2,299.4	2,297.5	2,245.4	2,271.5	2,299.2	2,289.9	2,301.2	2,345.6	27,588.1	9.250000
		3 phase	410.9	402.9	409.1	403.6	404.6	402.0	391.8	404.0	404.1	393.5	402.0	406.1	4,834.6	17.650000
		Total Bills	2,717.5	2,706.9	2,731.0	2,709.5	2,704.0	2,699.5	2,637.2	2,675.5	2,703.3	2,683.4	2,703.2	2,751.7	32,422.7	
		Min Bills	11.0	14.0	8.0	14.0	8.0	6.0	11.0	7.0	13.0	6.0	12.0	11.0	121.0	3.000000
		S 0-500	0	0	0	0	0	284,043	787,364	620,507	364,158	(1,031)	1,022	(1)	2,056,063	0.079527
		S Over	0	0	0	0	0	208,282	851,275	982,560	521,035	(616)	0	0	2,562,537	0.104633
		N 0-500	795,997	791,377	758,982	798,938	732,291	486,903	4,011	0	227,958	616,801	691,633	671,988	6,576,879	0.079527
		N Over	1,378,998	1,323,893	1,091,528	722,636	607,435	372,266	17,653	0	312,712	593,993	739,662	1,131,717	8,292,494	0.087337
		Total kWh	2,174,996	2,115,269	1,850,510	1,521,574	1,339,725	1,351,495	1,660,302	1,603,067	1,425,864	1,209,148	1,432,317	1,803,704	19,487,972	
		Rev	212,363	207,026	184,413	155,145	139,723	143,982	181,267	180,318	157,357	128,929	148,102	181,179	2,019,803	
Rate 09S	O	**1 phase**	461.1	459.6	446.7	462.1	463.4	471.1	502.5	489.9	482.3	488.0	490.1	467.9	5,684.6	10.250000
		3 phase	468.1	477.5	462.3	458.7	456.8	458.4	487.2	471.6	472.0	474.0	471.0	463.2	5,620.9	17.350000
		Total Bills	929.2	937.1	909.0	920.8	920.2	929.5	989.7	961.5	954.3	962.0	961.1	931.1	11,305.5	
		Min Bills	1.0	1.0	4.0	3.0	12.0	3.0	2.0	1.0	1.0	6.0	6.0	7.0	47.0	5.000000
		BLC	43,425	44,738	44,551	45,068	44,171	43,499	44,144	44,093	45,256	45,894	47,257	43,560	535,657	0.730000
		S kW	0	0	0	0	0	10,040	28,261	30,291	19,693	(33)	35	(0)	88,287	5.900000
		N kW	33,137	33,768	32,940	31,310	28,978	17,750	0	0	11,646	33,774	36,519	33,467	293,291	4.440000
		Total kW	33,137	33,768	32,940	31,310	28,978	27,790	28,261	30,291	31,339	33,741	36,554	33,467	381,578	
		S kWh	0	0	0	0	0	2,711,961	8,177,460	8,866,446	5,832,743	(5,824)	6,714	0	25,589,500	0.059716
		N kWh	12,167,822	11,921,529	10,646,215	9,029,379	8,123,248	4,898,418	0	0	3,317,360	9,857,424	11,845,606	11,581,726	93,388,728	0.055631
		Total kWh	12,167,822	11,921,529	10,646,215	9,029,379	8,123,248	7,610,380	8,177,460	8,866,446	9,150,102	9,851,600	11,852,320	11,581,726	118,978,228	
		Rev	868,590	858,798	783,657	686,941	625,549	617,050	700,902	753,584	746,930	744,550	869,457	837,561	9,093,570	
Rate 09P	O	**Bills**	6	6	6	6	6	6	6	6	6	6	5.1	6	71.1	202.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	3,292	3,129	3,200	3,305	3,263	3,578	3,724	3,556	3,110	3,300	3,195	3,117	39,767	1.230000
		S kW	0	0	0	0	0	0	2,914	2,970	2,743	0	0	0	8,628	5.830000
		N kW	2,537	2,500	2,573	2,663	2,444	2,649	0	0	0	2,643	2,466	2,398	22,872	4.760000
		Total kW	2,537	2,500	2,573	2,663	2,444	2,649	2,914	2,970	2,743	2,643	2,466	2,398	31,500	
		On-Peak kW	0	0	0	0	0	0	2,829	2,819	2,673	0	0	0	8,321	0.860000
		S On-Peak kWh	0	0	0	0	0	0	326,735	334,447	344,365	0	0	0	1,005,547	0.058938
		S Mid-Peak kWh	0	0	0	0	0	0	499,469	567,414	500,399	0	0	0	1,567,282	0.055790
		S Off-Peak kWh	0	0	0	0	0	0	340,090	398,245	339,222	0	0	0	1,077,558	0.053767
		NS Mid-Peak kWh	726,574	714,080	698,035	697,480	627,840	641,448	0	0	0	674,934	666,585	655,921	6,102,898	0.051464

		NS Off-Peak kWh	487,832	509,834	434,984	416,069	371,217	424,821	0	0	0	407,755	402,374	455,902	3,910,787	0.050170
		Total kWh	1,214,406	1,223,914	1,133,019	1,113,549	999,057	1,066,269	1,166,294	1,300,106	1,183,987	1,082,689	1,068,959	1,111,823	13,664,072	
		Rev	79,203	79,288	75,140	74,720	67,796	72,545	90,624	98,107	89,781	73,042	71,190	73,091	944,527	
Rate 09T	O	**Bills**	1	1	1	1	1	1	1	1	1	1	1	1	12	200.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	933	947	944	987	899	908	925	1,052	911	904	915	873	11,198	0.320000
		S kW	0	0	0	0	0	0	741	824	687	0	0	0	2,251	3.790000
		N kW	947	913	884	932	819	751	0	0	0	699	778	813	7,535	4.060000
		Total kW	947	913	884	932	819	751	741	824	687	699	778	813	9,786	
		On-Peak kW	0	0	0	0	0	0	614	735	663	0	0	0	2,011	0.730000
		S On-Peak kWh	0	0	0	0	0	0	54,114	54,166	53,242	0	0	0	161,522	0.052528
		S Mid-Peak kWh	0	0	0	0	0	0	96,716	107,628	89,124	0	0	0	293,468	0.049680
		S Off-Peak kWh	0	0	0	0	0	0	55,349	63,419	52,783	0	0	0	171,551	0.047818
		NS Mid-Peak kWh	225,142	197,694	181,329	191,014	153,987	130,089	0	0	0	118,553	152,002	171,202	1,521,012	0.045607
		NS Off-Peak kWh	143,453	149,977	120,348	131,362	102,227	99,181	0	0	0	81,782	100,980	122,129	1,051,439	0.044419
		Total kWh	368,595	347,671	301,677	322,376	256,214	229,270	206,179	225,213	195,149	200,335	252,982	293,331	3,198,992	
		Rev	20,984	19,888	17,705	18,845	15,375	13,880	14,046	15,419	13,326	12,368	15,069	17,011	193,916	
Rate 19P	O	**Bills**	6	6	6	6	6	6	6	6	6	6	6	6	72	208.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	28,974	28,897	26,724	29,031	27,599	27,112	27,706	27,196	28,813	25,110	26,362	26,687	330,209	1.230000
		S kW	0	0	0	0	0	0	27,061	26,329	27,937	0	0	0	81,327	5.910000
		N kW	26,280	25,949	23,825	26,268	24,629	25,094	0	0	0	23,808	24,374	24,266	224,491	4.780000
		Total kW	26,280	25,949	23,825	26,268	24,629	25,094	27,061	26,329	27,937	23,808	24,374	24,266	305,817	
		On-peak kW	0	0	0	0	0	0	26,542	26,024	27,541	0	0	0	80,107	0.870000
		S On-peak kWh	0	0	0	0	0	0	3,966,893	3,371,688	3,987,154	0	0	0	11,325,735	0.061492
		S Mid-peak kWh	0	0	0	0	0	0	6,505,304	6,348,380	6,591,910	0	0	0	19,445,593	0.050557
		S Off-peak kWh	0	0	0	0	0	0	5,014,885	4,861,372	5,033,281	0	0	0	14,909,538	0.045836
		N Mid-peak kWh	7,900,619	7,902,970	7,687,376	9,127,779	8,336,070	8,163,090	0	0	0	7,444,844	7,953,759	7,609,396	72,125,903	0.048407
		N Off-peak kWh	5,827,819	6,059,143	5,401,697	6,300,377	5,815,072	6,070,089	0	0	0	5,713,831	6,030,953	5,559,697	52,778,678	0.044753
		Total kWh	13,728,438	13,962,113	13,089,073	15,428,156	14,151,142	14,233,179	15,487,082	14,581,440	15,612,344	13,158,675	13,984,712	13,169,093	170,585,447	
		Rev	805,762	814,550	761,864	886,325	816,688	821,349	1,021,029	964,055	1,034,910	762,027	805,100	767,224	10,260,882	
Rate 19T	O	**Bills**	1	1	1	1	1	1	1	1	1	1	1	1	12	215.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.000000
		BLC	17,180	16,375	21,675	19,489	14,563	16,699	16,446	16,337	13,417	16,708	17,158	16,524	202,572	0.330000
		S kW	0	0	0	0	0	0	15,316	15,064	12,579	0	0	0	42,959	4.920000
		N kW	16,912	13,835	21,043	18,892	13,931	15,540	0	0	0	15,412	16,557	16,220	148,343	4.640000
		Total kW	16,912	13,835	21,043	18,892	13,931	15,540	15,316	15,064	12,579	15,412	16,557	16,220	191,302	
		On-peak kW	0	0	0	0	0	0	15,180	15,064	12,555	0	0	0	42,799	0.950000
		S On-peak kWh	0	0	0	0	0	0	2,401,845	2,105,233	1,893,425	0	0	0	6,400,503	0.064184
		S Mid-peak kWh	0	0	0	0	0	0	4,237,881	4,091,573	3,278,347	0	0	0	11,607,801	0.053947
		S Off-peak kWh	0	0	0	0	0	0	3,429,444	3,486,826	2,697,651	0	0	0	9,613,921	0.049504
		N Mid-peak kWh	6,439,972	2,520,221	4,268,261	6,406,036	4,883,604	5,674,612	0	0	0	5,277,519	5,825,032	5,884,811	47,180,068	0.051774
		N Off-peak kWh	4,788,311	2,047,787	3,104,489	4,872,626	3,737,445	5,001,627	0	0	0	4,486,881	4,846,995	5,011,252	37,897,413	0.048356
		Total kWh	11,228,283	4,568,008	7,372,750	11,278,662	8,621,049	10,676,239	10,069,171	9,683,632	7,869,423	9,764,400	10,672,027	10,896,063	112,699,707	
		Rev	649,323	299,320	476,115	661,593	503,234	613,486	647,969	622,494	510,390	567,447	618,667	627,932	6,797,970	
Rate 24S	O	**In Bills**	0	0	0	0	0	0	2241.2	2245.3	2244.1	2293.7	0	0	0	9,024	16.850000
		Out-Bills	2093.8	2130.5	2131.9	2214	2269	0	0	0	0	2245.6	2226.1	2201.3	17,512	3.000000
		Min Bills	18.6	18.2	50.8	55.5	37.7	6.8	0.1	0.5	0.6	3.1	13.4	16.1	221	3.000000
		In-kW						38,747	45,409	44,353	38,265				166,774	7.760000
		Out-kW	**Out of Season - No Impact**					0	0	0	0	**Out of Season - No Impact**			-	0.000000
		Total kW						38,747	45,409	44,353	38,265				166,774	
		In <164 kWh per k\	466	0	0	0	15,958	5,935,980	7,838,390	6,578,801	5,243,274	0	0	0	25,612,869	0.075272
		In >164 kWh per k\	0	0	0	0	677	4,169,982	9,487,053	11,795,714	6,957,878	0	0	0	32,411,305	0.071700
		Out-kWh	131,672	104,821	105,851	981,833	5,093,369	255	0	0	0	3,122,012	369,673	142,517	10,052,004	0.078114
		Total kWh	132,138	104,821	105,851	981,833	5,110,005	10,106,217	17,325,443	18,374,515	12,201,152	3,122,012	369,673	142,517	68,076,178	
		Rev	16,658	14,634	14,817	83,503	406,033	1,084,281	1,660,443	1,722,943	1,229,137	250,619	35,595	17,785	6,536,448	
Rate 40	O	**In Bills**	2	2	2	2	2	2	2	2	2	2	2	2	24	0.000000
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.500000
		kWh	449	449	449	449	449	449	449	449	449	449	449	449	5,388	0.061730
		Rev	28	28	28	28	28	28	28	28	28	28	28	28	333	
Rate 42	O	**In Bills**	10	10	10	10	10	10	10	10	10	10	10	10	120	0.000000
		kWh	2,129	2,077	1,931	1,735	1,699	1,655	1,767	1,671	1,626	1,607	1,636	2,065	21,598	0.098630
		Rev	210	205	190	171	168	163	174	165	160	158	161	204	2,130	

Rate 15		1csa	673	666	668	672	669	671	667	670	668	672	671	670	8,039	10.880000
		2csa	66	66	65	65	65	65	65	65	65	64	64	64	779	12.920000
		2csf	22	22	22	22	22	22	22	22	22	22	23	23	266	15.510000
		4csa	17	17	17	17	17	17	17	17	17	17	17	17	204	17.470000
		4csf	10	10	10	10	10	10	10	10	10	9	9	9	117	18.270000
		Min Bill	1.0	3.6	1.4	2.9	2.3	2.4	2.0	2.0	2.7	2.0	4.0	6.3	32.6	3.000000
		kWh	35,752	35,570	35,671	35,572	35,449	35,440	35,422	35,652	35,547	34,887	35,063	34,667	424,692	
		Rev	9,000	8,934	8,944	8,970	8,949	8,972	8,927	8,961	8,933	8,944	8,958	8,960	107,451	
Rate 41A	O															
		100 S	832	831	831	831	831	831	831	831	830	830	830	830	9,969	9.320000
		200 S	171	171	169	169	169	169	169	169	170	170	169	169	2,034	12.270000
		250 S	20	20	22	22	22	22	22	22	22	22	22	22	260	13.330000
		400 S	83	83	83	83	83	83	83	83	83	83	83	83	996	15.120000
		41A kWh	53,883	48,976	43,454	44,506	43,694	43,404	45,345	43,717	43,365	39,906	38,606	32,430	521,285	
		Rev 41A	11,374	11,365	11,367	11,367	11,367	11,367	11,367	11,367	11,370	11,370	11,357	11,357	136,394	
		All 41 Bills	26	26	26	26	26	26	26	26	26	26	26	26	312	
		Total All 41 kWh	77,020	71,324	64,965	63,849	61,986	60,696	61,332	60,365	61,811	57,781	57,932	52,830	751,891	
		Rev All 41	12,585	12,530	12,489	12,374	12,321	12,270	12,200	12,235	12,334	12,307	12,371	12,433	148,451	
Rate 41B	155	400 M	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000000
	39	100S	5	5	5	5	5	5	5	5	4	4	4	4	56	3.320000
	74	200 S	5	5	5	5	5	5	5	5	3	3	3	3	52	4.550000
	100	250 S	1	1	1	1	1	1	1	1	1	1	1	1	12	5.480000
	157	400 S	1	1	1	1	1	1	1	1	1	1	1	1	12	7.510000
		kWh	1,232	1,341	1,347	1,411	1,388	1,382	1,447	1,397	1,080	1,035	1,013	867	14,940	
		Rev 41B	52	52	52	52	52	52	52	52	40	40	40	40	578	
Rate 41C	**O**	**kWh**	405	440	442	463	456	454	475	459	660	715	701	599	6,270	0.05133
		Rev 41C	21	23	23	24	23	23	24	24	34	37	36	31	322	
Rate 41CM	**O**	**Bills**	12	12	12	12	12	12	12	12	12	12	12	12	142	2.88
		kWh	21,501	20,567	19,722	17,469	16,448	15,456	14,064	14,792	16,706	16,124	17,612	18,935	209,395	0.05133
		Rev 41CM	1,138	1,090	1,047	931	879	828	756	793	891	861	937	1,005	11,157	
SPECIAL CONTRACTS			**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**		**As of 6/1/2022**
Rate 26	Micron	Bills	1	1	1	1	1	1	1	1	1	1	1	1	12	
		Contract kW	69,000	69,000	69,000	79,000	79,000	79,000	79,000	79,000	79,000	79,000	79,000	79,000	918,000	1.67
		kW	75,602	75,994	78,177	80,421	89,224	94,876	96,812	96,545	90,833	80,808	78,389	80,063	1,017,744	10.98
		kWh IPC	50,869,270	44,096,520	46,571,000	43,288,600	47,665,490	48,805,200	51,267,950	52,625,260	50,585,100	49,801,240	51,220,700	54,548,210	591,344,540	0.028150
		kWh PPA	3,466,730	5,198,480	8,246,000	10,241,400	12,189,510	12,673,800	13,223,050	12,106,740	9,915,900	7,469,760	4,188,300	2,947,790	101,867,460	
		kWh PPA Embedde	0	0	0	0	0	0	0	0	0	0	0	0	0	0.002632
		Excess Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Capacity Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Rev IPC	2,377,310	2,190,961	2,284,587	2,233,527	2,453,393	2,547,535	2,638,119	2,673,395	2,553,247	2,421,107	2,434,504	2,546,554	29,354,238	
		Rev PPA Fixed	9,124	13,682	21,703	26,955	32,083	33,357	34,803	31,865	26,099	19,660	11,024	7,759	268,115	
		Rev PPA Excess Ge	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Rev PPA Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Total Rev	2,386,434	2,204,644	2,306,291	2,260,482	2,485,476	2,580,892	2,672,922	2,705,260	2,579,346	2,440,767	2,445,528	2,554,312	29,622,353	
Rate 29	Simplot	Bills	1	1	1	1	1	1	1	1	1	1	1	1	12	
		Contract kW	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	300,000	2.31
		kW	23,000	22,757	22,589	22,648	21,678	21,552	22,620	22,332	21,170	21,488	22,601	22,823	267,258	7.88
		kWh	14,525,952	15,858,114	15,796,851	10,004,150	14,154,104	13,643,597	14,708,422	14,504,488	14,666,594	16,258,484	15,803,836	15,075,409	175,000,001	0.028345
		Rev	650,728	686,573	683,513	519,784	629,771	614,308	652,906	644,856	640,294	687,922	683,806	664,908	7,759,368	
Rate 30	DOE	Bills	1	1	1	1	1	1	1	1	1	1	1	1	12	
		Contract kW	44,343	44,306	40,900	36,094	30,910	28,035	24,362	24,517	26,522	38,301	38,514	45,882	422,686	8.5
		kWh	25,600,000	23,600,000	22,100,000	18,700,000	16,500,000	15,800,000	14,700,000	14,300,000	14,900,000	20,800,000	22,200,000	24,900,000	234,100,000	0.029709
		Rev	1,137,466	1,077,733	1,004,219	862,357	752,934	707,700	643,799	633,233	668,101	943,506	986,909	1,129,751	10,547,708	

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BRADY, DI TESTIMONY

EXHIBIT NO. 29

2023 Proposed Billing Determinants

Rate	State		Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
IDAHO															
Rate 01	I	**Bills**	490,124	489,968	489,175	488,869	488,833	490,266	491,169	492,205	492,961	493,490	494,545	496,102	5,897,706
		Min Bills	4317.0	5209.0	5532.0	6124.0	6327.0	7040.0	6746.0	6992.0	6196.0	6095.0	5680.0	4607.0	70,865
		S 0-800	0	0	0	0	0	107,705,737	291,989,525	291,836,540	274,547,850	165,245,533	1,339,673	0	1,132,664,858
		S 801-2000	0	0	0	0	0	26,992,602	124,621,446	186,566,162	144,752,733	42,838,290	307,424	0	526,078,657
		S Over 2000	0	0	0	0	0	3,317,782	19,892,419	40,629,156	27,427,387	5,887,679	52,441	0	97,206,864
		N 0-800	308,603,018	285,279,810	282,368,836	276,613,660	261,630,242	172,597,029	3,801,286	0	0	114,611,674	274,630,797	273,741,005	2,253,877,358
		N 801-2000	181,074,217	163,221,926	144,830,325	96,638,421	80,154,063	43,601,180	1,199,924	0	0	25,787,003	95,143,097	153,536,687	985,186,843
		N Over 2000	100,268,352	92,836,831	65,246,897	22,716,236	15,426,489	6,523,651	191,294	0	0	3,000,955	23,386,704	79,524,007	409,121,417
		Total kWh	589,945,587	541,338,567	492,446,058	395,968,317	357,210,794	360,737,981	441,695,895	519,031,858	446,727,970	357,371,134	394,860,136	506,801,700	5,404,135,997
Rate 03	I	**Bills**	19	19	19	19	19	19	19	19	19	19	19	19	225
		Total kWh	488,670	448,386	407,887	327,969	295,883	298,791	365,801	429,850	370,004	296,021	327,035	419,789	4,476,086
Rate 05	I	**Bills**	991	986	986	986	990	988	986	980	986	985	979	993	11,836
		Min Bills	2.0	3.0	2.0	2.0	4.0	3.0	2.0	3.0	3.0	1.0	2.0	2.0	29
		S Peak	0	0	0	0	0	73,623	244,425	297,960	254,108	128,468	1,219	0	999,802
		S Off Peak	0	0	0	0	0	326,158	1,068,942	1,270,715	1,137,789	601,957	4,874	0	4,410,435
		N Peak	353,659	345,296	316,405	250,974	229,201	139,106	2,441	0	0	82,674	245,279	314,792	2,279,827
		N Off Peak	1,539,285	1,366,262	1,238,094	990,981	910,510	595,021	17,308	0	0	332,836	967,550	1,299,438	9,257,286
		Total kWh	1,892,943	1,711,559	1,554,498	1,241,955	1,139,711	1,133,908	1,333,117	1,568,675	1,391,896	1,145,934	1,218,922	1,614,231	16,947,350
Rate 06	I	**Bills**	12,300	12,461	12,646	12,853	12,995	13,158	13,422	13,524	13,716	13,914	14,076	14,388	159,453
		Min Bills	79.0	104.0	110.0	100.0	116.0	126.0	110.0	141.0	140.0	160.0	164.0	132.0	1,482
		S 0-800	0	0	0	0	0	2,051,568	7,084,721	6,998,160	6,060,077	3,605,974	36,437	0	25,836,936
		S 801-2000	0	0	0	0	0	336,577	1,840,392	2,937,785	2,105,840	712,107	7,711	0	7,940,411
		S Over 2000	0	0	0	0	0	101,560	490,603	731,086	527,696	178,508	3,527	0	2,032,980
		N 0-800	7,566,814	6,218,974	5,398,532	5,075,688	4,673,904	3,057,927	83,552	0	0	2,570,480	8,189,198	8,880,983	51,716,052
		N 801-2000	4,570,064	3,514,475	2,546,593	1,438,269	1,135,857	575,237	18,685	0	0	443,790	2,686,331	4,896,001	21,825,301
		N Over 2000	3,713,895	2,721,836	1,474,936	557,381	385,301	196,784	8,351	0	0	100,399	961,738	3,440,195	13,560,815
		Total kWh	15,850,773	12,455,285	9,420,060	7,071,338	6,195,062	6,319,652	9,526,304	10,667,031	8,693,613	7,611,257	11,884,942	17,217,179	122,912,496
Rate 07	I	**Bills**	30,369	30,320	30,303	30,329	30,210	30,338	30,348	30,406	30,369	30,571	30,572	30,674	364,810
		Min Bills	162.0	202.0	195.0	169.0	208.0	162.0	197.0	156.0	158.0	164.0	189.0	215.0	2,177
		S 0-300	0	0	0	0	0	2,117,834	5,448,832	4,985,729	4,869,976	3,001,748	24,600	0	20,448,718
		S Over	0	0	0	0	0	1,824,743	6,201,802	7,623,209	6,596,113	2,888,691	20,601	0	25,155,159
		N 0-300	5,973,181	5,636,154	5,389,761	5,564,306	5,193,310	3,345,939	80,908	0	0	2,190,665	5,077,315	5,011,164	43,462,704
		N Over	8,235,210	8,045,351	6,642,173	4,959,378	4,416,609	2,780,570	83,392	0	0	2,018,639	4,993,608	7,043,648	49,218,578
		Total kWh	14,208,391	13,681,505	12,031,934	10,523,684	9,609,919	10,069,086	11,814,934	12,608,938	11,466,089	10,099,744	10,116,124	12,054,812	138,285,160
Rate 08	I	**Bills**	82	82	84	85	86	88	89	90	90	90	91	93	1,050
		Min Bills	0.0	0.0	1.0	0.0	0.0	0.0	0.0	1.0	0.0	2.0	1.0	1.0	6
		S 0-300	0	0	0	0	0	3,172	10,788	9,995	10,666	6,454	57	0	41,132
		S Over	0	0	0	0	0	1,748	12,069	22,086	23,998	8,878	169	0	68,948
		N 0-300	14,137	14,187	13,145	12,700	9,982	5,859	152	0	0	3,925	16,377	14,611	105,075
		N Over	28,918	24,904	18,518	8,584	7,447	3,346	131	0	0	3,395	21,525	38,785	155,553
		Total kWh	43,055	39,090	31,663	21,284	17,429	14,126	23,140	32,081	34,664	22,653	38,129	53,395	370,708
Rate 09S	I	**Bills**	37473.4	37518.3	37564.4	37635.7	37677.7	37704.6	37761.8	37824	37924.9	37975.7	38108.3	37993.2	453,162
		Min Bills	124.0	155.0	180.0	174.0	138.0	126.0	164.0	132.0	152.0	149.0	158.0	132.0	1,784
		BLC	1,234,995	1,261,854	1,246,605	1,260,028	1,267,685	1,283,905	1,248,027	1,243,213	1,231,494	1,250,562	1,239,715	1,242,584	15,010,667
		S kW	0	0	0	0	0	388,390	954,495	999,523	993,941	556,495	4,971	0	3,897,816
		N kW	876,295	893,936	886,742	882,243	903,630	572,451	14,868	0	0	419,937	911,529	882,874	7,244,505
		kW Total	876,295	893,936	886,742	882,243	903,630	960,841	969,363	999,523	993,941	976,432	916,501	882,874	11,142,321
		S kWh	0	0	0	0	0	106,429,828	281,656,066	305,711,331	295,926,298	152,217,968	1,356,127	0	1,143,297,617
		N kWh	292,742,285	293,509,062	273,130,416	253,892,738	250,372,471	154,953,501	4,314,151	0	0	115,549,812	258,969,687	280,812,878	2,178,247,001

		Total kWh	292,742,285	293,509,062	273,130,416	253,892,738	250,372,471	261,383,329	285,970,217	305,711,331	295,926,298	267,767,780	260,325,814	280,812,878	3,321,544,618
Rate 09P	I	**Bills**	281.4	281.1	279	276.8	280.4	275.7	285.9	279.7	281	280	282.1	278.8	3,362
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
		BLC	161,070	157,417	160,006	157,428	159,471	167,508	172,468	165,516	154,215	159,557	159,756	160,908	1,935,320
		S kW	0	0	0	0	0	0	140,515	142,116	139,062	141,174	0	(270)	562,598
		N kW	122,555	118,748	121,749	118,891	120,018	132,429	2,223	0	0	0	128,829	123,437	988,878
		Total kW	122,555	118,748	121,749	118,891	120,018	132,429	142,738	142,116	139,062	141,174	128,829	123,167	1,551,476
		On-peak kW	0	0	0	0	0	0	131,493	133,093	130,008	131,415	0	(340)	525,669
		S On-peak kWh	0	0	0	0	0	0	7,458,614	7,670,305	7,647,899	6,824,805	0	0	29,601,623
		S Mid-peak kWh	0	0	0	0	0	0	10,414,972	10,630,151	10,879,434	9,712,760	0	0	41,637,317
		S Off-peak kWh	0	0	0	0	0	0	35,022,708	38,428,477	35,747,585	34,528,530	0	0	143,727,301
		N On-peak kWh	11,099,904	10,559,968	10,345,919	10,874,684	10,290,804	10,547,528	0	0	0	0	10,997,644	10,683,576	85,400,026
		N Mid-peak kWh	11,296,591	10,729,769	10,537,625	11,210,443	10,694,244	11,119,677	0	0	0	0	11,372,637	10,870,847	87,831,834
		N Off-peak kWh	27,235,357	27,671,727	24,570,320	25,165,165	24,160,052	27,707,574	0	0	0	0	26,900,769	26,532,976	209,943,940
		Total kWh	49,631,851	48,961,464	45,453,864	47,250,292	45,145,100	49,374,779	52,896,294	56,728,933	54,274,918	51,066,095	49,271,050	48,087,399	598,142,039
Rate 09T	I	**Bills**	4	4	4	4	4	4	4	4	4	4	4	4	48
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
		BLC	1,374	1,288	1,220	1,432	1,490	1,439	1,386	1,339	1,486	1,580	1,501	1,473	17,008
		S kW	0	0	0	0	0	0	1,176	990	1,044	1,189	0	0	4,400
		N kW	1,090	994	946	1,208	1,366	1,377	0	0	0	0	1,235	1,269	9,486
		Total kW	1,090	994	946	1,208	1,366	1,377	1,176	990	1,044	1,189	1,235	1,269	13,886
		On-peak kW	0	0	0	0	0	0	1,027	832	891	1,018	0	0	3,767
		S On-peak kWh	0	0	0	0	0	0	33,165	24,083	28,203	25,210	0	0	110,660
		S Mid-peak kWh	0	0	0	0	0	0	51,785	36,518	40,463	40,253	0	0	169,020
		S Off-peak kWh	0	0	0	0	0	0	213,120	171,466	181,735	194,362	0	0	760,683
		N On-peak kWh	71,700	61,108	57,802	65,925	71,263	67,286	0	0	0	0	72,835	74,551	542,469
		N Mid-peak kWh	74,456	66,349	60,911	70,033	75,809	71,570	0	0	0	0	75,641	77,582	572,351
		N Off-peak kWh	173,701	175,365	149,673	162,941	177,795	186,090	0	0	0	0	179,449	196,945	1,401,959
		Total kWh	319,857	302,822	268,387	298,899	324,867	324,946	298,070	232,066	250,401	259,826	327,925	349,077	3,557,143
Rate 19S	I	**Bills**	1	1	1	1	1	1	1	1	1	1	1	1	12
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
		BLC	1,209	1,203	1,176	1,170	1,177	1,213	1,171	1,184	1,188	1,162	1,164	1,150	14,167
		S kW	0	0	0	0	0	0	1,067	1,086	1,080	1,058	0	0	4,291
		N kW	1,142	1,127	1,104	1,135	1,152	1,134	0	0	0	0	1,134	1,123	9,051
		Total kW	1,142	1,127	1,104	1,135	1,152	1,134	1,067	1,086	1,080	1,058	1,134	1,123	13,342
		On-peak kW	0	0	0	0	0	0	830	895	866	848	0	0	3,439
		S On-peak kWh	0	0	0	0	0	15,186	72,153	77,575	81,111	78,585	0	0	324,610
		S Mid-peak kWh	0	0	0	0	0	19,311	90,864	99,176	105,959	103,593	0	0	418,903
		S Off-peak kWh	0	0	0	0	0	67,396	328,195	352,012	343,120	368,497	0	0	1,459,219
		N On-peak kWh	121,298	124,751	113,939	126,095	121,616	86,802	0	0	0	0	126,064	117,161	937,724
		N Mid-peak kWh	124,357	129,140	118,204	129,497	125,204	88,967	0	0	0	0	129,587	120,529	965,486
		N Off-peak kWh	336,667	317,850	279,175	308,717	300,952	242,383	0	0	0	0	330,883	312,059	2,428,686
		Total kWh	582,322	571,741	511,317	564,309	547,771	520,046	491,212	528,763	530,190	550,674	586,535	549,749	6,534,628
Rate 19P	I	**Bills**	113	113	113	113	113	113	113	113	113	113	113	113	1,356
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
		BLC	431,617	440,148	420,070	427,664	439,780	445,858	437,209	444,833	443,608	434,900	436,890	438,634	5,241,211
		S kW	0	0	0	0	0	0	391,774	402,402	406,562	400,556	0	(575)	1,600,720
		N kW	378,684	385,302	367,585	369,769	374,451	380,809	0	0	0	0	389,446	387,351	3,033,396
		Total kW	378,684	385,302	367,585	369,769	374,451	380,809	391,774	402,402	406,562	400,556	389,446	386,777	4,634,116
		On-peak kW	0	0	0	0	0	0	376,296	386,737	390,330	384,753	0	(192)	1,537,925
		S On-peak kWh	0	0	0	0	0	0	28,850,445	28,546,246	30,640,333	27,694,697	0	0	115,731,721
		S Mid-peak kWh	0	0	0	0	0	0	37,159,894	36,904,813	39,760,363	36,013,270	0	0	149,838,340
		S Off-peak kWh	0	0	0	0	0	0	129,282,859	139,182,703	136,589,792	130,881,667	0	0	535,937,021
		N On-peak kWh	42,825,906	42,579,852	39,164,829	43,167,842	41,003,880	40,184,243	0	0	0	0	43,514,945	41,794,107	334,235,604
		N Mid-peak kWh	43,038,301	42,960,026	39,497,565	43,655,658	41,504,801	40,877,795	0	0	0	0	43,834,897	42,064,849	337,433,892
		N Off-peak kWh	111,025,731	118,639,767	99,613,937	106,623,757	101,977,752	111,963,209	0	0	0	0	114,250,609	110,023,987	874,118,749
		Total kWh	196,889,938	204,179,645	178,276,331	193,447,257	184,486,432	193,025,248	195,293,198	204,633,762	206,990,488	194,589,634	201,600,451	193,882,943	2,347,295,327
Rate 19T	I	**Bills**	2	2	2	2	2	2	2	2	2	2	2	2	24
		Min Bills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-

		BLC	5,069	5,130	4,339	4,350	5,393	5,239	4,887	5,131	5,541	5,005	4,679	5,251	60,014
		S kW	0	0	0	0	0	0	4,757	5,020	5,412	4,876	0	0	20,063
		N kW	4,997	5,021	4,246	4,295	5,247	5,088	0	0	0	0	4,551	5,134	38,580
		Total kW	4,997	5,021	4,246	4,295	5,247	5,088	4,757	5,020	5,412	4,876	4,551	5,134	58,643
		On-peak kW	0	0	0	0	0	0	4,529	4,722	5,186	4,634	0	0	19,071
		S On-peak kWh	0	0	0	0	0	0	365,330	357,420	427,079	367,027	0	0	1,516,856
		S Mid-peak kWh	0	0	0	0	0	0	456,627	459,872	535,646	456,828	0	0	1,908,973
		S Off-peak kWh	0	0	0	0	0	0	1,846,406	2,016,303	2,078,860	1,941,946	0	0	7,883,515
		N On-peak kWh	628,706	614,421	474,389	526,466	596,933	603,009	0	0	0	0	561,956	600,646	4,606,525
		N Mid-peak kWh	626,332	615,646	475,024	532,592	599,586	597,293	0	0	0	0	564,016	597,709	4,608,196
		N Off-peak kWh	1,675,969	1,739,298	1,217,779	1,322,629	1,544,785	1,701,860	0	0	0	0	1,509,648	1,629,647	12,341,615
		Total kWh	2,931,006	2,969,365	2,167,192	2,381,687	2,741,303	2,902,162	2,668,363	2,833,595	3,041,585	2,765,801	2,635,620	2,828,001	32,865,680
Rate 24	I	**In Bills**	0	0	0	0	0	19327.8	19243	19478.2	19621.3	0	0	0	77,670
	I	**Out-Bills**	18525	18838.8	18916.6	19284.1	19398	0	0	0	0	19478.4	19081.8	18953.8	152,477
		Min Bills	39.9	23.9	62.5	71.2	48.7	22.3	-0.3	0.0	6.9	34.6	44.7	24.3	379
		In-kW						1,007,972	1,080,974	1,018,561	957,920				4,065,427
		Out-kW	Out of Season - No Impact					0	0	0	0	Out of Season - No Impact			-
		Total kW						1,007,972	1,080,974	1,018,561	957,920				4,065,427
		In-kWh	(451)	(71,914)	0	0	30,276	287,426,700	457,854,983	435,332,630	326,716,896	883,204	7,163	347,305	1,508,526,794
		Out-kWh	2,605,766	2,575,541	2,950,218	28,547,278	151,846,820	661,503	(257,707)	(5,393,540)	5,555,976	139,914,453	23,656,636	3,333,035	355,995,978
		Total kWh	2,605,316	2,503,627	2,950,218	28,547,278	151,877,097	288,088,203	457,597,276	429,939,089	332,272,872	140,797,657	23,663,799	3,680,340	1,864,522,772
Rate 40	I	**In Bills**	1663	1663	1663	1663	1663	1663	1663	1663	1663	1663	1663	1663	19,956
		Min Bills	70.6	68.8	68.9	70.8	71.5	71.8	67.9	70.9	71.9	72.6	70.9	70.3	847
		kWh	1,111,671	1,129,997	1,135,643	1,141,087	1,153,527	1,159,902	1,165,140	1,176,306	1,183,323	1,187,351	1,189,839	1,191,515	13,925,301
		Intermittent Usage	14	14	14	14	14	14	14	14	14	14	14	14	168
Rate 42	I	**Bills**	766	766	766	766	766	766	766	766	766	766	766	766	9,192
		kWh	247,623	249,052	216,602	249,052	231,141	225,244	235,982	234,167	240,982	235,926	242,437	239,753	2,847,961
Rate 15		1csa	7,515	7,518	7,512	7,495	7,503	7,493	7,470	7,455	7,430	7,438	7,439	7,446	89,714
		2csa	769	772	776	774	790	790	795	791	802	789	797	813	9,459
		2csf	808	812	807	814	794	793	794	795	794	795	798	796	9,599
		4chf	105	104	104	104	100	99	95	92	92	90	90	89	1,164
		4csa	139	141	151	152	157	157	151	153	152	150	149	149	1,801
		4csf	440	447	445	446	445	447	453	450	454	452	456	453	5,387
		1khf	71	79	79	80	80	80	81	80	81	82	83	80	956
		Min Bill	34.2	30.8	34.4	35.7	31.8	37.6	42.6	36.2	38.2	39.1	34.3	38.8	434
		Total kWh	467,630	460,083	454,542	448,316	445,066	440,449	434,588	434,010	429,419	424,087	418,486	410,747	5,267,423
Rate 41A	I														
		70 S	36	36	36	36	36	36	36	36	36	36	35	36	431
		100 S	15,573	14,950	13,395	16,513	14,949	14,952	14,957	14,804	14,963	14,992	14,994	15,005	180,046
		200 S	1,793	1,667	1,565	1,765	1,668	1,670	1,671	1,642	1,671	1,674	1,675	1,676	20,137
		250 S	240	238	233	246	238	228	227	228	230	231	230	230	2,799
		400 S	119	120	100	144	122	125	126	126	126	126	126	126	1,486
		41A Variable Usage	3,624	3,624	3,624	3,624	3,624	3,624	3,624	3,402	3,624	3,624	3,624	3,624	43,270
		41A kWh	431,570	391,271	341,515	413,338	356,774	341,204	342,933	334,813	319,578	302,319	295,621	282,208	4,153,143
		All Rate 41 Bills	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	35,760
		All Rate 41 kWh	2,294,057	2,126,315	1,939,585	2,126,315	1,927,140	1,868,190	1,866,664	1,879,169	1,904,924	1,904,924	1,951,450	1,971,281	23,760,014
															-
Rate 41B	29	70 S	0	0	0	0	0	0	0	0	0	0	0	0	-
	39	100 S	3,219	3,092	3,008	2,976	2,957	2,060	1,917	1,913	675	661	661	660	23,799
	74	200 S	148	127	120	120	117	113	110	110	68	65	64	64	1,226
	100	250 S	858	832	826	813	794	749	674	649	574	433	419	418	8,039
	157	400 S	127	127	127	125	123	121	122	120	70	70	57	56	1,245
		Variable Usage Cha	0	0	0	0	0	0	0	0	0	0	0	0	-
		kwh	273,073	256,567	239,127	263,502	241,734	198,240	187,222	185,109	108,196	90,770	86,911	84,537	2,214,987
															-
Rate 41BM		100 S	0	0	0	0	0	0	0	0	0	0	0	0	-
		200 S	0	0	0	0	0	0	0	0	0	0	0	0	-
		250 S	33	33	33	33	33	33	33	33	33	33	33	33	396

		400 S	0	0	0	0	0	0	0	0	0	0	0	0	-
		Bills	6	6	6	6	6	7	4	4	4	4	4	4	61
		kWh	10,274	8,601	7,518	7,717	6,344	5,846	5,160	4,299	4,997	5,114	5,893	6,340	78,103
															-
Rate 41C		**kWh**	857,989	844,827	805,767	903,470	845,378	873,468	896,048	892,087	951,296	951,591	951,646	930,670	10,704,238
															-
Rate 41CM	**I**	**Bills**	1230	1228	1226	1229	1230	1231	1233	1230	1228	1227	1226	1228	14,746
		kWh	721,151	625,049	545,658	538,287	476,911	449,432	435,301	462,861	520,856	555,130	611,379	667,526	6,609,543
															-
Rate 09S TOU	I	**Bills**	37473.4	37518.3	37564.4	37635.7	37677.7	37704.6	37761.8	37824	37924.9	37975.7	38108.3	37993.2	453,162
		Min Bills	124	155	180	174	138	126	164	132	152	149	158	132	1,784
		BLC	1,234,995	1,261,854	1,246,605	1,260,028	1,267,685	1,283,905	1,248,027	1,243,213	1,231,494	1,250,562	1,239,715	1,242,584	15,010,667
		S kW	0	0	0	0	0	388,390	954,495	999,523	993,941	556,495	4,971	0	3,897,816
		N kW	876,295	893,936	886,742	882,243	903,630	572,451	14,868	0	0	419,937	911,529	882,874	7,244,505
		kW Total	876,295	893,936	886,742	882,243	903,630	960,841	969,363	999,523	993,941	976,432	916,501	882,874	11,142,321
		S On-peak kWh	0	0	0	0	0	14,902,260	39,345,426	43,384,600	40,177,715	20,707,976	203,810	0	158,721,787
		S Mid-peak kWh	0	0	0	0	0	21,368,181	55,903,775	62,139,039	58,851,349	30,472,640	292,401	0	229,027,384
		S Off-peak kWh	0	0	0	0	0	70,159,387	186,406,865	200,187,692	196,897,234	101,037,352	859,916	0	755,548,446
		N On-peak kWh	62,279,428	66,275,196	61,650,260	57,174,536	56,124,199	32,736,594	634,547	0	0	25,846,693	58,333,605	61,883,748	482,938,805
		N Mid-peak kWh	64,317,629	68,677,467	64,349,644	60,822,507	60,323,472	35,368,238	680,640	0	0	27,346,279	61,243,599	63,867,562	506,997,039
		N Off-peak kWh	166,145,229	158,556,399	147,130,512	135,895,695	133,924,800	86,848,668	2,998,964	0	0	62,356,841	139,392,483	155,061,568	1,188,311,158
		Total kWh	292,742,285	293,509,062	273,130,416	253,892,738	250,372,471	261,383,329	285,970,217	305,711,331	295,926,298	267,767,780	260,325,814	280,812,878	3,321,544,618

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BRADY, DI TESTIMONY

EXHIBIT NO. 30

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

AVERAGE

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	786,100.5	761,910.5	810,884.1	849,798.1	889,410.6	882,292.4	739,722.5	603,685.1	565,117.7	460,156.2	414,198.9	578,194.8	8,341,471.4
Bridger Coal													
Energy (MWh)	124,033.1	76,906.0	48,937.0	52,205.3	57,219.6	103,063.0	168,516.7	225,325.0	213,150.9	221,858.4	233,383.2	248,640.8	1,773,238.9
Expense ($ x 1000)	$ 3,883.4	$ 2,497.3	$ 1,723.4	$ 1,807.2	$ 2,191.7	$ 3,570.9	$ 5,475.0	$ 7,110.2	$ 6,739.6	$ 7,010.3	$ 7,322.0	$ 7,781.4	$ 57,112.4
Valmy													
Energy (MWh)	121.5	-	-	-	-	166.4	30,862.0	36,500.4	18,944.3	5,165.1	39,955.1	49,495.5	181,210.3
Expense ($ x 1000)	$ 5.8	$ -	$ -	$ -	$ -	$ 7.9	$ 1,436.8	$ 1,694.9	$ 884.0	$ 240.5	$ 1,859.4	$ 2,281.5	$ 8,410.6
Bridger Gas													
Energy (MWh)	-	35,241.7	-	2,431.8	1,151.2	3,960.5	20,893.2	32,167.9	18,107.6	24,179.7	-	-	138,133.7
Expense ($ x 1000)	$ -	$ 1,297.2	$ -	$ 107.3	$ 43.9	$ 174.1	$ 1,006.2	$ 1,559.2	$ 814.8	$ 1,070.3	$ -	$ -	$ 6,072.8
Langley Gulch													
Energy (MWh)	129,390.0	114,764.4	57,729.0	53,023.0	86,144.4	126,796.3	214,814.5	215,911.8	207,623.4	221,421.4	159,251.6	125,022.9	1,711,892.7
Expense ($ x 1000)	$ 10,055.9	$ 3,250.2	$ 3,580.0	$ 1,781.3	$ 2,457.2	$ 3,864.7	$ 7,210.1	$ 7,795.7	$ 6,909.8	$ 7,462.7	$ 11,314.8	$ 13,032.6	$ 78,715.1
Danskin													
Energy (MWh)	13,089.2	144.4	735.0	17.5	157.3	21,732.9	91,822.7	71,882.8	4,729.6	432.8	553.9	7,834.8	213,132.9
Expense ($ x 1000)	$ 1,716.8	$ 6.7	$ 70.4	$ 1.0	$ 7.0	$ 1,051.8	$ 5,015.8	$ 4,284.0	$ 258.5	$ 24.1	$ 63.2	$ 1,257.5	$ 13,756.8
Bennett Mountain													
Energy (MWh)	3,593.0	108.5	353.6	6.1	118.4	10,534.4	52,008.4	38,590.4	2,352.8	-	689.7	2,853.8	111,209.3
Expense ($ x 1000)	$ 464.9	$ 4.9	$ 32.9	$ 0.3	$ 5.7	$ 515.7	$ 2,870.6	$ 2,305.2	$ 127.1	$ -	$ 76.6	$ 445.8	$ 6,849.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.5	$ 1,111.1	$ 1,207.5	$ 1,173.8	$ 1,207.5	$ 1,173.8	$ 1,207.5	$ 1,207.5	$ 1,173.8	$ 1,207.5	$ 1,173.8	$ 1,207.5	$ 14,259.2
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	147,710.0	44,687.6	78,700.4	24,845.4	50,190.5	112,253.4	221,549.1	175,750.7	73,528.3	51,327.0	168,173.5	225,320.1	1,374,036.1
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	223,482.2	108,916.2	161,143.9	110,184.8	140,943.6	202,339.6	315,901.5	264,236.1	149,125.0	123,723.6	237,439.5	295,120.5	2,332,556.4
Market Expense ($ x 1000)	$ 7,109.0	$ 1,484.7	$ 2,193.0	$ 717.3	$ 1,311.7	$ 3,269.4	$ 7,687.3	$ 6,730.4	$ 2,731.8	$ 1,919.8	$ 6,578.8	$ 10,393.9	$ 52,127.0
Market Expense - No Wheeling ($ x 1000)	$ 6,005.68	$ 1,150.92	$ 1,605.15	$ 531.70	$ 936.77	$ 2,430.91	$ 6,032.49	$ 5,417.70	$ 2,182.54	$ 1,536.45	$ 5,322.66	$ 8,710.94	$ 41,863.9
Elkhorn Wind Expense ($ x 1000)	$ 2,451.0	$ 1,720.3	$ 1,870.3	$ 1,914.6	$ 1,926.4	$ 1,795.5	$ 2,109.1	$ 1,843.1	$ 1,419.1	$ 1,543.2	$ 1,926.7	$ 2,221.4	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.4	$ 270.6	$ 456.4	$ 551.6	$ 686.4	$ 755.1	$ 792.2	$ 732.7	$ 591.6	$ 430.4	$ 223.2	$ 174.7	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.1	$ 1,956.5	$ 2,308.4	$ 1,951.7	$ 1,687.2	$ 1,464.7	$ 1,095.4	$ 1,270.7	$ 1,510.6	$ 2,009.0	$ 2,450.0	$ 2,444.1	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.8	$ 497.5	$ 617.5	$ 534.1	$ 481.9	$ 432.2	$ 481.0	$ 496.2	$ 472.7	$ 536.7	$ 595.1	$ 595.3	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 11,763.9	$ 5,595.9	$ 6,857.8	$ 5,483.7	$ 5,718.6	$ 6,878.4	$ 10,510.2	$ 9,760.3	$ 6,176.5	$ 6,055.6	$ 10,517.6	$ 14,146.5	$ 99,465.0
Storage													
Black Mesa Battery Energy (MWh)	(1,231.6)	(983.0)	(1,238.9)	(1,124.7)	(967.4)	(854.0)	(877.7)	(871.0)	(805.5)	(922.2)	(911.7)	(1,102.7)	(11,890.3)
80 MW Grid Battery Energy (MWh)	(2,447.3)	(1,979.2)	(2,467.2)	(2,252.3)	(1,948.3)	(1,709.9)	(1,752.9)	(1,740.0)	(1,617.6)	(1,841.0)	(1,790.9)	(2,177.3)	(23,723.7)
11 MW Grid Battery Energy (MWh)	(332.6)	(261.4)	(316.8)	(300.0)	(256.0)	(225.4)	(241.6)	(236.5)	(214.4)	(251.6)	(231.4)	(277.8)	(3,145.4)

Total Storage (MWh)	(4,011.4)	(3,223.6)	(4,022.9)	(3,677.0)	(3,171.6)	(2,789.2)	(2,872.2)	(2,847.5)	(2,637.5)	(3,014.8)	(2,933.9)	(3,557.8)	(38,759.4)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.3	8,800.0	8,106.7	800.0	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.2	33.5	74.9	73.1	88.6	102.2	98.2	88.9	75.2	68.7	47.6	24.8	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.4	225,952.5	246,142.3	288,603.1	313,597.5	318,696.2	295,393.9	281,711.2	234,049.4	222,197.3	177,903.2	183,093.7	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	49,744.8	86,332.7	104,135.1	184,194.9	131,842.8	65,626.2	8,733.1	11,500.0	37,597.0	57,258.7	9,118.6	10,498.6	756,582.5
Revenue ($ x 1000)	$ 2,016.2	$ 3,149.8	$ 2,928.0	$ 5,401.5	$ 3,539.0	$ 1,886.0	$ 363.9	$ 606.0	$ 1,622.8	$ 2,360.9	$ 467.9	$ 484.4	$ 24,826.5
Revenue - No Wheeling ($ x 1000)	$ 1,644.61	$ 2,504.99	$ 2,150.23	$ 4,025.64	$ 2,554.24	$ 1,395.80	$ 298.62	$ 520.11	$ 1,342.01	$ 1,933.24	$ 399.80	$ 406.00	$ 19,175.3
Total Energy	1,428,850.9	1,234,421.5	1,217,841.8	1,168,470.8	1,353,816.9	1,602,921.8	1,927,228.2	1,763,858.9	1,373,841.6	1,218,929.6	1,251,370.2	1,476,225.0	17,017,777.3
Total NPSE	$ 42,370.7	$ 27,921.2	$ 24,164.6	$ 20,892.7	$ 24,326.8	$ 37,795.5	$ 58,527.8	$ 58,366.8	$ 38,788.0	$ 36,567.6	$ 47,715.9	$ 56,826.4	$ 479,915.2

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1981

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	792,720.5	868,647.5	806,477.0	844,673.8	693,665.0	868,212.9	712,875.4	546,547.0	603,413.2	456,539.7	358,142.4	632,637.8	8,184,552.0
Bridger Coal													
Energy (MWh)	125,632.9	75,815.2	46,769.8	44,383.7	49,018.5	91,570.6	166,180.9	238,667.4	232,977.2	231,209.7	240,568.8	250,686.7	1,793,481.27
Expense ($ x 1000)	$ 3,929.37	$ 2,465.92	$ 1,661.07	$ 1,582.25	$ 1,955.60	$ 3,240.12	$ 5,407.83	$ 7,494.24	$ 7,310.26	$ 7,279.46	$ 7,528.89	$ 7,840.28	$ 57,695.29
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	40,144.1	42,831.9	1,535.4	282.6	40,297.4	51,238.0	176,450.9
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,867.74	$ 1,991.24	$ 71.80	$ 13.16	$ 1,876.93	$ 2,366.95	$ 8,193.6
Bridger Gas													
Energy (MWh)	-	30,048.1	-	4,725.1	226.4	974.4	33,091.8	28,406.7	14,879.1	29,853.2	-	-	142,204.8
Expense ($ x 1000)	$ -	$ 1,099.29	$ -	$ 210.77	$ 8.83	$ 42.08	$ 1,572.08	$ 1,372.58	$ 656.29	$ 1,307.35	$ -	$ -	$ 6,269.3
Langley Gulch													
Energy (MWh)	178,716.7	8,151.3	-	-	189,688.2	207,604.3	215,555.0	216,497.2	212,066.9	221,374.3	176,754.7	149,975.9	1,776,384.5
Expense ($ x 1000)	$ 13,597.30	$ 221.74	$ -	$ -	$ 5,134.39	$ 6,069.07	$ 7,204.54	$ 7,786.00	$ 7,016.50	$ 7,432.39	$ 12,387.60	$ 15,084.51	$ 81,934.0
Danskin													
Energy (MWh)	-	-	-	-	-	1,658.0	100,192.6	97,164.2	-	-	5,322.4	-	204,337.1
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 70.78	$ 5,259.45	$ 5,473.72	$ -	$ -	$ 592.97	$ -	$ 11,396.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	1,387.3	48,037.1	35,720.4	3,521.1	-	486.1	-	89,151.9
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 62.57	$ 2,535.48	$ 2,022.16	$ 180.70	$ -	$ 54.14	$ -	$ 4,855.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	79,913.8	26,799.4	71,423.8	7,974.7	62,844.7	75,528.6	223,295.9	188,212.8	42,002.8	51,890.9	192,905.3	153,036.2	1,175,828.8
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	155,686.0	91,028.0	153,867.3	93,314.1	153,597.8	165,614.8	317,648.4	276,698.1	117,599.5	124,287.4	262,171.3	222,836.6	2,134,349.2
Market Expense ($ x 1000)	$ 3,279.43	$ 817.22	$ 1,799.19	$ 201.96	$ 1,561.04	$ 2,029.49	$ 7,414.09	$ 7,166.49	$ 1,535.87	$ 1,952.53	$ 7,622.81	$ 6,483.81	$ 41,863.9
Market Expense - No Wheeling ($ x 1000)	$ 2,682.53	$ 617.05	$ 1,265.70	$ 142.39	$ 1,091.63	$ 1,465.34	$ 5,746.22	$ 5,760.67	$ 1,222.14	$ 1,564.94	$ 6,181.94	$ 5,340.73	$ 33,081.3
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 8,440.8	$ 5,062.0	$ 6,518.3	$ 5,094.4	$ 5,873.5	$ 5,912.8	$ 10,223.9	$ 10,103.2	$ 5,216.1	$ 6,084.1	$ 11,376.9	$ 10,776.3	$ 90,682.4
Storage													
Black Mesa Battery Energy (MWh)	(1,256.78)	(892.75)	(1,132.3)	(1,147.9)	(938.2)	(861.2)	(868.9)	(870.5)	(814.4)	(975.3)	(951.0)	(1,178.9)	(11,888.1)
80 MW Grid Battery Energy (MWh)	(2,466.44)	(1,775.24)	(2,269.9)	(2,284.3)	(1,867.7)	(1,763.1)	(1,750.9)	(1,737.4)	(1,603.4)	(1,999.3)	(1,868.2)	(2,326.3)	(23,712.2)

11 MW Grid Battery Energy (MWh)	(336.65)	(242.84)	(286.4)	(300.3)	(251.0)	(230.6)	(239.5)	(234.9)	(217.3)	(270.0)	(249.3)	(296.7)	(3,155.5)
Total Storage (MWh)	(4,059.9)	(2,910.8)	(3,688.7)	(3,732.6)	(3,056.9)	(2,854.9)	(2,859.4)	(2,842.8)	(2,635.0)	(3,244.6)	(3,068.5)	(3,801.9)	(38,755.8)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	22,764.2	62,343.7	31,800.9	103,569.5	43,008.2	51,697.3	7,929.8	5,737.8	44,440.3	63,638.7	7,255.2	10,466.5	454,652.1
Revenue ($ x 1000)	$ 1,331.1	$ 2,503.6	$ 1,184.3	$ 3,597.0	$ 1,310.2	$ 1,652.0	$ 420.6	$ 344.6	$ 1,843.3	$ 2,616.7	$ 373.2	$ 639.8	$ 17,816.4
Revenue - No Wheeling ($ x 1000)	$ 1,161.1	$ 2,037.9	$ 946.7	$ 2,823.4	$ 988.9	$ 1,265.9	$ 361.3	$ 301.7	$ 1,511.4	$ 2,141.4	$ 319.0	$ 561.6	$ 14,420.4
Total Energy	1,428,850.93	1,234,421.46	1,217,841.84	1,168,470.80	1,353,816.92	1,602,921.81	1,927,228.24	1,763,858.91	1,373,841.60	1,218,929.61	1,251,370.18	1,476,225.01	17,017,777.31
Total NPSE	$ 41,138.3	$ 24,764.2	$ 21,823.3	$ 20,403.7	$ 29,103.9	$ 37,363.4	$ 59,017.5	$ 60,362.0	$ 37,108.9	$ 36,564.8	$ 50,474.3	$ 53,793.8	$ 475,314.0

Wheeling 3-Year Average $ 7.47

1982

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	807,357.3	900,601.9	1,074,415.8	1,008,560.2	1,134,295.4	1,155,438.1	1,193,723.0	877,453.3	765,593.0	575,288.8	656,255.0	1,084,226.2	11,233,208.0
Bridger Coal													
Energy (MWh)	124,993.1	50,669.3	34,203.4	32,779.7	37,125.8	71,746.2	114,961.6	165,360.7	104,903.7	156,413.4	202,298.2	215,894.3	1,311,349.54
Expense ($ x 1000)	$ 3,910.97	$ 1,742.66	$ 1,299.62	$ 1,248.49	$ 1,613.37	$ 2,669.51	$ 3,933.56	$ 5,384.18	$ 3,623.50	$ 5,126.34	$ 6,427.28	$ 6,838.50	$ 43,817.98
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	-	3,695.9	-	40.5	32,801.4	2,465.2	39,124.5
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ -	$ 173.71	$ -	$ 1.92	$ 1,538.65	$ 115.38	$ 1,835.4
Bridger Gas													
Energy (MWh)	-	44,106.1	-	3,054.3	716.4	4,833.7	15,701.8	26,010.2	4,399.5	15,949.5	-	-	114,771.5
Expense ($ x 1000)	$ -	$ 1,390.39	$ -	$ 117.44	$ 24.04	$ 180.25	$ 642.32	$ 1,082.34	$ 167.22	$ 601.32	$ -	$ -	$ 4,205.3
Langley Gulch													
Energy (MWh)	162,902.6	3,576.4	-	-	-	27,234.3	200,974.1	215,512.3	214,339.5	223,932.0	7,617.0	-	1,056,088.1
Expense ($ x 1000)	$ 10,880.87	$ 87.07	$ -	$ -	$ -	$ 713.12	$ 5,953.07	$ 6,856.28	$ 6,276.61	$ 6,652.49	$ 488.24	$ -	$ 37,907.8
Danskin													
Energy (MWh)	63.5	-	-	-	-	-	183.6	739.9	-	-	-	-	986.9
Expense ($ x 1000)	$ 7.06	$ -	$ -	$ -	$ -	$ -	$ 8.71	$ 35.74	$ -	$ -	$ -	$ -	$ 51.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	2,074.6	-	-	-	-	2,074.6
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 97.56	$ -	$ -	$ -	$ -	$ 97.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	76,635.1	25,643.3	622.9	661.1	5,033.6	46,392.7	68,923.8	118,857.5	23,851.0	27,332.3	120,567.0	9,252.5	523,772.7
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	152,407.2	89,871.8	83,066.4	86,000.5	95,786.7	136,478.9	163,276.3	207,342.9	99,447.7	99,728.8	189,833.0	79,052.9	1,482,293.1
Market Expense ($ x 1000)	$ 2,873.53	$ 714.13	$ 15.07	$ 17.63	$ 114.02	$ 1,255.78	$ 2,134.69	$ 3,756.12	$ 698.99	$ 845.60	$ 3,976.30	$ 322.35	$ 16,724.2
Market Expense - No Wheeling ($ x 1000)	$ 2,301.12	$ 522.59	$ 10.42	$ 12.69	$ 76.42	$ 909.26	$ 1,619.87	$ 2,868.33	$ 520.84	$ 641.45	$ 3,075.74	$ 253.24	$ 12,812.0
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 8,059.4	$ 4,967.5	$ 5,263.0	$ 4,964.7	$ 4,858.3	$ 5,356.8	$ 6,097.6	$ 7,210.9	$ 4,514.8	$ 5,160.6	$ 8,270.7	$ 5,688.8	$ 70,413.1
Storage													
Black Mesa Battery Energy (MWh)	(1,134.97)	(924.46)	(1,448.2)	(1,209.5)	(1,077.4)	(886.1)	(875.8)	(841.4)	(638.5)	(952.7)	(892.3)	(1,059.1)	(11,940.3)
80 MW Grid Battery Energy (MWh)	(2,207.54)	(1,968.88)	(2,942.9)	(2,398.3)	(2,167.0)	(1,760.0)	(1,757.6)	(1,690.1)	(1,296.4)	(1,845.3)	(1,728.7)	(2,132.2)	(23,894.8)

11 MW Grid Battery Energy (MWh)	(304.37)	(255.22)	(373.7)	(325.1)	(285.3)	(232.2)	(242.4)	(228.8)	(174.5)	(253.9)	(236.3)	(270.9)	(3,182.5)
Total Storage (MWh)	(3,646.9)	(3,148.6)	(4,764.7)	(3,932.8)	(3,529.7)	(2,878.3)	(2,875.8)	(2,760.4)	(2,109.4)	(3,051.9)	(2,857.2)	(3,462.1)	(39,017.7)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	18,145.0	77,241.5	215,296.3	246,667.3	224,263.7	110,382.9	63,008.5	21,477.2	47,657.0	71,637.6	12,527.9	85,070.0	1,193,374.8
Revenue ($ x 1000)	$ 878.8	$ 2,882.2	$ 5,680.7	$ 6,602.6	$ 5,424.2	$ 3,001.5	$ 1,926.7	$ 978.0	$ 1,676.3	$ 2,577.3	$ 537.0	$ 3,400.8	$ 35,566.1
Revenue - No Wheeling ($ x 1000)	$ 743.2	$ 2,305.3	$ 4,072.6	$ 4,760.2	$ 3,749.1	$ 2,177.1	$ 1,456.0	$ 817.5	$ 1,320.4	$ 2,042.2	$ 443.5	$ 2,765.4	$ 26,652.4
Total Energy	1,428,850.93	1,234,421.48	1,217,841.83	1,168,470.81	1,353,816.94	1,602,921.83	1,927,228.25	1,763,858.88	1,373,841.59	1,218,929.59	1,251,370.20	1,476,224.98	17,017,777.31
Total NPSE	$ 38,481.5	$ 23,724.3	$ 15,710.1	$ 16,841.3	$ 18,513.3	$ 29,536.0	$ 40,075.6	$ 44,326.2	$ 31,406.4	$ 32,030.4	$ 33,217.9	$ 27,607.4	$ 360,384.2

Wheeling 3-Year Average $ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1983

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,291,179.9	1,043,293.8	1,144,542.7	1,145,167.5	1,230,303.6	1,255,844.0	1,073,430.3	877,964.0	750,148.8	602,517.6	740,356.6	1,113,103.0	12,267,851.7
Bridger Coal													
Energy (MWh)	114,579.2	37,720.4	30,750.2	32,944.6	45,147.6	83,296.6	130,229.2	163,269.4	127,194.8	149,725.3	196,151.5	220,114.3	1,331,123.15
Expense ($ x 1000)	$ 3,611.44	$ 1,370.22	$ 1,200.30	$ 1,253.23	$ 1,844.24	$ 3,001.99	$ 4,373.02	$ 5,324.00	$ 4,265.11	$ 4,933.90	$ 6,250.28	$ 6,959.90	$ 44,387.63
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	1,473.5	4,772.2	-	40.5	20,555.8	4,966.8	31,930.4
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 69.04	$ 224.15	$ -	$ 1.92	$ 959.19	$ 230.13	$ 1,490.2
Bridger Gas													
Energy (MWh)	-	29,983.8	-	2,863.5	2,651.0	7,486.8	22,278.1	35,538.4	12,965.7	22,288.5	-	-	136,055.7
Expense ($ x 1000)	$ -	$ 960.13	$ -	$ 111.75	$ 90.44	$ 283.24	$ 925.55	$ 1,502.73	$ 500.84	$ 853.86	$ -	$ -	$ 5,228.5
Langley Gulch													
Energy (MWh)	-	-	-	-	-	13,793.4	216,137.6	215,040.4	214,279.6	219,085.5	-	-	878,336.5
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 367.43	$ 6,490.54	$ 6,944.39	$ 6,368.13	$ 6,611.75	$ -	$ -	$ 26,782.2
Danskin													
Energy (MWh)	-	-	-	-	-	123.1	1,270.7	185.1	-	-	-	-	1,578.9
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 5.11	$ 62.10	$ 9.82	$ -	$ -	$ -	$ -	$ 77.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,876.2	1,978.8	-	-	-	-	4,855.0
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 131.06	$ 95.94	$ -	$ -	$ -	$ -	$ 227.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	1,060.8	3,362.3	456.4	50.3	2,907.3	36,213.5	115,634.1	118,795.4	29,970.7	24,172.2	73,953.8	6,416.2	412,993.1
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	76,833.0	67,590.9	82,900.0	85,389.7	93,660.4	126,299.8	209,986.6	207,280.8	105,567.4	96,568.7	143,219.8	76,216.6	1,371,513.5
Market Expense ($ x 1000)	$ 45.12	$ 98.75	$ 10.53	$ 1.31	$ 67.85	$ 994.99	$ 3,619.70	$ 3,729.08	$ 867.15	$ 743.97	$ 2,397.45	$ 226.65	$ 12,802.6
Market Expense - No Wheeling ($ x 1000)	$ 37.20	$ 73.64	$ 7.12	$ 0.93	$ 46.13	$ 724.50	$ 2,755.99	$ 2,841.76	$ 643.29	$ 563.42	$ 1,845.06	$ 178.73	$ 9,717.8
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 5,795.4	$ 4,518.6	$ 5,259.8	$ 4,953.0	$ 4,828.0	$ 5,172.0	$ 7,233.7	$ 7,184.3	$ 4,637.3	$ 5,082.6	$ 7,040.0	$ 5,614.3	$ 67,318.9
Storage													
Black Mesa Battery Energy (MWh)	(1,287.82)	(1,143.90)	(1,419.1)	(1,218.1)	(1,143.3)	(864.3)	(889.9)	(873.3)	(833.7)	(910.7)	(941.6)	(1,134.8)	(12,660.5)
80 MW Grid Battery Energy (MWh)	(2,492.56)	(2,319.18)	(2,832.3)	(2,476.5)	(2,356.5)	(1,746.3)	(1,777.8)	(1,744.1)	(1,691.5)	(1,862.7)	(1,856.3)	(2,256.3)	(25,411.9)

11 MW Grid Battery Energy (MWh)	(343.85)	(315.68)	(376.7)	(326.1)	(295.3)	(229.7)	(245.2)	(239.7)	(222.4)	(253.5)	(250.5)	(289.9)	(3,388.5)
Total Storage (MWh)	(4,124.2)	(3,778.8)	(4,628.1)	(4,020.8)	(3,795.1)	(2,840.3)	(2,912.9)	(2,857.0)	(2,747.6)	(3,026.9)	(3,048.3)	(3,680.9)	(41,460.9)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	252,536.0	166,374.7	281,940.2	382,549.8	327,836.7	201,533.4	31,833.2	29,219.9	68,491.7	90,535.7	23,816.0	117,613.3	1,974,280.4
Revenue ($ x 1000)	$ 9,325.1	$ 5,198.4	$ 6,997.9	$ 10,108.7	$ 8,109.8	$ 5,414.9	$ 1,200.8	$ 1,361.9	$ 2,642.7	$ 3,314.4	$ 1,065.9	$ 4,741.5	$ 59,482.0
Revenue - No Wheeling ($ x 1000)	$ 7,438.8	$ 3,955.7	$ 4,892.0	$ 7,251.3	$ 5,661.0	$ 3,909.6	$ 963.1	$ 1,143.7	$ 2,131.2	$ 2,638.2	$ 888.0	$ 3,863.0	$ 44,735.4
Total Energy	1,428,850.96	1,234,421.47	1,217,841.83	1,168,470.79	1,353,816.94	1,602,921.79	1,927,228.23	1,763,858.92	1,373,841.58	1,218,929.55	1,251,370.20	1,476,224.98	17,017,777.24
Total NPSE	$ 16,583.7	$ 20,069.4	$ 14,290.3	$ 13,322.6	$ 16,094.7	$ 27,032.8	$ 43,451.2	$ 44,386.8	$ 31,629.2	$ 31,234.6	$ 30,213.7	$ 26,428.4	$ 329,484.0

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1984

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,165,120.1	1,005,842.4	1,072,179.7	1,104,538.3	1,203,764.7	1,262,895.6	1,081,669.5	922,060.6	797,505.3	583,026.6	735,916.1	916,636.8	11,851,155.6
Bridger Coal													
Energy (MWh)	124,571.2	42,998.0	32,752.8	30,296.0	47,137.9	74,918.3	126,075.0	167,059.1	158,831.7	161,414.7	202,615.8	250,179.6	1,418,850.09
Expense ($ x 1000)	$ 3,898.83	$ 1,522.01	$ 1,257.90	$ 1,177.05	$ 1,901.49	$ 2,760.82	$ 4,253.45	$ 5,432.90	$ 5,175.92	$ 5,270.35	$ 6,436.33	$ 7,825.69	$ 46,912.74
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	-	162.0	-	40.5	19,837.7	30,497.3	50,659.1
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.67	$ -	$ 1.92	$ 926.28	$ 1,417.57	$ 2,359.2
Bridger Gas													
Energy (MWh)	-	31,682.0	-	841.2	2,031.3	1,644.4	5,468.7	11,764.3	12,098.5	11,976.8	-	-	77,507.3
Expense ($ x 1000)	$ -	$ 1,041.00	$ -	$ 33.70	$ 71.03	$ 63.81	$ 232.91	$ 509.72	$ 479.32	$ 470.44	$ -	$ -	$ 2,901.9
Langley Gulch													
Energy (MWh)	-	-	-	-	-	13,739.9	214,881.5	214,264.2	118,525.2	219,048.7	-	4,156.5	784,616.0
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 372.87	$ 6,575.90	$ 7,051.62	$ 3,593.79	$ 6,735.09	$ -	$ 382.87	$ 24,712.1
Danskin													
Energy (MWh)	-	-	-	-	-	122.5	1,160.2	61.5	-	-	-	-	1,344.1
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 5.29	$ 58.27	$ 3.29	$ -	$ -	$ -	$ -	$ 66.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	3,081.6	1,915.0	-	-	-	-	4,996.6
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 142.30	$ 93.34	$ -	$ -	$ -	$ -	$ 235.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	4,426.7	2,713.6	1,103.7	79.2	4,248.6	40,084.5	120,153.2	90,450.6	37,707.5	25,501.4	69,415.0	48,800.1	444,684.0
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	80,198.8	66,942.1	83,547.2	85,418.6	95,001.7	130,170.7	214,505.7	178,936.0	113,304.1	97,897.9	138,681.1	118,600.6	1,403,204.4
Market Expense ($ x 1000)	$ 204.15	$ 78.30	$ 26.37	$ 2.19	$ 100.50	$ 1,075.30	$ 3,722.78	$ 2,935.59	$ 1,147.54	$ 806.69	$ 2,283.39	$ 1,842.28	$ 14,225.1
Market Expense - No Wheeling ($ x 1000)	$ 171.09	$ 58.03	$ 18.13	$ 1.60	$ 68.77	$ 775.90	$ 2,825.31	$ 2,259.98	$ 865.89	$ 616.21	$ 1,764.91	$ 1,477.78	$ 10,903.6
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 5,929.3	$ 4,503.0	$ 5,270.8	$ 4,953.6	$ 4,850.6	$ 5,223.4	$ 7,303.0	$ 6,602.6	$ 4,859.9	$ 5,135.4	$ 6,959.8	$ 6,913.3	$ 68,504.7
Storage													
Black Mesa Battery Energy (MWh)	(1,272.54)	(1,028.43)	(1,417.1)	(1,157.3)	(1,114.9)	(850.9)	(869.0)	(851.2)	(806.9)	(868.9)	(953.3)	(1,102.7)	(12,293.1)
80 MW Grid Battery Energy (MWh)	(2,574.08)	(2,187.77)	(2,813.6)	(2,316.7)	(2,306.7)	(1,702.0)	(1,736.9)	(1,730.1)	(1,612.5)	(1,702.3)	(1,794.8)	(2,185.7)	(24,663.2)

11 MW Grid Battery Energy (MWh)	(344.73)	(286.11)	(359.2)	(310.6)	(302.3)	(227.6)	(239.2)	(230.3)	(215.2)	(236.1)	(237.3)	(282.8)	(3,271.4)
Total Storage (MWh)	(4,191.4)	(3,502.3)	(4,589.8)	(3,784.6)	(3,723.9)	(2,780.5)	(2,845.1)	(2,811.6)	(2,634.6)	(2,807.4)	(2,985.4)	(3,571.3)	(40,227.8)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	139,766.9	135,526.8	212,265.2	337,514.8	304,080.8	198,240.8	21,060.9	19,459.0	58,713.3	73,934.3	20,645.8	23,393.0	1,544,601.7
Revenue ($ x 1000)	$ 5,713.6	$ 4,524.0	$ 5,662.2	$ 8,807.1	$ 7,767.6	$ 5,236.6	$ 725.8	$ 789.8	$ 2,177.0	$ 2,632.7	$ 895.7	$ 1,225.3	$ 46,157.3
Revenue - No Wheeling ($ x 1000)	$ 4,669.7	$ 3,511.7	$ 4,076.7	$ 6,286.1	$ 5,496.3	$ 3,755.8	$ 568.5	$ 644.4	$ 1,738.4	$ 2,080.5	$ 741.5	$ 1,050.5	$ 34,620.2
Total Energy	1,428,850.92	1,234,421.47	1,217,841.86	1,168,470.82	1,353,816.95	1,602,921.81	1,927,228.25	1,763,858.90	1,373,841.57	1,218,929.59	1,251,370.20	1,476,224.97	17,017,777.31
Total NPSE	$ 20,616.5	$ 20,960.8	$ 15,694.6	$ 14,470.6	$ 16,497.3	$ 26,807.6	$ 43,207.0	$ 43,374.7	$ 30,432.5	$ 32,045.5	$ 30,456.9	$ 33,679.8	$ 339,780.9

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1985

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,153,565.0	1,002,266.7	1,063,634.4	1,212,128.4	1,149,775.3	936,564.5	719,629.0	594,046.5	715,658.8	521,946.7	392,289.7	543,294.2	10,004,799.2
Bridger Coal													
Energy (MWh)	125,632.9	50,896.6	36,487.4	37,546.8	42,636.4	83,222.1	163,605.3	237,147.7	206,339.5	212,993.2	241,092.5	250,686.7	1,688,286.99
Expense ($ x 1000)	$ 3,929.37	$ 1,749.20	$ 1,365.32	$ 1,385.60	$ 1,771.96	$ 2,999.83	$ 5,333.70	$ 7,450.48	$ 6,543.23	$ 6,755.10	$ 7,543.96	$ 7,840.28	$ 54,668.03
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	35,652.1	42,850.2	1,212.4	40.5	41,036.0	47,058.8	167,971.5
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,665.49	$ 1,992.06	$ 56.73	$ 1.92	$ 1,909.85	$ 2,178.31	$ 7,810.1
Bridger Gas													
Energy (MWh)	-	29,200.7	-	311.9	135.1	976.3	17,970.3	31,586.4	16,198.7	20,284.0	-	-	116,663.3
Expense ($ x 1000)	$ -	$ 1,043.69	$ -	$ 13.55	$ 5.12	$ 41.22	$ 833.50	$ 1,491.44	$ 698.76	$ 867.34	$ -	$ -	$ 4,994.6
Langley Gulch													
Energy (MWh)	-	-	-	-	-	114,121.0	215,734.3	216,631.6	176,180.7	220,232.8	178,553.2	153,424.1	1,274,877.8
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 3,278.27	$ 7,074.88	$ 7,643.10	$ 5,724.02	$ 7,256.44	$ 12,303.66	$ 15,230.63	$ 58,511.0
Danskin													
Energy (MWh)	383.4	-	-	-	-	1,492.2	110,445.0	56,301.4	250.2	-	427.3	3,481.3	172,780.7
Expense ($ x 1000)	$ 46.78	$ -	$ -	$ -	$ -	$ 62.45	$ 5,657.65	$ 3,092.53	$ 13.72	$ -	$ 47.14	$ 522.26	$ 9,442.5
Bennett Mountain													
Energy (MWh)	249.7	-	-	-	-	774.0	42,931.3	34,231.2	-	-	243.0	1,762.0	80,191.1
Expense ($ x 1000)	$ 29.84	$ -	$ -	$ -	$ -	$ 35.11	$ 2,216.92	$ 1,896.95	$ -	$ -	$ 26.52	$ 259.06	$ 4,464.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	7,732.3	2,436.2	1,723.8	54.3	4,628.9	93,583.9	229,391.1	185,873.2	21,325.4	30,716.6	163,007.3	230,356.0	970,828.8
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	83,504.5	66,664.7	84,167.3	85,393.7	95,382.0	183,670.1	323,743.6	274,358.5	96,922.0	103,113.1	232,273.3	300,156.4	1,929,349.2
Market Expense ($ x 1000)	$ 355.91	$ 76.17	$ 45.56	$ 1.56	$ 112.51	$ 2,467.18	$ 7,619.27	$ 6,956.89	$ 728.01	$ 1,078.40	$ 6,266.96	$ 9,915.96	$ 35,624.4
Market Expense - No Wheeling ($ x 1000)	$ 298.15	$ 57.97	$ 32.68	$ 1.15	$ 77.94	$ 1,768.17	$ 5,905.87	$ 5,568.54	$ 568.72	$ 848.97	$ 5,049.40	$ 8,195.35	$ 28,372.9
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 6,056.4	$ 4,502.9	$ 5,285.3	$ 4,953.2	$ 4,859.8	$ 6,215.7	$ 10,383.6	$ 9,911.1	$ 4,562.7	$ 5,368.2	$ 10,244.3	$ 13,630.9	$ 85,974.0
Storage													
Black Mesa Battery Energy (MWh)	(1,359.73)	(1,078.49)	(1,397.8)	(1,171.1)	(918.9)	(875.1)	(882.4)	(875.3)	(815.7)	(1,003.6)	(870.1)	(1,068.9)	(12,317.0)
80 MW Grid Battery Energy (MWh)	(2,731.69)	(2,325.83)	(2,790.3)	(2,384.8)	(1,857.9)	(1,732.1)	(1,757.2)	(1,750.6)	(1,718.2)	(1,894.4)	(1,682.9)	(2,134.7)	(24,760.6)

11 MW Grid Battery Energy (MWh)	(371.15)	(298.08)	(355.4)	(315.3)	(238.0)	(230.5)	(241.1)	(240.8)	(218.5)	(270.3)	(220.2)	(268.6)	(3,268.0)
Total Storage (MWh)	(4,462.6)	(3,702.4)	(4,543.5)	(3,871.2)	(3,014.8)	(2,837.7)	(2,880.6)	(2,866.7)	(2,752.4)	(3,168.3)	(2,773.1)	(3,472.2)	(40,345.5)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	132,940.9	136,890.8	208,121.0	451,715.0	244,783.2	35,512.4	3,893.9	10,334.8	71,093.0	78,778.6	9,722.4	3,284.8	1,387,070.6
Revenue ($ x 1000)	$ 5,931.2	$ 4,762.7	$ 5,828.2	$ 12,511.9	$ 6,363.6	$ 1,183.1	$ 194.9	$ 558.2	$ 2,818.4	$ 3,063.6	$ 508.2	$ 187.1	$ 43,911.0
Revenue - No Wheeling ($ x 1000)	$ 4,938.2	$ 3,740.2	$ 4,273.6	$ 9,137.8	$ 4,535.3	$ 917.8	$ 165.8	$ 481.0	$ 2,287.4	$ 2,475.2	$ 435.5	$ 162.5	$ 33,550.5
Total Energy	1,428,850.93	1,234,421.48	1,217,841.84	1,168,470.78	1,353,816.90	1,602,921.83	1,927,228.26	1,763,858.90	1,373,841.60	1,218,929.60	1,251,370.20	1,476,224.97	17,017,777.29
Total NPSE	$ 20,633.1	$ 20,952.0	$ 15,650.6	$ 10,953.8	$ 17,715.0	$ 35,067.4	$ 58,337.9	$ 57,382.9	$ 33,281.3	$ 34,250.4	$ 48,597.5	$ 57,839.9	$ 421,022.2

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1986

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,014,443.6	1,004,353.3	1,232,902.0	1,175,608.2	1,242,534.9	1,222,624.4	802,870.1	774,467.9	756,537.7	551,371.1	552,958.9	838,261.2	11,168,933.4
Bridger Coal													
Energy (MWh)	125,603.1	46,484.0	31,317.0	33,197.2	38,200.7	79,652.8	140,328.9	176,322.5	146,579.8	171,932.7	213,836.6	250,418.8	1,453,874.02
Expense ($ x 1000)	$ 3,928.51	$ 1,622.28	$ 1,216.60	$ 1,260.49	$ 1,644.30	$ 2,897.09	$ 4,663.71	$ 5,699.72	$ 4,823.10	$ 5,573.18	$ 6,759.37	$ 7,832.57	$ 47,920.92
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	17,883.9	25,159.0	-	40.5	35,835.0	40,663.0	119,702.9
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 843.56	$ 1,179.05	$ -	$ 1.92	$ 1,678.02	$ 1,887.95	$ 5,596.3
Bridger Gas													
Energy (MWh)	-	35,589.0	-	1,790.9	865.4	2,634.0	18,729.8	32,605.4	5,415.3	29,702.6	-	-	127,332.5
Expense ($ x 1000)	$ -	$ 1,174.89	$ -	$ 72.06	$ 30.44	$ 102.72	$ 802.23	$ 1,421.65	$ 215.80	$ 1,174.37	$ -	$ -	$ 4,994.2
Langley Gulch													
Energy (MWh)	7,855.0	-	-	-	-	20,328.7	215,611.5	216,246.9	144,086.4	219,822.6	91,607.0	36,247.9	951,805.9
Expense ($ x 1000)	$ 569.74	$ -	$ -	$ -	$ -	$ 552.86	$ 6,637.87	$ 7,158.59	$ 4,396.18	$ 6,799.48	$ 5,940.00	$ 3,353.55	$ 35,408.3
Danskin													
Energy (MWh)	255.9	-	-	-	-	122.5	82,925.5	9,355.7	-	-	-	-	92,659.6
Expense ($ x 1000)	$ 29.20	$ -	$ -	$ -	$ -	$ 5.33	$ 3,960.88	$ 480.33	$ -	$ -	$ -	$ -	$ 4,475.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	22,203.5	702.2	-	-	-	-	22,905.7
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,084.16	$ 35.88	$ -	$ -	$ -	$ -	$ 1,120.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	36,694.4	3,738.5	52.7	169.7	2,915.6	43,028.2	235,212.1	169,596.9	48,785.9	34,744.7	121,460.2	77,227.7	773,626.5
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	112,466.6	67,967.0	82,496.2	85,509.1	93,668.7	133,114.4	329,564.6	258,082.3	124,382.6	107,141.2	190,726.2	147,028.1	1,732,146.9
Market Expense ($ x 1000)	$ 1,465.32	$ 108.45	$ 1.20	$ 4.71	$ 67.66	$ 1,162.12	$ 7,015.47	$ 5,549.29	$ 1,463.26	$ 1,100.21	$ 4,098.43	$ 2,919.96	$ 24,956.1
Market Expense - No Wheeling ($ x 1000)	$ 1,191.24	$ 80.53	$ 0.81	$ 3.44	$ 45.88	$ 840.73	$ 5,258.59	$ 4,282.51	$ 1,098.86	$ 840.69	$ 3,191.20	$ 2,343.12	$ 19,177.6
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 6,949.5	$ 4,525.5	$ 5,253.4	$ 4,955.5	$ 4,827.7	$ 5,288.2	$ 9,736.3	$ 8,625.1	$ 5,092.9	$ 5,359.9	$ 8,386.1	$ 7,778.7	$ 76,778.7
Storage													
Black Mesa Battery Energy (MWh)	(1,216.85)	(1,117.51)	(1,483.7)	(1,207.1)	(1,077.6)	(868.7)	(870.3)	(880.7)	(694.7)	(931.5)	(834.7)	(1,064.9)	(12,248.3)
80 MW Grid Battery Energy (MWh)	(2,486.49)	(2,232.65)	(3,001.7)	(2,393.4)	(2,123.0)	(1,719.8)	(1,762.7)	(1,760.3)	(1,364.1)	(1,850.6)	(1,696.6)	(2,128.0)	(24,519.3)

11 MW Grid Battery Energy (MWh)	(343.08)	(293.13)	(385.8)	(316.4)	(279.1)	(228.5)	(241.2)	(242.7)	(188.2)	(249.2)	(204.8)	(273.7)	(3,245.8)
Total Storage (MWh)	(4,046.4)	(3,643.3)	(4,871.3)	(3,916.9)	(3,479.6)	(2,816.9)	(2,874.2)	(2,883.7)	(2,247.0)	(3,031.3)	(2,736.2)	(3,466.6)	(40,013.4)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	30,645.9	142,314.5	370,219.4	412,393.9	331,659.2	173,189.7	4,307.4	16,106.0	35,837.9	80,315.9	8,808.1	16,045.8	1,621,843.7
Revenue ($ x 1000)	$ 1,449.5	$ 4,796.1	$ 9,169.8	$ 10,872.8	$ 7,985.2	$ 4,700.1	$ 209.9	$ 816.7	$ 1,372.2	$ 3,255.7	$ 421.9	$ 862.0	$ 45,911.8
Revenue - No Wheeling ($ x 1000)	$ 1,220.6	$ 3,733.1	$ 6,404.5	$ 7,792.5	$ 5,507.9	$ 3,406.5	$ 177.7	$ 696.4	$ 1,104.5	$ 2,655.8	$ 356.1	$ 742.2	$ 33,797.7
Total Energy	1,428,850.94	1,234,421.49	1,217,841.83	1,168,470.82	1,353,816.93	1,602,921.82	1,927,228.25	1,763,858.89	1,373,841.58	1,218,929.59	1,251,370.18	1,476,225.01	17,017,777.33
Total NPSE	$ 26,529.4	$ 20,945.4	$ 12,128.4	$ 12,528.5	$ 15,959.0	$ 27,764.1	$ 52,885.8	$ 48,247.1	$ 31,656.3	$ 32,718.1	$ 39,371.8	$ 38,356.3	$ 371,204.3

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1987

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,003,291.6	936,478.0	821,438.3	613,947.8	694,452.3	631,436.2	634,293.2	520,576.3	535,778.8	463,890.7	388,369.4	466,181.3	7,710,133.8
Bridger Coal													
Energy (MWh)	125,632.9	68,053.2	45,292.7	56,605.1	56,526.2	116,701.6	175,085.8	246,652.0	239,552.2	237,086.2	242,600.0	250,686.7	1,860,474.48
Expense ($ x 1000)	$ 3,929.37	$ 2,242.66	$ 1,618.58	$ 1,933.77	$ 2,171.63	$ 3,963.49	$ 5,664.11	$ 7,724.11	$ 7,499.63	$ 7,448.64	$ 7,587.37	$ 7,840.28	$ 59,623.64
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	41,664.4	41,842.6	17,068.1	684.8	42,316.5	52,302.1	196,000.1
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,938.87	$ 1,947.15	$ 801.26	$ 31.53	$ 1,966.93	$ 2,414.38	$ 9,105.9
Bridger Gas													
Energy (MWh)	-	28,396.0	-	4,965.0	1,411.9	2,417.3	22,833.9	24,340.3	12,322.0	36,658.9	-	-	133,345.4
Expense ($ x 1000)	$ -	$ 1,074.03	$ -	$ 229.01	$ 56.94	$ 107.95	$ 1,121.74	$ 1,216.33	$ 562.75	$ 1,661.22	$ -	$ -	$ 6,030.0
Langley Gulch													
Energy (MWh)	17,951.8	-	-	151,692.8	216,765.7	208,813.2	215,639.5	215,381.6	212,840.2	220,919.6	179,380.5	157,471.7	1,796,856.6
Expense ($ x 1000)	$ 1,419.10	$ -	$ -	$ 4,894.57	$ 6,027.17	$ 6,271.82	$ 7,410.31	$ 7,967.18	$ 7,239.44	$ 7,626.85	$ 12,953.84	$ 16,425.82	$ 78,236.1
Danskin													
Energy (MWh)	-	-	-	-	-	47,176.9	124,986.5	109,593.7	-	-	197.7	11,826.6	293,781.5
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 2,183.88	$ 6,812.18	$ 6,407.21	$ -	$ -	$ 22.77	$ 1,863.44	$ 17,289.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	21,946.6	75,256.0	60,121.6	1,315.0	-	243.0	2,265.4	161,147.6
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 1,045.04	$ 4,092.47	$ 3,553.56	$ 68.66	$ -	$ 27.90	$ 350.50	$ 9,138.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	39,038.0	9,554.6	63,005.5	34,786.5	45,397.5	175,884.1	246,952.5	178,963.6	72,011.3	37,909.2	164,030.0	286,780.7	1,354,313.4
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	114,810.2	73,783.1	145,449.1	120,125.8	136,150.6	265,970.3	341,304.9	267,449.0	147,607.9	110,305.7	233,296.0	356,581.1	2,312,833.8
Market Expense ($ x 1000)	$ 1,714.24	$ 289.83	$ 1,616.35	$ 997.77	$ 1,132.23	$ 5,087.39	$ 8,635.99	$ 6,998.80	$ 2,676.84	$ 1,440.72	$ 6,583.79	$ 13,184.06	$ 50,358.0
Market Expense - No Wheeling ($ x 1000)	$ 1,422.65	$ 218.46	$ 1,145.74	$ 737.94	$ 793.14	$ 3,773.65	$ 6,791.42	$ 5,662.06	$ 2,138.96	$ 1,157.56	$ 5,358.59	$ 11,042.00	$ 40,242.2
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 7,180.9	$ 4,663.4	$ 6,398.4	$ 5,690.0	$ 5,575.0	$ 8,221.2	$ 11,269.1	$ 10,004.6	$ 6,133.0	$ 5,676.8	$ 10,553.5	$ 16,477.5	$ 97,843.3
Storage													
Black Mesa Battery Energy (MWh)	(1,265.31)	(1,006.39)	(1,054.6)	(1,101.2)	(995.6)	(852.7)	(868.7)	(868.1)	(805.7)	(896.1)	(897.6)	(1,088.2)	(11,700.0)
80 MW Grid Battery Energy (MWh)	(2,521.19)	(1,961.85)	(2,071.9)	(2,171.7)	(1,977.5)	(1,733.9)	(1,736.9)	(1,743.5)	(1,675.7)	(1,811.1)	(1,755.1)	(2,227.5)	(23,387.9)

11 MW Grid Battery Energy (MWh)	(348.22)	(260.40)	(269.0)	(292.5)	(262.8)	(223.4)	(239.2)	(234.9)	(216.2)	(251.4)	(231.3)	(273.3)	(3,102.5)
Total Storage (MWh)	(4,134.7)	(3,228.6)	(3,395.5)	(3,565.3)	(3,236.0)	(2,810.0)	(2,844.8)	(2,846.4)	(2,697.5)	(2,958.6)	(2,883.9)	(3,589.0)	(38,190.3)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	31,619.8	95,046.2	37,160.0	63,976.6	61,939.8	9,182.0	5,283.3	9,158.6	24,869.8	69,923.8	10,099.9	619.3	418,879.2
Revenue ($ x 1000)	$ 1,717.1	$ 3,691.4	$ 1,321.4	$ 2,463.3	$ 1,955.4	$ 323.9	$ 271.8	$ 475.7	$ 1,069.5	$ 3,141.3	$ 563.8	$ 40.9	$ 17,035.3
Revenue - No Wheeling ($ x 1000)	$ 1,480.9	$ 2,981.4	$ 1,043.8	$ 1,985.4	$ 1,492.8	$ 255.3	$ 232.3	$ 407.3	$ 883.8	$ 2,619.0	$ 488.4	$ 36.3	$ 13,906.5
Total Energy	1,428,850.93	1,234,421.47	1,217,841.86	1,168,470.77	1,353,816.92	1,602,921.82	1,927,228.24	1,763,858.90	1,373,841.57	1,218,929.60	1,251,370.19	1,476,224.97	17,017,777.24
Total NPSE	$ 27,314.3	$ 22,707.6	$ 21,523.7	$ 27,397.3	$ 29,317.1	$ 45,087.4	$ 63,404.0	$ 62,807.9	$ 39,735.7	$ 36,368.7	$ 49,578.7	$ 63,696.6	$ 492,067.9

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1988

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	537,905.8	515,706.8	400,960.2	501,926.1	497,614.3	496,996.2	617,091.2	466,009.6	475,857.0	428,490.0	374,706.7	457,972.0	5,771,235.7
Bridger Coal													
Energy (MWh)	125,632.9	104,497.9	68,674.7	74,666.2	76,514.0	135,603.6	209,956.7	250,462.5	242,600.0	249,339.5	242,600.0	250,686.7	2,031,234.74
Expense ($ x 1000)	$ 3,929.37	$ 3,290.91	$ 2,291.11	$ 2,453.25	$ 2,746.96	$ 4,507.56	$ 6,667.78	$ 7,833.82	$ 7,587.37	$ 7,801.48	$ 7,587.37	$ 7,840.28	$ 64,537.26
Valmy													
Energy (MWh)	121.5	-	-	-	-	1,701.4	44,184.8	48,741.0	38,015.5	10,735.1	43,044.7	67,608.1	254,152.2
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ 80.55	$ 2,052.89	$ 2,251.95	$ 1,775.21	$ 500.93	$ 1,999.38	$ 3,096.85	$ 11,763.5
Bridger Gas													
Energy (MWh)	-	45,349.0	-	673.8	954.1	7,038.3	24,464.4	42,309.2	16,880.3	12,869.7	-	-	150,538.8
Expense ($ x 1000)	$ -	$ 1,828.35	$ -	$ 32.99	$ 40.90	$ 335.76	$ 1,281.44	$ 2,254.53	$ 822.01	$ 621.32	$ -	$ -	$ 7,217.3
Langley Gulch													
Energy (MWh)	202,790.8	208,671.3	164,696.9	207,951.3	229,231.8	207,880.4	215,408.7	215,915.5	213,506.4	221,148.0	180,745.9	155,888.8	2,423,835.7
Expense ($ x 1000)	$ 16,388.38	$ 6,113.44	$ 10,379.68	$ 7,081.47	$ 6,720.99	$ 6,592.88	$ 7,821.84	$ 8,442.27	$ 7,672.44	$ 8,067.24	$ 13,775.52	$ 17,334.78	$ 116,390.9
Danskin													
Energy (MWh)	21,295.1	386.7	24,937.4	-	1,963.4	88,409.9	128,984.7	122,141.3	1,048.4	-	889.0	12,480.9	402,536.8
Expense ($ x 1000)	$ 2,883.64	$ 18.91	$ 2,395.22	$ -	$ 84.91	$ 4,428.74	$ 7,459.92	$ 7,609.71	$ 61.85	$ -	$ 109.17	$ 2,089.71	$ 27,141.8
Bennett Mountain													
Energy (MWh)	7,240.1	-	4,672.3	-	675.8	45,330.8	78,979.9	67,480.1	4,772.9	-	486.1	3,649.8	213,287.7
Expense ($ x 1000)	$ 966.15	$ -	$ 440.20	$ -	$ 32.97	$ 2,264.96	$ 4,567.56	$ 4,191.01	$ 264.99	$ -	$ 59.20	$ 599.49	$ 13,386.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	259,337.6	105,299.7	235,097.4	54,126.8	162,240.5	217,765.3	217,198.1	185,104.2	96,771.7	53,791.2	172,734.8	279,122.9	2,038,590.1
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	335,109.8	169,528.2	317,540.9	139,466.2	252,993.6	307,851.5	311,550.6	273,589.6	172,368.3	126,187.7	242,000.8	348,923.3	2,997,110.5
Market Expense ($ x 1000)	$ 13,363.61	$ 3,672.04	$ 6,962.46	$ 1,582.91	$ 4,449.98	$ 6,879.32	$ 8,270.68	$ 7,852.49	$ 3,885.40	$ 2,205.81	$ 7,274.39	$ 13,717.34	$ 80,116.4
Market Expense - No Wheeling ($ x 1000)	$ 11,426.53	$ 2,885.52	$ 5,206.44	$ 1,178.62	$ 3,238.15	$ 5,252.76	$ 6,648.35	$ 6,469.88	$ 3,162.58	$ 1,804.03	$ 5,984.18	$ 11,632.48	$ 64,889.5
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 17,184.8	$ 7,330.5	$ 10,459.1	$ 6,130.6	$ 8,020.0	$ 9,700.3	$ 11,126.0	$ 10,812.5	$ 7,156.6	$ 6,323.2	$ 11,179.1	$ 17,068.0	$ 122,490.6
Storage													
Black Mesa Battery Energy (MWh)	(1,235.07)	(1,031.00)	(1,085.4)	(1,076.4)	(816.1)	(826.3)	(868.6)	(863.5)	(798.1)	(910.4)	(911.3)	(1,056.7)	(11,478.8)
80 MW Grid Battery Energy (MWh)	(2,471.21)	(1,929.32)	(2,171.3)	(2,184.6)	(1,653.6)	(1,642.4)	(1,736.9)	(1,736.5)	(1,613.8)	(1,827.6)	(1,746.2)	(2,049.0)	(22,762.3)

11 MW Grid Battery Energy (MWh)	(325.05)	(256.51)	(277.6)	(286.8)	(218.5)	(215.8)	(239.2)	(237.0)	(216.7)	(248.3)	(222.4)	(269.1)	(3,012.7)
Total Storage (MWh)	(4,031.3)	(3,216.8)	(3,534.2)	(3,547.7)	(2,688.2)	(2,684.5)	(2,844.7)	(2,836.9)	(2,628.6)	(2,986.2)	(2,879.9)	(3,374.7)	(37,253.8)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	11.2	32,487.6	6,323.6	41,341.2	17,127.9	5,657.6	4,840.2	9,859.8	23,503.3	49,120.1	8,173.9	728.2	199,174.5
Revenue ($ x 1000)	$ 0.9	$ 1,572.3	$ 246.9	$ 1,585.0	$ 614.4	$ 234.0	$ 243.9	$ 607.9	$ 1,121.0	$ 1,947.4	$ 445.8	$ 47.1	$ 8,666.6
Revenue - No Wheeling ($ x 1000)	$ 0.8	$ 1,329.6	$ 199.7	$ 1,276.2	$ 486.5	$ 191.8	$ 207.7	$ 534.3	$ 945.4	$ 1,580.5	$ 384.7	$ 41.6	$ 7,178.8
Total Energy	1,428,850.94	1,234,421.47	1,217,841.85	1,168,470.81	1,353,816.93	1,602,921.83	1,927,228.23	1,763,858.91	1,373,841.58	1,218,929.61	1,251,370.19	1,476,224.98	17,017,777.33
Total NPSE	$ 57,853.4	$ 35,428.7	$ 40,546.5	$ 31,226.6	$ 34,474.1	$ 51,294.6	$ 66,100.6	$ 67,251.2	$ 42,720.0	$ 38,431.8	$ 51,294.1	$ 66,347.6	$ 584,457.0

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1989

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	554,645.1	642,609.4	1,043,334.6	1,199,078.5	937,308.5	828,375.1	738,030.8	594,338.5	580,406.8	461,061.5	388,305.5	455,772.5	8,423,266.7
Bridger Coal													
Energy (MWh)	125,632.8	87,336.9	40,187.4	45,961.0	68,255.2	103,368.7	175,722.0	244,235.3	239,207.4	241,249.1	242,570.4	250,686.7	1,864,412.77
Expense ($ x 1000)	$ 3,929.37	$ 2,797.31	$ 1,471.74	$ 1,627.62	$ 2,509.29	$ 3,579.68	$ 5,682.45	$ 7,654.53	$ 7,489.68	$ 7,568.51	$ 7,586.52	$ 7,840.28	$ 59,736.98
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	42,726.8	43,872.1	10,046.6	684.8	42,616.5	53,230.7	193,298.9
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,986.22	$ 2,037.61	$ 466.87	$ 31.53	$ 1,980.29	$ 2,455.88	$ 8,964.2
Bridger Gas													
Energy (MWh)	-	37,815.2	-	1,171.7	2,557.7	1,676.4	23,412.4	26,772.5	31,874.6	27,379.6	-	-	152,660.0
Expense ($ x 1000)	$ -	$ 1,440.12	$ -	$ 54.31	$ 103.81	$ 75.28	$ 1,156.55	$ 1,346.41	$ 1,466.05	$ 1,248.61	$ -	$ -	$ 6,891.1
Langley Gulch													
Energy (MWh)	198,833.8	206,651.4	-	-	-	161,150.3	215,488.7	215,688.0	213,398.1	221,458.2	177,420.4	154,381.1	1,764,469.9
Expense ($ x 1000)	$ 15,390.29	$ 5,767.62	$ -	$ -	$ -	$ 4,870.56	$ 7,445.89	$ 8,022.25	$ 7,297.51	$ 7,686.76	$ 12,954.00	$ 16,369.55	$ 85,804.4
Danskin													
Energy (MWh)	24,096.9	-	-	-	-	1,897.2	75,647.5	69,855.8	400.9	-	197.7	12,154.6	184,250.5
Expense ($ x 1000)	$ 3,098.29	$ -	$ -	$ -	$ -	$ 85.24	$ 4,101.31	$ 4,078.81	$ 22.38	$ -	$ 22.91	$ 1,927.24	$ 13,336.2
Bennett Mountain													
Energy (MWh)	1,997.3	-	-	-	-	1,918.9	49,527.2	22,875.6	-	-	243.0	3,020.5	79,582.5
Expense ($ x 1000)	$ 252.62	$ -	$ -	$ -	$ -	$ 89.99	$ 2,706.30	$ 1,348.48	$ -	$ -	$ 28.06	$ 470.12	$ 4,895.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	248,936.4	37,893.6	2,107.3	148.5	25,773.5	124,937.8	214,778.5	179,016.5	47,375.9	45,570.7	165,462.9	297,792.0	1,389,793.5
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	324,708.6	102,122.1	84,550.8	85,487.9	116,526.6	215,024.0	309,131.0	267,501.9	122,972.5	117,967.2	234,728.9	367,592.4	2,348,313.9
Market Expense ($ x 1000)	$ 11,824.75	$ 1,161.61	$ 53.62	$ 4.31	$ 639.15	$ 3,502.04	$ 7,454.94	$ 7,023.77	$ 1,787.21	$ 1,759.90	$ 6,556.29	$ 13,720.84	$ 55,488.4
Market Expense - No Wheeling ($ x 1000)	$ 9,965.36	$ 878.57	$ 37.88	$ 3.20	$ 446.64	$ 2,568.84	$ 5,850.69	$ 5,686.64	$ 1,433.34	$ 1,419.52	$ 5,320.39	$ 11,496.53	$ 45,107.6
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 15,723.6	$ 5,323.5	$ 5,290.5	$ 4,955.2	$ 5,228.5	$ 7,016.3	$ 10,328.4	$ 10,029.2	$ 5,427.3	$ 5,938.7	$ 10,515.3	$ 16,932.1	$ 102,708.7
Storage													
Black Mesa Battery Energy (MWh)	(1,186.86)	(899.72)	(1,368.9)	(1,235.7)	(901.2)	(862.6)	(875.7)	(873.9)	(845.7)	(1,014.5)	(925.0)	(1,007.9)	(11,997.8)
80 MW Grid Battery Energy (MWh)	(2,363.50)	(1,805.74)	(2,775.7)	(2,442.0)	(1,840.0)	(1,711.0)	(1,751.0)	(1,727.3)	(1,711.5)	(2,029.0)	(1,775.9)	(1,979.9)	(23,912.5)

11 MW Grid Battery Energy (MWh)	(325.13)	(243.61)	(352.4)	(330.9)	(249.5)	(226.6)	(241.1)	(233.2)	(226.9)	(277.9)	(225.1)	(245.3)	(3,177.7)
Total Storage (MWh)	(3,875.5)	(2,949.1)	(4,497.1)	(4,008.6)	(2,990.7)	(2,800.1)	(2,867.9)	(2,834.4)	(2,784.0)	(3,321.4)	(2,926.0)	(3,233.2)	(39,088.0)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	107.1	65,150.5	191,951.3	447,895.8	81,526.4	28,140.3	3,882.1	8,353.1	56,605.7	69,815.5	9,737.0	498.7	963,663.4
Revenue ($ x 1000)	$ 6.4	$ 2,800.1	$ 5,619.7	$ 13,511.9	$ 2,593.0	$ 998.1	$ 203.9	$ 483.0	$ 2,659.9	$ 2,970.1	$ 528.2	$ 30.7	$ 32,405.1
Revenue - No Wheeling ($ x 1000)	$ 5.6	$ 2,313.4	$ 4,186.0	$ 10,166.4	$ 1,984.1	$ 787.9	$ 174.9	$ 420.6	$ 2,237.1	$ 2,448.7	$ 455.5	$ 26.9	$ 25,207.1
Total Energy	1,428,850.91	1,234,421.48	1,217,841.81	1,168,470.77	1,353,816.93	1,602,921.81	1,927,228.28	1,763,858.90	1,373,841.60	1,218,929.60	1,251,370.23	1,476,225.01	17,017,777.33
Total NPSE	$ 54,889.7	$ 30,947.4	$ 15,970.7	$ 10,238.5	$ 22,690.3	$ 38,337.0	$ 58,570.2	$ 58,497.7	$ 38,010.4	$ 36,569.0	$ 49,589.1	$ 64,330.0	$ 485,837.9

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1990

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	674,066.3	641,743.9	717,544.6	679,737.8	673,218.5	757,882.1	542,780.4	493,669.8	521,253.3	438,890.0	383,395.4	441,092.9	6,965,274.7
Bridger Coal													
Energy (MWh)	125,632.9	91,192.6	50,671.1	69,676.6	58,950.2	114,253.1	182,376.4	248,143.7	242,299.3	242,997.1	242,600.0	250,686.7	1,919,479.59
Expense ($ x 1000)	$ 3,929.37	$ 2,908.21	$ 1,773.28	$ 2,309.73	$ 2,241.46	$ 3,892.99	$ 5,873.98	$ 7,767.07	$ 7,578.71	$ 7,618.84	$ 7,587.37	$ 7,840.28	$ 61,321.29
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	41,835.4	42,828.9	18,666.9	684.8	39,587.4	55,412.1	199,137.0
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,943.80	$ 1,988.42	$ 872.64	$ 31.53	$ 1,845.28	$ 2,553.11	$ 9,240.5
Bridger Gas													
Energy (MWh)	-	36,479.8	-	993.4	562.4	4,267.6	22,479.7	29,708.4	20,014.0	19,902.1	-	-	134,407.4
Expense ($ x 1000)	$ -	$ 1,398.12	$ -	$ 46.34	$ 22.91	$ 193.41	$ 1,118.69	$ 1,504.55	$ 926.08	$ 913.05	$ -	$ -	$ 6,123.2
Langley Gulch													
Energy (MWh)	200,284.9	208,772.7	18,159.6	768.6	224,601.6	207,179.0	215,986.2	215,691.4	213,564.6	221,650.6	178,479.9	156,019.3	2,061,158.3
Expense ($ x 1000)	$ 15,536.09	$ 5,857.90	$ 1,128.37	$ 26.61	$ 6,310.50	$ 6,292.02	$ 7,503.17	$ 8,066.45	$ 7,342.81	$ 7,735.19	$ 13,067.18	$ 16,545.72	$ 95,412.0
Danskin													
Energy (MWh)	865.9	-	-	-	-	7,233.4	140,865.3	118,376.0	-	1,905.8	197.7	14,516.3	283,960.5
Expense ($ x 1000)	$ 111.94	$ -	$ -	$ -	$ -	$ 331.53	$ 7,783.83	$ 7,002.78	$ -	$ 108.83	$ 23.05	$ 2,316.56	$ 17,678.5
Bennett Mountain													
Energy (MWh)	998.6	-	-	-	-	2,467.2	96,541.0	65,676.5	1,363.7	-	243.0	2,517.1	169,807.0
Expense ($ x 1000)	$ 127.05	$ -	$ -	$ -	$ -	$ 116.36	$ 5,313.64	$ 3,902.70	$ 71.19	$ -	$ 28.23	$ 394.09	$ 9,953.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	154,823.5	33,654.8	121,362.4	71,005.0	49,694.9	124,698.1	290,828.0	182,897.3	78,838.0	53,205.4	170,390.5	306,999.0	1,638,396.8
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	230,595.7	97,883.3	203,805.9	156,344.4	140,448.0	214,784.3	385,180.5	271,382.7	154,434.6	125,601.9	239,656.5	376,799.4	2,596,917.1
Market Expense ($ x 1000)	$ 7,228.68	$ 1,033.09	$ 3,240.65	$ 1,997.16	$ 1,232.47	$ 3,509.86	$ 10,815.01	$ 7,296.07	$ 3,030.22	$ 2,100.38	$ 6,751.44	$ 14,459.47	$ 62,694.5
Market Expense - No Wheeling ($ x 1000)	$ 6,072.25	$ 781.71	$ 2,334.15	$ 1,466.80	$ 861.28	$ 2,578.45	$ 8,642.72	$ 5,929.95	$ 2,441.35	$ 1,702.97	$ 5,478.74	$ 12,166.39	$ 50,456.8
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 11,830.5	$ 5,226.6	$ 7,586.8	$ 6,418.8	$ 5,643.1	$ 7,025.9	$ 13,120.4	$ 10,272.5	$ 6,435.3	$ 6,222.2	$ 10,673.7	$ 17,601.9	$ 108,057.9
Storage													
Black Mesa Battery Energy (MWh)	(1,236.10)	(951.08)	(1,054.4)	(1,064.0)	(924.2)	(853.8)	(872.5)	(866.7)	(827.1)	(924.4)	(879.3)	(1,069.9)	(11,523.5)
80 MW Grid Battery Energy (MWh)	(2,436.03)	(1,865.05)	(2,091.7)	(2,098.7)	(1,829.6)	(1,716.3)	(1,750.9)	(1,731.0)	(1,671.2)	(1,900.0)	(1,717.1)	(2,175.0)	(22,982.5)

11 MW Grid Battery Energy (MWh)	(339.74)	(254.74)	(265.3)	(278.4)	(242.7)	(228.7)	(239.2)	(233.2)	(219.4)	(252.1)	(223.4)	(268.8)	(3,045.3)
Total Storage (MWh)	(4,011.9)	(3,070.9)	(3,411.4)	(3,441.1)	(2,996.5)	(2,798.8)	(2,862.5)	(2,830.9)	(2,717.7)	(3,076.5)	(2,819.8)	(3,513.6)	(37,551.3)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	2,500.6	64,566.0	15,145.2	24,285.1	54,653.4	22,797.7	2,246.2	8,694.4	29,961.6	51,892.3	7,920.8	423.5	285,086.8
Revenue ($ x 1000)	$ 159.9	$ 2,771.4	$ 562.8	$ 957.7	$ 1,719.2	$ 842.5	$ 117.0	$ 489.1	$ 1,386.2	$ 2,105.7	$ 421.3	$ 26.0	$ 11,558.6
Revenue - No Wheeling ($ x 1000)	$ 141.2	$ 2,289.1	$ 449.7	$ 776.3	$ 1,311.0	$ 672.2	$ 100.2	$ 424.1	$ 1,162.4	$ 1,718.1	$ 362.1	$ 22.9	$ 9,429.2
Total Energy	1,428,850.95	1,234,421.47	1,217,841.82	1,168,470.77	1,353,816.90	1,602,921.81	1,927,228.24	1,763,858.88	1,373,841.60	1,218,929.61	1,251,370.20	1,476,224.98	17,017,777.23
Total NPSE	$ 47,877.1	$ 31,038.4	$ 24,753.7	$ 24,957.2	$ 29,940.6	$ 40,627.7	$ 67,907.6	$ 64,478.8	$ 40,341.1	$ 37,588.9	$ 49,833.6	$ 65,591.2	$ 527,065.3

Wheeling 3-Year Average $ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1991

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	497,530.1	470,410.1	401,941.8	452,086.4	593,144.5	597,331.5	663,446.4	537,861.9	509,034.1	448,522.6	370,598.5	437,953.1	5,979,860.9
Bridger Coal													
Energy (MWh)	125,632.9	105,247.9	70,300.0	74,821.0	72,703.9	130,988.0	180,927.0	248,124.7	242,226.6	247,199.9	242,600.0	250,686.7	1,991,458.37
Expense ($ x 1000)	$ 3,929.37	$ 3,312.48	$ 2,337.85	$ 2,457.70	$ 2,637.29	$ 4,374.68	$ 5,832.20	$ 7,766.53	$ 7,576.61	$ 7,739.87	$ 7,587.37	$ 7,840.28	$ 63,392.23
Valmy													
Energy (MWh)	121.5	-	-	-	-	162.0	40,089.9	42,934.2	27,973.6	674.5	41,123.4	60,203.8	213,282.9
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ 7.67	$ 1,868.69	$ 1,995.81	$ 1,306.08	$ 31.07	$ 1,913.74	$ 2,766.70	$ 9,895.5
Bridger Gas													
Energy (MWh)	-	42,394.4	-	2,377.1	614.7	5,208.0	12,736.6	15,197.7	14,589.3	21,106.9	-	-	114,224.8
Expense ($ x 1000)	$ -	$ 1,670.81	$ -	$ 113.93	$ 25.68	$ 242.53	$ 651.22	$ 790.80	$ 693.85	$ 995.72	$ -	$ -	$ 5,184.5
Langley Gulch													
Energy (MWh)	199,094.3	209,024.9	168,140.2	212,228.3	228,755.4	207,881.7	215,510.1	215,164.5	213,172.4	221,382.8	178,732.6	156,335.2	2,425,422.1
Expense ($ x 1000)	$ 15,873.97	$ 5,999.16	$ 10,258.20	$ 7,076.69	$ 6,572.12	$ 6,458.27	$ 7,663.07	$ 8,237.81	$ 7,501.92	$ 7,907.84	$ 13,400.47	$ 16,975.61	$ 113,925.1
Danskin													
Energy (MWh)	43,240.9	759.7	784.4	493.0	-	54,002.2	120,712.0	100,347.0	-	-	634.2	16,317.6	337,291.0
Expense ($ x 1000)	$ 5,718.50	$ 35.77	$ 73.69	$ 27.83	$ -	$ 2,602.14	$ 6,813.65	$ 6,102.17	$ -	$ -	$ 77.05	$ 2,674.57	$ 24,125.4
Bennett Mountain													
Energy (MWh)	7,240.1	1,736.2	3,971.4	225.6	-	24,333.1	66,085.6	35,022.1	1,363.7	-	243.0	4,027.4	144,248.3
Expense ($ x 1000)	$ 944.55	$ 78.07	$ 365.89	$ 12.60	$ -	$ 1,188.21	$ 3,736.68	$ 2,128.37	$ 72.96	$ -	$ 28.94	$ 646.64	$ 9,202.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	281,241.6	137,741.3	254,025.7	89,961.3	98,375.4	183,656.1	234,984.2	197,083.5	84,332.7	47,777.3	179,513.8	301,818.0	2,090,510.9
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	357,013.8	201,969.8	336,469.2	175,300.7	189,128.5	273,742.3	329,336.7	285,568.9	159,929.3	120,173.8	248,779.8	371,618.4	3,049,031.3
Market Expense ($ x 1000)	$ 13,912.68	$ 4,802.65	$ 7,548.21	$ 2,760.42	$ 2,533.24	$ 5,504.42	$ 8,468.48	$ 7,889.17	$ 3,284.84	$ 1,926.79	$ 7,381.00	$ 14,623.95	$ 80,635.9
Market Expense - No Wheeling ($ x 1000)	$ 11,811.99	$ 3,773.81	$ 5,650.81	$ 2,088.47	$ 1,798.44	$ 4,132.63	$ 6,713.30	$ 6,417.09	$ 2,654.93	$ 1,569.93	$ 6,040.15	$ 12,369.57	$ 65,021.1
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 17,570.2	$ 8,218.7	$ 10,903.4	$ 7,040.5	$ 6,580.3	$ 8,580.1	$ 11,191.0	$ 10,759.7	$ 6,648.9	$ 6,089.1	$ 11,235.1	$ 17,805.1	$ 122,622.2
Storage													
Black Mesa Battery Energy (MWh)	(1,188.59)	(844.56)	(1,165.2)	(1,064.1)	(985.7)	(861.3)	(875.6)	(868.2)	(803.8)	(934.1)	(848.6)	(1,110.3)	(11,549.9)
80 MW Grid Battery Energy (MWh)	(2,320.77)	(1,704.55)	(2,256.5)	(2,093.5)	(1,950.3)	(1,719.6)	(1,750.9)	(1,736.5)	(1,645.6)	(1,853.5)	(1,738.1)	(2,211.7)	(22,981.4)

11 MW Grid Battery Energy (MWh)	(310.86)	(220.59)	(292.8)	(274.7)	(260.8)	(226.3)	(241.0)	(235.0)	(220.5)	(254.6)	(215.9)	(284.6)	(3,037.6)
Total Storage (MWh)	(3,820.2)	(2,769.7)	(3,714.4)	(3,432.2)	(3,196.8)	(2,807.2)	(2,867.5)	(2,839.6)	(2,669.9)	(3,042.2)	(2,802.6)	(3,606.6)	(37,569.0)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	-	20,337.7	6,267.9	34,305.3	41,019.4	8,371.6	3,040.6	3,429.3	26,702.2	59,354.7	6,489.5	428.9	209,746.9
Revenue ($ x 1000)	$ -	$ 987.4	$ 248.7	$ 1,304.0	$ 1,372.5	$ 327.4	$ 169.3	$ 171.5	$ 1,227.3	$ 2,463.3	$ 354.0	$ 27.0	$ 8,652.4
Revenue - No Wheeling ($ x 1000)	$ -	$ 835.5	$ 201.9	$ 1,047.8	$ 1,066.1	$ 264.9	$ 146.6	$ 145.8	$ 1,027.8	$ 2,020.0	$ 305.5	$ 23.8	$ 7,085.7
Total Energy	1,428,850.96	1,234,421.49	1,217,841.85	1,168,470.77	1,353,816.90	1,602,921.82	1,927,228.25	1,763,858.89	1,373,841.57	1,218,929.60	1,251,370.18	1,476,224.98	17,017,777.26
Total NPSE	$ 60,538.6	$ 36,746.5	$ 38,518.5	$ 32,538.6	$ 31,884.7	$ 46,744.2	$ 62,954.2	$ 62,073.1	$ 41,073.6	$ 37,365.3	$ 50,918.8	$ 67,047.5	$ 569,970.2

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1992

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	567,350.4	598,175.8	466,006.8	464,625.5	447,567.3	493,021.3	491,130.2	380,378.8	345,001.1	388,447.4	372,879.0	413,738.0	5,428,321.3
Bridger Coal													
Energy (MWh)	125,632.9	104,507.9	68,944.2	72,570.5	85,839.9	135,834.5	217,757.1	250,532.5	242,600.0	249,998.5	242,600.0	250,686.7	2,047,504.78
Expense ($ x 1000)	$ 3,929.37	$ 3,291.20	$ 2,298.86	$ 2,392.97	$ 3,015.38	$ 4,514.20	$ 6,892.31	$ 7,835.84	$ 7,587.37	$ 7,820.47	$ 7,587.37	$ 7,840.28	$ 65,005.62
Valmy													
Energy (MWh)	121.5	-	-	-	-	2,228.0	45,484.7	47,659.5	37,180.5	12,026.8	44,062.0	65,642.3	254,405.3
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ 105.48	$ 2,109.49	$ 2,206.43	$ 1,737.99	$ 558.50	$ 2,044.73	$ 3,009.23	$ 11,777.6
Bridger Gas													
Energy (MWh)	-	44,197.3	-	1,369.0	1,268.5	8,019.1	28,835.7	39,684.6	15,991.3	18,392.7	-	-	157,758.2
Expense ($ x 1000)	$ -	$ 1,782.18	$ -	$ 67.15	$ 54.45	$ 382.22	$ 1,510.17	$ 2,115.02	$ 778.66	$ 887.62	$ -	$ -	$ 7,577.5
Langley Gulch													
Energy (MWh)	200,832.4	208,721.8	166,054.5	211,919.7	230,404.8	207,973.1	215,441.5	215,410.0	213,875.1	221,881.6	183,296.3	155,172.5	2,430,983.1
Expense ($ x 1000)	$ 16,304.33	$ 6,114.85	$ 10,420.20	$ 7,215.28	$ 6,753.76	$ 6,595.69	$ 7,823.00	$ 8,423.02	$ 7,685.28	$ 8,093.19	$ 13,873.25	$ 17,297.56	$ 116,599.4
Danskin													
Energy (MWh)	14,722.8	-	63.8	-	3,384.2	84,729.6	148,180.3	136,060.3	28,161.0	394.3	197.7	21,827.6	437,721.6
Expense ($ x 1000)	$ 1,987.47	$ -	$ 5.99	$ -	$ 152.52	$ 4,254.88	$ 8,616.72	$ 8,543.47	$ 1,536.86	$ 23.65	$ 24.21	$ 3,651.19	$ 28,797.0
Bennett Mountain													
Energy (MWh)	8,488.4	-	1,401.7	-	2,129.9	43,324.3	96,235.1	93,615.3	27,878.0	-	486.1	4,782.5	278,341.2
Expense ($ x 1000)	$ 1,132.73	$ -	$ 132.06	$ -	$ 99.82	$ 2,153.48	$ 5,554.81	$ 5,860.08	$ 1,585.05	$ -	$ 59.20	$ 785.54	$ 17,362.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	237,229.1	51,130.3	202,031.0	78,661.4	193,212.9	225,424.0	290,552.1	230,485.2	166,927.5	77,264.9	171,218.0	315,090.3	2,239,226.5
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	313,001.3	115,358.8	284,474.5	164,000.8	283,966.0	315,510.2	384,904.6	318,970.6	242,524.1	149,661.4	240,484.0	384,890.7	3,197,746.9
Market Expense ($ x 1000)	$ 12,017.16	$ 1,719.28	$ 5,981.26	$ 2,407.60	$ 5,404.74	$ 7,092.64	$ 11,720.36	$ 9,743.25	$ 6,641.21	$ 3,227.88	$ 7,277.39	$ 15,478.23	$ 88,711.0
Market Expense - No Wheeling ($ x 1000)	$ 10,245.22	$ 1,337.37	$ 4,472.22	$ 1,820.05	$ 3,961.57	$ 5,408.87	$ 9,550.13	$ 8,021.68	$ 5,394.37	$ 2,650.76	$ 5,998.51	$ 13,124.71	$ 71,985.5
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 16,003.5	$ 5,782.3	$ 9,724.9	$ 6,772.1	$ 8,743.4	$ 9,856.4	$ 14,027.8	$ 12,364.2	$ 9,388.4	$ 7,170.0	$ 11,193.4	$ 18,560.3	$ 129,586.6
Storage													
Black Mesa Battery Energy (MWh)	(1,221.57)	(1,015.92)	(1,192.9)	(966.2)	(827.7)	(852.0)	(882.7)	(882.3)	(813.1)	(900.8)	(922.3)	(1,038.2)	(11,515.6)
80 MW Grid Battery Energy (MWh)	(2,457.27)	(1,994.49)	(2,317.0)	(1,940.7)	(1,683.7)	(1,711.0)	(1,765.0)	(1,764.7)	(1,637.0)	(1,817.7)	(1,811.8)	(2,013.1)	(22,913.5)

11 MW Grid Battery Energy (MWh)	(333.42)	(268.32)	(299.6)	(261.8)	(210.9)	(225.4)	(243.0)	(238.9)	(211.8)	(240.9)	(242.4)	(253.8)	(3,030.2)
Total Storage (MWh)	(4,012.3)	(3,278.7)	(3,809.5)	(3,168.7)	(2,722.3)	(2,788.4)	(2,890.7)	(2,885.8)	(2,661.9)	(2,959.4)	(2,976.6)	(3,305.2)	(37,459.3)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	84.0	59,247.4	11,511.4	31,522.3	11,707.4	5,381.5	2,142.4	5,473.6	11,632.3	41,179.7	7,609.0	328.4	187,819.3
Revenue ($ x 1000)	$ 5.9	$ 2,744.4	$ 488.5	$ 1,162.4	$ 405.0	$ 229.3	$ 112.1	$ 340.2	$ 603.4	$ 1,713.4	$ 415.1	$ 19.3	$ 8,239.0
Revenue - No Wheeling ($ x 1000)	$ 5.3	$ 2,301.8	$ 402.5	$ 926.9	$ 317.6	$ 189.1	$ 96.1	$ 299.3	$ 516.5	$ 1,405.8	$ 358.3	$ 16.9	$ 6,836.1
Total Energy	1,428,850.92	1,234,421.47	1,217,841.83	1,168,470.79	1,353,816.91	1,602,921.81	1,927,228.26	1,763,858.90	1,373,841.61	1,218,929.60	1,251,370.19	1,476,224.99	17,017,777.28
Total NPSE	$ 55,853.4	$ 32,645.0	$ 36,921.6	$ 32,398.4	$ 35,856.1	$ 51,250.9	$ 71,789.2	$ 71,471.3	$ 48,196.7	$ 39,905.0	$ 51,397.2	$ 69,490.3	$ 598,578.3

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1993

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	471,058.7	511,285.8	820,399.1	1,002,773.4	1,095,890.3	1,071,254.0	761,464.4	591,165.2	547,779.4	458,643.4	375,618.4	491,635.4	8,198,967.4
Bridger Coal													
Energy (MWh)	125,632.9	100,134.9	53,856.8	42,944.8	47,089.2	100,140.4	174,039.0	248,542.0	242,588.7	238,771.2	242,553.8	250,686.7	1,866,980.37
Expense ($ x 1000)	$ 3,929.37	$ 3,165.42	$ 1,864.91	$ 1,540.86	$ 1,900.13	$ 3,486.79	$ 5,633.99	$ 7,778.53	$ 7,587.04	$ 7,497.12	$ 7,586.04	$ 7,840.28	$ 59,810.48
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	40,803.5	44,801.8	18,375.0	684.8	41,208.5	54,015.0	200,010.2
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,900.49	$ 2,077.71	$ 859.52	$ 31.53	$ 1,917.54	$ 2,490.84	$ 9,283.4
Bridger Gas													
Energy (MWh)	-	48,539.0	-	171.0	-	2,812.9	18,026.1	30,853.6	17,152.3	34,225.3	-	-	151,780.2
Expense ($ x 1000)	$ -	$ 1,848.24	$ -	$ 7.90	$ -	$ 126.70	$ 890.60	$ 1,551.93	$ 788.89	$ 1,561.19	$ -	$ -	$ 6,775.5
Langley Gulch													
Energy (MWh)	202,181.6	208,970.8	-	-	-	39,615.8	215,269.3	215,964.2	213,006.8	220,774.9	175,879.8	155,035.7	1,646,699.0
Expense ($ x 1000)	$ 15,559.67	$ 5,842.50	$ -	$ -	$ -	$ 1,209.51	$ 7,452.09	$ 8,046.93	$ 7,297.82	$ 7,677.77	$ 12,925.58	$ 16,433.53	$ 82,445.4
Danskin													
Energy (MWh)	57,250.8	1,109.0	-	-	-	-	80,781.0	57,858.0	-	-	65.1	2,823.8	199,887.8
Expense ($ x 1000)	$ 7,335.42	$ 49.77	$ -	$ -	$ -	$ -	$ 4,396.48	$ 3,381.16	$ -	$ -	$ 7.87	$ 450.46	$ 15,621.2
Bennett Mountain													
Energy (MWh)	11,609.1	-	-	-	-	774.0	31,882.9	31,506.5	811.7	-	1,579.7	2,265.4	80,429.3
Expense ($ x 1000)	$ 1,471.23	$ -	$ -	$ -	$ -	$ 37.15	$ 1,748.88	$ 1,854.79	$ 41.32	$ -	$ 182.75	$ 353.29	$ 5,689.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	286,657.9	108,197.5	67,498.3	1,725.8	9,068.8	49,884.5	216,324.4	176,392.3	57,810.5	40,582.1	177,977.5	271,564.8	1,463,684.5
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	362,430.1	172,426.0	149,941.8	87,065.2	99,821.9	139,970.7	310,676.9	264,877.6	133,407.2	112,978.6	247,243.5	341,365.3	2,422,204.9
Market Expense ($ x 1000)	$ 14,158.00	$ 3,603.20	$ 1,795.58	$ 49.63	$ 235.36	$ 1,440.08	$ 7,402.06	$ 7,004.30	$ 2,197.14	$ 1,566.97	$ 7,147.15	$ 12,563.52	$ 59,163.0
Market Expense - No Wheeling ($ x 1000)	$ 12,016.86	$ 2,795.04	$ 1,291.41	$ 36.74	$ 167.62	$ 1,067.48	$ 5,786.26	$ 5,686.77	$ 1,765.33	$ 1,263.85	$ 5,817.78	$ 10,535.11	$ 48,230.2
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 17,775.1	$ 7,240.0	$ 6,544.0	$ 4,988.8	$ 4,949.5	$ 5,515.0	$ 10,263.9	$ 10,029.3	$ 5,759.3	$ 5,783.0	$ 11,012.7	$ 15,970.7	$ 105,831.3
Storage													
Black Mesa Battery Energy (MWh)	(1,304.52)	(923.93)	(1,212.7)	(1,204.3)	(894.4)	(845.7)	(875.2)	(863.9)	(787.0)	(912.5)	(894.1)	(1,080.3)	(11,798.7)
80 MW Grid Battery Energy (MWh)	(2,579.22)	(1,893.00)	(2,417.2)	(2,440.9)	(1,794.5)	(1,694.4)	(1,750.6)	(1,741.4)	(1,605.1)	(1,838.5)	(1,779.9)	(2,123.0)	(23,657.7)

11 MW Grid Battery Energy (MWh)	(347.60)	(246.35)	(314.5)	(321.3)	(233.1)	(219.6)	(240.8)	(238.9)	(215.7)	(248.5)	(227.8)	(276.5)	(3,130.5)
Total Storage (MWh)	(4,231.3)	(3,063.3)	(3,944.4)	(3,966.4)	(2,922.0)	(2,759.7)	(2,866.7)	(2,844.2)	(2,607.8)	(2,999.5)	(2,901.8)	(3,479.9)	(38,586.9)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	-	30,966.9	48,628.8	249,193.3	199,748.6	69,338.1	7,140.2	8,772.7	31,596.4	66,415.1	7,827.7	1,240.8	720,868.5
Revenue ($ x 1000)	$ -	$ 1,406.7	$ 1,669.6	$ 7,496.4	$ 5,346.5	$ 2,194.8	$ 384.0	$ 501.4	$ 1,428.3	$ 2,982.6	$ 428.8	$ 78.1	$ 23,917.3
Revenue - No Wheeling ($ x 1000)	$ -	$ 1,175.4	$ 1,306.3	$ 5,635.1	$ 3,854.5	$ 1,676.9	$ 330.7	$ 435.9	$ 1,192.3	$ 2,486.5	$ 370.4	$ 68.8	$ 18,532.8
Total Energy	1,428,850.94	1,234,421.47	1,217,841.81	1,168,470.81	1,353,816.91	1,602,921.81	1,927,228.24	1,763,858.88	1,373,841.60	1,218,929.60	1,251,370.19	1,476,224.98	17,017,777.24
Total NPSE	$ 62,572.8	$ 35,158.1	$ 21,567.5	$ 16,154.4	$ 18,944.8	$ 31,798.3	$ 57,269.5	$ 58,682.4	$ 39,406.1	$ 36,633.0	$ 50,233.8	$ 61,826.6	$ 495,631.7
Wheeling 3-Year Average	$ 7.47												

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1994

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	958,118.7	815,981.8	638,515.2	573,505.8	599,491.0	586,018.3	599,142.7	451,620.7	441,352.9	418,703.9	374,381.1	455,211.1	6,912,043.2
Bridger Coal													
Energy (MWh)	125,632.9	95,420.6	58,899.4	68,423.2	75,820.0	119,579.4	187,037.3	249,142.5	242,600.0	243,466.9	242,600.0	250,686.7	1,959,308.91
Expense ($ x 1000)	$ 3,929.37	$ 3,029.82	$ 2,009.94	$ 2,273.69	$ 2,727.01	$ 4,046.31	$ 6,008.09	$ 7,795.82	$ 7,587.37	$ 7,632.35	$ 7,587.37	$ 7,840.28	$ 62,467.42
Valmy													
Energy (MWh)	121.5	-	-	-	-	243.1	44,710.6	48,224.0	43,518.0	11,614.2	43,763.4	58,829.0	251,023.7
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ 11.51	$ 2,076.33	$ 2,232.93	$ 2,020.48	$ 540.11	$ 2,031.42	$ 2,705.42	$ 11,624.0
Bridger Gas													
Energy (MWh)	-	23,126.1	-	4,413.6	463.1	3,068.5	23,591.8	43,012.3	37,344.6	27,305.5	-	-	162,325.5
Expense ($ x 1000)	$ -	$ 907.61	$ -	$ 210.80	$ 19.32	$ 142.25	$ 1,201.70	$ 2,230.16	$ 1,770.39	$ 1,283.35	$ -	$ -	$ 7,765.6
Langley Gulch													
Energy (MWh)	27,139.3	33,124.3	115,076.9	160,655.6	229,487.2	207,232.8	215,682.8	216,068.5	214,614.3	221,497.2	183,000.2	157,899.2	1,981,478.3
Expense ($ x 1000)	$ 2,232.82	$ 950.52	$ 7,180.13	$ 5,342.95	$ 6,569.45	$ 6,416.60	$ 7,641.93	$ 8,242.04	$ 7,524.35	$ 7,883.83	$ 13,509.90	$ 16,991.02	$ 90,485.5
Danskin													
Energy (MWh)	-	-	-	-	-	56,837.3	130,208.8	129,192.5	9,406.1	-	263.7	13,304.1	339,212.4
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 2,730.78	$ 7,340.94	$ 7,812.88	$ 495.56	$ -	$ 31.41	$ 2,168.25	$ 20,579.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	27,622.7	86,480.5	65,712.5	4,784.4	-	486.1	3,272.2	188,358.3
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 1,362.52	$ 4,858.35	$ 3,967.11	$ 263.77	$ -	$ 57.66	$ 523.39	$ 11,032.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	63,219.2	32,469.0	110,100.1	44,546.1	92,737.6	200,999.7	248,168.8	195,050.4	110,046.6	58,296.8	170,714.9	288,229.2	1,614,578.3
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	138,991.4	96,697.5	192,543.7	129,885.5	183,490.6	291,085.9	342,521.3	283,535.8	185,643.3	130,693.3	239,980.9	358,029.6	2,573,098.7
Market Expense ($ x 1000)	$ 2,852.12	$ 1,021.06	$ 2,960.55	$ 1,312.32	$ 2,398.12	$ 5,940.16	$ 9,213.81	$ 8,152.15	$ 4,358.07	$ 2,324.63	$ 7,062.12	$ 13,745.40	$ 61,340.5
Market Expense - No Wheeling ($ x 1000)	$ 2,379.91	$ 778.54	$ 2,138.17	$ 979.59	$ 1,705.43	$ 4,438.83	$ 7,360.15	$ 6,695.25	$ 3,536.09	$ 1,889.19	$ 5,786.99	$ 11,592.52	$ 49,280.7
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 8,138.2	$ 5,223.5	$ 7,390.8	$ 5,931.6	$ 6,487.3	$ 8,886.3	$ 11,837.8	$ 11,037.8	$ 7,530.1	$ 6,408.4	$ 10,981.9	$ 17,028.1	$ 106,881.8
Storage													
Black Mesa Battery Energy (MWh)	(1,247.47)	(834.87)	(1,133.4)	(1,093.8)	(989.0)	(825.0)	(875.6)	(882.7)	(840.9)	(939.6)	(941.1)	(1,099.9)	(11,703.1)
80 MW Grid Battery Energy (MWh)	(2,508.98)	(1,622.99)	(2,286.0)	(2,119.3)	(1,958.2)	(1,672.9)	(1,750.9)	(1,764.7)	(1,661.7)	(1,896.3)	(1,920.1)	(2,174.9)	(23,336.9)

11 MW Grid Battery Energy (MWh)	(334.28)	(231.99)	(278.5)	(293.8)	(268.3)	(219.5)	(239.1)	(238.9)	(223.8)	(258.0)	(247.5)	(277.4)	(3,110.9)
Total Storage (MWh)	(4,090.7)	(2,689.9)	(3,697.8)	(3,506.9)	(3,215.4)	(2,717.4)	(2,865.6)	(2,886.2)	(2,726.4)	(3,093.9)	(3,108.7)	(3,552.2)	(38,150.9)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	19,859.7	53,225.0	29,712.8	53,582.3	45,405.7	6,500.5	3,574.0	9,670.5	37,620.2	53,523.6	7,947.2	573.1	321,194.5
Revenue ($ x 1000)	$ 1,148.3	$ 2,199.4	$ 1,174.8	$ 2,177.8	$ 1,531.5	$ 263.8	$ 174.3	$ 578.1	$ 1,933.6	$ 2,386.7	$ 431.1	$ 36.9	$ 14,036.4
Revenue - No Wheeling ($ x 1000)	$ 999.9	$ 1,801.9	$ 952.9	$ 1,777.6	$ 1,192.3	$ 215.2	$ 147.6	$ 505.9	$ 1,652.6	$ 1,986.9	$ 371.8	$ 32.6	$ 11,637.3
Total Energy	1,428,850.93	1,234,421.47	1,217,841.83	1,168,470.79	1,353,816.91	1,602,921.80	1,927,228.27	1,763,858.88	1,373,841.59	1,218,929.58	1,251,370.20	1,476,224.97	17,017,777.22
Total NPSE	$ 29,654.1	$ 26,330.9	$ 30,234.2	$ 28,694.5	$ 31,713.4	$ 46,950.4	$ 66,157.9	$ 67,204.1	$ 43,759.0	$ 38,426.3	$ 50,798.7	$ 65,585.1	$ 527,907.5

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1995

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	629,205.8	740,356.2	872,859.4	1,083,299.8	1,180,796.0	1,091,883.4	852,501.1	773,838.5	679,112.0	439,483.2	374,410.0	937,105.3	9,654,850.7
Bridger Coal													
Energy (MWh)	125,632.9	59,086.1	39,493.8	38,241.8	54,178.0	80,210.6	154,969.3	216,543.0	188,485.0	219,823.9	237,133.3	250,638.2	1,664,435.73
Expense ($ x 1000)	$ 3,929.37	$ 1,984.75	$ 1,451.79	$ 1,405.59	$ 2,104.15	$ 2,913.16	$ 5,085.14	$ 6,857.38	$ 6,029.21	$ 6,951.70	$ 7,429.97	$ 7,838.89	$ 53,981.10
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	-	39,019.0	-	162.0	41,731.6	22,096.0	103,130.1
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,818.26	$ -	$ 7.67	$ 1,940.85	$ 1,024.25	$ 4,796.8
Bridger Gas													
Energy (MWh)	-	38,532.9	-	2,431.7	877.8	1,450.2	17,104.1	32,285.3	17,561.9	43,204.1	-	-	153,448.1
Expense ($ x 1000)	$ -	$ 1,342.66	$ -	$ 103.40	$ 32.53	$ 59.49	$ 773.52	$ 1,485.58	$ 738.61	$ 1,802.89	$ -	$ -	$ 6,338.7
Langley Gulch													
Energy (MWh)	191,482.2	202,785.4	-	-	-	42,889.1	215,290.8	216,212.6	209,125.1	221,412.7	181,688.6	12,005.3	1,492,891.8
Expense ($ x 1000)	$ 13,997.29	$ 5,280.46	$ -	$ -	$ -	$ 1,216.21	$ 6,925.74	$ 7,481.51	$ 6,663.17	$ 7,154.08	$ 11,953.75	$ 1,145.58	$ 61,817.8
Danskin													
Energy (MWh)	10,632.4	-	-	-	-	60.9	38,288.5	463.0	246.7	-	1,018.9	-	50,710.4
Expense ($ x 1000)	$ 1,254.44	$ -	$ -	$ -	$ -	$ 2.84	$ 1,912.08	$ 26.62	$ 12.72	$ -	$ 110.00	$ -	$ 3,318.7
Bennett Mountain													
Energy (MWh)	2,246.9	-	-	-	-	1,241.7	56,340.7	3,111.8	-	-	972.1	-	63,913.3
Expense ($ x 1000)	$ 262.96	$ -	$ -	$ -	$ -	$ 51.84	$ 2,890.79	$ 163.75	$ -	$ -	$ 103.88	$ -	$ 3,473.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	196,664.3	8,619.3	43,414.3	139.0	5,495.1	51,651.2	203,039.1	128,868.0	27,931.0	61,201.2	178,345.2	51,709.0	957,076.6
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	272,436.5	72,847.8	125,857.8	85,478.4	96,248.2	141,737.4	297,391.6	217,353.4	103,527.6	133,597.7	247,611.2	121,509.4	1,915,596.9
Market Expense ($ x 1000)	$ 8,225.46	$ 242.24	$ 1,069.25	$ 3.92	$ 139.14	$ 1,420.74	$ 6,256.14	$ 4,540.50	$ 899.30	$ 2,137.66	$ 6,788.08	$ 2,105.88	$ 33,828.3
Market Expense - No Wheeling ($ x 1000)	$ 6,756.51	$ 177.86	$ 744.97	$ 2.88	$ 98.10	$ 1,034.94	$ 4,739.57	$ 3,577.94	$ 690.67	$ 1,680.53	$ 5,455.96	$ 1,719.65	$ 26,679.6
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 12,514.8	$ 4,622.8	$ 5,997.6	$ 4,954.9	$ 4,879.9	$ 5,482.4	$ 9,217.3	$ 7,920.5	$ 4,684.7	$ 6,199.7	$ 10,650.9	$ 7,155.2	$ 84,280.7
Storage													
Black Mesa Battery Energy (MWh)	(1,106.23)	(1,009.51)	(1,292.8)	(1,187.5)	(1,011.9)	(854.5)	(897.6)	(875.6)	(791.9)	(902.0)	(932.7)	(1,191.3)	(12,053.5)
80 MW Grid Battery Energy (MWh)	(2,187.82)	(2,024.87)	(2,585.8)	(2,393.3)	(2,038.7)	(1,720.6)	(1,779.4)	(1,738.0)	(1,616.7)	(1,786.5)	(1,823.6)	(2,426.0)	(24,121.2)

11 MW Grid Battery Energy (MWh)	(307.03)	(272.57)	(338.2)	(321.8)	(268.5)	(228.0)	(245.6)	(236.9)	(224.7)	(248.3)	(242.9)	(312.2)	(3,246.8)
Total Storage (MWh)	(3,601.1)	(3,307.0)	(4,216.9)	(3,902.7)	(3,319.1)	(2,803.2)	(2,922.6)	(2,850.5)	(2,633.3)	(2,936.7)	(2,999.1)	(3,929.6)	(39,421.5)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	2,103.7	101,866.1	62,369.5	325,754.4	288,650.1	74,200.0	6,027.4	22,023.8	56,508.0	58,083.4	8,147.2	46,318.1	1,052,051.7
Revenue ($ x 1000)	$ 124.9	$ 3,894.0	$ 1,957.1	$ 9,220.4	$ 7,689.8	$ 2,124.2	$ 294.2	$ 1,107.5	$ 2,317.8	$ 2,570.9	$ 422.9	$ 2,146.3	$ 33,869.8
Revenue - No Wheeling ($ x 1000)	$ 109.2	$ 3,133.1	$ 1,491.2	$ 6,787.2	$ 5,533.8	$ 1,569.9	$ 249.2	$ 943.0	$ 1,895.7	$ 2,137.0	$ 362.0	$ 1,800.3	$ 26,011.6
Total Energy	1,428,850.95	1,234,421.48	1,217,841.84	1,168,470.80	1,353,816.94	1,602,921.83	1,927,228.24	1,763,858.91	1,373,841.59	1,218,929.58	1,251,370.22	1,476,224.98	17,017,777.36
Total NPSE	$ 48,335.9	$ 27,755.6	$ 20,320.4	$ 14,356.8	$ 16,768.6	$ 31,219.8	$ 51,877.4	$ 49,109.5	$ 34,311.2	$ 36,610.2	$ 48,796.6	$ 33,383.2	$ 420,703.3

Wheeling 3-Year Average $ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1996

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,250,147.6	1,050,397.2	1,097,538.9	1,040,497.6	1,113,862.5	1,211,285.7	831,576.1	796,940.8	673,648.9	505,588.0	417,966.8	841,480.6	10,830,930.5
Bridger Coal													
Energy (MWh)	107,324.5	36,762.1	29,523.4	34,083.2	39,635.7	67,466.5	126,275.0	165,447.1	149,456.8	165,957.3	212,121.2	247,567.9	1,381,620.54
Expense ($ x 1000)	$ 3,402.77	$ 1,342.65	$ 1,165.02	$ 1,285.98	$ 1,685.61	$ 2,546.36	$ 4,259.18	$ 5,386.74	$ 4,905.90	$ 5,401.18	$ 6,709.99	$ 7,750.47	$ 45,841.85
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	10,505.1	5,620.8	-	40.5	35,745.2	30,373.8	82,406.9
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 495.94	$ 263.32	$ -	$ 1.92	$ 1,674.01	$ 1,411.38	$ 3,852.3
Bridger Gas													
Energy (MWh)	-	34,025.5	-	4,398.7	2,650.5	4,028.8	17,535.1	42,079.9	13,367.2	16,449.2	-	-	134,534.8
Expense ($ x 1000)	$ -	$ 1,067.26	$ -	$ 168.31	$ 88.59	$ 149.38	$ 713.25	$ 1,742.09	$ 505.48	$ 617.05	$ -	$ -	$ 5,051.4
Langley Gulch													
Energy (MWh)	-	-	-	-	-	23,882.9	216,216.5	216,676.4	214,936.2	223,602.6	177,596.7	41,890.4	1,114,801.7
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 622.35	$ 6,370.63	$ 6,862.29	$ 6,266.57	$ 6,614.90	$ 10,759.34	$ 3,669.72	$ 41,165.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	82,001.4	1,337.3	1,688.8	1,948.6	197.7	-	87,173.8
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,742.56	$ 63.06	$ 82.10	$ 96.30	$ 19.16	$ -	$ 4,003.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	9,039.4	4,037.4	-	-	486.1	-	13,562.9
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 420.84	$ 195.16	$ -	$ -	$ 47.21	$ -	$ 663.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	1,353.9	3,034.2	391.7	384.5	5,550.6	41,735.0	241,638.8	175,610.1	55,903.8	57,038.9	173,258.5	81,401.8	837,301.8
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	77,126.0	67,262.8	82,835.2	85,723.9	96,303.7	131,821.2	335,991.3	264,095.5	131,500.5	129,435.4	242,524.6	151,202.2	1,795,822.2
Market Expense ($ x 1000)	$ 53.43	$ 87.47	$ 9.24	$ 10.40	$ 129.34	$ 1,134.70	$ 6,938.17	$ 5,538.24	$ 1,627.21	$ 1,778.83	$ 5,874.53	$ 2,986.84	$ 26,168.4
Market Expense - No Wheeling ($ x 1000)	$ 43.32	$ 64.81	$ 6.31	$ 7.53	$ 87.88	$ 822.97	$ 5,133.29	$ 4,226.55	$ 1,209.65	$ 1,352.79	$ 4,580.40	$ 2,378.82	$ 19,914.3
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 5,801.6	$ 4,509.7	$ 5,258.9	$ 4,959.5	$ 4,869.7	$ 5,270.5	$ 9,611.0	$ 8,569.1	$ 5,203.6	$ 5,872.0	$ 9,775.3	$ 7,814.4	$ 77,515.4
Storage													
Black Mesa Battery Energy (MWh)	(1,175.63)	(1,139.91)	(1,436.8)	(1,265.2)	(1,065.1)	(842.4)	(882.3)	(872.7)	(777.3)	(839.2)	(890.7)	(1,053.5)	(12,240.9)
80 MW Grid Battery Energy (MWh)	(2,351.24)	(2,343.56)	(2,914.1)	(2,518.3)	(2,162.9)	(1,682.7)	(1,751.1)	(1,736.5)	(1,560.1)	(1,695.2)	(1,793.7)	(2,087.5)	(24,596.9)

11 MW Grid Battery Energy (MWh)	(333.07)	(304.37)	(363.1)	(341.1)	(274.5)	(218.9)	(241.4)	(236.9)	(205.7)	(233.2)	(227.1)	(259.2)	(3,238.6)
Total Storage (MWh)	(3,859.9)	(3,787.8)	(4,713.9)	(4,124.6)	(3,502.5)	(2,744.0)	(2,874.9)	(2,846.1)	(2,543.2)	(2,767.7)	(2,911.6)	(3,400.3)	(40,076.5)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	204,806.3	176,224.2	233,559.0	280,784.1	208,819.1	153,270.9	3,328.8	19,437.0	43,138.3	43,590.4	10,307.3	16,007.9	1,393,273.2
Revenue ($ x 1000)	$ 7,471.0	$ 5,477.1	$ 5,894.5	$ 7,517.1	$ 5,095.4	$ 3,928.9	$ 151.2	$ 933.5	$ 1,676.2	$ 1,612.1	$ 466.9	$ 774.8	$ 40,998.6
Revenue - No Wheeling ($ x 1000)	$ 5,941.2	$ 4,160.8	$ 4,150.0	$ 5,419.8	$ 3,535.7	$ 2,784.1	$ 126.3	$ 788.3	$ 1,354.0	$ 1,286.5	$ 389.9	$ 655.2	$ 30,591.8
Total Energy	1,428,850.94	1,234,421.47	1,217,841.83	1,168,470.78	1,353,816.91	1,602,921.86	1,927,228.27	1,763,858.86	1,373,841.59	1,218,929.59	1,251,370.21	1,476,224.98	17,017,777.29
Total NPSE	$ 18,235.3	$ 19,861.4	$ 15,357.6	$ 16,010.1	$ 18,990.3	$ 28,277.6	$ 50,829.2	$ 46,611.7	$ 33,788.0	$ 34,056.2	$ 45,548.3	$ 38,236.8	$ 376,209.3

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1997

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,300,991.3	1,093,940.3	1,071,701.8	1,018,577.9	1,118,426.1	1,192,855.5	1,041,480.5	866,665.1	730,894.9	561,326.0	677,594.2	873,137.5	11,547,591.0
Bridger Coal													
Energy (MWh)	100,183.3	35,338.5	34,686.1	32,018.4	38,048.5	69,662.3	120,325.1	154,997.0	121,645.8	150,778.1	193,448.3	244,918.8	1,296,050.08
Expense ($ x 1000)	$ 3,197.37	$ 1,301.71	$ 1,313.51	$ 1,226.59	$ 1,639.88	$ 2,609.55	$ 4,087.93	$ 5,085.89	$ 4,105.45	$ 4,964.22	$ 6,172.49	$ 7,674.20	$ 43,378.79
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	-	5,602.1	-	40.5	33,122.4	30,763.9	69,650.4
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ -	$ 263.72	$ -	$ 1.92	$ 1,553.18	$ 1,434.61	$ 3,259.2
Bridger Gas													
Energy (MWh)	-	35,312.0	-	3,740.8	2,612.4	2,679.7	16,145.4	36,424.8	23,622.8	17,730.9	-	-	138,268.8
Expense ($ x 1000)	$ -	$ 1,095.74	$ -	$ 141.48	$ 86.30	$ 98.26	$ 649.48	$ 1,491.84	$ 884.43	$ 657.88	$ -	$ -	$ 5,105.4
Langley Gulch													
Energy (MWh)	-	-	-	-	-	20,118.2	216,119.2	215,625.4	214,201.5	223,445.7	-	21,858.0	911,368.0
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 519.68	$ 6,313.62	$ 6,771.61	$ 6,192.91	$ 6,554.02	$ -	$ 1,926.88	$ 28,278.7
Danskin													
Energy (MWh)	-	-	-	-	-	61.6	3,049.3	308.7	-	-	-	-	3,419.5
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 2.48	$ 143.40	$ 15.92	$ -	$ -	$ -	$ -	$ 161.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	3,698.4	2,090.5	-	-	-	-	5,788.9
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 162.14	$ 99.00	$ -	$ -	$ -	$ -	$ 261.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	1,515.9	2,080.6	973.6	654.3	5,741.8	47,425.9	145,409.6	132,703.2	43,689.3	35,713.6	115,222.6	73,733.9	604,864.3
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	77,288.1	66,309.2	83,417.1	85,993.7	96,494.9	137,512.1	239,762.0	221,188.6	119,286.0	108,110.1	184,488.6	143,534.3	1,563,384.6
Market Expense ($ x 1000)	$ 57.53	$ 58.88	$ 22.57	$ 17.34	$ 132.72	$ 1,277.95	$ 4,284.35	$ 4,052.95	$ 1,233.26	$ 1,077.74	$ 3,760.76	$ 2,656.67	$ 18,632.7
Market Expense - No Wheeling ($ x 1000)	$ 46.21	$ 43.34	$ 15.30	$ 12.45	$ 89.83	$ 923.71	$ 3,198.24	$ 3,061.74	$ 906.93	$ 810.98	$ 2,900.12	$ 2,105.93	$ 14,114.8
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 5,804.5	$ 4,488.3	$ 5,267.9	$ 4,964.5	$ 4,871.7	$ 5,371.2	$ 7,675.9	$ 7,404.3	$ 4,900.9	$ 5,330.2	$ 8,095.1	$ 7,541.5	$ 71,715.9
Storage													
Black Mesa Battery Energy (MWh)	(1,266.83)	(1,147.74)	(1,450.9)	(1,193.4)	(1,090.7)	(873.1)	(877.0)	(875.2)	(828.2)	(873.0)	(876.8)	(1,041.7)	(12,394.4)
80 MW Grid Battery Energy (MWh)	(2,549.15)	(2,393.16)	(2,962.6)	(2,458.1)	(2,236.4)	(1,758.6)	(1,751.2)	(1,755.0)	(1,656.3)	(1,750.0)	(1,731.4)	(1,933.6)	(24,935.5)

11 MW Grid Battery Energy (MWh)	(336.24)	(299.22)	(377.1)	(322.4)	(289.1)	(232.5)	(243.3)	(244.7)	(221.2)	(236.7)	(221.6)	(256.2)	(3,280.1)
Total Storage (MWh)	(4,152.2)	(3,840.1)	(4,790.5)	(3,973.8)	(3,616.3)	(2,864.2)	(2,871.5)	(2,874.9)	(2,705.6)	(2,859.7)	(2,829.8)	(3,231.5)	(40,610.0)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	248,378.6	218,624.3	213,389.9	256,562.3	211,834.9	137,555.0	14,772.2	26,075.3	68,028.4	61,908.1	12,404.2	17,874.4	1,487,407.6
Revenue ($ x 1000)	$ 9,010.1	$ 6,544.1	$ 5,600.0	$ 6,735.0	$ 5,177.3	$ 3,638.4	$ 559.5	$ 1,222.5	$ 2,672.6	$ 2,228.2	$ 535.2	$ 878.2	$ 44,801.0
Revenue - No Wheeling ($ x 1000)	$ 7,154.9	$ 4,911.1	$ 4,006.1	$ 4,818.7	$ 3,595.0	$ 2,610.9	$ 449.2	$ 1,027.7	$ 2,164.5	$ 1,765.8	$ 442.6	$ 744.7	$ 33,691.1
Total Energy	1,428,850.93	1,234,421.46	1,217,841.82	1,168,470.80	1,353,816.93	1,602,921.84	1,927,228.25	1,763,858.89	1,373,841.58	1,218,929.59	1,251,370.21	1,476,224.98	17,017,777.28
Total NPSE	$ 16,493.7	$ 18,760.5	$ 15,809.6	$ 16,710.8	$ 18,862.4	$ 28,580.7	$ 43,840.0	$ 44,373.2	$ 31,911.6	$ 32,345.0	$ 32,315.6	$ 36,064.5	$ 347,177.8

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1998

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,223,780.9	1,079,596.8	1,112,674.9	1,160,395.9	1,238,229.9	1,218,531.6	955,932.7	778,483.5	711,680.5	501,927.8	379,696.0	655,686.4	11,016,616.8
Bridger Coal													
Energy (MWh)	124,435.8	43,914.6	33,756.7	33,694.7	45,915.6	69,735.1	136,009.6	191,684.5	163,580.5	186,052.0	219,003.6	250,589.5	1,498,372.16
Expense ($ x 1000)	$ 3,894.94	$ 1,548.38	$ 1,286.78	$ 1,274.80	$ 1,866.32	$ 2,611.63	$ 4,539.40	$ 6,141.87	$ 5,312.42	$ 5,979.59	$ 6,908.08	$ 7,837.48	$ 49,201.69
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	2,462.0	26,842.1	-	40.5	38,900.8	44,637.7	113,004.7
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 115.79	$ 1,253.29	$ -	$ 1.92	$ 1,814.67	$ 2,070.39	$ 5,261.8
Bridger Gas													
Energy (MWh)	-	36,495.7	-	1,777.7	2,117.3	1,519.9	24,087.8	48,537.0	18,449.2	19,617.7	-	-	152,602.2
Expense ($ x 1000)	$ -	$ 1,211.01	$ -	$ 71.89	$ 74.83	$ 59.59	$ 1,037.56	$ 2,127.59	$ 738.45	$ 778.80	$ -	$ -	$ 6,099.7
Langley Gulch													
Energy (MWh)	-	-	-	-	-	17,340.8	215,269.7	217,103.4	209,978.0	220,264.1	185,732.5	120,963.2	1,186,651.7
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 474.50	$ 6,641.31	$ 7,200.68	$ 6,415.49	$ 6,826.46	$ 11,768.14	$ 11,100.85	$ 50,427.4
Danskin													
Energy (MWh)	-	-	-	-	-	61.6	20,607.8	4,498.4	-	-	131.8	-	25,299.6
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 2.63	$ 986.16	$ 234.42	$ -	$ -	$ 13.45	$ -	$ 1,236.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	7,917.4	1,755.4	-	-	2,430.3	251.7	12,354.8
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 384.34	$ 86.32	$ -	$ -	$ 248.14	$ 34.61	$ 753.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	3,315.4	1,591.9	419.7	44.2	2,996.9	41,017.7	177,300.5	142,092.7	28,450.8	50,884.8	190,590.6	162,538.4	801,243.5
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	79,087.5	65,820.4	82,863.3	85,383.6	93,750.0	131,104.0	271,653.0	230,578.1	104,047.4	123,281.3	259,856.6	232,338.8	1,759,763.9
Market Expense ($ x 1000)	$ 138.36	$ 46.93	$ 10.53	$ 1.09	$ 73.31	$ 1,119.27	$ 5,283.01	$ 4,811.03	$ 861.30	$ 1,653.99	$ 6,819.26	$ 6,503.58	$ 27,321.7
Market Expense - No Wheeling ($ x 1000)	$ 113.60	$ 35.04	$ 7.39	$ 0.76	$ 50.92	$ 812.89	$ 3,958.69	$ 3,749.69	$ 648.79	$ 1,273.91	$ 5,395.67	$ 5,289.53	$ 21,336.9
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 5,871.8	$ 4,480.0	$ 5,260.0	$ 4,952.8	$ 4,832.8	$ 5,260.4	$ 8,436.4	$ 8,092.3	$ 4,642.8	$ 5,793.1	$ 10,590.6	$ 10,725.1	$ 78,938.0
Storage													
Black Mesa Battery Energy (MWh)	(1,162.21)	(1,163.82)	(1,456.9)	(1,196.7)	(1,138.8)	(886.4)	(869.3)	(863.9)	(819.1)	(900.1)	(917.3)	(1,225.8)	(12,600.2)
80 MW Grid Battery Energy (MWh)	(2,306.91)	(2,271.20)	(2,895.2)	(2,406.4)	(2,313.0)	(1,772.8)	(1,751.3)	(1,736.3)	(1,678.4)	(1,829.2)	(1,809.3)	(2,318.0)	(25,088.0)

11 MW Grid Battery Energy (MWh)	(316.07)	(311.63)	(368.3)	(315.9)	(300.5)	(233.2)	(241.8)	(237.2)	(218.8)	(251.6)	(222.5)	(303.6)	(3,321.1)
Total Storage (MWh)	(3,785.2)	(3,746.7)	(4,720.5)	(3,919.0)	(3,752.2)	(2,892.4)	(2,862.4)	(2,837.4)	(2,716.4)	(2,980.8)	(2,949.0)	(3,847.4)	(41,009.3)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	197,587.2	213,645.3	252,949.8	397,538.2	336,129.8	152,930.4	8,141.3	22,692.9	66,102.2	51,539.1	9,383.2	7,513.5	1,716,152.8
Revenue ($ x 1000)	$ 7,648.0	$ 6,809.7	$ 6,630.2	$ 10,668.4	$ 8,478.7	$ 3,963.3	$ 380.7	$ 1,173.5	$ 2,617.4	$ 1,991.3	$ 450.5	$ 409.7	$ 51,221.3
Revenue - No Wheeling ($ x 1000)	$ 6,172.1	$ 5,213.9	$ 4,740.8	$ 7,699.0	$ 5,968.0	$ 2,821.0	$ 319.9	$ 1,004.0	$ 2,123.6	$ 1,606.3	$ 380.4	$ 353.6	$ 38,402.7
Total Energy	1,428,850.94	1,234,421.50	1,217,841.83	1,168,470.77	1,353,816.92	1,602,921.82	1,927,228.21	1,763,858.90	1,373,841.60	1,218,929.60	1,251,370.17	1,476,224.96	17,017,777.22
Total NPSE	$ 18,620.8	$ 18,848.5	$ 14,744.8	$ 12,744.4	$ 15,737.0	$ 28,063.4	$ 47,127.3	$ 48,426.4	$ 32,992.3	$ 34,453.6	$ 47,922.7	$ 49,724.2	$ 382,223.9

Wheeling 3-Year Average $ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

1999

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,235,081.9	1,071,591.9	1,085,508.7	1,042,566.2	1,141,955.7	1,270,802.0	919,773.7	777,180.6	664,018.2	475,023.2	378,146.6	705,067.6	10,766,716.3
Bridger Coal													
Energy (MWh)	124,183.3	43,755.2	37,860.1	36,001.1	42,140.8	66,328.6	136,109.1	185,686.3	165,871.6	191,179.6	222,108.5	250,589.5	1,501,813.38
Expense ($ x 1000)	$ 3,887.67	$ 1,543.79	$ 1,404.80	$ 1,341.14	$ 1,757.71	$ 2,513.58	$ 4,542.25	$ 5,969.25	$ 5,378.43	$ 6,127.10	$ 6,997.45	$ 7,837.48	$ 49,300.65
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	12,002.3	25,133.0	-	40.5	40,427.5	43,906.4	121,631.2
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 564.58	$ 1,175.09	$ -	$ 1.92	$ 1,882.72	$ 2,037.79	$ 5,667.9
Bridger Gas													
Energy (MWh)	-	33,802.5	-	3,556.0	1,039.5	710.4	21,422.5	40,615.2	11,149.6	18,956.9	-	-	131,252.6
Expense ($ x 1000)	$ -	$ 1,124.36	$ -	$ 144.40	$ 36.84	$ 27.91	$ 924.65	$ 1,784.38	$ 447.53	$ 754.11	$ -	$ -	$ 5,244.2
Langley Gulch													
Energy (MWh)	-	-	-	-	-	13,722.1	215,336.4	216,229.0	209,433.7	220,596.4	181,284.0	103,928.5	1,160,530.1
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 376.92	$ 6,670.31	$ 7,202.21	$ 6,425.59	$ 6,864.17	$ 11,506.76	$ 9,579.74	$ 48,625.7
Danskin													
Energy (MWh)	-	-	-	-	-	60.9	25,742.1	1,799.6	1,110.0	-	2,093.6	66.0	30,872.1
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 2.72	$ 1,227.43	$ 91.88	$ 54.85	$ -	$ 213.61	$ 9.19	$ 1,599.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	5,452.1	2,361.8	-	-	243.0	-	8,056.9
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 265.79	$ 119.52	$ -	$ -	$ 24.92	$ -	$ 410.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	2,201.2	1,890.0	760.6	231.3	4,511.4	39,396.9	205,818.1	156,614.6	55,077.2	59,521.5	191,224.3	135,571.1	852,818.0
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	77,973.3	66,118.6	83,204.1	85,570.6	95,264.5	129,483.1	300,170.6	245,100.0	130,673.9	131,918.1	260,490.3	205,371.5	1,811,338.4
Market Expense ($ x 1000)	$ 93.24	$ 55.70	$ 18.82	$ 6.44	$ 108.79	$ 1,047.49	$ 6,169.48	$ 5,175.83	$ 1,666.98	$ 1,962.74	$ 6,953.37	$ 5,384.02	$ 28,642.9
Market Expense - No Wheeling ($ x 1000)	$ 76.80	$ 41.58	$ 13.14	$ 4.71	$ 75.09	$ 753.22	$ 4,632.16	$ 4,006.02	$ 1,255.59	$ 1,518.15	$ 5,525.05	$ 4,371.39	$ 22,272.9
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 5,835.0	$ 4,486.5	$ 5,265.8	$ 4,956.7	$ 4,856.9	$ 5,200.7	$ 9,109.8	$ 8,348.6	$ 5,249.6	$ 6,037.3	$ 10,720.0	$ 9,806.9	$ 79,874.0
Storage													
Black Mesa Battery Energy (MWh)	(1,219.97)	(1,151.55)	(1,377.4)	(1,124.2)	(1,123.4)	(870.1)	(882.7)	(879.3)	(777.9)	(852.1)	(979.2)	(1,162.1)	(12,399.9)
80 MW Grid Battery Energy (MWh)	(2,456.45)	(2,331.77)	(2,784.8)	(2,304.9)	(2,237.0)	(1,730.2)	(1,760.9)	(1,754.8)	(1,564.3)	(1,724.9)	(1,948.4)	(2,278.7)	(24,877.3)

11 MW Grid Battery Energy (MWh)	(336.18)	(301.75)	(359.7)	(300.7)	(303.1)	(230.4)	(241.2)	(237.0)	(212.7)	(237.1)	(251.9)	(293.5)	(3,305.3)
Total Storage (MWh)	(4,012.6)	(3,785.1)	(4,521.9)	(3,729.8)	(3,663.5)	(2,830.7)	(2,884.8)	(2,871.1)	(2,554.8)	(2,814.1)	(3,179.5)	(3,734.4)	(40,582.4)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	207,294.0	203,047.6	230,426.4	284,169.7	236,606.1	195,806.2	10,187.8	17,282.3	40,785.2	38,237.0	8,194.5	12,088.3	1,484,125.1
Revenue ($ x 1000)	$ 7,938.5	$ 6,526.5	$ 6,347.8	$ 7,926.3	$ 6,041.0	$ 4,983.2	$ 462.3	$ 892.7	$ 1,634.2	$ 1,471.8	$ 411.0	$ 664.9	$ 45,300.3
Revenue - No Wheeling ($ x 1000)	$ 6,390.2	$ 5,009.8	$ 4,626.7	$ 5,803.7	$ 4,273.7	$ 3,520.7	$ 386.2	$ 763.6	$ 1,329.6	$ 1,186.2	$ 349.8	$ 574.6	$ 34,214.9
Total Energy	1,428,850.95	1,234,421.47	1,217,841.83	1,168,470.77	1,353,816.90	1,602,921.85	1,927,228.25	1,763,858.89	1,373,841.59	1,218,929.60	1,251,370.20	1,476,224.97	17,017,777.27
Total NPSE	$ 18,286.2	$ 19,047.1	$ 15,150.9	$ 15,629.3	$ 18,052.3	$ 26,756.6	$ 48,209.6	$ 48,261.6	$ 34,422.3	$ 35,377.8	$ 47,964.5	$ 46,971.8	$ 385,215.3

Wheeling 3-Year Average $ 7.47

2000

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,177,062.3	1,025,758.9	1,063,824.3	1,113,599.8	1,025,771.8	922,963.5	755,900.8	549,604.2	611,660.4	453,721.2	374,657.2	462,891.2	9,537,415.5
Bridger Coal													
Energy (MWh)	125,632.9	46,571.7	33,862.3	39,805.9	53,719.9	95,960.0	162,350.0	234,984.8	226,160.4	222,295.7	238,959.6	250,685.4	1,730,988.53
Expense ($ x 1000)	$ 3,929.37	$ 1,624.80	$ 1,289.81	$ 1,450.58	$ 2,090.94	$ 3,366.45	$ 5,297.60	$ 7,388.26	$ 7,114.00	$ 7,022.82	$ 7,482.55	$ 7,840.25	$ 55,897.43
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	34,679.6	41,898.6	-	40.5	40,400.1	47,845.3	164,985.7
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,622.15	$ 1,948.30	$ -	$ 1.92	$ 1,881.50	$ 2,213.37	$ 7,673.0
Bridger Gas													
Energy (MWh)	-	29,625.0	-	550.1	2,516.6	4,015.4	21,797.6	25,982.9	13,475.2	26,999.8	-	-	124,962.4
Expense ($ x 1000)	$ -	$ 1,044.32	$ -	$ 23.66	$ 94.48	$ 167.18	$ 997.62	$ 1,209.63	$ 573.38	$ 1,139.35	$ -	$ -	$ 5,249.6
Langley Gulch													
Energy (MWh)	4,761.3	-	-	-	-	136,554.2	215,900.8	216,926.0	210,782.0	221,742.6	183,305.9	159,414.3	1,349,387.1
Expense ($ x 1000)	$ 374.13	$ -	$ -	$ -	$ -	$ 3,875.80	$ 6,998.80	$ 7,564.48	$ 6,766.17	$ 7,220.32	$ 12,315.89	$ 15,523.85	$ 60,639.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	84,988.8	81,533.9	-	-	580.4	13,372.1	180,475.1
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,280.98	$ 4,454.00	$ -	$ -	$ 63.40	$ 1,976.71	$ 10,775.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	1,838.3	34,609.0	55,706.6	4,383.7	-	243.0	2,391.2	99,171.9
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 77.70	$ 1,757.59	$ 3,056.01	$ 215.19	$ -	$ 26.19	$ 347.17	$ 5,479.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	4,987.8	1,762.6	2,228.6	222.4	8,676.4	83,001.4	227,048.1	189,220.3	41,544.8	55,538.8	176,667.5	291,193.6	1,082,092.1
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	80,760.0	65,991.1	84,672.1	85,561.8	99,429.5	173,087.6	321,400.6	277,705.6	117,141.4	127,935.3	245,933.5	360,994.0	2,040,612.4
Market Expense ($ x 1000)	$ 227.24	$ 55.61	$ 58.94	$ 6.32	$ 212.11	$ 2,176.46	$ 7,346.46	$ 7,074.38	$ 1,442.29	$ 1,992.67	$ 6,659.58	$ 12,956.37	$ 40,208.4
Market Expense - No Wheeling ($ x 1000)	$ 189.98	$ 42.44	$ 42.29	$ 4.66	$ 147.30	$ 1,556.49	$ 5,650.56	$ 5,661.03	$ 1,131.98	$ 1,577.83	$ 5,339.99	$ 10,781.35	$ 32,125.9
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 5,948.2	$ 4,487.4	$ 5,294.9	$ 4,956.7	$ 4,929.2	$ 6,004.0	$ 10,128.3	$ 10,003.6	$ 5,126.0	$ 6,097.0	$ 10,534.9	$ 16,216.9	$ 89,727.0
Storage													
Black Mesa Battery Energy (MWh)	(1,273.16)	(1,203.42)	(1,415.5)	(1,221.0)	(957.8)	(872.3)	(883.0)	(873.1)	(805.2)	(916.8)	(887.3)	(1,144.4)	(12,452.9)
80 MW Grid Battery Energy (MWh)	(2,543.51)	(2,523.16)	(2,871.4)	(2,427.4)	(1,969.5)	(1,744.6)	(1,751.2)	(1,741.0)	(1,584.1)	(1,851.2)	(1,743.8)	(2,299.7)	(25,050.4)

11 MW Grid Battery Energy (MWh)	(336.68)	(319.39)	(364.7)	(329.6)	(261.4)	(228.6)	(245.0)	(234.8)	(213.2)	(254.1)	(227.3)	(289.3)	(3,304.0)
Total Storage (MWh)	(4,153.4)	(4,046.0)	(4,651.5)	(3,978.1)	(3,188.6)	(2,845.5)	(2,879.2)	(2,848.8)	(2,602.4)	(3,022.0)	(2,858.4)	(3,733.4)	(40,807.3)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	158,131.2	155,465.2	206,082.6	355,744.8	138,118.4	49,103.5	5,811.8	7,541.7	42,083.6	53,049.6	7,801.9	753.7	1,179,687.9
Revenue ($ x 1000)	$ 6,661.0	$ 5,206.7	$ 5,566.8	$ 10,113.7	$ 3,966.1	$ 1,611.8	$ 296.5	$ 399.1	$ 1,672.6	$ 2,138.4	$ 416.3	$ 41.9	$ 38,090.9
Revenue - No Wheeling ($ x 1000)	$ 5,479.9	$ 4,045.5	$ 4,027.5	$ 7,456.5	$ 2,934.4	$ 1,245.0	$ 253.1	$ 342.7	$ 1,358.3	$ 1,742.2	$ 358.0	$ 36.3	$ 29,279.4
Total Energy	1,428,850.94	1,234,421.48	1,217,841.81	1,168,470.81	1,353,816.91	1,602,921.81	1,927,228.25	1,763,858.88	1,373,841.58	1,218,929.62	1,251,370.19	1,476,224.98	17,017,777.26
Total NPSE	$ 20,092.7	$ 20,368.7	$ 15,846.1	$ 13,430.5	$ 20,590.3	$ 35,497.3	$ 56,153.5	$ 59,688.6	$ 36,622.6	$ 36,408.0	$ 48,918.3	$ 62,441.9	$ 434,870.0

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2001

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	552,748.8	538,036.7	524,468.4	520,027.3	569,434.5	621,169.1	553,042.5	451,074.6	434,807.6	405,936.6	371,689.5	445,257.4	5,987,692.9
Bridger Coal													
Energy (MWh)	125,632.8	107,814.8	71,617.0	72,584.8	73,897.9	137,201.8	218,306.4	250,686.7	242,600.0	250,038.1	242,600.0	250,686.7	2,043,666.96
Expense ($ x 1000)	$ 3,929.37	$ 3,386.31	$ 2,375.73	$ 2,393.38	$ 2,671.63	$ 4,553.55	$ 6,908.19	$ 7,840.28	$ 7,587.37	$ 7,821.61	$ 7,587.37	$ 7,840.28	$ 64,895.07
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	47,085.1	50,504.2	42,809.6	17,324.0	47,268.8	69,079.7	274,193.0
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 2,182.17	$ 2,333.23	$ 1,988.91	$ 805.49	$ 2,187.67	$ 3,162.45	$ 12,665.7
Bridger Gas													
Energy (MWh)	-	30,745.6	-	1,673.5	883.4	4,764.2	27,513.0	42,717.7	28,482.4	20,118.4	-	-	156,898.1
Expense ($ x 1000)	$ -	$ 1,260.36	$ -	$ 83.50	$ 38.64	$ 230.48	$ 1,464.07	$ 2,313.96	$ 1,410.24	$ 987.33	$ -	$ -	$ 7,788.6
Langley Gulch													
Energy (MWh)	198,592.6	208,685.8	159,830.2	197,724.8	228,936.4	207,738.9	215,601.9	216,018.1	214,314.2	221,547.0	185,059.2	156,921.7	2,410,970.5
Expense ($ x 1000)	$ 16,414.49	$ 6,186.16	$ 10,168.78	$ 6,817.76	$ 6,791.88	$ 6,667.05	$ 7,923.39	$ 8,549.18	$ 7,793.77	$ 8,179.26	$ 14,118.22	$ 17,611.91	$ 117,221.9
Danskin													
Energy (MWh)	22,168.0	483.3	-	-	-	43,414.8	133,241.9	124,265.9	24,288.4	-	295.8	13,372.3	361,530.5
Expense ($ x 1000)	$ 3,037.96	$ 23.96	$ -	$ -	$ -	$ 2,180.41	$ 7,814.96	$ 7,827.72	$ 1,317.37	$ -	$ 37.03	$ 2,266.03	$ 24,505.4
Bennett Mountain													
Energy (MWh)	2,621.4	-	-	-	-	21,624.1	92,068.6	70,216.1	1,136.4	-	243.0	3,272.2	191,181.8
Expense ($ x 1000)	$ 354.38	$ -	$ -	$ -	$ -	$ 1,091.41	$ 5,387.62	$ 4,420.34	$ 61.63	$ -	$ 29.99	$ 544.52	$ 11,889.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	252,238.4	89,400.7	154,902.5	46,981.2	110,088.1	168,387.4	247,803.7	192,688.5	107,186.9	63,926.9	169,050.9	289,121.0	1,891,776.0
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	328,010.5	153,629.2	237,346.0	132,320.6	200,841.2	258,473.6	342,156.1	281,173.9	182,783.5	136,323.4	238,316.9	358,921.5	2,850,296.4
Market Expense ($ x 1000)	$ 12,774.32	$ 3,127.69	$ 4,389.76	$ 1,366.42	$ 2,930.71	$ 5,271.93	$ 9,868.11	$ 8,405.78	$ 4,386.24	$ 2,690.44	$ 7,283.88	$ 14,434.11	$ 76,929.4
Market Expense - No Wheeling ($ x 1000)	$ 10,890.27	$ 2,459.93	$ 3,232.74	$ 1,015.50	$ 2,108.42	$ 4,014.19	$ 8,017.18	$ 6,966.52	$ 3,585.63	$ 2,212.95	$ 6,021.18	$ 12,274.57	$ 62,799.1
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 16,648.5	$ 6,904.9	$ 8,485.4	$ 5,967.5	$ 6,890.3	$ 8,461.7	$ 12,494.9	$ 11,309.1	$ 7,579.6	$ 6,732.1	$ 11,216.1	$ 17,710.1	$ 120,400.2
Storage													
Black Mesa Battery Energy (MWh)	(1,169.61)	(962.05)	(1,221.4)	(1,003.1)	(869.5)	(846.2)	(875.6)	(868.2)	(831.4)	(913.2)	(948.4)	(1,128.9)	(11,637.4)
80 MW Grid Battery Energy (MWh)	(2,356.85)	(1,828.61)	(2,390.3)	(1,981.3)	(1,772.5)	(1,716.0)	(1,736.8)	(1,736.5)	(1,643.5)	(1,804.2)	(1,921.3)	(2,180.2)	(23,068.1)

11 MW Grid Battery Energy (MWh)	(315.88)	(238.99)	(319.8)	(262.9)	(228.2)	(225.8)	(239.1)	(236.9)	(218.6)	(243.2)	(237.9)	(280.1)	(3,047.3)
Total Storage (MWh)	(3,842.3)	(3,029.7)	(3,931.5)	(3,247.2)	(2,870.2)	(2,788.1)	(2,851.5)	(2,841.5)	(2,693.5)	(2,960.6)	(3,107.6)	(3,589.2)	(37,752.9)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	-	27,930.3	17,705.4	41,289.1	30,992.4	9,128.1	3,227.6	9,863.6	29,611.7	51,663.4	8,946.4	815.6	231,173.5
Revenue ($ x 1000)	$ -	$ 1,334.6	$ 727.4	$ 1,681.7	$ 1,072.8	$ 378.3	$ 171.1	$ 622.7	$ 1,555.1	$ 2,211.1	$ 502.0	$ 55.5	$ 10,312.3
Revenue - No Wheeling ($ x 1000)	$ -	$ 1,125.9	$ 595.1	$ 1,373.3	$ 841.3	$ 310.1	$ 147.0	$ 549.0	$ 1,333.9	$ 1,825.2	$ 435.2	$ 49.4	$ 8,585.6
Total Energy	1,428,850.93	1,234,421.46	1,217,841.84	1,168,470.80	1,353,816.92	1,602,921.84	1,927,228.28	1,763,858.90	1,373,841.60	1,218,929.58	1,251,370.20	1,476,225.00	17,017,777.35
Total NPSE	$ 56,886.7	$ 34,846.0	$ 35,130.6	$ 30,693.8	$ 32,761.4	$ 46,424.3	$ 69,371.2	$ 68,434.6	$ 44,684.3	$ 39,379.7	$ 51,704.5	$ 67,445.3	$ 579,489.1

Wheeling 3-Year Average $ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2002

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	530,478.9	500,179.5	571,011.9	749,779.5	690,474.9	699,685.9	548,521.0	449,495.2	409,544.9	406,703.4	372,357.1	439,478.2	6,367,710.4
Bridger Coal													
Energy (MWh)	125,632.8	106,121.8	67,469.9	70,293.8	57,438.7	121,919.4	205,507.9	250,111.8	242,559.3	247,328.2	242,600.0	250,686.7	1,987,670.33
Expense ($ x 1000)	$ 3,929.37	$ 3,337.62	$ 2,256.45	$ 2,327.49	$ 2,197.97	$ 4,113.68	$ 6,539.74	$ 7,823.73	$ 7,586.20	$ 7,743.57	$ 7,587.37	$ 7,840.28	$ 63,283.47
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	44,125.8	44,269.0	40,747.6	17,089.0	43,439.0	60,595.9	250,387.9
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 2,047.24	$ 2,052.61	$ 1,896.99	$ 795.02	$ 2,016.96	$ 2,784.18	$ 11,598.8
Bridger Gas													
Energy (MWh)	-	46,595.2	-	1,770.3	49.0	4,732.9	28,629.0	34,181.4	30,520.5	29,949.0	-	-	176,427.2
Expense ($ x 1000)	$ -	$ 1,836.27	$ -	$ 85.25	$ 2.05	$ 220.49	$ 1,464.96	$ 1,779.98	$ 1,453.03	$ 1,413.68	$ -	$ -	$ 8,255.7
Langley Gulch													
Energy (MWh)	199,553.5	208,920.8	145,532.2	-	213,170.8	207,525.2	215,823.8	215,637.7	213,972.9	222,117.9	181,687.3	154,851.5	2,178,793.5
Expense ($ x 1000)	$ 15,922.82	$ 6,006.65	$ 8,960.18	$ -	$ 6,140.33	$ 6,458.87	$ 7,687.41	$ 8,270.13	$ 7,542.47	$ 7,947.29	$ 13,536.90	$ 16,931.96	$ 105,405.0
Danskin													
Energy (MWh)	27,015.6	259.7	-	-	-	20,608.5	138,557.1	126,681.1	39,783.9	-	197.7	14,318.0	367,421.6
Expense ($ x 1000)	$ 3,577.78	$ 12.19	$ -	$ -	$ -	$ 991.18	$ 7,864.51	$ 7,732.92	$ 2,210.65	$ -	$ 23.70	$ 2,349.33	$ 24,762.3
Bennett Mountain													
Energy (MWh)	4,369.0	596.3	-	-	-	6,305.0	96,163.8	69,970.6	1,363.7	-	486.1	2,517.1	181,771.5
Expense ($ x 1000)	$ 571.07	$ 26.58	$ -	$ -	$ -	$ 305.23	$ 5,441.20	$ 4,269.93	$ 73.09	$ -	$ 57.99	$ 404.93	$ 11,150.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	267,065.2	113,525.6	131,492.1	30,707.6	47,616.2	151,375.8	257,066.0	204,988.7	120,273.5	62,640.6	174,663.2	304,812.1	1,866,226.3
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	342,837.3	177,754.2	213,935.6	116,046.9	138,369.3	241,462.0	351,418.4	293,474.0	195,870.1	135,037.1	243,929.2	374,612.5	2,824,746.7
Market Expense ($ x 1000)	$ 13,137.04	$ 3,937.31	$ 3,605.01	$ 855.02	$ 1,200.65	$ 4,400.27	$ 9,849.95	$ 8,421.17	$ 4,752.06	$ 2,487.77	$ 7,246.08	$ 14,654.12	$ 74,546.5
Market Expense - No Wheeling ($ x 1000)	$ 11,142.24	$ 3,089.35	$ 2,622.85	$ 625.65	$ 844.99	$ 3,269.59	$ 7,929.84	$ 6,890.04	$ 3,853.70	$ 2,019.89	$ 5,941.46	$ 12,377.38	$ 60,607.0
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 16,900.5	$ 7,534.3	$ 7,875.5	$ 5,577.7	$ 5,626.8	$ 7,717.1	$ 12,407.5	$ 11,232.6	$ 7,847.7	$ 6,539.1	$ 11,136.4	$ 17,812.9	$ 118,208.1
Storage													
Black Mesa Battery Energy (MWh)	(1,228.23)	(947.68)	(1,159.3)	(1,086.0)	(913.9)	(843.4)	(875.6)	(882.3)	(837.0)	(975.0)	(931.1)	(1,066.2)	(11,745.7)
80 MW Grid Battery Energy (MWh)	(2,407.31)	(1,844.47)	(2,302.6)	(2,180.9)	(1,901.9)	(1,679.1)	(1,736.8)	(1,750.6)	(1,685.3)	(1,967.5)	(1,822.8)	(2,104.3)	(23,383.4)

11 MW Grid Battery Energy (MWh)	(319.74)	(251.89)	(293.1)	(296.6)	(241.2)	(223.3)	(239.1)	(238.9)	(221.5)	(263.8)	(243.0)	(275.9)	(3,108.0)
Total Storage (MWh)	(3,955.3)	(3,044.0)	(3,755.1)	(3,563.5)	(3,057.0)	(2,745.8)	(2,851.4)	(2,871.8)	(2,743.8)	(3,206.2)	(2,996.9)	(3,446.3)	(38,237.1)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	-	28,948.0	22,570.0	54,532.3	56,314.9	17,023.1	2,959.2	6,996.9	32,702.0	58,354.9	8,280.1	507.0	289,188.3
Revenue ($ x 1000)	$ -	$ 1,368.6	$ 896.8	$ 2,113.7	$ 1,771.6	$ 678.1	$ 154.3	$ 401.3	$ 1,647.2	$ 2,631.5	$ 471.7	$ 31.2	$ 12,166.0
Revenue - No Wheeling ($ x 1000)	$ -	$ 1,152.3	$ 728.2	$ 1,706.4	$ 1,350.9	$ 551.0	$ 132.2	$ 349.1	$ 1,402.9	$ 2,195.6	$ 409.9	$ 27.4	$ 10,005.9
Total Energy	1,428,850.93	1,234,421.50	1,217,841.82	1,168,470.79	1,353,816.93	1,602,921.81	1,927,228.24	1,763,858.90	1,373,841.59	1,218,929.59	1,251,370.22	1,476,225.01	17,017,777.33
Total NPSE	$ 57,403.5	$ 35,803.9	$ 33,023.4	$ 22,990.0	$ 29,637.4	$ 42,746.4	$ 68,665.3	$ 67,224.0	$ 45,463.5	$ 38,872.1	$ 50,917.8	$ 66,458.0	$ 561,365.3

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2003

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	549,352.8	566,762.0	486,790.1	613,989.8	878,135.9	778,846.8	611,808.0	477,579.0	414,163.9	408,111.3	374,086.4	433,578.3	6,593,204.4
Bridger Coal													
Energy (MWh)	125,632.9	101,742.5	65,841.9	63,050.9	76,555.4	122,345.1	193,840.4	247,338.2	242,565.5	245,553.9	242,600.0	250,686.7	1,977,753.47
Expense ($ x 1000)	$ 3,929.37	$ 3,211.66	$ 2,209.63	$ 2,119.16	$ 2,748.14	$ 4,125.91	$ 6,203.94	$ 7,743.87	$ 7,586.37	$ 7,692.46	$ 7,587.37	$ 7,840.28	$ 62,998.16
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	44,736.2	45,523.4	38,498.8	15,928.8	40,134.4	63,646.9	248,590.0
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 2,075.79	$ 2,109.87	$ 1,796.75	$ 743.30	$ 1,869.66	$ 2,920.18	$ 11,521.3
Bridger Gas													
Energy (MWh)	-	29,405.7	-	787.3	415.9	1,506.8	27,132.6	32,504.2	19,514.2	16,498.1	-	-	127,764.8
Expense ($ x 1000)	$ -	$ 1,156.45	$ -	$ 37.77	$ 17.36	$ 69.90	$ 1,385.61	$ 1,688.88	$ 926.72	$ 776.38	$ -	$ -	$ 6,059.1
Langley Gulch													
Energy (MWh)	201,500.0	208,844.5	161,032.1	103,988.7	-	203,822.3	215,423.6	215,429.8	213,812.8	221,818.3	181,722.5	159,440.5	2,086,835.1
Expense ($ x 1000)	$ 15,976.31	$ 5,994.22	$ 9,885.33	$ 3,470.83	$ -	$ 6,333.87	$ 7,660.09	$ 8,247.69	$ 7,523.72	$ 7,922.90	$ 13,512.01	$ 17,133.35	$ 103,660.3
Danskin													
Energy (MWh)	19,018.2	-	367.5	92.4	-	3,639.0	126,807.5	110,747.0	20,187.7	-	197.7	4,762.7	285,819.8
Expense ($ x 1000)	$ 2,506.35	$ -	$ 34.52	$ 5.22	$ -	$ 178.62	$ 7,173.35	$ 6,753.13	$ 1,086.84	$ -	$ 23.65	$ 782.61	$ 18,544.3
Bennett Mountain													
Energy (MWh)	6,116.6	-	934.5	-	-	7,998.2	79,783.1	77,196.7	1,818.2	-	486.1	15,606.0	189,939.3
Expense ($ x 1000)	$ 797.98	$ -	$ 86.09	$ -	$ -	$ 385.68	$ 4,507.83	$ 4,723.85	$ 99.84	$ -	$ 57.88	$ 2,505.74	$ 13,164.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	252,714.7	74,341.2	191,610.2	51,306.1	55,844.1	111,596.5	237,328.9	190,599.5	135,139.8	63,302.8	173,801.8	299,604.0	1,837,189.6
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	328,486.9	138,569.7	274,053.7	136,645.5	146,597.2	201,682.7	331,681.4	279,084.9	210,736.5	135,699.3	243,067.9	369,404.5	2,795,710.0
Market Expense ($ x 1000)	$ 12,522.34	$ 2,445.05	$ 5,460.84	$ 1,440.58	$ 1,442.33	$ 3,228.62	$ 8,738.90	$ 7,686.78	$ 5,238.93	$ 2,537.48	$ 6,985.43	$ 14,538.52	$ 72,265.8
Market Expense - No Wheeling ($ x 1000)	$ 10,634.73	$ 1,889.77	$ 4,029.64	$ 1,057.36	$ 1,025.21	$ 2,395.07	$ 6,966.21	$ 6,263.13	$ 4,229.52	$ 2,064.65	$ 5,687.25	$ 12,300.68	$ 58,543.2
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 16,393.0	$ 6,334.7	$ 9,282.3	$ 6,009.4	$ 5,807.1	$ 6,842.6	$ 11,443.9	$ 10,605.7	$ 8,223.5	$ 6,583.8	$ 10,882.2	$ 17,736.2	$ 116,144.3
Storage													
Black Mesa Battery Energy (MWh)	(1,275.29)	(805.48)	(1,177.5)	(988.1)	(878.2)	(827.6)	(875.7)	(875.2)	(821.3)	(963.8)	(844.7)	(1,127.2)	(11,460.0)
80 MW Grid Battery Energy (MWh)	(2,520.96)	(1,658.70)	(2,280.3)	(1,962.2)	(1,816.3)	(1,653.6)	(1,751.0)	(1,750.6)	(1,642.3)	(1,838.6)	(1,676.0)	(2,189.4)	(22,739.7)

11 MW Grid Battery Energy (MWh)	(337.94)	(209.65)	(304.4)	(266.6)	(233.4)	(216.1)	(241.1)	(238.5)	(215.7)	(255.8)	(203.0)	(278.9)	(3,001.0)
Total Storage (MWh)	(4,134.2)	(2,673.8)	(3,762.1)	(3,216.8)	(2,927.8)	(2,697.3)	(2,867.8)	(2,864.3)	(2,679.3)	(3,058.1)	(2,723.7)	(3,595.5)	(37,200.6)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	41.3	34,215.2	13,633.1	35,543.1	58,645.8	34,673.5	5,408.8	8,586.9	19,701.2	43,888.0	6,151.9	423.5	260,912.5
Revenue ($ x 1000)	$ 2.9	$ 1,553.6	$ 542.3	$ 1,381.8	$ 1,951.5	$ 1,210.2	$ 288.6	$ 506.6	$ 959.0	$ 1,802.6	$ 304.0	$ 27.2	$ 10,530.3
Revenue - No Wheeling ($ x 1000)	$ 2.6	$ 1,298.0	$ 440.5	$ 1,116.3	$ 1,513.5	$ 951.2	$ 248.2	$ 442.5	$ 811.8	$ 1,474.8	$ 258.0	$ 24.0	$ 8,581.4
Total Energy	1,428,850.93	1,234,421.47	1,217,841.84	1,168,470.78	1,353,816.93	1,602,921.83	1,927,228.26	1,763,858.87	1,373,841.58	1,218,929.59	1,251,370.18	1,476,224.98	17,017,777.24
Total NPSE	$ 56,102.1	$ 33,562.3	$ 35,783.6	$ 27,373.9	$ 24,062.8	$ 40,344.3	$ 65,529.0	$ 65,829.8	$ 44,785.3	$ 38,981.3	$ 50,658.9	$ 67,256.8	$ 552,218.8

Wheeling 3-Year Average $ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2004

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	502,582.4	556,777.9	616,274.4	635,197.8	746,862.3	660,396.6	569,674.6	485,210.3	475,454.6	419,509.1	358,416.2	451,797.6	6,478,153.8
Bridger Coal													
Energy (MWh)	125,632.9	107,633.5	70,610.5	82,767.6	87,011.1	123,533.3	199,898.2	250,015.4	242,600.0	250,165.5	242,600.0	250,686.7	2,033,154.78
Expense ($ x 1000)	$ 3,929.37	$ 3,381.10	$ 2,346.79	$ 2,686.27	$ 3,048.90	$ 4,160.11	$ 6,378.29	$ 7,820.95	$ 7,587.37	$ 7,825.27	$ 7,587.37	$ 7,840.28	$ 64,592.07
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	40,201.7	46,008.8	40,611.5	12,067.8	45,883.6	66,537.6	251,432.5
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,873.67	$ 2,130.16	$ 1,890.93	$ 560.33	$ 2,125.92	$ 3,049.14	$ 11,635.9
Bridger Gas													
Energy (MWh)	-	28,859.9	-	3,831.7	4,086.8	5,254.3	16,047.4	22,977.7	21,374.7	33,958.6	-	-	136,391.1
Expense ($ x 1000)	$ -	$ 1,170.91	$ -	$ 189.60	$ 176.89	$ 251.95	$ 845.09	$ 1,231.48	$ 1,047.10	$ 1,650.61	$ -	$ -	$ 6,563.6
Langley Gulch													
Energy (MWh)	199,287.8	208,772.7	133,355.4	50,821.4	45,408.0	206,689.2	214,989.1	216,602.1	214,267.9	221,181.0	182,476.9	161,077.9	2,054,929.5
Expense ($ x 1000)	$ 16,295.31	$ 6,136.95	$ 8,475.54	$ 1,744.57	$ 1,338.30	$ 6,578.94	$ 7,834.07	$ 8,497.93	$ 7,725.58	$ 8,096.33	$ 13,897.17	$ 17,669.08	$ 104,289.8
Danskin													
Energy (MWh)	39,928.0	-	-	-	-	38,762.5	130,704.9	123,229.6	1,679.5	-	1,994.7	13,268.3	349,567.5
Expense ($ x 1000)	$ 5,437.39	$ -	$ -	$ -	$ -	$ 1,929.58	$ 7,597.06	$ 7,648.92	$ 89.61	$ -	$ 242.50	$ 2,229.26	$ 25,174.3
Bennett Mountain													
Energy (MWh)	7,739.4	-	-	-	-	12,851.9	88,858.8	62,086.5	4,220.9	-	486.1	2,139.5	178,383.0
Expense ($ x 1000)	$ 1,036.63	$ -	$ -	$ -	$ -	$ 646.87	$ 5,189.01	$ 3,863.85	$ 234.71	$ -	$ 59.42	$ 352.74	$ 11,383.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	278,970.3	77,098.9	102,543.6	56,809.0	105,430.6	159,938.7	273,274.9	186,512.5	96,897.0	54,499.9	182,224.2	282,819.8	1,857,019.5
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	354,742.5	141,327.5	184,987.1	142,148.4	196,183.7	250,024.9	367,627.4	274,997.9	172,493.6	126,896.4	251,490.3	352,620.2	2,815,539.9
Market Expense ($ x 1000)	$ 14,301.12	$ 2,663.53	$ 2,826.46	$ 1,672.57	$ 2,846.10	$ 4,769.28	$ 10,410.15	$ 7,923.44	$ 3,980.18	$ 2,203.18	$ 7,884.64	$ 14,190.62	$ 75,671.3
Market Expense - No Wheeling ($ x 1000)	$ 12,217.40	$ 2,087.65	$ 2,060.53	$ 1,248.24	$ 2,058.60	$ 3,574.64	$ 8,368.97	$ 6,530.32	$ 3,256.42	$ 1,796.10	$ 6,523.55	$ 12,078.14	$ 61,800.6
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 17,975.6	$ 6,532.6	$ 7,313.2	$ 6,200.3	$ 6,840.5	$ 8,022.1	$ 12,846.7	$ 10,872.9	$ 7,250.4	$ 6,315.3	$ 11,718.5	$ 17,513.7	$ 119,401.7
Storage													
Black Mesa Battery Energy (MWh)	(1,211.84)	(831.79)	(1,093.8)	(1,037.7)	(837.3)	(763.8)	(868.2)	(882.0)	(819.7)	(892.2)	(943.1)	(1,200.3)	(11,381.5)
80 MW Grid Battery Energy (MWh)	(2,367.42)	(1,647.23)	(2,148.2)	(2,059.2)	(1,702.0)	(1,548.4)	(1,750.6)	(1,730.9)	(1,676.9)	(1,810.1)	(1,802.2)	(2,406.7)	(22,649.8)

11 MW Grid Battery Energy (MWh)	(323.57)	(221.74)	(276.9)	(279.5)	(225.5)	(205.9)	(242.8)	(238.2)	(215.7)	(242.6)	(233.4)	(306.4)	(3,012.2)
Total Storage (MWh)	(3,902.8)	(2,700.8)	(3,518.8)	(3,376.4)	(2,764.8)	(2,518.1)	(2,861.7)	(2,851.0)	(2,712.2)	(2,944.9)	(2,978.6)	(3,913.4)	(37,043.5)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	78.3	32,235.2	30,084.0	31,596.0	36,656.4	12,524.6	2,204.3	4,325.2	31,073.5	64,169.9	6,949.7	1,107.9	253,005.0
Revenue ($ x 1000)	$ 5.1	$ 1,492.7	$ 1,207.2	$ 1,300.7	$ 1,368.2	$ 476.0	$ 115.8	$ 253.8	$ 1,550.5	$ 2,943.4	$ 403.6	$ 72.6	$ 11,189.5
Revenue - No Wheeling ($ x 1000)	$ 4.5	$ 1,251.9	$ 982.5	$ 1,064.7	$ 1,094.4	$ 382.4	$ 99.3	$ 221.5	$ 1,318.4	$ 2,464.1	$ 351.7	$ 64.4	$ 9,299.7
Total Energy	1,428,850.92	1,234,421.48	1,217,841.84	1,168,470.80	1,353,816.91	1,602,921.83	1,927,228.23	1,763,858.91	1,373,841.60	1,218,929.60	1,251,370.19	1,476,224.97	17,017,777.28
Total NPSE	$ 61,171.2	$ 34,147.8	$ 31,756.4	$ 26,633.3	$ 27,478.1	$ 44,731.5	$ 67,815.1	$ 66,275.8	$ 42,775.7	$ 38,569.4	$ 52,257.4	$ 66,947.1	$ 562,448.8

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2005

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	535,163.9	489,349.9	482,191.3	576,436.7	855,261.5	645,856.0	709,742.8	537,194.7	482,049.6	418,609.5	370,787.5	580,443.2	6,683,086.4
Bridger Coal													
Energy (MWh)	125,632.9	104,566.0	67,573.6	72,683.2	64,139.3	129,881.0	184,854.4	246,352.5	242,600.0	245,981.4	242,600.0	250,686.7	1,977,551.02
Expense ($ x 1000)	$ 3,929.37	$ 3,292.87	$ 2,259.44	$ 2,396.21	$ 2,390.74	$ 4,342.84	$ 5,945.28	$ 7,715.52	$ 7,587.37	$ 7,704.78	$ 7,587.37	$ 7,840.28	$ 62,992.07
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	41,158.5	44,743.8	37,450.2	17,464.7	43,288.4	58,585.0	242,812.2
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,916.32	$ 2,073.78	$ 1,750.01	$ 811.76	$ 2,010.25	$ 2,694.54	$ 11,262.4
Bridger Gas													
Energy (MWh)	-	48,811.2	-	8,777.8	100.6	2,560.3	19,739.8	28,359.6	18,883.7	31,511.6	-	-	158,744.6
Expense ($ x 1000)	$ -	$ 1,923.68	$ -	$ 421.64	$ 4.20	$ 119.17	$ 1,009.78	$ 1,476.00	$ 898.58	$ 1,487.38	$ -	$ -	$ 7,340.4
Langley Gulch													
Energy (MWh)	199,501.3	208,976.4	161,084.6	156,146.6	22,581.1	208,276.8	214,999.7	215,745.5	213,661.5	221,544.4	180,831.7	148,959.5	2,152,308.9
Expense ($ x 1000)	$ 15,892.09	$ 5,997.83	$ 9,879.67	$ 5,210.76	$ 652.83	$ 6,470.03	$ 7,645.50	$ 8,259.45	$ 7,518.57	$ 7,913.42	$ 13,479.02	$ 16,249.61	$ 105,168.8
Danskin													
Energy (MWh)	24,095.6	647.3	372.0	-	-	41,926.9	108,535.7	106,277.2	92.5	-	349.3	-	282,296.5
Expense ($ x 1000)	$ 3,175.92	$ 30.57	$ 34.91	$ -	$ -	$ 1,997.85	$ 6,122.31	$ 6,418.74	$ 5.33	$ -	$ 42.70	$ -	$ 17,828.3
Bennett Mountain													
Energy (MWh)	4,743.5	1,385.4	700.8	-	-	12,070.8	36,295.5	43,128.7	1,477.3	-	729.1	-	100,531.2
Expense ($ x 1000)	$ 618.84	$ 63.27	$ 64.57	$ -	$ -	$ 578.60	$ 2,045.32	$ 2,606.46	$ 79.68	$ -	$ 86.82	$ -	$ 6,143.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	265,039.1	120,810.8	194,078.9	43,892.7	62,985.8	168,126.1	221,350.2	173,614.9	95,253.3	53,332.0	177,887.4	193,948.5	1,770,319.4
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	340,811.2	185,039.4	276,522.4	129,232.1	153,738.8	258,212.3	315,702.7	262,100.2	170,849.9	125,728.5	247,153.4	263,748.9	2,728,839.8
Market Expense ($ x 1000)	$ 13,200.17	$ 4,177.49	$ 5,531.14	$ 1,252.51	$ 1,637.17	$ 4,996.25	$ 7,822.13	$ 6,984.55	$ 3,712.79	$ 2,131.81	$ 7,301.04	$ 8,876.66	$ 67,623.7
Market Expense - No Wheeling ($ x 1000)	$ 11,220.50	$ 3,275.11	$ 4,081.50	$ 924.66	$ 1,166.71	$ 3,740.46	$ 6,168.79	$ 5,687.76	$ 3,001.31	$ 1,733.46	$ 5,972.34	$ 7,427.99	$ 54,400.6
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 16,978.8	$ 7,720.0	$ 9,334.1	$ 5,876.7	$ 5,948.6	$ 8,188.0	$ 10,646.5	$ 10,030.3	$ 6,995.3	$ 6,252.6	$ 11,167.3	$ 12,863.5	$ 112,001.7
Storage													
Black Mesa Battery Energy (MWh)	(1,226.90)	(901.46)	(1,143.5)	(1,146.6)	(989.6)	(880.1)	(882.7)	(863.9)	(832.1)	(954.2)	(938.6)	(1,084.7)	(11,844.3)
80 MW Grid Battery Energy (MWh)	(2,452.20)	(1,824.33)	(2,299.2)	(2,329.8)	(1,967.5)	(1,722.7)	(1,765.1)	(1,730.9)	(1,616.4)	(1,868.3)	(1,850.9)	(2,083.8)	(23,511.0)

11 MW Grid Battery Energy (MWh)	(333.95)	(234.48)	(285.5)	(299.0)	(266.6)	(229.3)	(241.2)	(234.9)	(210.3)	(253.5)	(244.9)	(268.1)	(3,101.6)
Total Storage (MWh)	(4,013.1)	(2,960.3)	(3,728.2)	(3,775.4)	(3,223.7)	(2,832.1)	(2,889.0)	(2,829.6)	(2,658.8)	(3,076.0)	(3,034.3)	(3,436.5)	(38,456.8)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	3.4	27,379.9	13,092.0	59,706.3	52,466.8	13,481.9	5,203.8	7,120.7	25,488.9	61,100.5	9,285.7	5,880.1	280,209.9
Revenue ($ x 1000)	$ 0.3	$ 1,296.8	$ 526.0	$ 2,532.6	$ 1,679.2	$ 519.7	$ 264.3	$ 428.6	$ 1,213.9	$ 2,726.9	$ 536.6	$ 370.3	$ 12,095.2
Revenue - No Wheeling ($ x 1000)	$ 0.2	$ 1,092.3	$ 428.2	$ 2,086.6	$ 1,287.3	$ 419.0	$ 225.5	$ 375.4	$ 1,023.5	$ 2,270.5	$ 467.3	$ 326.3	$ 10,002.2
Total Energy	1,428,850.92	1,234,421.46	1,217,841.83	1,168,470.78	1,353,816.91	1,602,921.81	1,927,228.25	1,763,858.90	1,373,841.60	1,218,929.60	1,251,370.22	1,476,224.99	17,017,777.27
Total NPSE	$ 57,096.7	$ 36,150.4	$ 35,874.8	$ 28,486.0	$ 24,758.9	$ 44,794.7	$ 60,433.7	$ 62,615.1	$ 42,121.5	$ 38,508.1	$ 50,866.9	$ 57,643.3	$ 541,443.0

Wheeling 3-Year Average	$ 7.47

2006

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	965,495.3	838,056.2	983,174.4	1,109,570.6	1,213,641.1	1,101,975.6	767,329.9	576,398.7	572,030.2	442,225.4	367,035.5	480,507.9	9,417,440.8
Bridger Coal													
Energy (MWh)	125,632.9	73,901.0	34,245.2	38,101.6	48,873.2	89,393.9	157,355.1	229,303.9	220,699.3	226,723.7	234,123.9	250,686.7	1,729,040.25
Expense ($ x 1000)	$ 3,929.37	$ 2,410.86	$ 1,300.83	$ 1,401.56	$ 1,951.46	$ 3,177.48	$ 5,153.80	$ 7,224.72	$ 6,956.82	$ 7,150.35	$ 7,343.36	$ 7,840.28	$ 55,840.89
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	27,813.4	37,198.2	-	162.0	39,481.1	45,810.2	150,586.6
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,302.64	$ 1,738.78	$ -	$ 7.67	$ 1,840.54	$ 2,122.66	$ 7,018.0
Bridger Gas													
Energy (MWh)	-	40,938.9	-	2,043.7	1,399.0	2,144.2	16,509.1	21,323.7	12,214.5	22,745.1	-	-	119,318.1
Expense ($ x 1000)	$ -	$ 1,422.64	$ -	$ 86.76	$ 51.78	$ 88.11	$ 744.75	$ 978.30	$ 512.07	$ 945.76	$ -	$ -	$ 4,830.2
Langley Gulch													
Energy (MWh)	41,948.5	46,566.0	-	-	-	37,530.9	215,104.9	216,433.6	212,369.7	221,791.6	185,895.6	157,792.4	1,335,433.3
Expense ($ x 1000)	$ 3,169.71	$ 1,215.60	$ -	$ -	$ -	$ 1,063.14	$ 6,906.49	$ 7,474.16	$ 6,749.17	$ 7,151.85	$ 12,278.54	$ 15,289.31	$ 61,298.0
Danskin													
Energy (MWh)	-	-	-	-	-	61.6	86,587.2	70,887.0	1,461.1	-	328.0	12,320.1	171,645.0
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 2.75	$ 4,338.92	$ 3,830.32	$ 69.10	$ -	$ 35.58	$ 1,801.96	$ 10,078.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	33,001.9	27,655.4	4,334.5	-	2,308.8	3,020.5	70,321.1
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,668.24	$ 1,507.68	$ 211.37	$ -	$ 246.19	$ 433.89	$ 4,067.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	44,081.9	26,134.3	8,071.4	128.2	3,773.0	47,653.6	231,834.9	214,263.7	70,070.6	59,358.1	185,092.6	277,593.1	1,168,055.3
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	119,854.1	90,362.8	90,514.9	85,467.6	94,526.1	137,739.8	326,187.3	302,749.0	145,667.2	131,754.7	254,358.6	347,393.6	2,126,575.7
Market Expense ($ x 1000)	$ 1,902.13	$ 796.42	$ 208.15	$ 3.66	$ 91.64	$ 1,296.84	$ 7,280.27	$ 7,721.20	$ 2,362.29	$ 2,098.51	$ 6,854.52	$ 11,984.10	$ 42,599.7
Market Expense - No Wheeling ($ x 1000)	$ 1,572.87	$ 601.21	$ 147.86	$ 2.70	$ 63.46	$ 940.90	$ 5,548.62	$ 6,120.79	$ 1,838.91	$ 1,655.14	$ 5,472.00	$ 9,910.66	$ 33,875.1
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 7,331.1	$ 5,046.1	$ 5,400.5	$ 4,954.7	$ 4,845.3	$ 5,388.4	$ 10,026.3	$ 10,463.4	$ 5,832.9	$ 6,174.3	$ 10,666.9	$ 15,346.2	$ 91,476.2
Storage													
Black Mesa Battery Energy (MWh)	(1,223.19)	(1,040.06)	(1,311.4)	(1,195.4)	(993.8)	(872.3)	(889.7)	(853.2)	(779.3)	(916.7)	(897.6)	(1,074.1)	(12,046.8)
80 MW Grid Battery Energy (MWh)	(2,443.54)	(2,057.61)	(2,640.7)	(2,351.7)	(1,970.8)	(1,756.5)	(1,752.3)	(1,713.8)	(1,548.6)	(1,817.3)	(1,746.5)	(2,085.9)	(23,885.3)

11 MW Grid Battery Energy (MWh)	(342.26)	(280.79)	(337.9)	(305.4)	(267.0)	(232.3)	(245.0)	(230.9)	(206.5)	(248.8)	(226.9)	(266.8)	(3,190.5)
Total Storage (MWh)	(4,009.0)	(3,378.5)	(4,290.0)	(3,852.5)	(3,231.6)	(2,861.1)	(2,887.0)	(2,797.9)	(2,534.4)	(2,982.8)	(2,871.0)	(3,426.8)	(39,122.6)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	22,989.8	78,011.0	132,019.9	351,536.4	315,076.9	83,514.9	4,065.5	5,199.7	27,325.2	45,756.1	7,241.1	998.1	1,073,734.6
Revenue ($ x 1000)	$ 1,111.6	$ 3,034.6	$ 3,706.3	$ 10,010.9	$ 8,220.4	$ 2,540.0	$ 205.5	$ 271.1	$ 1,129.0	$ 1,798.2	$ 370.1	$ 57.7	$ 32,455.3
Revenue - No Wheeling ($ x 1000)	$ 939.8	$ 2,451.9	$ 2,720.2	$ 7,385.2	$ 5,866.9	$ 1,916.2	$ 175.1	$ 232.3	$ 924.9	$ 1,456.5	$ 316.0	$ 50.2	$ 24,435.2
Total Energy	1,428,850.96	1,234,421.46	1,217,841.84	1,168,470.78	1,353,816.91	1,602,921.84	1,927,228.24	1,763,858.89	1,373,841.59	1,218,929.58	1,251,370.20	1,476,224.98	17,017,777.27
Total NPSE	$ 29,820.6	$ 25,479.5	$ 17,823.2	$ 13,545.4	$ 16,070.0	$ 30,797.8	$ 55,302.7	$ 57,409.6	$ 37,703.0	$ 36,696.7	$ 49,071.2	$ 61,142.2	$ 438,882.1

Wheeling 3-Year Average $ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2007

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	627,408.0	652,046.7	712,213.4	636,254.8	663,358.6	627,434.1	560,698.2	467,516.9	514,749.6	417,003.2	364,336.8	434,099.5	6,677,119.9
Bridger Coal													
Energy (MWh)	125,632.9	89,010.5	59,748.3	57,629.9	59,518.4	117,084.8	187,608.0	247,436.1	242,600.0	246,751.7	242,600.0	250,686.7	1,926,307.35
Expense ($ x 1000)	$ 3,929.37	$ 2,845.45	$ 2,034.36	$ 1,963.24	$ 2,257.86	$ 3,974.50	$ 6,024.52	$ 7,746.71	$ 7,587.37	$ 7,726.95	$ 7,587.37	$ 7,840.28	$ 61,517.98
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	42,200.0	45,610.5	20,101.5	684.8	43,601.0	58,084.8	210,404.0
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,964.42	$ 2,113.75	$ 937.37	$ 31.53	$ 2,024.18	$ 2,672.25	$ 9,749.3
Bridger Gas													
Energy (MWh)	-	22,500.6	-	951.5	1,379.2	4,270.4	18,690.1	29,621.3	24,561.4	38,502.7	-	-	140,477.3
Expense ($ x 1000)	$ -	$ 871.75	$ -	$ 45.03	$ 56.95	$ 195.48	$ 939.95	$ 1,516.29	$ 1,149.25	$ 1,787.02	$ -	$ -	$ 6,561.7
Langley Gulch													
Energy (MWh)	198,975.1	208,835.6	29,857.8	101,253.7	228,250.5	207,400.3	215,730.5	215,807.2	214,269.0	222,349.4	180,460.4	156,763.3	2,179,952.8
Expense ($ x 1000)	$ 15,662.07	$ 5,921.61	$ 1,889.90	$ 3,341.55	$ 6,479.43	$ 6,365.60	$ 7,575.85	$ 8,158.85	$ 7,446.08	$ 7,843.00	$ 13,295.57	$ 16,774.01	$ 100,753.5
Danskin													
Energy (MWh)	642.7	-	-	-	-	45,454.1	134,575.8	124,888.1	1,679.5	1,905.8	758.0	19,380.0	329,284.0
Expense ($ x 1000)	$ 83.96	$ -	$ -	$ -	$ -	$ 2,148.19	$ 7,517.86	$ 7,478.66	$ 86.20	$ 110.14	$ 89.42	$ 3,129.59	$ 20,644.0
Bennett Mountain													
Energy (MWh)	4,119.4	-	-	-	-	22,762.6	89,994.8	68,130.6	2,987.1	-	850.6	2,013.7	190,858.7
Expense ($ x 1000)	$ 530.24	$ -	$ -	$ -	$ -	$ 1,103.48	$ 5,028.44	$ 4,082.31	$ 163.52	$ -	$ 99.95	$ 318.99	$ 11,326.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	198,013.5	28,439.7	108,830.3	47,885.4	54,629.3	179,236.3	284,764.6	194,617.5	78,484.3	61,247.9	182,641.5	306,351.8	1,725,142.2
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	273,785.7	92,668.2	191,273.8	133,224.8	145,382.4	269,322.6	379,117.1	283,102.9	154,080.9	133,644.4	251,907.6	376,152.3	2,683,662.6
Market Expense ($ x 1000)	$ 9,431.85	$ 867.14	$ 2,950.50	$ 1,346.24	$ 1,347.51	$ 5,281.83	$ 10,542.81	$ 7,944.03	$ 3,075.31	$ 2,454.54	$ 7,526.56	$ 14,502.63	$ 67,271.0
Market Expense - No Wheeling ($ x 1000)	$ 7,952.82	$ 654.71	$ 2,137.61	$ 988.57	$ 939.47	$ 3,943.05	$ 8,415.81	$ 6,490.37	$ 2,489.08	$ 1,997.06	$ 6,162.35	$ 12,214.38	$ 54,385.3
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 13,711.1	$ 5,099.6	$ 7,390.2	$ 5,940.6	$ 5,721.3	$ 8,390.6	$ 12,893.5	$ 10,832.9	$ 6,483.1	$ 6,516.2	$ 11,357.3	$ 17,649.9	$ 111,986.4
Storage													
Black Mesa Battery Energy (MWh)	(1,268.79)	(772.27)	(1,121.7)	(1,038.7)	(907.1)	(847.4)	(868.4)	(865.8)	(843.0)	(945.0)	(921.0)	(1,120.9)	(11,520.1)
80 MW Grid Battery Energy (MWh)	(2,514.64)	(1,524.16)	(2,215.4)	(2,125.3)	(1,788.5)	(1,694.4)	(1,736.7)	(1,708.3)	(1,641.8)	(1,886.9)	(1,767.1)	(2,194.7)	(22,797.9)

11 MW Grid Battery Energy (MWh)	(338.40)	(213.57)	(282.7)	(272.4)	(243.3)	(221.5)	(240.7)	(232.9)	(221.5)	(260.1)	(228.4)	(286.1)	(3,041.4)
Total Storage (MWh)	(4,121.8)	(2,510.0)	(3,619.8)	(3,436.4)	(2,938.9)	(2,763.3)	(2,845.8)	(2,806.9)	(2,706.2)	(3,092.0)	(2,916.6)	(3,601.7)	(37,359.4)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	510.1	54,116.1	17,849.0	46,083.7	54,819.4	8,495.5	2,832.5	5,354.6	33,405.7	61,086.5	8,178.4	472.0	293,203.6
Revenue ($ x 1000)	$ 29.9	$ 2,188.7	$ 700.9	$ 1,736.6	$ 1,815.9	$ 355.3	$ 149.4	$ 315.8	$ 1,606.4	$ 2,824.1	$ 458.5	$ 30.4	$ 12,211.9
Revenue - No Wheeling ($ x 1000)	$ 26.1	$ 1,784.5	$ 567.6	$ 1,392.4	$ 1,406.5	$ 291.9	$ 128.3	$ 275.8	$ 1,356.9	$ 2,367.8	$ 397.4	$ 26.9	$ 10,021.8
Total Energy	1,428,850.93	1,234,421.47	1,217,841.83	1,168,470.80	1,353,816.91	1,602,921.82	1,927,228.24	1,763,858.89	1,373,841.60	1,218,929.59	1,251,370.20	1,476,224.96	17,017,777.24
Total NPSE	$ 50,388.8	$ 30,968.7	$ 25,441.7	$ 26,667.1	$ 30,141.4	$ 45,440.4	$ 67,162.1	$ 66,077.2	$ 40,747.0	$ 38,255.8	$ 51,025.4	$ 66,720.2	$ 541,225.9

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2008

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	497,754.8	516,053.1	650,723.0	847,638.7	875,471.5	879,557.2	666,727.3	616,656.0	505,170.3	438,387.0	369,264.7	431,758.4	7,295,162.0
Bridger Coal													
Energy (MWh)	125,632.9	101,278.3	51,676.7	49,365.1	60,239.9	112,064.0	173,663.7	247,648.4	240,087.2	240,827.5	242,600.0	250,686.7	1,895,770.36
Expense ($ x 1000)	$ 3,929.37	$ 3,198.30	$ 1,802.20	$ 1,725.52	$ 2,278.56	$ 3,829.97	$ 5,623.18	$ 7,752.81	$ 7,515.00	$ 7,556.37	$ 7,587.37	$ 7,840.28	$ 60,638.93
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	43,089.6	46,995.8	33,090.6	8,097.3	41,076.6	56,378.5	228,850.0
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 2,002.39	$ 2,178.19	$ 1,555.69	$ 378.08	$ 1,911.66	$ 2,596.19	$ 10,628.0
Bridger Gas													
Energy (MWh)	-	41,045.1	-	4,140.0	-	2,208.6	22,239.1	39,903.0	9,598.5	19,642.5	-	-	138,776.7
Expense ($ x 1000)	$ -	$ 1,569.13	$ -	$ 193.12	$ -	$ 99.74	$ 1,103.58	$ 2,016.44	$ 443.10	$ 899.12	$ -	$ -	$ 6,324.2
Langley Gulch													
Energy (MWh)	200,190.6	208,930.1	115,625.6	-	-	136,023.0	215,594.7	215,834.7	212,628.7	221,203.8	180,248.6	156,160.9	1,862,440.8
Expense ($ x 1000)	$ 15,509.05	$ 5,851.76	$ 6,933.10	$ -	$ -	$ 4,125.94	$ 7,476.50	$ 8,056.95	$ 7,298.52	$ 7,706.15	$ 13,112.96	$ 16,520.89	$ 92,591.8
Danskin													
Energy (MWh)	41,926.2	128.9	-	-	-	1,688.0	112,253.3	49,091.3	-	-	678.5	16,588.2	222,354.4
Expense ($ x 1000)	$ 5,373.80	$ 5.99	$ -	$ -	$ -	$ 76.94	$ 6,171.58	$ 2,860.30	$ -	$ -	$ 80.00	$ 2,641.75	$ 17,210.4
Bennett Mountain													
Energy (MWh)	7,739.4	-	-	-	-	4,015.2	57,699.2	21,734.0	1,363.7	-	243.0	5,034.2	97,828.7
Expense ($ x 1000)	$ 982.74	$ -	$ -	$ -	$ -	$ 183.93	$ 3,173.03	$ 1,279.80	$ 71.05	$ -	$ 28.17	$ 786.63	$ 6,505.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	281,078.3	107,593.8	103,639.3	5,641.0	54,898.6	101,979.0	244,798.3	161,391.2	81,286.6	50,510.9	180,093.9	310,593.4	1,683,504.3
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	356,850.4	171,822.4	186,082.8	90,980.4	145,651.7	192,065.2	339,150.8	249,876.6	156,883.2	122,907.4	249,360.0	380,393.8	2,642,024.7
Market Expense ($ x 1000)	$ 13,784.37	$ 3,600.88	$ 2,710.76	$ 149.20	$ 1,369.69	$ 2,803.78	$ 8,578.87	$ 6,421.70	$ 3,019.68	$ 1,967.16	$ 7,347.02	$ 14,637.20	$ 66,390.3
Market Expense - No Wheeling ($ x 1000)	$ 11,684.90	$ 2,797.23	$ 1,936.64	$ 107.07	$ 959.63	$ 2,042.06	$ 6,750.39	$ 5,216.21	$ 2,412.52	$ 1,589.88	$ 6,001.84	$ 12,317.27	$ 53,815.6
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 17,443.2	$ 7,242.2	$ 7,189.3	$ 5,059.1	$ 5,741.5	$ 6,489.6	$ 11,228.1	$ 9,558.8	$ 6,406.5	$ 6,109.1	$ 11,196.8	$ 17,752.8	$ 111,416.8
Storage													
Black Mesa Battery Energy (MWh)	(1,271.44)	(918.00)	(1,061.3)	(1,065.0)	(890.5)	(868.0)	(882.7)	(870.5)	(807.7)	(916.8)	(912.1)	(1,095.0)	(11,559.0)
80 MW Grid Battery Energy (MWh)	(2,553.44)	(1,877.67)	(2,100.8)	(2,160.1)	(1,792.5)	(1,730.9)	(1,751.0)	(1,745.4)	(1,619.1)	(1,826.2)	(1,755.9)	(2,190.8)	(23,103.8)

11 MW Grid Battery Energy (MWh)	(337.14)	(240.23)	(264.4)	(283.6)	(235.5)	(228.3)	(241.1)	(238.9)	(206.9)	(247.7)	(230.4)	(269.4)	(3,023.6)
Total Storage (MWh)	(4,162.0)	(3,035.9)	(3,426.5)	(3,508.7)	(2,918.5)	(2,827.2)	(2,874.8)	(2,854.8)	(2,633.7)	(2,990.6)	(2,898.5)	(3,555.2)	(37,686.4)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	0.5	27,786.6	29,057.1	108,820.9	38,313.7	42,324.0	4,606.7	10,932.9	17,271.5	51,411.3	7,153.4	338.9	338,017.6
Revenue ($ x 1000)	$ 0.0	$ 1,285.3	$ 1,101.8	$ 3,982.7	$ 1,235.7	$ 1,469.8	$ 247.7	$ 637.8	$ 746.9	$ 2,108.8	$ 376.7	$ 20.3	$ 13,213.4
Revenue - No Wheeling ($ x 1000)	$ 0.0	$ 1,077.7	$ 884.8	$ 3,169.9	$ 949.5	$ 1,153.7	$ 213.3	$ 556.1	$ 617.9	$ 1,724.8	$ 323.2	$ 17.8	$ 10,688.7
Total Energy	1,428,850.94	1,234,421.47	1,217,841.82	1,168,470.79	1,353,816.92	1,602,921.84	1,927,228.23	1,763,858.85	1,373,841.59	1,218,929.61	1,251,370.20	1,476,224.99	17,017,777.25
Total NPSE	$ 59,740.1	$ 35,001.0	$ 29,650.9	$ 20,108.3	$ 24,226.2	$ 36,954.2	$ 61,897.7	$ 57,528.9	$ 41,043.5	$ 37,605.0	$ 50,570.4	$ 66,483.8	$ 523,334.7

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2009

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	632,112.3	631,888.0	829,949.4	1,107,615.1	1,040,748.3	1,118,188.1	734,454.0	630,979.7	508,909.6	442,960.4	373,023.8	440,438.7	8,491,267.4
Bridger Coal													
Energy (MWh)	125,632.9	89,328.0	45,232.9	42,610.2	55,051.8	99,182.1	170,866.9	239,011.9	241,145.2	240,402.6	242,280.9	250,686.7	1,841,431.99
Expense ($ x 1000)	$ 3,929.37	$ 2,854.58	$ 1,616.86	$ 1,531.24	$ 2,129.22	$ 3,459.23	$ 5,542.71	$ 7,504.19	$ 7,545.48	$ 7,544.16	$ 7,578.18	$ 7,840.28	$ 59,075.50
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	41,809.8	45,345.6	37,845.3	483.2	40,269.2	50,649.3	216,523.9
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,945.35	$ 2,104.63	$ 1,767.63	$ 22.21	$ 1,875.67	$ 2,340.71	$ 10,062.0
Bridger Gas													
Energy (MWh)	-	36,975.0	-	919.4	1,195.9	3,315.8	24,069.7	30,711.2	25,373.1	23,176.2	-	-	145,736.2
Expense ($ x 1000)	$ -	$ 1,389.58	$ -	$ 42.14	$ 47.85	$ 147.04	$ 1,173.88	$ 1,523.66	$ 1,151.21	$ 1,042.75	$ -	$ -	$ 6,518.1
Langley Gulch													
Energy (MWh)	200,965.1	208,920.8	-	-	-	33,423.4	215,508.6	215,899.6	213,899.1	221,771.5	177,966.8	155,183.4	1,643,538.4
Expense ($ x 1000)	$ 15,302.36	$ 5,768.77	$ -	$ -	$ -	$ 1,006.67	$ 7,365.39	$ 7,941.65	$ 7,234.33	$ 7,613.26	$ 12,826.99	$ 16,218.55	$ 81,278.0
Danskin													
Energy (MWh)	833.7	-	-	-	-	-	84,841.7	42,119.3	61.7	1,248.7	678.5	14,651.6	144,435.0
Expense ($ x 1000)	$ 105.88	$ -	$ -	$ -	$ -	$ -	$ 4,552.19	$ 2,411.57	$ 3.40	$ 70.01	$ 78.73	$ 2,295.42	$ 9,517.2
Bennett Mountain													
Energy (MWh)	2,246.9	-	-	-	-	-	43,097.1	21,734.9	1,136.4	-	243.0	4,404.9	72,863.3
Expense ($ x 1000)	$ 280.84	$ -	$ -	$ -	$ -	$ -	$ 2,319.00	$ 1,260.23	$ 57.07	$ -	$ 27.73	$ 677.46	$ 4,622.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	193,085.2	39,474.6	57,305.0	137.1	10,091.5	38,876.1	222,945.9	172,328.1	75,946.0	50,420.0	180,298.0	311,190.2	1,352,097.6
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	268,857.4	103,703.1	139,748.5	85,476.4	100,844.6	128,962.3	317,298.3	260,813.5	151,542.6	122,816.5	249,564.0	380,990.6	2,310,617.9
Market Expense ($ x 1000)	$ 9,094.72	$ 1,207.47	$ 1,450.91	$ 3.70	$ 256.19	$ 1,117.19	$ 7,619.24	$ 6,679.39	$ 2,897.67	$ 1,951.07	$ 7,055.91	$ 14,386.25	$ 53,719.7
Market Expense - No Wheeling ($ x 1000)	$ 7,652.50	$ 912.62	$ 1,022.88	$ 2.68	$ 180.81	$ 826.81	$ 5,953.98	$ 5,392.21	$ 2,330.40	$ 1,574.47	$ 5,709.20	$ 12,061.87	$ 43,620.4
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 13,410.8	$ 5,357.6	$ 6,275.5	$ 4,954.7	$ 4,962.7	$ 5,274.3	$ 10,431.7	$ 9,734.8	$ 6,324.4	$ 6,093.7	$ 10,904.1	$ 17,497.4	$ 101,221.5
Storage													
Black Mesa Battery Energy (MWh)	(1,266.41)	(944.83)	(1,059.0)	(1,188.8)	(1,029.6)	(859.6)	(875.7)	(875.3)	(823.6)	(914.8)	(873.6)	(1,070.1)	(11,781.2)
80 MW Grid Battery Energy (MWh)	(2,512.58)	(1,795.76)	(2,118.4)	(2,412.5)	(2,053.1)	(1,733.7)	(1,751.0)	(1,736.9)	(1,616.7)	(1,832.6)	(1,667.7)	(2,106.2)	(23,337.1)

11 MW Grid Battery Energy (MWh)	(338.59)	(245.51)	(268.5)	(318.8)	(276.9)	(228.6)	(241.2)	(237.2)	(217.3)	(255.4)	(210.7)	(262.9)	(3,101.5)
Total Storage (MWh)	(4,117.6)	(2,986.1)	(3,445.8)	(3,920.1)	(3,359.6)	(2,821.9)	(2,867.9)	(2,849.4)	(2,657.6)	(3,002.8)	(2,751.9)	(3,439.2)	(38,219.9)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	598.8	59,393.4	39,860.4	352,906.5	154,350.2	97,779.7	6,142.0	9,814.3	38,338.3	53,192.7	7,854.9	459.5	820,690.7
Revenue ($ x 1000)	$ 37.6	$ 2,566.3	$ 1,347.5	$ 10,493.3	$ 4,477.0	$ 3,067.4	$ 317.3	$ 553.1	$ 1,777.4	$ 2,167.6	$ 417.4	$ 29.1	$ 27,251.0
Revenue - No Wheeling ($ x 1000)	$ 33.1	$ 2,122.7	$ 1,049.8	$ 7,857.3	$ 3,324.1	$ 2,337.1	$ 271.4	$ 479.8	$ 1,491.1	$ 1,770.3	$ 358.7	$ 25.6	$ 21,121.0
Total Energy	1,428,850.94	1,234,421.47	1,217,841.82	1,168,470.79	1,353,816.92	1,602,921.83	1,927,228.24	1,763,858.88	1,373,841.58	1,218,929.57	1,251,370.18	1,476,224.97	17,017,777.19
Total NPSE	$ 49,493.6	$ 31,223.1	$ 21,373.0	$ 13,148.1	$ 20,104.5	$ 30,437.8	$ 58,379.9	$ 56,391.0	$ 40,806.6	$ 37,283.4	$ 49,904.2	$ 65,206.3	$ 479,881.5

Wheeling 3-Year Average $ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2010

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	648,189.0	621,083.7	657,025.5	663,823.6	837,985.5	1,014,381.1	594,717.3	504,228.0	513,470.7	442,434.0	368,534.7	512,325.1	7,378,198.2
Bridger Coal													
Energy (MWh)	125,632.8	93,350.9	54,423.5	63,353.5	59,318.8	109,922.9	181,214.9	245,312.5	240,288.0	238,360.1	242,600.0	250,686.7	1,904,464.58
Expense ($ x 1000)	$ 3,929.37	$ 2,970.29	$ 1,881.21	$ 2,127.87	$ 2,252.08	$ 3,768.37	$ 5,840.53	$ 7,685.56	$ 7,520.80	$ 7,485.32	$ 7,587.37	$ 7,840.28	$ 60,889.05
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	43,581.9	46,857.2	39,918.5	16,649.9	43,889.3	55,526.1	246,544.5
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 2,024.34	$ 2,172.01	$ 1,860.04	$ 775.44	$ 2,037.03	$ 2,558.20	$ 11,432.8
Bridger Gas													
Energy (MWh)	-	34,988.2	-	25.0	-	11,328.9	29,086.0	32,344.2	28,075.5	32,276.0	-	-	168,123.8
Expense ($ x 1000)	$ -	$ 1,338.12	$ -	$ 1.16	$ -	$ 512.44	$ 1,444.21	$ 1,633.88	$ 1,296.71	$ 1,478.49	$ -	$ -	$ 7,705.0
Langley Gulch													
Energy (MWh)	197,416.3	208,810.1	97,343.3	22,490.3	9,307.4	57,578.7	215,958.4	215,895.6	213,585.0	221,091.8	181,118.0	158,172.1	1,798,767.0
Expense ($ x 1000)	$ 15,393.72	$ 5,848.56	$ 5,852.44	$ 734.64	$ 262.53	$ 1,754.41	$ 7,488.68	$ 8,059.16	$ 7,330.22	$ 7,702.38	$ 13,141.71	$ 16,620.32	$ 90,188.8
Danskin													
Energy (MWh)	129.0	-	63.8	-	-	1,326.4	131,125.9	107,195.0	124.2	-	130.3	1,741.3	241,835.9
Expense ($ x 1000)	$ 16.48	$ -	$ 5.69	$ -	$ -	$ 58.85	$ 7,211.10	$ 6,303.62	$ 7.11	$ -	$ 15.78	$ 277.23	$ 13,895.9
Bennett Mountain													
Energy (MWh)	2,246.9	-	-	-	-	1,741.5	82,509.7	62,586.0	1,136.4	-	1,822.7	3,398.1	155,441.4
Expense ($ x 1000)	$ 285.31	$ -	$ -	$ -	$ -	$ 80.42	$ 4,535.51	$ 3,702.69	$ 57.96	$ -	$ 211.28	$ 530.97	$ 9,404.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	181,979.1	43,933.2	111,046.7	71,652.7	76,583.7	59,902.6	259,559.6	181,794.5	75,028.9	42,159.8	178,956.2	246,905.5	1,529,502.3
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	257,751.3	108,161.7	193,490.2	156,992.1	167,336.8	149,988.8	353,912.1	270,279.9	150,625.5	114,556.3	248,222.2	316,705.9	2,488,022.7
Market Expense ($ x 1000)	$ 8,452.25	$ 1,373.46	$ 2,983.30	$ 1,961.59	$ 1,928.59	$ 1,761.77	$ 9,435.98	$ 7,290.31	$ 2,872.56	$ 1,611.66	$ 7,311.74	$ 11,489.42	$ 58,472.6
Market Expense - No Wheeling ($ x 1000)	$ 7,092.99	$ 1,045.31	$ 2,153.85	$ 1,426.39	$ 1,356.56	$ 1,314.34	$ 7,497.24	$ 5,932.43	$ 2,312.14	$ 1,296.75	$ 5,975.06	$ 9,645.20	$ 47,048.3
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 12,851.2	$ 5,490.2	$ 7,406.5	$ 6,378.4	$ 6,138.4	$ 5,761.8	$ 11,974.9	$ 10,275.0	$ 6,306.1	$ 5,815.9	$ 11,170.0	$ 15,080.7	$ 104,649.4
Storage													
Black Mesa Battery Energy (MWh)	(1,278.57)	(879.54)	(1,153.4)	(1,025.8)	(909.8)	(865.1)	(882.7)	(874.5)	(818.4)	(944.9)	(968.0)	(1,101.7)	(11,702.2)
80 MW Grid Battery Energy (MWh)	(2,460.06)	(1,848.76)	(2,236.1)	(2,077.0)	(1,775.3)	(1,716.8)	(1,765.0)	(1,755.2)	(1,630.0)	(1,854.2)	(1,886.9)	(2,205.6)	(23,211.0)

11 MW Grid Battery Energy (MWh)	(340.57)	(255.78)	(293.5)	(284.3)	(231.1)	(227.4)	(243.0)	(236.9)	(214.7)	(261.9)	(248.8)	(275.8)	(3,113.7)
Total Storage (MWh)	(4,079.2)	(2,984.1)	(3,683.0)	(3,387.1)	(2,916.2)	(2,809.3)	(2,890.7)	(2,866.6)	(2,663.0)	(3,061.0)	(3,103.7)	(3,583.1)	(38,026.9)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	1,354.4	54,975.0	27,038.8	23,502.7	30,901.6	60,988.9	6,279.3	7,879.7	45,643.8	65,643.5	9,794.1	1,865.6	335,867.4
Revenue ($ x 1000)	$ 87.5	$ 2,429.1	$ 1,046.0	$ 862.4	$ 985.5	$ 2,171.2	$ 348.9	$ 451.2	$ 2,184.5	$ 2,884.4	$ 554.7	$ 117.1	$ 14,122.4
Revenue - No Wheeling ($ x 1000)	$ 77.4	$ 2,018.5	$ 844.1	$ 686.9	$ 754.6	$ 1,715.6	$ 302.0	$ 392.3	$ 1,843.6	$ 2,394.0	$ 481.6	$ 103.1	$ 11,613.7
Total Energy	1,428,850.91	1,234,421.47	1,217,841.84	1,168,470.80	1,353,816.89	1,602,921.81	1,927,228.25	1,763,858.91	1,373,841.60	1,218,929.61	1,251,370.21	1,476,225.00	17,017,777.30
Total NPSE	$ 48,890.6	$ 31,637.0	$ 28,927.9	$ 25,493.0	$ 25,109.3	$ 33,383.1	$ 65,537.4	$ 63,844.2	$ 40,695.0	$ 37,438.2	$ 50,638.6	$ 61,156.3	$ 515,259.2

Wheeling 3-Year Average $ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2011

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	716,216.1	809,762.2	1,040,628.5	984,821.5	1,053,868.5	1,258,411.0	1,150,224.9	830,461.2	635,327.5	473,094.5	372,615.2	762,177.6	10,087,608.6
Bridger Coal													
Energy (MWh)	125,632.9	53,560.8	36,393.3	33,219.1	39,495.5	78,775.1	118,242.0	169,562.6	175,893.0	189,995.9	221,210.5	250,259.4	1,492,239.76
Expense ($ x 1000)	$ 3,929.37	$ 1,825.83	$ 1,362.61	$ 1,261.12	$ 1,681.57	$ 2,871.85	$ 4,027.98	$ 5,505.13	$ 5,667.02	$ 6,093.13	$ 6,971.60	$ 7,827.97	$ 49,025.18
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	-	18,621.2	-	40.5	38,922.4	42,970.2	100,675.8
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ -	$ 876.54	$ -	$ 1.92	$ 1,815.64	$ 1,996.06	$ 4,695.9
Bridger Gas													
Energy (MWh)	-	34,429.9	-	3,701.6	1,353.1	7,839.9	8,227.3	27,827.9	15,867.9	14,953.8	-	-	114,201.4
Expense ($ x 1000)	$ -	$ 1,142.07	$ -	$ 149.95	$ 47.85	$ 307.66	$ 354.10	$ 1,219.33	$ 635.46	$ 593.38	$ -	$ -	$ 4,449.8
Langley Gulch													
Energy (MWh)	188,759.4	101,344.4	-	-	-	13,764.2	203,021.5	215,220.0	210,191.1	220,979.4	179,009.1	55,201.9	1,387,491.0
Expense ($ x 1000)	$ 13,234.26	$ 2,539.60	$ -	$ -	$ -	$ 376.49	$ 6,268.60	$ 7,140.51	$ 6,421.72	$ 6,847.69	$ 11,390.50	$ 5,115.30	$ 59,334.7
Danskin													
Energy (MWh)	-	-	-	-	-	61.6	396.8	185.1	1,665.1	1,971.6	65.1	-	4,345.2
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 2.63	$ 20.17	$ 10.12	$ 81.89	$ 98.57	$ 6.92	$ -	$ 220.3
Bennett Mountain													
Energy (MWh)	249.7	-	-	-	-	-	2,228.3	1,958.9	-	-	2,673.4	-	7,110.2
Expense ($ x 1000)	$ 27.91	$ -	$ -	$ -	$ -	$ -	$ 103.39	$ 98.05	$ -	$ -	$ 272.96	$ -	$ 502.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	130,273.0	26,373.9	2,233.6	978.8	9,165.8	31,395.5	88,774.2	142,414.4	60,460.5	62,129.2	199,316.6	124,351.0	877,866.4
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	206,045.2	90,602.4	84,677.2	86,318.2	99,918.9	121,481.7	183,126.7	230,899.8	136,057.2	134,525.7	268,582.6	194,151.4	1,836,386.8
Market Expense ($ x 1000)	$ 5,080.34	$ 765.15	$ 54.76	$ 26.48	$ 216.99	$ 869.01	$ 2,805.24	$ 4,600.89	$ 1,833.74	$ 1,986.10	$ 7,120.70	$ 4,834.03	$ 30,193.4
Market Expense - No Wheeling ($ x 1000)	$ 4,107.29	$ 568.15	$ 38.08	$ 19.17	$ 148.53	$ 634.51	$ 2,142.16	$ 3,537.15	$ 1,382.14	$ 1,522.04	$ 5,631.94	$ 3,905.21	$ 23,636.3
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 9,865.5	$ 5,013.1	$ 5,290.7	$ 4,971.2	$ 4,930.4	$ 5,082.0	$ 6,619.8	$ 7,879.7	$ 5,376.1	$ 6,041.2	$ 10,826.9	$ 9,340.8	$ 81,237.5
Storage													
Black Mesa Battery Energy (MWh)	(1,077.45)	(931.87)	(1,426.8)	(1,080.9)	(990.7)	(865.4)	(880.1)	(869.8)	(777.2)	(866.9)	(892.4)	(1,069.3)	(11,728.8)
80 MW Grid Battery Energy (MWh)	(2,100.96)	(1,956.82)	(2,851.1)	(2,145.5)	(1,966.9)	(1,744.4)	(1,759.1)	(1,736.4)	(1,538.1)	(1,689.3)	(1,753.7)	(2,120.2)	(23,362.4)

11 MW Grid Battery Energy (MWh)	(290.67)	(247.29)	(371.7)	(287.2)	(261.6)	(228.5)	(243.3)	(234.9)	(207.5)	(232.9)	(219.4)	(279.6)	(3,104.6)
Total Storage (MWh)	(3,469.1)	(3,136.0)	(4,649.5)	(3,513.5)	(3,219.2)	(2,838.3)	(2,882.6)	(2,841.1)	(2,522.8)	(2,789.2)	(2,865.5)	(3,469.1)	(38,195.9)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	7,502.2	78,128.3	185,424.8	224,752.1	151,286.0	195,025.1	39,648.6	17,943.3	33,561.9	36,108.6	6,793.4	8,184.9	984,359.1
Revenue ($ x 1000)	$ 408.3	$ 2,781.1	$ 5,089.4	$ 6,237.9	$ 3,819.1	$ 5,133.2	$ 1,246.1	$ 879.3	$ 1,389.3	$ 1,405.5	$ 328.5	$ 455.1	$ 29,172.6
Revenue - No Wheeling ($ x 1000)	$ 352.2	$ 2,197.6	$ 3,704.3	$ 4,559.1	$ 2,689.1	$ 3,676.5	$ 949.9	$ 745.2	$ 1,138.6	$ 1,135.7	$ 277.8	$ 394.0	$ 21,820.1
Total Energy	1,428,850.96	1,234,421.48	1,217,841.83	1,168,470.80	1,353,816.91	1,602,921.84	1,927,228.24	1,763,858.87	1,373,841.60	1,218,929.60	1,251,370.20	1,476,224.96	17,017,777.29
Total NPSE	$ 43,150.8	$ 26,158.3	$ 16,392.1	$ 17,257.7	$ 20,282.5	$ 27,125.4	$ 41,515.0	$ 46,313.6	$ 35,293.4	$ 35,335.5	$ 47,986.1	$ 42,190.6	$ 406,353.4

Wheeling 3-Year Average	$ 7.47

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IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2012

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,139,742.1	1,009,320.7	1,010,613.1	970,253.1	720,629.3	671,525.7	736,201.3	541,931.2	581,497.4	428,371.3	361,968.2	450,863.3	8,622,916.6
Bridger Coal													
Energy (MWh)	125,632.9	53,303.0	39,253.5	39,841.7	60,076.1	103,554.6	160,446.9	239,992.1	232,091.6	230,158.8	240,565.9	250,686.7	1,775,603.62
Expense ($ x 1000)	$ 3,929.37	$ 1,818.41	$ 1,444.88	$ 1,451.61	$ 2,273.91	$ 3,585.04	$ 5,242.79	$ 7,532.40	$ 7,284.77	$ 7,249.22	$ 7,528.80	$ 7,840.28	$ 57,181.48
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	34,376.6	42,965.0	-	162.0	44,697.8	51,618.7	173,941.6
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,613.35	$ 1,995.83	$ -	$ 7.67	$ 2,073.07	$ 2,381.56	$ 8,077.2
Bridger Gas													
Energy (MWh)	-	31,337.4	-	974.1	507.7	1,871.3	12,628.4	32,386.0	7,906.1	22,575.0	-	-	110,186.0
Expense ($ x 1000)	$ -	$ 1,120.40	$ -	$ 42.45	$ 19.29	$ 79.09	$ 586.01	$ 1,529.05	$ 340.96	$ 965.66	$ -	$ -	$ 4,682.9
Langley Gulch													
Energy (MWh)	5,170.7	-	-	-	201,777.5	209,101.1	215,180.2	216,649.0	211,339.9	221,923.6	185,271.6	161,693.2	1,628,106.8
Expense ($ x 1000)	$ 422.59	$ -	$ -	$ -	$ 5,359.01	$ 5,997.88	$ 7,057.39	$ 7,643.69	$ 6,862.11	$ 7,310.06	$ 12,543.84	$ 15,822.85	$ 69,019.4
Danskin													
Energy (MWh)	-	-	-	-	-	33,968.8	103,315.4	85,430.9	1,511.5	1,905.8	545.5	16,810.7	243,488.6
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 1,507.24	$ 5,291.69	$ 4,707.91	$ 72.17	$ 102.05	$ 61.13	$ 2,524.26	$ 14,266.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	10,626.6	35,771.4	53,218.8	4,294.0	-	850.6	1,510.3	106,271.7
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 477.03	$ 1,851.17	$ 2,954.50	$ 214.84	$ -	$ 92.82	$ 222.05	$ 5,812.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	7,122.9	2,188.4	4,231.7	1,038.3	36,174.1	175,564.8	236,925.9	183,632.4	54,301.8	65,695.0	181,946.6	294,366.6	1,243,188.6
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	82,895.1	66,417.0	86,675.2	86,377.7	126,927.2	265,651.0	331,278.4	272,117.8	129,898.4	138,091.6	251,212.7	364,167.1	2,201,709.0
Market Expense ($ x 1000)	$ 339.21	$ 68.00	$ 104.72	$ 28.43	$ 882.98	$ 4,846.84	$ 7,681.83	$ 6,911.09	$ 1,889.15	$ 2,401.49	$ 7,214.34	$ 13,406.07	$ 45,774.2
Market Expense - No Wheeling ($ x 1000)	$ 286.01	$ 51.65	$ 73.11	$ 20.67	$ 612.78	$ 3,535.49	$ 5,912.15	$ 5,539.48	$ 1,483.55	$ 1,910.79	$ 5,855.32	$ 11,207.35	$ 36,488.4
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 6,044.3	$ 4,496.6	$ 5,325.7	$ 4,972.7	$ 5,394.6	$ 7,983.0	$ 10,389.8	$ 9,882.0	$ 5,477.5	$ 6,430.0	$ 11,050.3	$ 16,642.9	$ 94,089.5
Storage													
Black Mesa Battery Energy (MWh)	(1,281.67)	(1,151.23)	(1,312.2)	(1,176.4)	(955.4)	(845.3)	(880.4)	(866.6)	(791.0)	(919.3)	(986.3)	(1,118.7)	(12,284.4)
80 MW Grid Battery Energy (MWh)	(2,616.81)	(2,365.76)	(2,617.4)	(2,344.6)	(1,922.5)	(1,685.5)	(1,762.2)	(1,736.8)	(1,559.0)	(1,889.1)	(1,918.5)	(2,246.4)	(24,664.6)

11 MW Grid Battery Energy (MWh)	(344.84)	(295.39)	(348.4)	(315.4)	(246.5)	(224.3)	(241.5)	(231.3)	(213.2)	(252.9)	(249.9)	(286.7)	(3,250.3)
Total Storage (MWh)	(4,243.3)	(3,812.4)	(4,278.0)	(3,836.4)	(3,124.5)	(2,755.1)	(2,884.1)	(2,834.7)	(2,563.1)	(3,061.3)	(3,154.7)	(3,651.9)	(40,199.3)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	123,265.7	148,130.2	160,639.3	213,815.5	66,662.5	11,073.8	3,378.3	7,903.8	27,058.9	43,463.4	8,538.1	591.4	814,520.9
Revenue ($ x 1000)	$ 5,532.4	$ 5,188.3	$ 4,704.2	$ 6,248.2	$ 2,044.5	$ 385.6	$ 177.4	$ 447.9	$ 1,053.6	$ 1,711.7	$ 471.3	$ 37.8	$ 28,002.7
Revenue - No Wheeling ($ x 1000)	$ 4,611.7	$ 4,081.9	$ 3,504.3	$ 4,651.1	$ 1,546.6	$ 302.9	$ 152.1	$ 388.9	$ 851.5	$ 1,387.0	$ 407.5	$ 33.4	$ 21,918.8
Total Energy	1,428,850.93	1,234,421.47	1,217,841.83	1,168,470.81	1,353,816.91	1,602,921.81	1,927,228.24	1,763,858.89	1,373,841.60	1,218,929.61	1,251,370.20	1,476,224.99	17,017,777.29
Total NPSE	$ 21,365.8	$ 20,666.0	$ 16,894.6	$ 17,331.9	$ 28,444.1	$ 42,861.6	$ 57,221.9	$ 60,260.9	$ 37,699.3	$ 37,418.0	$ 49,908.8	$ 63,761.7	$ 459,918.5

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2013

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	478,267.1	528,065.9	440,890.2	493,061.6	568,572.6	629,598.1	522,814.4	420,474.8	450,038.6	422,196.4	369,506.5	423,562.5	5,747,048.8
Bridger Coal													
Energy (MWh)	125,632.9	105,206.1	63,822.7	76,356.9	62,965.3	124,458.7	195,676.5	250,575.7	242,600.0	247,592.1	242,600.0	250,686.7	1,988,173.52
Expense ($ x 1000)	$ 3,929.37	$ 3,311.28	$ 2,151.55	$ 2,501.88	$ 2,357.06	$ 4,186.77	$ 6,256.72	$ 7,837.08	$ 7,587.37	$ 7,751.16	$ 7,587.37	$ 7,840.28	$ 63,297.89
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	44,227.4	45,612.3	39,212.2	10,350.7	43,274.2	63,809.5	246,607.9
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 2,052.10	$ 2,115.18	$ 1,828.55	$ 483.79	$ 2,009.61	$ 2,927.53	$ 11,422.5
Bridger Gas													
Energy (MWh)	-	35,615.6	-	382.9	100.6	2,770.3	27,650.6	33,990.9	21,673.4	13,899.8	-	-	136,084.3
Expense ($ x 1000)	$ -	$ 1,403.41	$ -	$ 18.39	$ 4.20	$ 128.91	$ 1,415.45	$ 1,770.42	$ 1,031.55	$ 655.51	$ -	$ -	$ 6,427.8
Langley Gulch													
Energy (MWh)	202,642.6	208,931.2	165,612.5	212,515.7	228,507.8	207,474.8	216,044.6	215,835.9	214,464.4	221,671.4	181,957.8	159,934.0	2,435,592.6
Expense ($ x 1000)	$ 16,056.84	$ 6,006.94	$ 10,202.97	$ 7,098.33	$ 6,576.64	$ 6,457.37	$ 7,695.02	$ 8,277.52	$ 7,559.23	$ 7,931.81	$ 13,545.95	$ 17,190.63	$ 114,599.3
Danskin													
Energy (MWh)	48,899.3	327.0	541.6	-	-	42,768.4	141,443.2	130,823.7	10,034.9	-	678.5	20,450.6	395,967.2
Expense ($ x 1000)	$ 6,465.58	$ 15.04	$ 50.03	$ -	$ -	$ 2,050.96	$ 8,023.86	$ 7,983.46	$ 528.30	$ -	$ 82.39	$ 3,345.90	$ 28,545.5
Bennett Mountain													
Energy (MWh)	14,854.6	-	1,401.7	-	-	21,286.1	95,405.8	82,147.7	2,289.0	-	243.0	2,643.0	220,270.9
Expense ($ x 1000)	$ 1,941.64	$ -	$ 129.38	$ -	$ -	$ 1,052.48	$ 5,377.77	$ 5,010.95	$ 122.42	$ -	$ 29.00	$ 425.17	$ 14,088.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	284,039.0	97,934.5	229,268.6	55,413.2	115,819.4	174,951.3	291,496.4	216,048.7	112,590.9	57,134.1	176,726.8	306,312.1	2,117,735.1
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	359,811.2	162,163.0	311,712.2	140,752.6	206,572.5	265,037.5	385,848.9	304,534.1	188,187.5	129,530.7	245,992.8	376,112.5	3,076,255.5
Market Expense ($ x 1000)	$ 14,413.13	$ 3,335.09	$ 6,648.69	$ 1,595.29	$ 3,008.62	$ 5,197.21	$ 11,239.79	$ 8,973.82	$ 4,422.58	$ 2,286.89	$ 7,297.76	$ 15,039.39	$ 83,458.3
Market Expense - No Wheeling ($ x 1000)	$ 12,291.55	$ 2,603.58	$ 4,936.21	$ 1,181.39	$ 2,143.53	$ 3,890.44	$ 9,062.50	$ 7,360.08	$ 3,581.60	$ 1,860.14	$ 5,977.73	$ 12,751.44	$ 67,640.2
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 18,049.8	$ 7,048.5	$ 10,188.8	$ 6,133.4	$ 6,925.4	$ 8,337.9	$ 13,540.2	$ 11,702.6	$ 7,575.6	$ 6,379.3	$ 11,172.7	$ 18,187.0	$ 125,241.3
Storage													
Black Mesa Battery Energy (MWh)	(1,281.01)	(864.70)	(1,140.3)	(1,121.0)	(872.7)	(851.2)	(873.1)	(888.2)	(832.5)	(902.6)	(934.7)	(1,119.7)	(11,681.6)
80 MW Grid Battery Energy (MWh)	(2,550.74)	(1,790.44)	(2,301.9)	(2,235.0)	(1,774.2)	(1,708.5)	(1,737.7)	(1,778.6)	(1,656.4)	(1,838.4)	(1,880.3)	(2,198.3)	(23,450.5)

11 MW Grid Battery Energy (MWh)	(344.08)	(228.96)	(295.2)	(310.5)	(227.5)	(222.5)	(242.9)	(238.7)	(212.6)	(248.2)	(239.2)	(288.4)	(3,098.8)
Total Storage (MWh)	(4,175.8)	(2,884.1)	(3,737.4)	(3,666.4)	(2,874.5)	(2,782.2)	(2,853.7)	(2,905.5)	(2,701.5)	(2,989.2)	(3,054.2)	(3,606.5)	(38,230.9)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	-	28,989.3	8,618.9	39,608.6	23,713.5	8,141.5	3,321.5	7,137.4	26,881.7	45,588.3	7,779.3	485.8	200,265.9
Revenue ($ x 1000)	$ -	$ 1,356.6	$ 332.8	$ 1,424.9	$ 782.5	$ 319.8	$ 184.7	$ 410.2	$ 1,314.7	$ 1,836.3	$ 429.2	$ 33.1	$ 8,424.7
Revenue - No Wheeling ($ x 1000)	$ -	$ 1,140.1	$ 268.4	$ 1,129.1	$ 605.4	$ 259.0	$ 159.9	$ 356.9	$ 1,114.0	$ 1,495.7	$ 371.1	$ 29.4	$ 6,928.9
Total Energy	1,428,850.93	1,234,421.47	1,217,841.83	1,168,470.79	1,353,816.92	1,602,921.84	1,927,228.25	1,763,858.92	1,373,841.60	1,218,929.59	1,251,370.20	1,476,225.00	17,017,777.34
Total NPSE	$ 62,945.2	$ 34,847.5	$ 37,218.2	$ 31,440.4	$ 32,522.5	$ 45,512.6	$ 69,543.4	$ 68,750.5	$ 43,418.8	$ 38,430.3	$ 51,028.0	$ 68,249.0	$ 585,402.2

Wheeling 3-Year Average $ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2014

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	446,750.2	501,595.4	629,767.2	715,976.8	690,263.4	589,505.2	654,006.7	541,110.2	470,566.3	426,309.4	367,074.2	499,036.8	6,531,961.8
Bridger Coal													
Energy (MWh)	125,632.8	99,964.3	45,472.4	66,433.1	60,377.9	117,524.2	175,881.1	250,611.3	241,402.1	244,528.6	242,600.0	250,686.7	1,921,114.59
Expense ($ x 1000)	$ 3,929.37	$ 3,160.51	$ 1,623.75	$ 2,216.44	$ 2,282.54	$ 3,987.15	$ 5,687.03	$ 7,838.11	$ 7,552.88	$ 7,662.93	$ 7,587.37	$ 7,840.28	$ 61,368.36
Valmy													
Energy (MWh)	121.5	-	-	-	-	162.0	42,390.6	44,561.9	38,856.7	9,913.4	43,191.9	54,592.3	233,790.4
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ 7.67	$ 1,971.24	$ 2,067.01	$ 1,812.71	$ 461.72	$ 2,005.94	$ 2,516.57	$ 10,848.6
Bridger Gas													
Energy (MWh)	-	26,042.6	-	1,258.3	899.1	4,470.3	21,464.9	34,175.4	21,894.2	33,870.8	-	-	144,075.6
Expense ($ x 1000)	$ -	$ 997.83	$ -	$ 58.73	$ 36.66	$ 202.34	$ 1,067.85	$ 1,730.69	$ 1,013.08	$ 1,554.80	$ -	$ -	$ 6,662.0
Langley Gulch													
Energy (MWh)	200,769.8	209,050.4	128,154.3	-	216,534.7	207,360.7	215,546.8	215,740.6	214,067.3	222,263.7	181,748.1	158,004.0	2,169,240.5
Expense ($ x 1000)	$ 15,557.57	$ 5,865.31	$ 7,759.52	$ -	$ 6,086.07	$ 6,297.30	$ 7,488.43	$ 8,068.23	$ 7,359.51	$ 7,755.87	$ 13,191.73	$ 16,644.04	$ 102,073.6
Danskin													
Energy (MWh)	63,186.8	1,240.8	-	-	-	56,835.4	121,891.3	93,563.0	185.0	-	162.9	1,547.7	338,612.7
Expense ($ x 1000)	$ 8,149.55	$ 55.75	$ -	$ -	$ -	$ 2,674.93	$ 6,710.84	$ 5,510.00	$ 10.39	$ -	$ 19.76	$ 246.58	$ 23,377.8
Bennett Mountain													
Energy (MWh)	24,841.0	298.1	-	-	-	24,762.1	66,561.6	36,639.8	1,526.0	-	1,701.2	1,636.1	157,965.9
Expense ($ x 1000)	$ 3,160.47	$ 12.95	$ -	$ -	$ -	$ 1,197.44	$ 3,678.46	$ 2,164.05	$ 79.49	$ -	$ 197.58	$ 256.16	$ 10,746.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	293,059.1	126,213.6	112,612.6	50,693.2	43,505.3	201,814.8	239,228.7	181,583.7	105,536.5	52,548.8	179,909.7	263,686.7	1,850,392.6
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	368,831.3	190,442.2	195,056.2	136,032.6	134,258.4	291,901.0	333,581.2	270,069.1	181,133.1	124,945.3	249,175.7	333,487.1	2,808,913.0
Market Expense ($ x 1000)	$ 14,302.59	$ 4,233.61	$ 2,930.32	$ 1,414.49	$ 1,084.21	$ 5,798.19	$ 8,451.16	$ 7,251.63	$ 4,069.57	$ 2,089.99	$ 7,299.07	$ 12,186.59	$ 71,111.4
Market Expense - No Wheeling ($ x 1000)	$ 12,113.63	$ 3,290.88	$ 2,089.18	$ 1,035.85	$ 759.25	$ 4,290.77	$ 6,664.28	$ 5,895.32	$ 3,281.28	$ 1,697.49	$ 5,955.26	$ 10,217.03	$ 57,290.2
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 17,871.9	$ 7,735.8	$ 7,341.8	$ 5,987.9	$ 5,541.1	$ 8,738.3	$ 11,142.0	$ 10,237.9	$ 7,275.3	$ 6,216.7	$ 11,150.2	$ 15,652.6	$ 114,891.3
Storage													
Black Mesa Battery Energy (MWh)	(1,241.42)	(831.36)	(927.7)	(1,059.4)	(992.3)	(852.3)	(882.8)	(868.2)	(820.7)	(951.0)	(940.1)	(1,141.7)	(11,509.0)
80 MW Grid Battery Energy (MWh)	(2,504.21)	(1,624.58)	(1,782.5)	(2,123.3)	(1,972.8)	(1,705.2)	(1,765.2)	(1,736.5)	(1,681.9)	(1,928.6)	(1,888.1)	(2,251.6)	(22,964.3)

11 MW Grid Battery Energy (MWh)	(334.39)	(206.71)	(229.1)	(279.2)	(267.3)	(226.4)	(243.1)	(236.9)	(212.8)	(265.8)	(244.3)	(286.9)	(3,032.8)
Total Storage (MWh)	(4,080.0)	(2,662.7)	(2,939.3)	(3,461.9)	(3,232.5)	(2,783.9)	(2,891.1)	(2,841.5)	(2,715.4)	(3,145.4)	(3,072.5)	(3,680.2)	(37,506.2)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	-	17,535.7	23,886.2	36,444.3	58,970.2	7,267.0	5,496.9	9,677.8	27,998.4	62,022.2	9,162.0	2,203.9	260,664.6
Revenue ($ x 1000)	$ -	$ 796.8	$ 886.2	$ 1,454.9	$ 1,903.2	$ 269.5	$ 294.2	$ 577.3	$ 1,334.2	$ 2,777.9	$ 506.2	$ 133.3	$ 10,933.6
Revenue - No Wheeling ($ x 1000)	$ -	$ 665.8	$ 707.7	$ 1,182.7	$ 1,462.7	$ 215.2	$ 253.1	$ 505.1	$ 1,125.0	$ 2,314.7	$ 437.7	$ 116.8	$ 8,986.6
Total Energy	1,428,850.91	1,234,421.47	1,217,841.83	1,168,470.80	1,353,816.91	1,602,921.81	1,927,228.25	1,763,858.89	1,373,841.59	1,218,929.59	1,251,370.20	1,476,224.99	17,017,777.24
Total NPSE	$ 65,170.8	$ 35,450.3	$ 30,667.1	$ 23,921.4	$ 29,484.9	$ 46,453.5	$ 62,818.7	$ 61,502.1	$ 42,269.7	$ 37,939.0	$ 50,676.5	$ 61,388.5	$ 549,689.5

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2015

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	644,246.9	800,225.5	607,459.9	538,007.1	488,825.2	517,665.3	643,917.1	474,960.9	433,859.5	411,956.5	364,885.7	474,432.2	6,400,441.7
Bridger Coal													
Energy (MWh)	125,632.9	93,983.3	65,175.3	77,850.2	71,178.0	136,440.9	205,320.9	250,253.1	242,600.0	248,997.9	242,600.0	250,686.7	2,010,719.14
Expense ($ x 1000)	$ 3,929.37	$ 2,988.48	$ 2,190.45	$ 2,544.83	$ 2,593.36	$ 4,531.66	$ 6,534.38	$ 7,827.79	$ 7,587.37	$ 7,791.64	$ 7,587.37	$ 7,840.28	$ 63,946.98
Valmy													
Energy (MWh)	121.5	-	-	-	-	1,498.9	43,131.8	48,359.1	39,946.4	16,623.9	42,407.5	67,853.1	259,942.0
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ 70.96	$ 2,005.95	$ 2,237.61	$ 1,861.28	$ 774.29	$ 1,970.98	$ 3,107.77	$ 12,034.6
Bridger Gas													
Energy (MWh)	-	36,103.4	-	364.8	199.8	7,789.1	20,344.4	31,018.5	18,013.8	16,581.0	-	-	130,414.7
Expense ($ x 1000)	$ -	$ 1,459.17	$ -	$ 17.90	$ 8.61	$ 372.02	$ 1,067.49	$ 1,655.98	$ 878.74	$ 801.79	$ -	$ -	$ 6,261.7
Langley Gulch													
Energy (MWh)	202,132.1	93,322.4	134,603.8	171,693.1	229,360.1	207,983.4	215,112.8	215,880.3	213,963.0	221,573.1	182,877.3	157,476.0	2,245,977.3
Expense ($ x 1000)	$ 16,361.91	$ 2,737.63	$ 8,585.52	$ 5,851.87	$ 6,724.57	$ 6,596.01	$ 7,811.43	$ 8,440.93	$ 7,688.34	$ 8,082.27	$ 13,858.70	$ 17,417.26	$ 110,156.4
Danskin													
Energy (MWh)	2,846.0	-	-	61.6	474.3	73,174.6	119,609.1	113,971.7	29,526.5	4,731.7	754.8	11,760.5	356,910.8
Expense ($ x 1000)	$ 386.94	$ -	$ -	$ 3.56	$ 22.50	$ 3,653.96	$ 6,896.92	$ 7,093.05	$ 1,691.85	$ 283.76	$ 93.67	$ 1,967.60	$ 22,093.8
Bennett Mountain													
Energy (MWh)	1,747.6	-	-	-	1,576.8	42,195.3	71,644.4	72,356.8	2,126.7	-	243.0	2,139.5	194,030.2
Expense ($ x 1000)	$ 233.21	$ -	$ -	$ -	$ 76.93	$ 2,114.43	$ 4,143.41	$ 4,491.51	$ 116.23	$ -	$ 29.60	$ 351.43	$ 11,556.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	181,594.5	17,392.0	109,634.7	49,440.0	175,090.7	212,327.0	218,269.8	187,736.5	112,983.3	58,568.2	180,435.4	264,212.3	1,767,684.2
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	257,366.6	81,620.6	192,078.2	134,779.4	265,843.8	302,413.2	312,622.3	276,221.8	188,579.9	130,964.7	249,701.4	334,012.7	2,726,204.6
Market Expense ($ x 1000)	$ 9,288.59	$ 570.60	$ 3,018.42	$ 1,452.18	$ 4,791.30	$ 6,602.81	$ 8,170.50	$ 7,859.90	$ 4,501.79	$ 2,422.19	$ 7,573.99	$ 12,890.86	$ 69,143.1
Market Expense - No Wheeling ($ x 1000)	$ 7,932.20	$ 440.69	$ 2,199.52	$ 1,082.90	$ 3,483.49	$ 5,016.87	$ 6,540.17	$ 6,457.63	$ 3,657.88	$ 1,984.72	$ 6,226.26	$ 10,917.37	$ 55,939.7
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 13,690.4	$ 4,885.6	$ 7,452.2	$ 6,034.9	$ 8,265.3	$ 9,464.4	$ 11,017.9	$ 10,800.2	$ 7,651.9	$ 6,503.9	$ 11,421.2	$ 16,352.9	$ 113,540.8
Storage													
Black Mesa Battery Energy (MWh)	(1,265.32)	(1,106.75)	(1,066.3)	(1,048.2)	(794.4)	(821.4)	(875.6)	(877.3)	(829.8)	(936.2)	(926.1)	(1,096.3)	(11,643.6)
80 MW Grid Battery Energy (MWh)	(2,509.48)	(2,090.23)	(1,975.3)	(2,054.8)	(1,637.0)	(1,650.3)	(1,750.9)	(1,750.6)	(1,662.4)	(1,892.7)	(1,809.0)	(2,179.8)	(22,962.4)

11 MW Grid Battery Energy (MWh)	(344.18)	(287.14)	(258.8)	(276.7)	(200.5)	(216.8)	(241.0)	(240.8)	(219.4)	(248.3)	(234.6)	(273.7)	(3,041.6)
Total Storage (MWh)	(4,119.0)	(3,484.1)	(3,300.4)	(3,379.7)	(2,631.9)	(2,688.5)	(2,867.4)	(2,868.7)	(2,711.6)	(3,077.1)	(2,969.7)	(3,549.7)	(37,647.7)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	3,921.3	93,335.6	24,392.2	39,582.0	14,695.2	4,002.1	5,899.2	6,201.4	26,987.2	51,688.0	7,080.6	1,704.3	279,489.2
Revenue ($ x 1000)	$ 269.6	$ 3,971.6	$ 978.1	$ 1,562.1	$ 501.4	$ 162.7	$ 301.4	$ 376.8	$ 1,339.1	$ 2,169.0	$ 401.8	$ 107.7	$ 12,141.3
Revenue - No Wheeling ($ x 1000)	$ 240.4	$ 3,274.4	$ 795.9	$ 1,266.4	$ 391.7	$ 132.8	$ 257.3	$ 330.5	$ 1,137.5	$ 1,782.9	$ 348.9	$ 95.0	$ 10,053.7
Total Energy	1,428,850.93	1,234,421.47	1,217,841.83	1,168,470.79	1,353,816.92	1,602,921.80	1,927,228.25	1,763,858.91	1,373,841.59	1,218,929.59	1,251,370.22	1,476,224.97	17,017,777.27
Total NPSE	$ 50,834.2	$ 26,518.2	$ 32,078.2	$ 30,004.3	$ 34,631.6	$ 50,258.7	$ 64,543.1	$ 66,633.7	$ 44,637.2	$ 39,133.7	$ 51,589.9	$ 65,295.1	$ 558,245.3

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2016

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	536,402.2	589,739.9	671,951.7	781,505.7	798,213.2	592,262.4	643,237.7	479,247.2	471,804.2	421,128.3	364,446.4	443,054.1	6,792,992.8
Bridger Coal													
Energy (MWh)	125,632.8	99,558.8	58,525.2	55,141.2	67,136.2	122,127.1	185,989.9	248,509.5	242,600.0	243,002.4	242,600.0	250,686.7	1,941,509.95
Expense ($ x 1000)	$ 3,929.37	$ 3,148.85	$ 1,999.18	$ 1,891.66	$ 2,477.09	$ 4,119.63	$ 5,977.97	$ 7,777.61	$ 7,587.37	$ 7,618.99	$ 7,587.37	$ 7,840.28	$ 61,955.37
Valmy													
Energy (MWh)	121.5	-	-	-	-	162.0	42,753.4	45,546.9	35,995.3	9,386.6	41,870.5	58,437.7	234,273.9
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ 7.67	$ 1,987.41	$ 2,110.92	$ 1,685.16	$ 438.24	$ 1,947.05	$ 2,687.98	$ 10,870.2
Bridger Gas													
Energy (MWh)	-	41,113.1	-	4,054.5	1,922.1	7,852.6	22,659.7	28,027.3	12,645.8	34,314.6	-	-	152,589.7
Expense ($ x 1000)	$ -	$ 1,599.97	$ -	$ 192.25	$ 79.66	$ 361.54	$ 1,144.21	$ 1,440.64	$ 594.33	$ 1,599.48	$ -	$ -	$ 7,012.1
Langley Gulch													
Energy (MWh)	199,125.8	208,920.8	71,812.6	-	14,573.9	207,562.0	215,475.0	215,590.2	213,776.7	221,178.3	177,472.0	157,748.5	1,903,235.7
Expense ($ x 1000)	$ 15,729.32	$ 5,944.60	$ 4,499.88	$ -	$ 416.63	$ 6,392.75	$ 7,594.23	$ 8,180.25	$ 7,456.09	$ 7,830.95	$ 13,229.22	$ 16,887.39	$ 94,161.3
Danskin													
Energy (MWh)	20,805.2	-	63.8	-	-	56,378.9	120,862.1	125,990.7	278.4	-	98.9	3,419.6	327,897.6
Expense ($ x 1000)	$ 2,731.79	$ -	$ 5.80	$ -	$ -	$ 2,685.12	$ 6,758.57	$ 7,607.35	$ 16.04	$ -	$ 11.71	$ 553.91	$ 20,370.3
Bennett Mountain													
Energy (MWh)	9,237.3	-	-	-	-	28,574.9	77,264.9	59,992.9	4,675.5	-	1,093.7	15,354.3	196,193.3
Expense ($ x 1000)	$ 1,193.63	$ -	$ -	$ -	$ -	$ 1,380.46	$ 4,321.29	$ 3,595.82	$ 253.26	$ -	$ 129.00	$ 2,441.72	$ 13,315.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	262,960.3	58,550.6	110,789.1	20,886.0	99,876.9	188,688.8	228,842.6	190,321.3	103,302.0	54,203.7	186,504.2	298,804.2	1,803,729.6
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	338,732.5	122,779.2	193,232.7	106,225.4	190,630.0	278,775.0	323,195.0	278,806.7	178,898.7	126,600.2	255,770.2	368,604.6	2,762,250.0
Market Expense ($ x 1000)	$ 12,740.49	$ 1,895.37	$ 2,999.70	$ 582.04	$ 2,570.12	$ 5,547.56	$ 8,258.82	$ 7,719.40	$ 3,993.09	$ 2,099.46	$ 7,606.31	$ 14,335.24	$ 70,347.6
Market Expense - No Wheeling ($ x 1000)	$ 10,776.35	$ 1,458.04	$ 2,172.18	$ 426.04	$ 1,824.11	$ 4,138.18	$ 6,549.52	$ 6,297.83	$ 3,221.49	$ 1,694.59	$ 6,213.25	$ 12,103.37	$ 56,874.9
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 16,534.6	$ 5,903.0	$ 7,424.8	$ 5,378.1	$ 6,606.0	$ 8,585.7	$ 11,027.2	$ 10,640.4	$ 7,215.5	$ 6,213.8	$ 11,408.2	$ 17,538.9	$ 114,476.0
Storage													
Black Mesa Battery Energy (MWh)	(1,227.44)	(900.47)	(1,075.9)	(1,047.1)	(921.2)	(845.0)	(875.6)	(868.6)	(802.0)	(917.4)	(864.4)	(1,131.7)	(11,476.8)
80 MW Grid Battery Energy (MWh)	(2,412.62)	(1,794.82)	(2,122.2)	(2,153.2)	(1,819.3)	(1,676.2)	(1,750.9)	(1,726.9)	(1,650.3)	(1,770.2)	(1,704.3)	(2,220.7)	(22,801.6)

11 MW Grid Battery Energy (MWh)	(324.41)	(242.61)	(271.0)	(274.4)	(246.2)	(220.2)	(241.1)	(233.0)	(215.1)	(243.3)	(223.2)	(272.3)	(3,006.6)
Total Storage (MWh)	(3,964.5)	(2,937.9)	(3,469.1)	(3,474.7)	(2,986.6)	(2,741.4)	(2,867.6)	(2,828.4)	(2,667.4)	(2,931.0)	(2,791.8)	(3,624.8)	(37,285.0)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	39.6	50,738.5	20,492.2	63,657.6	29,358.0	8,483.3	5,633.9	4,930.9	19,090.1	56,015.8	7,140.4	574.1	266,154.3
Revenue ($ x 1000)	$ 3.0	$ 2,267.2	$ 793.3	$ 2,562.8	$ 1,028.8	$ 339.0	$ 279.3	$ 287.6	$ 869.7	$ 2,549.3	$ 395.1	$ 36.5	$ 11,411.6
Revenue - No Wheeling ($ x 1000)	$ 2.7	$ 1,888.2	$ 640.3	$ 2,087.3	$ 809.5	$ 275.6	$ 237.2	$ 250.8	$ 727.1	$ 2,130.9	$ 341.7	$ 32.2	$ 9,423.6
Total Energy	1,428,850.93	1,234,421.48	1,217,841.85	1,168,470.77	1,353,816.91	1,602,921.83	1,927,228.26	1,763,858.88	1,373,841.60	1,218,929.60	1,251,370.20	1,476,225.00	17,017,777.31
Total NPSE	$ 56,617.6	$ 32,748.1	$ 27,964.5	$ 22,012.4	$ 25,992.3	$ 46,811.8	$ 63,898.6	$ 65,528.8	$ 42,438.6	$ 38,217.1	$ 50,947.6	$ 66,279.2	$ 541,444.8

Wheeling 3-Year Average	$ 7.47

IPCO NORMALIZED POWER SUPPLY EXPENSES FOR JANUARY 1, 2023 -- DECEMBER 31, 2023 (Multiple Gas Prices/37 Hydro Year Conditions)
AURORA Developed Results - 2023 General Rate Case

2017

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	778,184.8	1,022,708.0	1,079,181.1	1,061,274.0	1,204,380.1	1,166,144.6	713,872.3	680,956.5	619,576.2	466,433.4	368,689.2	467,311.9	9,628,712.1
Bridger Coal													
Energy (MWh)	125,632.9	38,795.8	35,298.2	39,650.6	39,246.2	77,683.8	140,123.2	191,297.6	185,950.2	202,467.5	225,735.4	250,686.7	1,552,567.88
Expense ($ x 1000)	$ 3,929.37	$ 1,401.15	$ 1,331.11	$ 1,446.11	$ 1,674.38	$ 2,840.42	$ 4,657.79	$ 6,130.71	$ 5,956.57	$ 6,452.01	$ 7,101.85	$ 7,840.28	$ 50,761.75
Valmy													
Energy (MWh)	121.5	-	-	-	-	-	22,908.3	27,299.1	2,264.6	40.5	37,229.8	43,401.2	133,265.0
Expense ($ x 1000)	$ 5.75	$ -	$ -	$ -	$ -	$ -	$ 1,077.72	$ 1,271.64	$ 106.32	$ 1.92	$ 1,740.19	$ 2,015.27	$ 6,218.8
Bridger Gas													
Energy (MWh)	-	23,737.1	-	8,142.2	1,831.6	4,394.9	22,704.8	44,428.9	23,632.0	19,221.5	-	-	148,092.9
Expense ($ x 1000)	$ -	$ 789.42	$ -	$ 330.70	$ 64.93	$ 172.76	$ 980.49	$ 1,952.48	$ 948.84	$ 764.93	$ -	$ -	$ 6,004.6
Langley Gulch													
Energy (MWh)	156,070.5	-	-	-	-	33,152.4	215,567.2	216,268.8	211,569.2	221,311.8	185,432.3	158,400.6	1,397,772.8
Expense ($ x 1000)	$ 11,042.79	$ -	$ -	$ -	$ -	$ 906.54	$ 6,677.16	$ 7,203.48	$ 6,488.26	$ 6,885.50	$ 11,806.10	$ 14,739.78	$ 65,749.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	101,468.4	27,143.6	125.1	-	164.8	3,323.3	132,225.2
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,892.42	$ 1,409.23	$ 6.43	$ -	$ 16.89	$ 465.85	$ 6,790.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	58,788.1	9,396.6	974.1	-	1,701.2	10,697.6	81,557.6
Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,870.65	$ 493.08	$ 44.06	$ -	$ 174.47	$ 1,477.45	$ 5,059.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 1,207.53	$ 1,111.14	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 1,173.82	$ 1,207.53	$ 14,259.18
Purchased Power (Excluding PURPA)													
Market Energy (MWh)	104,972.7	4,423.4	824.6	63.8	3,422.6	39,253.3	260,399.7	206,353.2	65,453.0	58,768.6	194,209.3	293,536.9	1,231,681.1
Elkhorn Wind Energy (MWh)	33,655.9	23,622.4	25,682.3	26,290.7	26,451.8	24,654.7	28,961.0	25,307.9	19,486.0	21,189.8	26,456.0	30,502.9	312,261.4
Jackpot Solar Energy (MWh)	9,761.6	12,439.8	20,980.2	25,354.8	31,549.0	34,708.5	36,414.5	33,679.6	27,194.7	19,783.6	10,259.4	8,031.8	270,157.5
Neal Hot Springs Energy (MWh)	20,096.4	15,853.7	18,705.2	15,814.5	13,671.9	11,869.0	8,876.4	10,296.2	12,240.4	16,278.9	19,852.6	19,805.0	183,360.2
Raft River Geothermal Energy (MWh)	8,791.6	7,114.1	8,829.8	7,638.0	6,890.9	6,180.3	6,877.6	7,094.9	6,759.6	7,674.5	8,509.7	8,512.9	90,873.8
Black Mesa Solar Energy (MWh)	3,466.7	5,198.5	8,246.0	10,241.4	12,189.5	12,673.8	13,223.1	12,106.7	9,915.9	7,469.8	4,188.3	2,947.8	101,867.5
Total Energy Excl. PURPA (MWh)	180,744.8	68,651.9	83,268.1	85,403.2	94,175.7	129,339.5	354,752.2	294,838.6	141,049.7	131,165.2	263,475.3	363,337.3	2,190,201.5
Market Expense ($ x 1000)	$ 4,177.37	$ 127.36	$ 21.15	$ 1.86	$ 82.48	$ 1,060.03	$ 7,891.84	$ 6,984.75	$ 2,035.11	$ 1,929.78	$ 6,972.14	$ 12,392.65	$ 43,676.5
Market Expense - No Wheeling ($ x 1000)	$ 3,393.29	$ 94.32	$ 14.99	$ 1.38	$ 56.92	$ 766.83	$ 5,946.83	$ 5,443.43	$ 1,546.22	$ 1,490.82	$ 5,521.53	$ 10,200.12	$ 34,476.7
Elkhorn Wind Expense ($ x 1000)	$ 2,451.00	$ 1,720.31	$ 1,870.32	$ 1,914.63	$ 1,926.36	$ 1,795.48	$ 2,109.09	$ 1,843.05	$ 1,419.07	$ 1,543.15	$ 1,926.66	$ 2,221.38	$ 22,740.5
Jackpot Solar Expense ($ x 1000)	$ 212.37	$ 270.64	$ 456.44	$ 551.61	$ 686.37	$ 755.10	$ 792.22	$ 732.72	$ 591.64	$ 430.40	$ 223.20	$ 174.74	$ 5,877.5
Neal Hot Springs Expense ($ x 1000)	$ 2,480.08	$ 1,956.49	$ 2,308.39	$ 1,951.65	$ 1,687.23	$ 1,464.73	$ 1,095.43	$ 1,270.65	$ 1,510.57	$ 2,008.96	$ 2,449.99	$ 2,444.11	$ 22,628.3
Raft River Geothermal Expense ($ x 1000)	$ 614.80	$ 497.49	$ 617.48	$ 534.13	$ 481.89	$ 432.19	$ 480.95	$ 496.15	$ 472.71	$ 536.68	$ 595.09	$ 595.32	$ 6,354.9
Black Mesa Solar Expense ($ x 1000)													$ -
Total Expense Excl. PURPA ($ x 1000)	$ 9,151.5	$ 4,539.3	$ 5,267.6	$ 4,953.4	$ 4,838.8	$ 5,214.3	$ 10,424.5	$ 9,786.0	$ 5,540.2	$ 6,010.0	$ 10,716.5	$ 15,635.7	$ 92,077.8
Storage													
Black Mesa Battery Energy (MWh)	(1,155.67)	(1,073.31)	(1,391.9)	(1,200.8)	(1,054.6)	(858.3)	(887.1)	(875.2)	(811.0)	(935.2)	(863.7)	(1,075.5)	(12,182.3)
80 MW Grid Battery Energy (MWh)	(2,254.15)	(2,224.37)	(2,852.1)	(2,383.6)	(2,130.6)	(1,708.3)	(1,753.7)	(1,736.8)	(1,614.5)	(1,835.9)	(1,689.8)	(2,135.1)	(24,319.0)

11 MW Grid Battery Energy (MWh)	(320.93)	(288.66)	(363.6)	(323.1)	(277.6)	(227.4)	(243.3)	(235.2)	(221.5)	(258.1)	(215.0)	(274.5)	(3,248.8)
Total Storage (MWh)	(3,730.8)	(3,586.3)	(4,607.7)	(3,907.5)	(3,462.8)	(2,794.0)	(2,884.2)	(2,847.3)	(2,646.9)	(3,029.1)	(2,768.5)	(3,485.2)	(39,750.1)
Black Mesa Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11 MW Grid Battery Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response													
Energy (MWh)	-	-	-	-	-	1,653.33	8,800.00	8,106.67	800.00	-	-	-	19,360.0
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Solar													
Energy (MWh)	36.15	33.52	74.93	73.10	88.61	102.22	98.16	88.94	75.20	68.73	47.60	24.77	811.9
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PURPA													
Energy (MWh)	202,761.41	225,952.50	246,142.34	288,603.09	313,597.50	318,696.17	295,393.89	281,711.20	234,049.41	222,197.34	177,903.16	183,093.65	2,990,101.66
Expense ($ x 1000)	$ 15,288.7	$ 17,307.7	$ 13,620.6	$ 15,939.5	$ 16,234.2	$ 22,444.1	$ 24,159.5	$ 23,255.9	$ 17,326.7	$ 15,857.5	$ 15,856.3	$ 17,158.0	$ 214,448.8
Surplus Sales													
Energy (MWh)	10,970.4	141,871.0	221,515.1	310,767.9	296,040.0	125,451.2	4,364.2	14,830.3	43,577.0	40,947.1	6,240.1	566.9	1,217,141.1
Revenue ($ x 1000)	$ 588.9	$ 4,334.3	$ 5,899.8	$ 8,927.3	$ 7,340.2	$ 3,453.8	$ 217.4	$ 776.3	$ 1,824.7	$ 1,622.4	$ 292.5	$ 30.4	$ 35,308.0
Revenue - No Wheeling ($ x 1000)	$ 507.0	$ 3,274.6	$ 4,245.3	$ 6,606.1	$ 5,128.9	$ 2,516.7	$ 184.8	$ 665.6	$ 1,499.2	$ 1,316.5	$ 245.9	$ 26.1	$ 26,216.7
Total Energy	1,428,850.92	1,234,421.50	1,217,841.85	1,168,470.80	1,353,816.89	1,602,921.79	1,927,228.26	1,763,858.90	1,373,841.58	1,218,929.60	1,251,370.21	1,476,224.98	17,017,777.28
Total NPSE	$ 40,036.8	$ 20,814.4	$ 15,527.0	$ 14,916.2	$ 16,679.7	$ 29,298.2	$ 56,730.4	$ 51,933.7	$ 35,766.5	$ 35,557.0	$ 48,293.6	$ 60,509.5	$ 435,154.3

Wheeling 3-Year Average	$ 7.47

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF IDAHO POWER COMPANY FOR	)	CASE NO. IPC-E-23-11
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC SERVICE	)	
IN THE STATE OF IDAHO AND FOR	)	
ASSOCIATED REGULATORY ACCOUNTING	)	
TREATMENT.	)	
	)	

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

KELLEY NOE

Q. Please state your name and business address.

A. My name is Kelley Noe. My business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Regulatory Consultant.

Q. Please describe your educational background.

A. In May of 2004, I received a Bachelor of Business Administration in Finance from Boise State University. I have also attended electric utility ratemaking courses, including "The Basics: Practical Regulatory Training for the Electric Industry," a course offered through New Mexico State University's Center for Public Utilities as well as "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Electric Utilities Consultants, Inc.

Q. Please describe your business experience with Idaho Power Company.

A. In September 2006, I accepted a position at Idaho Power as a Financial Analyst in the Finance Department. My primary duties included performing credit reviews on current and prospective transmission customers as well as providing the financial support for Grid Operations, Planning, and Operations Analysis and Development. In October 2010, I accepted a Regulatory Analyst II position within the Regulatory Affairs department of the Company. In 2015, I was promoted to Senior Regulatory Analyst, and in 2020 was promoted to my current position, Regulatory Consultant. My duties as a Regulatory Consultant include gathering, analyzing, and coordinating data from various departments throughout the Company required for preparing jurisdictional separation studies, developing complex cost-related studies, and the analysis of strategic regulatory issues.

Q. What is the scope of your testimony in this proceeding?

A. I am sponsoring testimony to summarize the development of the system revenue requirement for purposes of forecasting the Company's rate base, revenues, and expenses for the 2023 Test Year, as well as, quantifying the Idaho Jurisdictional Revenue Requirement resulting from the Jurisdictional Separation Study ("JSS") for the twelve months ending December 31, 2023.

Q. Have you prepared exhibits for this proceeding?

A. Yes. I am offering the following exhibits:

1. Exhibit No. 31, Major Plant Additions Annualized for 2023

2. Exhibit No. 32, Depreciation & Amortization Annualizing Adjustments

3. Exhibit No. 33, Summary of Payroll-Related

Annualizing Adjustments

4. Exhibit No. 34, Development of System Revenue Requirement

5. Exhibit No. 35, Jurisdictional Separation Study - Idaho Revenue Requirement.

Development of the System Revenue Requirement

Q. Could you briefly summarize how the Company developed its 2023 Test Year?

A. Yes. As described in the Direct Testimonies and Exhibits of Company Witnesses Ms. Paula Jeppsen and Mr. Matthew Larkin, the development of the 2023 Test Year begins with 2022 actual financial data ("2022 Actuals"). The 2022 Actuals were adjusted to reflect currently approved ratemaking adjustments and amounts previously deferred related to wildfire mitigation ("WFM") in 2022 to arrive at 2022 adjusted actual financial information ("2022 Base"). The 2022 Base was then adjusted to reach 2023 forecasted financial levels ("2023 Unadjusted Test Year"). After the 2023 Unadjusted Test Year figures were compiled, they were provided to me as the starting point for the development of the Company's total 2023 Test Year figures used in this filing.

Q. Were any additional adjustments made to the 2023 Unadjusted Test Year amounts to reach the Company's total 2023 Test Year figures?

A. Yes. Exhibits 31 through 33 illustrate the annualizing adjustments used to develop the total 2023 rate base and net income figures used in the Company's 2023 Test Year.

Q. Please describe the role of annualizing adjustments in this filing.

A. At Mr. Larkin's direction, I performed several annualizing adjustments to amounts that are incurred within the Test Year but need to be reflected for the full year on an ongoing basis.

Q. Please describe the annualizing adjustments made for "Major Plant Additions."

A. "Major Plant Additions," illustrated in Exhibit No. 31, are defined as those investments exceeding $8 million that will close to the Company's electric plant-in-service accounts during the calendar year 2023. A month-by-month forecast of 2023 electric plant-in-service and the 13-month average balances provided by Ms. Jeppsen form the beginning point for the analysis. Annualizing adjustments are applied only to the 2023 plant additions that qualify as Major Plant Additions to establish the amount of investment that would have been recorded had the plant been in service throughout the entire year.

As reflected in Exhibit No. 31, the difference between what had been forecast for these investments in the initial analysis compared to the annualized forecast, as illustrated in column 8 – Net Annualizing Adjustments, is the $161,434,512 annualizing adjustment for the Company's electric plant-in-service investment in this filing. Additional annualizing adjustments associated with Major Plant Additions include $498,233 in property taxes (column 11 – Annual Composite Property Tax) and $75,269 in property insurance (column 13 – Annual Insurance Expense). Because none of the Major Plant Additions were attributable to load growth not already accounted for within the load forecast (see Summary on Exhibit No. 31), an imputed revenue adjustment was not required.

Q.   How did you determine the Depreciation & Amortization Annualizing Adjustments?

A.   Depreciation and amortization expenses presented in Exhibit No. 32 are forecast on a month-by-month basis during 2023 and summarized in the column entitled "Forecasted Depreciation Expense" (column 4). The expenses for December 2023 are multiplied by twelve to calculate the "Annualized Depreciation Expense" (column 3). The difference between these two columns equals the "Annualizing Adjustment" (column 5) of $8,884,245 depreciation expense and $95,740 amortization expense. Adjustments of $4,442,123 to Accumulated Depreciation and $47,870 to Accumulated Amortization, illustrated as the

“Reserve Adjustment” (column 6), are conventionally computed as half the expense amounts.

Q. Were there any additional labor-related annualizing adjustments?

A. Yes. As set forth in Exhibit No. 33, Summary of Payroll-Related Annualizing Adjustments, there are two additional labor-related annualizing adjustments in this filing totaling $9,561,383.

The first adjustment utilizes 2022 actual labor data as a proxy to annualize 2023 payroll and reflects an entire year of expense at that year-end level. Because the method applied to forecast the 2023 Operations and Maintenance (“O&M”) labor expense (detailed in the Direct Testimony of Mr. Larkin) provided only a forecast of the annual 2023 O&M labor expense, a December labor expense amount from which a conventional annualizing labor adjustment could be calculated was not known. Therefore, an annualizing adjustment based upon actual 2022 labor was calculated and used as a proxy to adjust the O&M labor total for the 2023 Test Year. After applying the Company’s O&M and benefit loading percentages, the annualizing adjustment is $3,683,272.

The second adjustment of $5,878,111 reflects the projected 2024 salary structure adjustment of 3 percent. This adjustment was applied to the annualized 2023 payroll and has been adjusted by the Company’s O&M and benefit loading percentages.

Q. How is Exhibit No. 34, Development of System Revenue Requirement organized?

A. Exhibit No. 34 provides the development of the adjusted total electric system rate base and net income for the test year ending December 31, 2023.

The first set of data, displayed in column 3 “2022 Actual”, is the unadjusted 2022 actual results of operations provided by Ms. Jeppsen. The adjustments proposed by the Company for purposes of developing the 2023 adjusted total electric system combined rate base and net income are shown in columns 4 (“2022 Actual Adjustments”), 6 (“Forecast Adjustments”), and 8 (“Annualizing Adjustment”), with the total system adjusted test year rate base, expenses, and revenues summarized in column 9. The proposed adjustments and resulting base amounts are set forth in columns 4 through 8 and result in the 2023 test year data set in column 9, described more fully as follows:

(1) Column 4, titled “2022 Actual Adjustments”, was provided by Ms. Jeppsen and Company Witness Ms. Jessica Brady. It reflects currently approved regulatory adjustments that should be applied to the 2022 actual results prior to applying methods to adjust to 2023 levels, as well as adjustments to reflect WFM related expenses

deferred in 2022 thus resetting 2022 actual WFM-related O&M to what it would have been absent the deferral;

(2) Column 5, titled “2022 Base” is the adjusted base to which the methods to create a 2023 test year were applied;

(3) Column 6, titled “Forecast Adjustments”, reflects the results of the various methods from the Forecast Methodology Manual sponsored by Mr. Larkin and detailed in his testimony, that were used to adjust totals from the 2022 Base to a 2023 Unadjusted Test Year.

(4) Column 7, titled “2023 Unadjusted Test Year”, includes the resulting dataset once the standard regulatory adjustments and various methods were applied;

(5) Column 8, titled “Annualizing Adjustment”, includes standard annualizing adjustments, to reflect changes that occur within the test year, but need to be incorporated for the full year on an ongoing basis. All annualizing adjustments included in this filing were discussed earlier in my testimony.

(6) Column 9, titled “2023 Test Year”, is the resulting dataset for the 2023 test year (twelve months ending December 31, 2023).

Q. How did you develop the total combined rate base for the 2023 Test Year?

A. Page two of Exhibit No. 34 summarizes the development of rate base components for the 2023 Test Year. The total combined rate base, based on actual, unadjusted 2022 results was $3,870,331,388 (column 3, line 67). After adjustments, the total combined rate base for the 2023 Test Year increases to $4,092,522,974 (column 9, line 67).

Q. Have you prepared any exhibits that detail the total system net income?

A. Yes. Page two of Exhibit No. 34 also includes the development of the total system net income for the twelve months ending December 31, 2023. Operating revenues are summarized on line 73. Total operating expenses are summarized on line 84.

Idaho Jurisdictional Revenue Requirement

Q. Have you prepared an exhibit that sets forth the Idaho jurisdictional revenue deficiency?

A. Yes. I prepared Exhibit No. 35 titled "Jurisdictional Separation Study – Idaho Revenue Requirement" consisting of 36 pages.

Q. Please describe what is included in the Jurisdictional Separation Study report.

A. Exhibit No. 35 is the complete Jurisdictional Separation Study report detailing the allocation of each component of rate base, operating revenues, and expenses by Federal Energy Regulatory Commission ("FERC") account resulting in the Idaho jurisdictional revenue deficiency.

The JSS is organized as follows:

- Summary of Results
- Table 1 - Electric Plant in Service;
- Table 2 - Accumulated Provision for Depreciation (and Amortization);
- Table 3 - Additions & Deductions to Rate Base;
- Table 4 - Operating Revenues;
- Table 5 - Operation & Maintenance Expenses;
- Table 6 - Depreciation & Amortization Expense;
- Table 7 - Taxes Other Than Income Taxes;
- Table 8 - Regulatory Debits & Credits;
- Table 9 - Income Taxes;
- Table 10 - Calculation of Federal Income Tax;
- Table 11 – Oregon State Income Tax;
- Table 12 – Idaho State Income Tax and Other State Income Tax;
- Table 13 - Development of Labor Related Allocator;
- Table 14 - Allocation Factors;
- Table 15 - Allocation Factors-Ratios.

Q. Please discuss the methodology used to jurisdictionally separate costs in the preparation of this study.

A. A three-step process was used to separate costs among jurisdictions. The three steps are functionalization, classification, and allocation of costs. In all three steps, recognition was given to the way in which costs are incurred by relating these costs to utility operations.

Q. Would you please briefly explain what each of the three steps (functionalization, classification, and allocation) entails?

A. Functionalized costs are identified with utility operating functions such as generation, transmission, and distribution. Individual plant items are examined and, where possible, the associated investment costs are assigned to one or more operating functions. Classification groups the functionalized costs into three categories: demand-related, energy-related, and customer-related.

Once the Company's total system costs are classified and assigned to the appropriate function, they are allocated among jurisdictions.

The process of allocation is one of apportioning the total system cost among jurisdictions by introducing allocation factors into the process. An allocation factor is an array of numbers which specifies the jurisdictional value as a share or percent of the total system quantity. For example, in the case of energy-related costs, the allocation factor is annual jurisdictional energy use, adjusted for losses, divided by the total system energy use.

Once individual accounts have been allocated to the various jurisdictions, it is possible to summarize these into total utility rate base and net income by jurisdiction. The results are stated in a summary form to measure adequacy of revenues for the jurisdiction under consideration. The measure of adequacy is typically the rate of return earned on rate base, which is compared to the requested rate of return.

Q. Is the methodology used to separate costs by jurisdiction and calculate the Idaho jurisdictional revenue requirement in the present case primarily the same methodology utilized in the Company’s last general rate case, Case No. IPC-E-11-08?

A. Yes.

Q. How have the various functional plant and cost items been allocated?

A. The average of the twelve monthly coincident peak demands was used to allocate the demand-related costs. This allocation method has been used by the Company for at least two decades in all of its filings requiring a jurisdictional separation study. This allocation method was adopted by this Commission and also accepted by the Public Utility Commission of Oregon. The demand-related allocation factors used in the study are designated as D10, D11, D12 and D60. The respective values used in these demand allocation factors are shown at line numbers 1048 through 1051 of Exhibit No. 35.

Q. How were the energy-related expenses allocated among jurisdictions?

A. Energy-related expenses were allocated based on normalized jurisdictional kilowatt-hour sales and adjusted for losses to establish energy requirements at the generation level. The energy-related allocation factors used in the study are designated as E10 and E99. The respective values used in these energy allocation factors are shown on lines 1054 and 1055 of Exhibit No. 35.

Q. What was the method by which you allocated customer-related costs?

A. The principal customer-related expenses which required allocation, were meter reading (FERC Account 902) and customer accounting and billing (FERC Account 903). These accounts were allocated based upon a review of actual costs to read meters and prepare monthly bills or statements.

Q. What method was used to allocate certain labor-related administrative and general expenses?

A. In accordance with FERC-approved procedures, administrative and general expenses were allocated in accordance with functionalized wages and salaries. These labor-related allocation factors are shown on lines 848 through 1043 of Exhibit No. 35.

Q. Please describe the derivation of the 2023 total system allocation factors used in this case.

A. The allocation factors in the 2023 JSS were based on either the 2022 year-end data or 2023 forecast data. The capacity or demand–related allocation factors (D10, D11, D12 and D60) were created using the 2022 demand ratios from the load research analysis applied to the 2023 test year energy. The energy-related allocation factors were the 2023 test year load at generation level (E10) and at customer level (E99). This data is prepared by the Company’s Load Research and Forecasting Department and is further described in workpapers filed by Mr. Larkin.

Q. Briefly describe the manner in which you allocated electric plant-in-service as shown in Table 1 of Exhibit No. 35.

A. Both production and transmission plant were allocated to each jurisdiction based on the average of the twelve-monthly coincident peaks. Distribution plant, unless otherwise noted, was directly allocated to Idaho based on 2022 actual jurisdictional data.

Q. Please describe the manner in which you allocated general electric plant-in-service.

A. General plant was allocated on the same basis as the sum of the allocated investments in production, transmission, and distribution plant.

Q. How have you allocated the accumulated provision for depreciation and amortization of other utility plant?

A. Accumulated provision for depreciation and amortization totals, as shown on Table 2 of Exhibit No. 35, were allocated based on the related plant account as allocated in Table 1.

Q. How did you allocate other additions to or deductions from rate base?

A. Table 3 of Exhibit No. 35 details the allocation of all other additions to or deductions from rate base. Deductions from rate base include customer advances for construction that were directly assigned to customers by jurisdiction, and the accumulated deferred income taxes that were allocated by plant, customer advances for construction, and labor. Additions to rate base include: (1) materials and supplies which were functionalized and allocated by the respective plant allocators, (2) fuel inventory that was allocated on the basis of energy, (3) components of Idaho Energy Resources Co. (“IERCo”) the Company’s fuel subsidiary, which were allocated based on energy, and (4) Commission-ordered deferred investment was either directly assigned to a specific jurisdiction or allocated based on demand.

All rate base items, with the exception of other deferred programs, reflect a 13-month average of ending balances or average of year-end balances.

Q. How did you assign the firm operating revenues to each jurisdiction?

A. Table 4 of Exhibit No. 35 contains the firm operating revenues directly assigned to each jurisdiction for the test year (twelve months ending December 31, 2023). Opportunity sales and financial losses are also credited to each jurisdiction in proportion to generation-level energy use.

Other operating revenues were either allocated among jurisdictions in a manner that offset related allocations of rate base or, where a particular revenue item could be associated with a specific jurisdiction, directly assigned.

Lastly, at the direction of Mr. Larkin I included the transfer adjustments for both the Power Cost Adjustment ("PCA") mechanism and the Energy Efficiency rider labor in this table to more accurately reflect the net impact to customers in the revenue requirement calculation. The Direct Testimony of Mr. Pawel Goralski details the quantification of the revenue transfer from the PCA, and Mr. Larkin details the quantification of the Energy Efficiency rider offset.

Q. How are operation and maintenance expenses allocated to each jurisdiction?

A. The allocation of each O&M expense is detailed on Table 5 of Exhibit No. 35. In general, the basis for each allocation is identifiable with the source code listed on Exhibit No. 35. Demands are identified by a source code beginning with a “D” prefix, energy use is identified by a source code beginning with an “E” prefix, related plant is identified by a line number source code, and customer-weighted allocation factors begin with a “CW” prefix.

Q. In what manner are supervision and engineering expenses treated throughout the allocation of operation and maintenance expenses?

A. For the applicable expense account in each functional group, the labor component was separately allocated in accordance with the detail provided on Table 13 of Exhibit No. 35. The total of allocated labor in each functional group became the basis for the allocation of supervision and engineering expense. Total allocated labor expense served the additional purpose of allocating employee pension and other labor-related taxes and expenses. Table 13 of Exhibit No. 35 details the development of all the labor-related allocation factors used in this study.

Q. How have you allocated depreciation expense and amortization of limited term plant?

A. The allocation of depreciation expense and amortization of limited term plant is set forth in Table 6 of Exhibit No. 35. These expenses were identified by type of production plant or by primary plant account for other functional plant groups and allocated consistent with the related plant account.

Q. How did you approach the allocation of taxes other than income taxes?

A. As set forth in Table 7 of Exhibit No. 35, taxes other than income taxes were treated individually and allocated in a manner consistent with the bases by which the respective taxes are assessed.

Q. How did you address the amortization of regulatory debits and credits?

A. Table 8 of Exhibit No. 35 details the amortization of regulatory debits and credits and were directly assigned to the appropriate jurisdiction.

Q. Does the JSS report detail how deferred income taxes and investment tax credit adjustments were allocated?

A. Yes. The expenses shown on Table 9 of Exhibit No. 35 consist of deferred income taxes and the investment tax credit adjustments, which were allocated based on the Company’s plant investment and net income before tax adjustments. State and federal income tax liabilities are also summarized on Table 9. The income taxes shown on Tables 10 through 12 were obtained from the Company's Tax Department.

Q. How were federal and state income taxes, shown on Tables 10 through 12 of Exhibit No. 35, allocated in the JSS?

A. The respective tax bases were developed, and taxes were calculated directly for each jurisdiction. Operating income before taxes represents adjusted operating revenues less all adjusted operating expenses treated heretofore with the exception of deferred income taxes and investment tax credits. Adjusted interest expense was allocated by the combined rate base to develop net operating income before taxes. As discussed earlier in this testimony, subsequent additions to or deductions from the respective tax bases were allocated to each jurisdiction by aligning it with its causation or fundamental association. In this manner, taxable income for each jurisdiction was developed and the appropriate tax rate was applied. Final tax amounts result after the allocation of adjustments and tax credits. All details relating to the calculation of federal, Oregon, Idaho, and other state income taxes are found on Tables 10, 11, and 12.

Q. What is the purpose of Tables 13 through 15 of

Exhibit No. 35?

A. Tables 13 through 15 of Exhibit No. 35 list the principal allocation factors used in the JSS and the respective jurisdictional values for each allocation factor. Table 15 lists the ratios of the principal allocation factors included in Table 14.

Q. How was the Idaho jurisdictional revenue deficiency developed?

A. The summary of JSS results is presented on pages one and two of Exhibit No. 35. The development of the Idaho jurisdictional revenue deficiency is presented in the column entitled “Idaho Retail” on page one of Exhibit No. 35. As discussed further in Mr. Larkin’s testimony, due to the approved balancing account mechanisms for recovery of coal-related costs at the Jim Bridger Power Plant (“Bridger”) and North Valmy Power Plant (“Valmy”), a true revenue deficiency cannot be computed until the levelized revenue requirement associated with these mechanisms is accounted for in the calculation. While the approved revenue collection is embedded in the Firm Jurisdictional Sales contained on line 9 of the JSS, the corresponding costs were removed from the determination of the Company’s non-levelized revenue requirement as described by Mr. Larkin. Therefore, JSS summary information contained on lines 6 through 38 will understate required revenues because it only reflects currently approved revenues related to non-fuel coal recovery, not the corresponding currently approved costs.

Q. How was the Idaho jurisdictional revenue requirement calculated before adjusting for Bridger and Valmy?

A. The pre-adjusted Idaho consolidated operating income of $287,151,546 (line 26) resulted in a return on rate base of 7.34 percent (line 27). Based upon the Company's request for an overall rate of return of 7.702 percent provided by Company Witness Mr. Brian Buckham, the Company's Idaho jurisdictional net income should be $301,346,128, as shown on line 32. The resulting earnings deficiency is $14,194,582, as shown on line 33. Inclusion of Hells Canyon Relicensing Construction Work in Progress allowed in the Company's most recent rate case (Case No. IPC-E-11-08) of $6,537,444, as shown on line 34, increases the earnings deficiency to $20,732,026, as shown on line 35. Once again, as discussed previously, this figure is understated and must be adjusted because it includes Bridger and Valmy coal-related revenue recovery without reflecting the corresponding costs.

Q. What net-to-gross or incremental income tax factor did you use in developing the Idaho jurisdictional revenue deficiency?

A. The composite incremental tax multiplier of 1.347 is the assimilation of the federal effective tax rate, an Idaho composite tax rate, an Oregon composite tax rate, and an additional state composite tax rate. This value, as shown on line 37 of Exhibit No. 35, was provided by the Company's Tax Department and is included in my workpapers.

Q. Why were the Valmy and Bridger revenue requirements added to the Idaho Jurisdictional revenue deficiency calculation contained on lines 40 and 41 of the JSS?

A. To determine the true revenue deficiency, at Mr. Larkin's direction the levelized revenue requirements for Valmy and Bridger were added to the Idaho Jurisdictional revenue requirement calculation on lines 40 and 41, respectively. The addition of these amounts appropriately includes the costs authorized for recovery through these mechanisms to align with the currently approved retail rates embedded in the 2023 Test Year retail revenue forecast. In addition, as discussed in Mr. Larkin's testimony, the Company is requesting recovery of the full annual levelized revenue requirement approved in Case No. IPC-E-21-17 and amortization of previously deferred levelized revenue requirement amount.

Q. Were any other adjustments included in the revenue requirement calculation?

A. Yes, at the direction of Company Witness Mr. Timothy Tatum, I calculated the Idaho jurisdictional revenue requirement of the 120 MW of battery storage that is scheduled to come online in 2023 and included that result as a reduction to the Idaho jurisdictional revenue requirement in an effort to mitigate the increase to customers ("Battery Mitigation") by adding the investment tax credits to the current accumulated deferred investment tax credit ("ADITC") mechanism and adjusting the yearly cap. The impact of this mitigation option is reflected on line 42 of the JSS and is discussed fully in the testimony of Mr. Tatum.

Q. What is the resulting Idaho jurisdictional revenue deficiency including the Battery Mitigation?

A. The result of the Jurisdictional Separation Study, as shown on page one, line 43 of Exhibit No. 35, indicates a total revenue deficiency of $111.3 million for the Idaho retail jurisdiction. This represents a required 8.61 percent increase in normalized Idaho jurisdictional revenues.

Q. Does this conclude your testimony?

A. Yes, it does.

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DECLARATION OF KELLEY NOE

I, Kelley Noe, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Kelley Noe. I am employed by Idaho Power Company as Regulatory Consultant in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 31-35 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibit are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: ____________________
Kelley Noe

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

NOE, DI
TESTIMONY

EXHIBIT NO. 31

Idaho Power Company
Major Plant Additions Annualized for 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	Project Type	Project ID	Description	In Service Date	Annualized Plant	Adjustment for Plant Est to Close 2023	Net Annualizing Adjustments	State	Annual Composite Property Tax Rate	Annual Property Tax	Annual Insurance Rate Per $1000	Annual Insurance Expense
	Thermal:											
1	21	JBRG160152	Jim Bridger Flu Gas Desulfurization (FGD) pond	September, 2023	13,451,811	4,139,019	9,312,792	WY	0.166%	15,459	$ 0.46625	4,342
2	21	JBRG160152	Jim Bridger Flu Gas Desulfurization (FGD) pond	October, 2023	90,660	20,922	69,738	WY	0.166%	116	$ 0.46625	33
3	21	JBRG160152	Jim Bridger Flu Gas Desulfurization (FGD) pond	November, 2023	59,908	9,217	50,692	WY	0.166%	84	$ 0.46625	24
4	21	JBRG160152	Jim Bridger Flu Gas Desulfurization (FGD) pond	December, 2023	187,014	14,386	172,628	WY	0.166%	287	$ 0.46625	80
5	21 Total				13,789,393	4,183,543	9,605,851			15,946		4,479
	Hydro Production:											
6	23	LSPR140001	LSPR U13 Turbine and Generator Refurbishment	December, 2023	13,407,405	1,031,339	12,376,066	ID	0.324%	40,098	$ 0.46625	5,770
7	23 Total				13,407,405	1,031,339	12,376,066			40,098		5,770
	Other Production:											
8	24	HMWY220002	2023 Peak Capacity Resource HMWY - 80MW	July, 2023	80,131,922	36,983,964	43,147,958	ID	0.324%	139,799	$ 0.46625	20,118
9		HMWY220002	2023 Peak Capacity Resource HMWY - 80MW	August, 2023	16,244,744	6,247,978	9,996,765	ID	0.324%	32,390	$ 0.46625	4,661
10		HMWY220002	2023 Peak Capacity HMWY Degradation Mitigation	July, 2023	14,627,794	6,751,290	7,876,504	ID	0.324%	25,520	$ 0.46625	3,672
11		HMWY220002	2023 Peak Capacity HMWY Degradation Mitigation	August, 2023	2,965,419	1,140,546	1,824,874	ID	0.324%	5,913	$ 0.46625	851
12		BMSU220002	2023 Peak Capacity Resource BMSU - 40MW	October, 2023	48,426,919	11,175,443	37,251,476	ID	0.324%	120,695	$ 0.46625	17,369
13		BMSU220002	2023 Peak Capacity Resource BMSU - 40MW	November, 2023	2,021,173	310,950	1,710,223	ID	0.324%	5,541	$ 0.46625	797
14		BMSU220002	2023 Peak Capacity BMSU Degradation Mitigation	October, 2023	10,004,104	2,308,639	7,695,465	ID	0.324%	24,933	$ 0.46625	3,588
15		BMSU220002	2023 Peak Capacity BMSU Degradation Mitigation	November, 2023	378,461	58,225	320,236	ID	0.324%	1,038	$ 0.46625	149
16		DNPR160002	Danskin major overhaul, upgrade, and inspection	June, 2023	28,805,688	15,510,755	13,294,933	ID	0.324%	43,076	$ 0.46625	6,199
17	24 Total				203,606,223	80,487,789	123,118,434			398,904		57,404
	General Land and Buildings:											
18	51	CHQB220012	New Distribution Center at Boise Bench	December, 2023	17,695,340	1,361,180	16,334,160	ID	0.265%	43,286	$ 0.46625	7,616
19	51 Total				17,695,340	1,361,180	16,334,160			43,286		7,616
20	Total				$ 248,498,362	$ 87,063,851	$ 161,434,512			$ 498,233		$ 75,269

Summary

2023 Peak Capacity Resource HMWY - 80MW	$ 96,376,665	$ 43,231,942	$ 53,144,723	Capacity resource to meet summer peak beginning 2023
2023 Peak Capacity HMWY Degradation Mitigation	17,593,213	7,891,835	9,701,378	Capacity resource to meet summer peak beginning 2023
2023 Peak Capacity Resource BMSU - 40MW	50,448,092	11,486,393	38,961,699	Capacity resource to meet summer peak beginning 2023
2023 Peak Capacity BMSU Degradation Mitigation	10,382,565	2,366,864	8,015,701	Capacity resource to meet summer peak beginning 2023
Danskin major overhaul, upgrade, and inspection	28,805,688	15,510,755	13,294,933	Routine maintenance/Reliability
New Distribution Center at Boise Bench	17,695,340	1,361,180	16,334,160	New facility to house current materials and supplies inventory and prepare for growth in inventory levels
LSPR U13 Turbine and Generator Refurbishment	13,407,405	1,031,339	12,376,066	Replace existing turbines/Refurbish existing generators
Jim Bridger Flu Gas Desulfurization (FGD) pond	13,789,393	4,183,543	9,605,851	Compliance required by the Coal Combustion Rules established by the EPA
Total	$ 248,498,362	$ 87,063,851	$ 161,434,512	

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

NOE, DI
TESTIMONY

EXHIBIT NO. 32

Idaho Power Company
Depreciation & Amortization Annualizing Adjustments
Estimated 2023

(1) Account	(2) Account Description	(3) Annualized Depreciation Expense	(4) Forecasted Depreciation Expense		(5) Annualizing Adjustment	(6) Reserve Adjustment
30100	Organization					
30200	Franchises and Consents	1,543,543	1,491,028		52,515	26,258
30300	Miscellaneous Intangible Plant	4,422,755	4,379,530		43,225	21,612
TOTAL	**INTANGIBLE PLANT- AMORT**	5,966,298	5,870,558		95,740	47,870
31020	Land and Land Rights	2,382	2,382		0	0
31100	Structures and Improvements	563,201	559,244		3,957	1,979
31200	Boiler Plant Equipment	6,584,388	6,171,214		413,174	206,587
31400	Turbogenerator Units	1,878,471	1,864,516		13,956	6,978
31500	Accessory electric Equipment	225,323	223,222		2,101	1,051
31600	Misc Power Plant Equipment	351,009	347,339		3,671	1,835
TOTAL	**STEAM PRODUCTION PLANT**	9,604,775	9,167,916		436,859	218,429
33000	Land and Land Rights				0	0
33100	Structures and Improvements	5,609,656	5,492,451		117,204	58,602
33200	Reservoirs, Dams, Waterways	5,235,046	5,210,790		24,256	12,128
33300	Waterwheel, Turbines, Generato	10,598,627	10,491,523		107,104	53,552
33400	Accessory Electric Equipment	2,439,434	2,424,611		14,823	7,412
33500	Misc Power Plant Equipment	937,450	931,562		5,888	2,944
33600	Roads, Railroads and Bridges	538,928	536,914		2,014	1,007
TOTAL	**HYDRO PRODUCTION PLANT**	25,359,140	25,087,850		271,290	135,645
34000	LAND AND LAND RIGHTS					
34100	Structures and Improvements	4,190,693	4,098,677		92,016	46,008
34200	Fuel Holders, Producers, Acces	277,392	277,508		(116)	(58)
34300	Prime Movers	10,925,820	10,712,761		213,059	106,530
34400	Generators	1,596,062	1,594,750		1,312	656
34500	Accessory Electric Equipment	2,758,832	2,741,883		16,949	8,475
34600	Misc Power Plant Equipment	239,317	231,735		7,582	3,791
TOTAL	**OTHER PRODUCTION PLANT**	19,988,116	19,657,314		330,803	165,401
35020	Land and Land Rights	416,355	412,063	*	4,292	2,146
35200	Structures and Improvements	1,920,891	1,908,869		12,023	6,011
35300	Station Equipment	10,291,818	10,197,461		94,357	47,178
35400	Towers and Fixtures	2,890,165	2,839,713		50,452	25,226
35500	Poles and Fixtures	6,155,439	6,030,005		125,434	62,717
35600	Overhead Conductors, Devices	4,098,377	4,042,321		56,057	28,028
35900	Roads and Trails	2,693	2,693		0	0
TOTAL	**TRANSMISSION PLANT**	25,775,739	25,433,125		342,614	171,307
36022	ROW Renewal Cost	30,928	29,976		952	476
36100	Structures and improvements	1,393,285	1,328,548		64,736	32,368
36200	Station Equipment	6,761,927	6,491,454		270,474	135,237
TOTAL	**SUBSTATION EQUIPMENT**	8,186,140	7,849,978		336,162	168,081
363	Battery Storage	8,740,027	2,791,254		5,948,773	2,974,387
TOTAL	BATTERY STORAGE	8,740,027	2,791,254		5,948,773	2,974,387
36400	Poles, Towers and Fixtures	6,652,506	6,508,229		144,277	72,138
36500	Overhead Conductors, Devices	3,687,824	3,622,711		65,113	32,556
36600	Underground Conduit	1,327,818	1,296,790		31,029	15,514
36700	Underground Conductors, Device	7,931,228	7,666,237		264,991	132,496
36800	Line Transformers	14,560,366	14,287,602		272,764	136,382
36900	Services	1,163,810	1,156,367		7,443	3,722
37000	Meters	5,908,929	5,762,874		146,055	73,028
37100	Installations, Cust Premises	193,380	193,303		77	39
37300	Street Lighting, Signal System	217,455	208,871		8,584	4,292
TOTAL	**DISTRIBUTION LINES**	41,643,317	40,702,983		940,333	470,167
38900	Land and Land Rights					
39000	Structures and Improvements	3,366,802	3,314,372		52,430	26,215
39100	Office Furniture, Equipment	6,992,274	6,957,077		35,197	17,598
39200	Transportation Equipment	72,444	72,444		0	0
39300	Stores Equipment	227,417	215,091		12,326	6,163
39400	Tools, Shop, Garage Equipment	808,645	797,039		11,606	5,803
39500	Laboratory Equipment	781,567	774,650		6,918	3,459
39600	Power Operated Equipment	0	0		0	0
39700	Communication Equipment	5,615,068	5,492,570		122,498	61,249
39800	Miscellaneous Equipment	860,793	824,356		36,437	18,218
TOTAL	**GENERAL EQUIPMENT PLANT**	18,725,011	18,447,600		277,411	138,706
DEPR ON ELECTRIC PLANT IN SERVICE		158,022,265	149,138,020	#	8,884,245	4,442,123
	Amortization of Disallowed Costs	(296,299)	(296,299)		0	0
TOTAL DEPRECIATION & AMORTIZATION		163,692,264	154,712,279		8,979,985	4,489,993

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

NOE, DI
TESTIMONY

EXHIBIT NO. 33

Idaho Power Company
Summary of Adjustments to 2023
Operating Expenses

Line No.	Source Page		(1) Amount
1	A	Operating Payroll - Annualizing Adjustment	$ 3,683,272
2	A	2024 Salary Structure Adjustment	5,878,111
3		**Total Adjustments**	$9,561,383

Idaho Power Company
Detail of Adjustments to 2022
Operating Expenses

A

Line No.	Source Page				(1) Amount
		1) Operating Payroll (Various accts)			
1	1	Actual Total Year 2022 ST Payroll			216,374,243
2	1	Actual December 2022 ST Payroll	17,032,740		
3		Annualized December 2022 (Dec multiplied by 13)	x 13		221,425,623
4		Increase Over 2022 Actual			5,051,380
5	1	O&M and DSM Percentage			50.55%
6		Annualized December 2023 O&M and DSM ST payroll			2,553,589
7	2	Benefit Loading Percent			44.24%
8		Annualized December 2023 O&M and DSM ST w/Loading		$	3,683,272
		2) 2023 Operating Payroll SSA (Various accts)			
9		2023 O&M & DSM Labor Forecast		$	192,253,748
10	A	Annualized December 2023 O&M & DSM ST w/Loading			3,683,272
11		Total 2023 O&M & DSM Labor		$	195,937,021
12		2024 Structured Salary Adjustment	3.00%		5,878,111
13		Adjustment to Operating Expense		$	5,878,111

2022 ACTUAL for 111 - STRAIGHT TIME PAYROLL
By Account and Month

Source Page 1

	1 - O&M	2 - Construction	3 - Other	· Other - DSM - 2542	242 Accounts	Total
Jan,22	7,429,209	4,154,126	752,295	160,632	3,924,111	16,420,373
Feb,22	8,794,660	5,032,082	867,709	194,712	1,589,994	16,479,157
Mar,22	8,303,169	4,823,048	830,033	168,452	2,306,017	16,430,719
Apr,22	12,628,549	7,654,701	1,336,388	273,478	2,732,281	24,625,397
May,22	8,451,566	5,108,183	865,730	199,361	1,790,870	16,415,710
Jun,22	7,830,267	4,621,191	798,777	169,626	3,063,271	16,483,131
Jul,22	7,720,804	4,759,981	757,015	178,905	3,235,456	16,652,161
Aug,22	8,291,104	5,072,560	849,313	185,654	2,360,010	16,758,642
Sep,22	12,433,425	7,640,932	1,284,408	259,517	3,595,978	25,214,259
Oct,22	8,478,135	5,368,094	873,005	188,031	1,969,829	16,877,094
Nov,22	7,929,170	4,946,804	824,824	174,548	3,109,515	16,984,861
Dec,22	8,761,272	5,283,430	891,192	177,924	1,918,922	**17,032,740**
	107,051,329	64,465,132	10,930,688	2,330,839	31,596,255	**216,374,243**
% of Total	**49.48%**	29.79%	5.05%	1.08%	14.60%	100.00%

Annualized December (x 13)	221,425,623
Annualized Payroll Growth Factor	**2.33%**

2022 Actual Benefits Loading %

Source Page 2

	Feb-23	
111 - STRAIGHT TIME PAYROLL	16,700,119	
131 - INDIRECT BENEFIT LOADING	5,670,955	33.96%
140 - TAXES-EMPLOYER PAID	1,717,020	10.28%
Subtotal loading	**7,387,975**	**44.24%**

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

NOE, DI
TESTIMONY

EXHIBIT NO. 34

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
4	***SUMMARY OF RESULTS***							
5	**RATE OF RETURN UNDER PRESENT RATES**							
6	TOTAL COMBINED RATE BASE	3,870,331,388	(286,529,338)	3,583,802,050	351,776,405	3,935,578,455	156,944,519	4,092,522,974
7								
8	OPERATING REVENUES							
9	FIRM JURISDICTIONAL SALES	1,372,758,056	(221,241,806)	1,151,516,250	195,160,431	1,346,676,681	0	1,346,676,681
10	SYSTEM OPPORTUNITY SALES	145,798,279	(94,063,126)	51,735,153	(22,699,973)	29,035,180	0	29,035,180
11	OTHER OPERATING REVENUES	118,571,647	(29,285,298)	89,286,349	80,336	89,366,685	0	89,366,685
12	TOTAL OPERATING REVENUES	1,637,127,982	(344,590,231)	1,292,537,752	172,540,794	1,465,078,546	0	1,465,078,546
13	OPERATING EXPENSES							
14	OPERATION & MAINTENANCE EXPENSES	1,103,041,646	(392,959,807)	710,081,839	210,696,109	920,777,948	9,636,652	930,414,600
15	DEPRECIATION EXPENSE	163,581,418	(24,584,889)	138,996,530	9,845,191	148,841,721	8,884,245	157,725,966
16	AMORTIZATION OF LIMITED TERM PLANT	5,266,930	0	5,266,930	618,646	5,885,576	95,740	5,981,316
17	TAXES OTHER THAN INCOME	28,701,676	(1,596,793)	27,104,883	4,559,257	31,664,141	498,234	32,162,375
18	REGULATORY DEBITS/CREDITS	1,753,318	(173,640)	1,579,678	1,865,167	3,444,845	0	3,444,845
19	PROVISION FOR DEFERRED INCOME TAXES	(10,828,286)	0	(10,828,286)	(7,044,937)	(17,873,223)	0	(17,873,223)
20	INVESTMENT TAX CREDIT ADJUSTMENT	5,825,740	0	5,825,740	19,188,438	25,014,178	0	25,014,178
21	FEDERAL INCOME TAXES	32,209,533	4,643,860	36,853,393	6,099,210	42,952,604	(3,773,276)	39,179,328
22	STATE INCOME TAXES	11,819,161	1,411,508	13,230,668	(15,537,797)	(2,307,129)	(1,146,892)	(3,454,021)
23	TOTAL OPERATING EXPENSES	1,341,371,137	(413,259,761)	928,111,376	230,289,285	1,158,400,661	14,194,704	1,172,595,364
24	OPERATING INCOME	295,756,846	68,669,530	364,426,376	(57,748,491)	306,677,885	(14,194,704)	292,483,181
25	ADD: IERCO OPERATING INCOME	8,782,042	0	8,782,042	(6,940,924)	1,841,118	0	1,841,118
26	CONSOLIDATED OPERATING INCOME	304,538,888	68,669,530	373,208,418	(64,689,415)	308,519,003	(14,194,704)	294,324,299
27	RATE OF RETURN UNDER PRESENT RATES	7.87%		10.41%				7.19%
28								
29	**DEVELOPMENT OF REVENUE REQUIREMENTS**							
30	RATE OF RETURN @ **10.4%** ROE	7.702%	7.702%	7.702%	7.702%	7.702%	7.702%	7.702%
31								
32	RETURN	298,092,924	(22,068,490)	276,024,434	27,093,819	303,118,253	12,087,867	315,206,119
33	EARNINGS DEFICIENCY	(6,445,964)	(90,738,020)	(97,183,984)	91,783,233	(5,400,750)	26,282,570	20,881,820
34	ADD: CWIP (RELICENSING)	6,815,472	0	6,815,472	0	6,815,472	0	6,815,472
35	EARNINGS DEFICIENCY WITH CWIP	369,508	(90,738,020)	(90,368,512)	91,783,233	1,414,722	26,282,570	27,697,292
36								
37	NET-TO-GROSS TAX MULTIPLIER	1.347	1.347	1.347	1.347	1.347	1.347	1.347
38	REVENUE DEFICIENCY	497,587	(122,189,632)	(121,692,045)	123,597,138	1,905,092	35,392,635	37,297,728
39								
40	ADD: VALMY LEVELIZED REVENUE REQUIREMENT	0	0	0	36,957,501	36,957,501	0	36,957,501
41	ADD: BRIDGER LEVELIZED REVENUE REQUIREMENT	0	0	0	67,579,174	67,579,174	0	67,579,174
42	LESS: BATTERY ADITC MITIGATION	0	0	0	21,149,854	21,149,854	0	21,149,854
43	**REVENUE DEFICIENCY WITH VALMY AND BRIDGER**	**497,587**	**(122,189,632)**	**(121,692,045)**	**206,983,958**	**85,291,913**	**35,392,635**	**120,684,548**
44								
45	FIRM JURISDICTIONAL RETAIL REVENUES	1,372,758,056	(221,241,806)	1,151,516,250	195,160,431	1,346,676,681	0	1,346,676,681
46	PERCENT INCREASE REQUIRED							8.96%
47								
48	SALES AND WHEELING REVENUES REQUIRED	1,373,255,643	(343,431,438)	1,029,824,205	402,144,389	1,431,968,594	35,392,635	1,467,361,229

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
49	***SUMMARY OF RESULTS***							
50	**DEVELOPMENT OF RATE BASE COMPONENTS**							
51	ELECTRIC PLANT IN SERVICE							
52	INTANGIBLE PLANT	94,248,072	0	94,248,072	10,972,838	105,220,910	0	105,220,910
53	PRODUCTION PLANT	2,612,211,078	(728,213,069)	1,883,998,009	94,967,748	1,978,965,757	35,276,850	2,014,242,607
54	TRANSMISSION PLANT	1,325,332,196	(9,281,041)	1,316,051,155	30,141,720	1,355,473,916	0	1,355,473,916
55	DISTRIBUTION PLANT	2,112,875,054	0	2,112,875,054	200,700,828	2,313,575,882	109,823,501	2,423,399,384
56	GENERAL PLANT	476,150,325	0	476,150,325	24,760,007	500,910,332	16,334,160	517,244,492
57	TOTAL ELECTRIC PLANT IN SERVICE	6,620,816,724	(737,494,110)	5,883,322,614	370,824,182	6,254,146,797	161,434,512	6,415,581,308
58	LESS: ACCUM PROVISION FOR DEPRECIATION	2,505,846,014	(484,022,808)	2,021,823,206	59,406,156	2,081,229,362	4,442,122	2,085,671,484
59	AMORT OF OTHER UTILITY PLANT	40,225,910	0	40,225,910	1,641,727	41,867,637	47,870	41,915,507
60	NET ELECTRIC PLANT IN SERVICE	4,074,744,800	(253,471,301)	3,821,273,499	309,776,300	4,131,049,798	156,944,519	4,287,994,318
61	LESS: CUSTOMER ADV FOR CONSTRUCTION	13,139,360	0	13,139,360	(5,697,395)	7,441,965	0	7,441,965
62	LESS: ACCUM DEFERRED INCOME TAXES	404,274,757	0	404,274,757	(22,134,252)	382,140,505	0	382,140,505
63	ADD : PLT HLD FOR FUTURE+ACQUIS ADJ	7,773,040	(501,610)	7,271,430	1,607,122	8,878,552	0	8,878,552
64	ADD : WORKING CAPITAL	120,944,517	(18,125,045)	102,819,472	12,470,781	115,290,253	0	115,290,253
65	ADD : CONSERVATION+OTHER DFRD PROG.	54,682,328	(14,431,382)	40,250,946	(1,679,383)	38,571,563	0	38,571,563
66	ADD : SUBSIDIARY RATE BASE	29,600,820	0	29,600,820	1,769,938	31,370,758	0	31,370,758
67	TOTAL COMBINED RATE BASE	3,870,331,388	(286,529,338)	3,583,802,050	351,776,405	3,935,578,455	156,944,519	4,092,522,974
68								
69	**DEVELOPMENT OF NET INCOME COMPONENTS**							
70	OPERATING REVENUES							
71	SALES REVENUES	1,518,556,336	(315,304,933)	1,203,251,403	172,460,458	1,375,711,861	0	1,375,711,861
72	OTHER OPERATING REVENUES	118,571,647	(29,285,298)	89,286,349	80,336	89,366,685	0	89,366,685
73	TOTAL OPERATING REVENUES	1,637,127,982	(344,590,231)	1,292,537,752	172,540,794	1,465,078,546	0	1,465,078,546
74	OPERATING EXPENSES							
75	OPERATION & MAINTENANCE EXPENSES	1,103,041,646	(392,959,807)	710,081,839	210,696,109	920,777,948	9,636,652	930,414,600
76	DEPRECIATION EXPENSE	163,581,418	(24,584,889)	138,996,530	9,845,191	148,841,721	8,884,245	157,725,966
77	AMORTIZATION OF LIMITED TERM PLANT	5,266,930	0	5,266,930	618,646	5,885,576	95,740	5,981,316
78	TAXES OTHER THAN INCOME	28,701,676	(1,596,793)	27,104,883	4,559,257	31,664,141	498,234	32,162,375
79	REGULATORY DEBITS/CREDITS	1,753,318	(173,640)	1,579,678	1,865,167	3,444,845	0	3,444,845
80	PROVISION FOR DEFERRED INCOME TAXES	(10,828,286)	0	(10,828,286)	(7,044,937)	(17,873,223)	0	(17,873,223)
81	INVESTMENT TAX CREDIT ADJUSTMENT	5,825,740	0	5,825,740	19,188,438	25,014,178	0	25,014,178
82	FEDERAL INCOME TAXES	32,209,533	4,643,860	36,853,393	6,099,210	42,952,604	(3,773,276)	39,179,328
83	STATE INCOME TAXES	11,819,161	1,411,508	13,230,668	(15,537,797)	(2,307,129)	(1,146,892)	(3,454,021)
84	TOTAL OPERATING EXPENSES	1,341,371,137	(413,259,761)	928,111,376	230,289,285	1,158,400,661	14,194,704	1,172,595,364
85	OPERATING INCOME	295,756,846	68,669,530	364,426,376	(57,748,491)	306,677,885	(14,194,704)	292,483,181
86	ADD: IERCO OPERATING INCOME	8,782,042	0	8,782,042	(6,940,924)	1,841,118	0	1,841,118
87	CONSOLIDATED OPERATING INCOME	304,538,888	68,669,530	373,208,418	(64,689,415)	308,519,003	(14,194,704)	294,324,299
88								
89	**NET POWER SUPPLY COSTS:**							
90	ACCT 447/SURPLUS SALES + LOSS REV	(145,798,279)	94,063,126	(51,735,153)	22,699,973	(29,035,180)	0	(29,035,180)
91	ACCT 501/FUEL-THERMAL PLANTS	105,551,917	2,951,263	108,503,180	(42,980,180)	65,523,000	0	65,523,000
92	ACCT 547/FUEL - DIESEL+OTHER	124,647,878	(91,280,315)	33,367,563	86,286,112	119,653,675	0	119,653,675
93	ACCT 555/NON-FIRM PURCHASES+LOSSES	335,687,514	(273,080,921)	62,606,593	36,858,428	99,465,021	0	99,465,021
94	ACCT 555/DEMAND RESPONSE INCENTIVES	8,311,328	2,940,937	11,252,265	(1,012,262)	10,240,003	0	10,240,003
95	ACCT 555/CSPP PURCHASES	189,033,362	(55,179,493)	133,853,869	80,594,886	214,448,755	0	214,448,755
96	SUBTOTAL	617,433,720	(319,585,403)	297,848,317	182,446,957	480,295,274	0	480,295,274
97	ACCT 536/WATER FOR POWER	(9,801)	2,390,398	2,380,597	(2,380,597)	0	0	0
98	ACCT 565/TRANS OF ELECTRICTY BY OTHERS	11,322,964	(5,867,009)	5,455,955	4,807,184	10,263,139	0	10,263,139
99	TOTAL NET POWER SUPPLY COSTS	628,746,882	(323,062,013)	305,684,869	184,873,544	490,558,413	0	490,558,413
100	**OTHER O&M**							
101	TOTAL O&M EXPENSES	1,103,041,646	(392,959,807)	710,081,839	210,696,109	920,777,948	9,636,652	930,414,600
102	LESS: ACCT 501/FUEL - THERMAL PLANTS	(105,551,917)	(2,951,263)	(108,503,180)	42,980,180	(65,523,000)	0	(65,523,000)
103	ACCT 547/FUEL - DIESEL+OTHER	(124,647,878)	91,280,315	(33,367,563)	(86,286,112)	(119,653,675)	0	(119,653,675)
104	ACCT 555/NON-FIRM PURCHASES+LOSSES	(335,687,514)	273,080,921	(62,606,593)	(36,858,428)	(99,465,021)	0	(99,465,021)
105	ACCT 555/DEMAND RESPONSE INCENTIVES	(8,311,328)	(2,940,937)	(11,252,265)	1,012,262	(10,240,003)	0	(10,240,003)
106	ACCT 555/CSPP PURCHASES	(189,033,362)	55,179,493	(133,853,869)	(80,594,886)	(214,448,755)	0	(214,448,755)
107	SUBTOTAL	339,809,646	20,688,722	360,498,369	50,949,125	411,447,494	9,636,652	421,084,146
108	ACCT 536/WATER FOR POWER	9,801	(2,390,398)	(2,380,597)	2,380,597	0	0	0
109	ACCT 565/TRANS OF ELECTRICTY BY OTHERS	(11,322,964)	5,867,009	(5,455,955)	(4,807,184)	(10,263,139)	0	(10,263,139)
110	ACCT 416/MERCHANDISING EXPENSE	0	(4,701,875)	(4,701,875)	0	(4,701,875)	0	(4,701,875)
111	NET OTHER O&M	328,496,484	19,463,458	708,458,310	48,522,538	396,482,479	9,636,652	406,119,132

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
112	***TABLE 1-ELECTRIC PLANT IN SERVICE***							
113	INTANGIBLE PLANT							
114	301 - ORGANIZATION	$ 5,703	0	5,703	0	5,703.01	0	5,703
115	302 - FRANCHISES & CONSENTS	44,082,858	0	44,082,858	8,607,466	52,690,323.89	0	52,690,324
116	303 - MISCELLANEOUS	50,159,510	0	50,159,510	2,365,373	52,524,883.01	0	52,524,883
117								
118	TOTAL INTANGIBLE PLANT	94,248,072	0	94,248,072	10,972,838	105,220,910	0	105,220,910
119								
120	PRODUCTION PLANT							
121	310-316 / STEAM PRODUCTION	988,697,347	(728,213,069)	260,484,278	8,369,146	268,853,423	9,605,851	278,459,274
122	330-336 / HYDRAULIC PRODUCTION	1,052,316,966	0	1,052,316,966	39,289,345	1,091,606,311	12,376,066	1,103,982,377
123	340-346 / OTHER PRODUCTION-BASELOAD	400,759,427	0	400,759,427	33,192,819	433,952,246	9,327,906	443,280,152
124	340-346 / OTHER PRODUCTION-PEAKERS	170,437,338	0	170,437,338	14,116,438	184,553,776	3,967,027	188,520,803
125								
126	TOTAL PRODUCTION PLANT	2,612,211,078	(728,213,069)	1,883,998,009	94,967,748	1,978,965,757	35,276,850	2,014,242,607
127								
128	TRANSMISSION PLANT							
129	350 / LAND & LAND RIGHTS - SYSTEM SERVICE	40,030,371	0	40,030,371	1,008,686	41,039,057	0	41,039,057
130	DIRECT ASSIGNMENT	0	0	0	0	0	0	0
131	TOTAL ACCOUNT 350	40,030,371	0	40,030,371	1,008,686	41,039,057	0	41,039,057
132								0
133	352 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	93,682,301	0	93,161,500	7,400,127	100,561,627	0	100,561,627
134	DIRECT ASSIGNMENT	658	0	658	(0)	658	0	658
135	TOTAL ACCOUNT 352	93,682,960	(520,801)	93,162,158	7,400,127	100,562,285	0	100,562,285
136								0
137	353 / STATION EQUIPMENT - SYSTEM SERVICE	470,105,655	0	461,345,415	7,043,183	468,388,599	0	468,388,599
138	DIRECT ASSIGNMENT	111,594	0	111,594	0	111,594	0	111,594
139	TOTAL ACCOUNT 353	470,217,248	(8,760,239)	461,457,009	7,043,183	468,500,193	0	468,500,193
140								0
141	354 / TOWERS & FIXTURES - SYSTEM SERVICE	231,735,124	0	231,735,124	5,423,152	237,158,275	0	237,158,275
142	DIRECT ASSIGNMENT	0	0	0	0	0	0	0
143	TOTAL ACCOUNT 354	231,735,124	0	231,735,124	5,423,152	237,158,275	0	237,158,275
144								
145	355 / POLES & FIXTURES - SYSTEM SERVICE	227,137,112	0	227,137,112	8,895,605	236,032,717	0	236,032,717
146	DIRECT ASSIGNMENT	33,842	0	33,842	0	33,842	0	33,842
147	TOTAL ACCOUNT 355	227,170,953	0	227,170,953	8,895,605	236,066,559	0	236,066,559
148								
149	356 / OVERHEAD CONDUCTORS & DEVICES - SYSTEM SERVICE	262,078,779	0	262,078,779	9,652,007	271,730,786	0	271,730,786
150	DIRECT ASSIGNMENT	26,495	0	26,495	(0)	26,495	0	26,495
151	TOTAL ACCOUNT 356	262,105,274	0	262,105,274	9,652,007	271,757,281	0	271,757,281
152								
153	359 / ROADS & TRAILS - SYSTEM SERVICE	390,266	0	390,266	0	390,266	0	390,266
154	DIRECT ASSIGNMENT	0	0	0	0	0	0	0
155	TOTAL ACCOUNT 359	390,266	0	390,266	0	390,266	0	390,266
156								
157	TOTAL TRANSMISSION PLANT	1,325,332,196	(9,281,041)	1,316,051,155	30,141,720	1,355,473,916	0	1,355,473,916

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
158	***TABLE 1-ELECTRIC PLANT IN SERVICE***							
159								
160	DISTRIBUTION PLANT							
161	360 / LAND & LAND RIGHTS - SYSTEM SERVICE	8,367,229	0	8,367,229	1,234,491	9,601,720	0	9,601,720
162	PLUS: ADJUSTMENT FOR CIAC	430,656	0	430,656	0	430,656	0	430,656
163	NET DISTRIBUTION PLANT + CIAC	8,797,885	0	8,797,885	1,234,491	10,032,376	0	10,032,376
164								
165	361 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	55,682,517	0	55,682,517	6,702,098	62,384,614	0	62,384,614
166	PLUS: ADJUSTMENT FOR CIAC	8,009,324	0	8,009,324	0	8,009,324	0	8,009,324
167	NET DISTRIBUTION PLANT + CIAC	63,691,841	0	63,691,841	6,702,098	70,393,938	0	70,393,938
168								
169	362 / STATION EQUIPMENT - SYSTEM SERVICE	312,968,241	0	312,968,241	30,108,254	343,076,495	0	343,076,495
170	PLUS: ADJUSTMENT FOR CIAC	38,463,951	0	38,463,951	0	38,463,951	0	38,463,951
171	NET DISTRIBUTION PLANT + CIAC	351,432,193	0	351,432,193	30,108,254	381,540,447	0	381,540,447
172								
173	363 / STORAGE BATTERY EQUIPMENT	0	0	0	64,977,034	64,977,034	109,823,501	174,800,536
174	TOTAL BATTERY STORAGE EQUIPMENT	0	0	0	64,977,034	64,977,034	109,823,501	174,800,536
175								
176	364 / POLES, TOWERS & FIXTURES	313,204,206	0	313,204,206	21,031,319	334,235,525	0	334,235,525
177	365 / OVERHEAD CONDUCTORS & DEVICES	155,253,318	0	155,253,318	7,505,273	162,758,591	0	162,758,591
178	366 / UNDERGROUND CONDUIT	52,785,315	0	52,785,315	2,062,798	54,848,113	0	54,848,113
179	367 / UNDERGROUND CONDUCTORS & DEVICES	318,155,073	0	318,155,073	20,722,845	338,877,918	0	338,877,918
180	368 / LINE TRANSFORMERS	704,959,938	0	704,959,938	40,684,879	745,644,817	0	745,644,817
181	369 / SERVICES	67,920,301	0	67,920,301	1,786,963	69,707,265	0	69,707,265
182	370 / METERS	112,940,727	0	112,940,727	3,562,492	116,503,219	0	116,503,219
183	371 / INSTALLATIONS ON CUSTOMER PREMISES	4,931,439	0	4,931,439	(284,580)	4,646,860	0	4,646,860
184	373 / STREET LIGHTING SYSTEMS	5,706,749	0	5,706,749	606,962	6,313,711	0	6,313,711
185								
186	TOTAL DISTRIBUTION PLANT	2,112,875,054	0	2,112,875,054	200,700,828	2,313,575,882	109,823,501	2,423,399,384
187								
188	GENERAL PLANT							
189	389 / LAND & LAND RIGHTS	20,795,674	0	20,795,674	145,123	20,940,797	0	20,940,797
190	390 / STRUCTURES & IMPROVEMENTS	150,450,720	0	150,450,720	10,729,331	161,180,051	16,334,160	177,514,211
191	391 / OFFICE FURNITURE & EQUIPMENT	41,508,346	0	41,508,346	(69,823)	41,438,522	0	41,438,522
192	392 / TRANSPORTATION EQUIPMENT	113,442,849	0	113,442,849	6,471,742	119,914,591	0	119,914,591
193	393 / STORES EQUIPMENT	4,776,648	0	4,776,648	700,209	5,476,857	0	5,476,857
194	394 / TOOLS, SHOP & GARAGE EQUIPMENT	13,003,651	0	13,003,651	2,376,827	15,380,479	0	15,380,479
195	395 / LABORATORY EQUIPMENT	14,904,043	0	14,904,043	9,991	14,914,034	0	14,914,034
196	396 / POWER OPERATED EQUIPMENT	24,983,094	0	24,983,094	2,604,998	27,588,092	0	27,588,092
197	397 / COMMUNICATIONS EQUIPMENT	81,681,573	0	81,681,573	988,969	82,670,542	0	82,670,542
198	398 / MISCELLANEOUS EQUIPMENT	10,603,726	0	10,603,726	802,641	11,406,368	0	11,406,368
199								
200	TOTAL GENERAL PLANT	476,150,325	0	476,150,325	24,760,007	500,910,332	16,334,160	517,244,492
201								
202	TOTAL ELECTRIC PLANT IN SERVICE	6,620,816,724	(737,494,110)	5,883,322,614	370,824,182	6,254,146,797	161,434,512	6,415,581,308

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
203	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***							
204								
205	PRODUCTION PLANT							
206	310-316 / STEAM PRODUCTION	623,502,745	(479,095,034)	144,407,711	6,506,236	150,913,947	218,429	151,132,377
207	330-336 / HYDRAULIC PRODUCTION	488,914,925	0	488,914,925	21,283,505	510,198,431	135,645	510,334,076
208	340-346 / OTHER PRODUCTION-BASELOAD	91,850,187	0	91,850,187	4,041,884	95,892,071	96,942	95,989,012
209	340-346 / OTHER PRODUCTION-PEAKERS	64,863,838	0	64,863,838	2,854,345	67,718,183	68,459	67,786,643
210	TOTAL PRODUCTION PLANT	1,269,131,695	(479,095,034)	790,036,661	(444,409,063)	824,722,632	519,475	825,242,107
211								
212	TRANSMISSION PLANT							
213	350 / LAND & LAND RIGHTS	9,791,827	0	9,791,827	407,383	10,199,209	2,146	10,201,355
214	352 / STRUCTURES & IMPROVEMENTS	33,270,239	(440,425)	32,829,815	1,415,692	34,245,507	6,011	34,251,518
215	353 / STATION EQUIPMENT	124,151,809	(4,487,350)	119,664,459	3,558,295	123,222,754	47,178	123,269,932
216	354 / TOWERS & FIXTURES	77,744,499	0	77,744,499	2,678,088	80,422,588	25,226	80,447,813
217	355 / POLES & FIXTURES	76,949,162	0	76,949,162	3,571,160	80,520,322	62,717	80,583,039
218	356 / OVERHEAD CONDUCTORS & DEVICES	88,360,848	0	88,360,848	1,943,491	90,304,340	28,028	90,332,368
219	359 / ROADS & TRAILS	294,708	0	294,708	2,693	297,401	0	297,401
220	TOTAL TRANSMISSION PLANT	410,563,092	(4,927,775)	405,635,317	13,576,803	419,212,120	171,307	419,383,427
221								
222	DISTRIBUTION PLANT							
223	360 / LAND & LAND RIGHTS	209,604	0	209,604	29,362	238,966	476	239,442
224	361 / STRUCTURES & IMPROVEMENTS	15,872,260	0	15,872,260	874,274	16,746,534	32,368	16,778,902
225	362 / STATION EQUIPMENT	70,090,213	0	70,090,213	2,024,125	72,114,337	135,237	72,249,574
226	363 / STORAGE BATTERY EQUIPMENT	0	0	0	574,099	574,099	2,974,387	3,548,486
227	364 / POLES, TOWERS & FIXTURES	147,716,974	0	147,716,974	(3,061,639)	144,655,335	72,138	144,727,473
228	365 / OVERHEAD CONDUCTORS & DEVICES	57,720,036	0	57,720,036	(1,158,596)	56,561,440	32,556	56,593,997
229	366 / UNDERGROUND CONDUIT	18,655,459	0	18,655,459	209,737	18,865,196	15,514	18,880,710
230	367 / UNDERGROUND CONDUCTORS & DEVICES	101,743,223	0	101,743,223	3,651,254	105,394,477	132,496	105,526,973
231	368 / LINE TRANSFORMERS	196,632,795	0	196,632,795	3,028,561	199,661,355	136,382	199,797,737
232	369 / SERVICES	44,705,081	0	44,705,081	792,160	45,497,241	3,722	45,500,962
233	370 / METERS	38,331,595	0	38,331,595	(1,123,046)	37,208,549	73,028	37,281,576
234	371 / INSTALLATIONS ON CUSTOMER PREMISES	1,404,067	0	1,404,067	(218,331)	1,185,736	39	1,185,775
235	373 / STREET LIGHTING SYSTEMS	1,327,853	0	1,327,853	(1,299,129)	28,724	4,292	33,016
236	TOTAL DISTRIBUTION PLANT	694,409,158	0	694,409,158	4,322,831	698,731,989	3,612,634	702,344,623
237								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
238	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***							
239								
240	GENERAL PLANT							
241	389 / LAND & LAND RIGHTS	0	0	0	0	0	0	0
242	390 / STRUCTURES & IMPROVEMENTS	35,310,027	0	35,310,027	708,449	36,018,476	26,215	36,044,691
243	391 / OFFICE FURNITURE & EQUIPMENT	17,847,072	0	17,847,072	892,967	18,740,039	17,598	18,757,637
244	392 / TRANSPORTATION EQUIPMENT	23,370,984	0	23,370,984	604,738	23,975,721	0	23,975,721
245	393 / STORES EQUIPMENT	1,274,650	0	1,274,650	187,779	1,462,429	6,163	1,468,592
246	394 / TOOLS, SHOP & GARAGE EQUIPMENT	4,462,602	0	4,462,602	558,376	5,020,979	5,803	5,026,782
247	395 / LABORATORY EQUIPMENT	6,642,415	0	6,642,415	214,936	6,857,351	3,459	6,860,809
248	396 / POWER OPERATED EQUIPMENT	5,220,488	0	5,220,488	199,333	5,419,822	0	5,419,822
249	397 / COMMUNICATIONS EQUIPMENT	29,974,046	0	29,974,046	3,418,103	33,392,149	61,249	33,453,398
250	398 / MISCELLANEOUS EQUIPMENT	4,046,093	0	4,046,093	332,170	4,378,263	18,218	4,396,481
251	TOTAL GENERAL PLANT	128,148,377	0	128,148,377	7,116,850	135,265,227	138,706	135,403,933
252								
253	AMORTIZATION OF DISALLOWED COSTS	3,593,693	0	3,593,693	(296,299)	3,297,393	0	3,297,393
254								
255	TOTAL ACCUM PROVISION DEPRECIATION	2,505,846,014	(484,022,808)	2,021,823,206	59,406,156	2,081,229,362	4,442,122	2,085,671,484
256								
257	AMORTIZATION OF OTHER UTILITY PLANT							
258	302/FRANCHISES AND CONSENTS	17,415,328	0	17,415,328	1,336,488	18,751,817	26,258	18,778,074
259	303/MISCELLANEOUS INTANGIBLE PLANT	22,810,581	0	22,810,581	305,239	23,115,820	21,612	23,137,432
260								
261	TOTAL AMORT OF OTHER UTILITY PLANT	40,225,910	0	40,225,910	1,641,727	41,867,637	47,870	41,915,507
262								
263	TOTAL ACCUM PROVISION FOR DEPR							
264	& AMORTIZATION OF OTHER UTILITY PLANT	2,546,071,924	(484,022,808)	2,062,049,116	61,047,883	2,123,096,998	4,489,992	2,127,586,991
265								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
266	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***							0
267								0
268	NET ELECTRIC PLANT IN SERVICE	4,074,744,800	(253,471,301)	3,821,273,499	309,776,300	4,131,049,798	156,944,519	4,287,994,318
269	LESS:							0
270	252 CUSTOMER ADVANCES FOR CONSTRUCTION							
271	POWER SUPPLY	0	0	0	0	0	0	0
272	OTHER	13,139,360	0	13,139,360	(5,697,395)	7,441,965	0	7,441,965
273	TOTAL CUSTOMER ADV FOR CONSTRUCTION	13,139,360		13,139,360	(5,697,395)	7,441,965	0	7,441,965
274								
275	ACCUMULATED DEFERRED INCOME TAXES							
276	190 / ACCUMULATED DEFERRED INCOME TAXES							
277	CUSTOMER ADVANCES FOR CONSTUCTION	(2,158,794)	0	(2,158,794)	352,116	(1,806,678)	0	(1,806,678)
278	OTHER	(16,595,876)	0	(16,595,876)	(1,512,704)	(18,108,580)	0	(18,108,580)
279	TOTAL ACCOUNT 190	(18,754,670)	0	(18,754,670)	(1,160,588)	(19,915,258)	0	(19,915,258)
280	281 / ACCELERATED AMORTIZATION	0		0	0	0	0	0
281	282 / OTHER PROPERTY	422,636,515	0	422,636,515	(26,846,041)	395,790,474	0	395,790,474
282	283 / OTHER	392,912	0	392,912	5,872,377	6,265,289	0	6,265,289
283	TOTAL ACCUM DEFERRED INCOME TAXES	404,274,757	0	404,274,757	(22,134,252)	382,140,505	0	382,140,505
284								
285	NET ELECTRIC PLANT IN SERVICE	3,657,330,683	(253,471,301)	3,403,859,382	337,607,947	3,741,467,328	156,944,519	3,898,411,848
286	ADD:							
287	WORKING CAPITAL							
288	151 / FUEL INVENTORY	15,140,640	7,238,579	22,379,219	2,325,470	24,704,689	0	24,704,689
289	154 & 163 / PLANT MATERIALS & SUPPLIES							
290	PRODUCTION - GENERAL	14,502,120	(172,390)	14,329,729	1,807,299	16,137,028	0	16,137,028
291	TRANSMISSION - GENERAL	13,205,628	(156,979)	13,048,650	1,645,726	14,694,376	0	14,694,376
292	DISTRIBUTION - GENERAL	49,850,143	(592,581)	49,257,562	6,212,478	55,470,039	0	55,470,039
293	OTHER - UNCLASSIFIED	3,850,079	(45,767)	3,804,312	479,809	4,284,121	0	4,284,121
294	TOTAL ACCOUNT 154 & 163	81,407,970	(967,717)	80,440,253	10,145,311	90,585,564	0	90,585,564
295	165 / PREPAID ITEMS							
296	AD VALOREM TAXES	2,887,242	(2,887,242)	0	0	0	0	0
297	OTHER PROD-RELATED PREPAYMENTS	1,846,273	(1,846,273)	0	0	0	0	0
298	INSURANCE	7,961,890	(7,961,890)	0	0	0	0	0
299	PENSION EXPENSE	0	0	0	0	0	0	0
300	PREPAID CONTRACTS	4,697,751	(4,697,751)	0	0	0	0	0
301	MISCELLANEOUS PREPAYMENTS	7,002,751	(7,002,751)	0	0	0	0	0
302	TOTAL ACCOUNT 165	24,395,907	(24,395,907)	0	0	0	0	0
303	WORKING CASH ALLOWANCE	0	0	0	0	0	0	0
304								
305	TOTAL WORKING CAPITAL	120,944,517	(18,125,045)	102,819,472	12,470,781	115,290,253	0	115,290,253
306								
307	NET ELECTRIC PLANT IN SERVICE	3,778,275,200	(271,596,346)	3,506,678,854	350,078,728	3,856,757,582	156,944,519	4,013,702,101

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
308	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***							
309								
310	NET ELECTRIC PLANT IN SERVICE	3,778,275,200	(271,596,346)	3,506,678,854	350,078,728	3,856,757,582	156,944,519	4,013,702,101
311	ADD:							
312	105 / PLANT HELD FOR FUTURE USE							
313	HYDRAULIC PRODUCTION	104,155	(104,155)	0	0	0	0	0
314	TRANS LAND & LAND RIGHTS	2,658,989	93,517	2,752,506	0	2,752,506	0	2,752,506
315	TRANS STRUCTURES & IMPROVEMENTS	166,669	(166,669)	0	0	0	0	0
316	TRANS STATION EQUIPMENT	32,400	(32,400)	0	0	0	0	0
317	DIST LAND & LAND RIGHTS	3,669,456	206,203	3,875,659	1,622,140	5,497,799	0	5,497,799
318	DIST STRUCTURES & IMPROVEMENTS	498,106	(498,106)	0	0	0	0	0
319	DIST STATIONS EQUIPMENT	0	0	0	0	0	0	0
320	GEN LAND & LAND RIGHTS	0	0	0	0	0	0	0
321	GEN STRUCTURES & IMPROVEMENTS	0	0	0	0	0	0	0
322	COMMUNICATION	0	0	0	0	0	0	0
323	TOTAL PLANT HELD FOR FUTURE USE	7,129,775	(501,610)	6,628,165	1,622,140	8,250,305	0	8,250,305
324								
325	114/115 - ASSET EXCHANGE ACQUISITION ADJUSTMENT	643,265	0	643,265	(15,018)	628,247	0	628,247
326								
327	DEFERRED PROGRAMS:							
328	182 / CONSERVATION PROGRAMS							
329	IDAHO DEFERRED CONSERVATION PROGRAMS	0	0	0	0	0	0	0
330	OREGON DEFERRED CONSERVATION PROGRAMS	0	0	0		0	0	0
331	TOTAL CONSERVATION PROGRAMS	0	0	0		0	0	0
332	182&186 / MISC. OTHER REGULATORY ASSETS							
333	CUB FUND INTEREST (OPUC 15-399)	37,154	0	37,154	(37,154)	0	0	0
334	AM. FALLS BOND REFINANCING	135,528	0	135,528	(62,551)	72,977	0	72,977
335	SFAS 87 CAPITALIZED PENSION - OPUC ORDER 10-064	7,000,878	0	7,000,878	(219,697)	6,781,181	0	6,781,181
336	CLOUD COMPUTING - (IPUC Order 34707)	1,616,918	(409,326)	1,207,592	(201,265)	1,006,327	0	1,006,327
337	WILDFIRE MITIGATION (IPUC Order 35077)	27,078,227	(14,022,056)	13,056,171	0	13,056,171	0	13,056,171
338	SIEMENS LTP RATE BASE (IPUC Order 33420)	12,851,571	0	12,851,571	(643,866)	12,207,705	0	12,207,705
339	SIEMENS LTP DEFERRED RATE BASE (IPUC Order 33420)	8,612,494	0	8,612,494	(431,488)	8,181,006	0	8,181,006
340	SIEMENS LTP RATE BASE (OPUC ORDER 15-387)	511,105	0	511,105	(39,316)	471,789	0	471,789
341	SIEMENS LTP DEFERRED RATE BASE (OPUC ORDER 15-387)	138,550	0	138,550	(44,046)	94,504	0	94,504
342	TOTAL OTHER REGULATORY ASSETS	57,982,425	(14,431,382)	43,551,043	(1,679,383)	41,871,660	0	41,871,660
343	186 / MISC. OTHER DEFERRED PROGRAMS	0	0	0	0	0	0	0
344	254 / JIM BRIDGER PLANT END OF LIFE DEPR - OPUC ORDER 12-296	(3,285,386)	0	(3,285,386)	0	(3,285,386)	0	(3,285,386)
345	RECONNECT FEES - (OPUC ADV 16-09)	(14,711)		(14,711)	0	(14,711)	0	(14,711)
346	TOTAL DEFERRED PROGRAMS	54,682,328	(14,431,382)	40,250,946	(1,679,383)	38,571,563	0	38,571,563
347					0			
348	DEVELOPMENT OF IERCO RATE BASE				0			
349	INVESTMENT IN IERCO	23,664,134	0	23,664,134	(8,086,296)	15,577,838	0	15,577,838
350	PREPAID COAL ROYALTIES	834,822	0	834,822	(237,052)	597,770	0	597,770
351	NOTES PAYABLE TO/RECEIVABLE FROM SUBSIDIARY	5,101,864	0	5,101,864	10,093,286	15,195,150	0	15,195,150
352	TOTAL SUBSIDIARY RATE BASE	29,600,820	0	29,600,820	1,769,938	31,370,758	0	31,370,758
353					0			
354	TOTAL COMBINED RATE BASE	3,870,331,388	(286,529,338)	3,583,802,050	351,776,405	3,935,578,455	156,944,519	4,092,522,974

Exhibit No. 34
Case No. IPC-E-23-11
K. Noe, IPC
Page 8 of 29

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
355	***TABLE 4-OPERATING REVENUES***							
356	FIRM ENERGY SALES & OATT REFUNDS							
357	440-448 / RETAIL	1,372,758,056	(221,241,806)	1,151,516,250	18,316,923	1,169,833,173	0	1,169,833,173
358	442 / BASE REVENUE TRANSFER - PCA	0	0	0	173,368,953	173,368,953	0	173,368,953
359	442 / BASE REVENUE TRANSFER - EE RIDER	0	0	0	3,474,555	3,474,555	0	3,474,555
360	447 / SYSTEM OPPORTUNITY SALES	145,798,279	(94,063,126)	51,735,153	(32,559,873)	19,175,280	0	19,175,280
361	447.050 / SURPLUS SALES - TRANSMISSION LOSSES	0	0	0	9,859,900	9,859,900	0	9,859,900
362	TOTAL SALES OF ELECTRICITY	1,518,556,336	(315,304,933)	1,203,251,403	172,460,458	1,375,711,861	0	1,375,711,861
363								
364	OTHER OPERATING REVENUES							
365	415 / MERCHANDISING REVENUES	0	3,911,815	3,911,815	30,623	3,942,438	0	3,942,438
366								
367	449 / OATT TARIFF REFUND							
368	NETWORK	0	0	0	0	0	0	0
369	POINT-TO-POINT	0	0	0	0	0	0	0
370	TOTAL ACCOUNT 449	0	0	0	0	0	0	0
371								
372	451 / MISCELLANEOUS SERVICE REVENUES	4,936,204	0	4,936,204	1,271,884	6,208,088	0	6,208,088
373						0		
374	454 / RENTS FROM ELECTRIC PROPERTY					0		
375	SUBSTATION EQUIPMENT	3,215,758	0	3,215,758	0	3,215,758	0	3,215,758
376	TRANSFORMER RENTALS	17,330	0	17,330	0	17,330	0	17,330
377	LINE RENTALS	0	0	0	0	0	0	0
378	COGENERATION	1,832,348	0	1,832,348	60,186	1,892,534	0	1,892,534
379	DARK FIBER PROJECT	400,000	0	400,000	(400,000)	0	0	0
380	POLE ATTACHMENTS	1,634,179	0	1,634,179	0	1,634,179	0	1,634,179
381	FACILITIES CHARGES	10,470,031	0	10,470,031	(189,692)	10,280,339	0	10,280,339
382	OTHER RENTALS	1,072,002	0	1,072,002	0	1,072,002	0	1,072,002
383	WATER DISTRICT PAYMENTS	185,425	0	185,425	(101,177)	84,248	0	84,248
384	TOTAL ACCOUNT 454	18,827,074	0	18,827,074	(630,683)	18,196,391	0	18,196,391
385								
386	456 / OTHER ELECTRIC REVENUES							
387	TRANSMISSION NETWORK SERVICES - FIRM	10,337,634	0	10,337,634	743,001	11,080,635	0	11,080,635
388	TRANSMISSION NETWORK SERVICES - DIST FACILITIES	792,372	0	792,372	0	792,372	0	792,372
389	TRANSMISSION - POINT-TO-POINT & OTHER	49,667,827	0	49,667,827	(1,334,489)	48,333,338	0	48,333,338
390	PHOTOVOLTAIC STATION SERVICE	0	0	0	0	0	0	0
391	ENERGY EFFICIENCY RIDER	33,197,113	(33,197,113)	0	0	0	0	0
392	STANDBY SERVICE CHARGE	759,997	0	759,997	0	759,997	0	759,997
393	SIERRA PACIFIC USAGE CHARGE	51,764	0	51,764	0	51,764	0	51,764
394	ANTELOPE	0	0	0	0	0	0	0
395	MISCELLANEOUS	1,663	0	1,663	0	1,663	0	1,663
396	TOTAL ACCOUNT 456	94,808,370	(33,197,113)	61,611,257	(591,488)	61,019,769	0	61,019,769
397								
398	TOTAL OTHER OPERATING REVENUES	118,571,647	(29,285,298)	89,286,349	80,336	89,366,685	0	89,366,685
399								
400	TOTAL OPERATING REVENUES	1,637,127,982	(344,590,231)	1,292,537,752	172,540,794	1,465,078,546	0	1,465,078,546

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
401	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							
402	STEAM POWER GENERATION							
403	OPERATION							
404	500 / SUPERVISION & ENGINEERING	632,248	(725,308)	(93,060)	10,451	(82,609)	6,114	(76,495)
405	501 / FUEL	105,551,917	2,951,263	108,503,180	(42,980,180)	65,523,000	0	65,523,000
406	502 / STEAM EXPENSES							
407	LABOR	1,607,750	0	1,607,750	0	1,607,750	0	1,607,750
408	OTHER	7,690,737	(8,836,311)	(1,145,574)	0	(1,145,574)	0	(1,145,574)
409	TOTAL ACCOUNT 502	9,298,487	(8,836,311)	462,176	0	462,176	0	462,176
410	505 / ELECTRIC EXPENSES							
411	LABOR	626,112	0	626,112	0	626,112	0	626,112
412	OTHER	502,354	(1,072,607)	(570,253)	0	(570,253)	0	(570,253)
413	TOTAL ACCOUNT 505	1,128,466	(1,072,607)	55,859	0	55,859	0	55,859
414	506 / MISCELLANEOUS EXPENSES	8,586,280	(8,161,259)	425,021	13	425,034	7	425,042
415	507 / RENTS	229,461	(218,103)	11,358	0	11,358	0	11,358
416	STEAM OPERATION EXPENSES	125,426,860	(16,062,325)	109,364,535	(42,969,716)	66,394,819	6,121	66,400,940
417								
418	MAINTENANCE							
419	510 / SUPERVISION & ENGINEERING	(238,936)	(11,789)	(250,725)	0	(250,725)	0	(250,725)
420	511 / STRUCTURES	2,540,010	(2,414,279)	125,730	0	125,730	0	125,730
421	512 / BOILER PLANT						0	
422	LABOR	3,983,710	0	3,983,710	0	3,983,710	0	3,983,710
423	OTHER	4,790,370	(8,339,764)	(3,549,393)	0	(3,549,393)	0	(3,549,393)
424	TOTAL ACCOUNT 512	8,774,081	(8,339,764)	434,317	0	434,317	0	434,317
425	513 / ELECTRIC PLANT						0	
426	LABOR	1,522,637	0	1,522,637	0	1,522,637	0	1,522,637
427	OTHER	783,882	(2,192,346)	(1,408,464)	0	(1,408,464)	0	(1,408,464)
428	TOTAL ACCOUNT 513	2,306,519	(2,192,346)	114,173	0	114,173	0	114,173
429	514 / MISCELLANEOUS STEAM PLANT	9,592,111	(9,117,301)	474,809	0	474,809	0	474,809
430	STEAM MAINTENANCE EXPENSES	22,973,785	(22,075,479)	898,305	0	898,305	0	898,305
431	TOTAL STEAM GENERATION EXPENSES	148,400,644	(38,137,804)	110,262,840	(42,969,716)	67,293,124	6,121	67,299,245
432								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
433	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							
434	HYDRAULIC POWER GENERATION							
435	OPERATION							
436	535 / SUPERVISION & ENGINEERING	5,758,397	0	5,758,397	455,619	6,214,016	262,711	6,476,728
437	536 / WATER FOR POWER						0	
438	WATER FOR POWER/WCLOUD SEEDING	6,637,301	0	6,637,301	(210,258)	6,427,043	54,646	6,481,689
439	WATER LEASE	(9,801)	2,390,398	2,380,597	(2,380,597)	0	0	0
440	TOTAL ACCOUNT 536	6,627,500	2,390,398	9,017,898	(2,590,855)	6,427,043	54,646	6,481,689
441	537 / HYDRAULIC EXPENSES	18,433,658	124,562	18,558,220	1,237,383	19,795,603	394,497	20,190,100
442	538 / ELECTRIC EXPENSES						0	
443	LABOR	1,510,454	0	1,510,454	0	1,510,454	95,472	1,605,926
444	OTHER	449,278	0	449,278	180,701	629,979	0	629,979
445	TOTAL ACCOUNT 538	1,959,732	0	1,959,732	180,701	2,140,433	95,472	2,235,905
446	539 / MISCELLANEOUS EXPENSES	5,131,195	(227)	5,130,968	386,324	5,517,292	213,191	5,730,483
447	540 / RENTS	303,402	0	303,402	0	303,402	0	303,402
448	HYDRAULIC OPERATION EXPENSES	38,213,885	2,514,733	40,728,618	(330,828)	40,397,790	1,020,517	41,418,307
449								
450	MAINTENANCE							
451	541 / SUPERVISION & ENGINEERING	110,982	0	110,982	9,442	120,425	5,514	125,939
452	542 / STRUCTURES	932,291	0	932,291	64,830	997,121	36,545	1,033,666
453	543 / RESERVOIRS, DAMS & WATERWAYS	454,092	0	454,092	38,359	492,451	16,036	508,487
454	544 / ELECTRIC PLANT						0	
455	LABOR	1,799,397	0	1,799,397	0	1,799,397	111,584	1,910,981
456	OTHER	812,446	0	812,446	198,915	1,011,361	0	1,011,361
457	TOTAL ACCOUNT 544	2,611,843	0	2,611,843	198,915	2,810,758	111,584	2,922,342
458	545 / MISCELLANEOUS HYDRAULIC PLANT	3,919,209	(108)	3,919,101	252,325	4,171,426	138,826	4,310,252
459	HYDRAULIC MAINTENANCE EXPENSES	8,028,417	(108)	8,028,309	563,871	8,592,180	308,505	8,900,686
460	TOTAL HYDRAULIC GENERATION EXPENSES	46,242,302	2,514,625	48,756,927	233,043	48,989,970	1,329,023	50,318,993

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
461	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							
462	OTHER POWER GENERATION							
463	OPERATION							
464	546 / SUPERVISION & ENGINEERING	627,106	0	627,106	55,260	682,366	32,326	714,692
465	547 / FUEL							
466	DIESEL FUEL	10,499	0	10,499	0	10,499	0	10,499
467	OTHER	124,647,878	(91,280,315)	33,367,563	86,286,112	119,653,675	0	119,653,675
468	TOTAL ACCOUNT 547	124,658,377	(91,280,315)	33,378,062	86,286,112	119,664,175	0	119,664,175
469	548 / GENERATING EXPENSES							
470	LABOR	3,234,939	0	3,234,939		3,234,939	198,160	3,433,099
471	OTHER	1,667,550	0	1,667,550	343,492	2,011,042	0	2,011,042
472	TOTAL ACCOUNT 548	4,902,489	0	4,902,489	343,492	5,245,981	198,160	5,444,141
473	549 / MISCELLANEOUS EXPENSES	9,124	0	9,124	43,934	53,058	22,895	75,953
474	550 / RENTS	0	0	0	0	0	0	0
475	OTHER POWER OPER EXPENSES	130,197,096	(91,280,315)	38,916,781	86,728,798	125,645,579	253,381	125,898,960
476								
477	MAINTENANCE							
478	551 / SUPERVISION & ENGINEERING	0	0	0	0	0	0	0
479	552 / STRUCTURES	159,030	0	159,030	5,316	164,346	2,832	167,178
480	553 / GENERATING & ELECTRIC PLANT			0		0	0	
481	LABOR	56,825	0	56,825	0	56,825	3,674	60,498
482	OTHER	870,985	0	870,985	6,648	877,633	0	877,633
483	TOTAL ACCOUNT 553	927,810	0	927,810	6,648	934,458	3,674	938,132
484	554 / MISCELLANEOUS EXPENSES	6,730,628	0	6,730,628	(3,372,657)	3,357,971	29,364	3,387,334
485	OTHER POWER MAINT EXPENSES	7,817,468	0	7,817,468	(3,360,693)	4,456,775	35,869	4,492,644
486	TOTAL OTHER POWER GENERATION EXP	138,014,564	(91,280,315)	46,734,249	83,368,105	130,102,354	289,250	130,391,604
487								
488	OTHER POWER SUPPLY EXPENSE							
489	555.0 / PURCHASED POWER							
490	POWER EXPENSE	332,661,556	(270,054,963)	62,606,593	36,858,428	99,465,021	0	99,465,021
491	OTHER	0	0	0	0	0	0	0
492	TRANSMISSION LOSSES	3,025,958	(3,025,958)	(0)	0	0	0	0
493	DEMAND RESPONSE INCENTIVE	8,311,328	2,940,937	11,252,265	(1,012,262)	10,240,003	0	10,240,003
494	TOTAL 555.0/PURCHASED POWER	343,998,842	(270,139,984)	73,858,858	35,846,166	109,705,024	0	109,705,024
495	555.1 / COGENERATION & SMALL POWER PROD	189,033,362	(55,179,493)	133,853,869	80,594,886	214,448,755	0	214,448,755
496	555/TOTAL	533,032,204	(325,319,477)	207,712,727	116,441,052	324,153,778	0	324,153,778
497	556 / LOAD CONTROL & DISPATCHING EXPENSES	0	0	0	0	0	0	0
498	557 / OTHER EXPENSES							
499	IDAHO POWER COST-RELATED EXPENSES	(99,392,327)	99,392,327	0	0	0	0	0
500	OREGON POWER COST-RELATED EXPENSES	(1,267,068)	1,267,068	0	0	0	0	0
501	OTHER	6,143,689	135,744	6,279,434	473,536	6,752,970	277,021	7,029,991
502	557/TOTAL	(94,515,705)	100,795,139	6,279,434	473,536	6,752,970	277,021	7,029,991
503	TOTAL OTHER POWER SUPPLY EXPENSES	438,516,499	(224,524,338)	213,992,161	116,914,588	330,906,748	277,021	331,183,769
504				0		0		0
505	TOTAL PRODUCTION EXPENSES	771,174,009	(351,427,832)	419,746,177	157,546,020	577,292,197	1,901,415	579,193,611
506	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
507	TRANSMISSION EXPENSES							
508	OPERATION							
509	560 / SUPERVISION & ENGINEERING	3,193,933	(6)	3,193,927	251,886	3,445,814	147,211	3,593,025
510	561 / LOAD DISPATCHING	5,375,576	0	5,375,576	454,303	5,829,880	187,405	6,017,285
511	562 / STATION EXPENSES	2,788,678	(1,453)	2,787,225	214,444	3,001,669	120,418	3,122,087
512	563 / OVERHEAD LINE EXPENSES	1,121,678	0	1,121,678	57,232	1,178,910	26,779	1,205,690
513	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	11,322,964	(5,867,009)	5,455,955	4,807,184	10,263,139	0	10,263,139
514	566 / MISCELLANEOUS EXPENSES	8	0	8	0	8	0	8
515	567 / RENTS	4,855,402	0	4,855,402	0	4,855,402	0	4,855,402
516	TOTAL TRANSMISSION OPERATION	28,658,239	(5,868,468)	22,789,771	5,785,050	28,574,821	481,814	29,056,635
517								
518	MAINTENANCE							
519	568 / SUPERVISION & ENGINEERING	206,814	0	206,814	9,586	216,400	5,608	222,008
520	569 / STRUCTURES	1,907,634	0	1,907,634	151,682	2,059,316	88,601	2,147,917
521	570 / STATION EQUIPMENT	2,611,391	(489)	2,610,902	297,615	2,908,517	144,194	3,052,711
522	571 / OVERHEAD LINES	2,274,243	805,534	3,079,777	116,824	3,196,601	55,564	3,252,166
523	573 / MISCELLANEOUS PLANT	5,113	0	5,113	442	5,555	226	5,781
524	TOTAL TRANSMISSION MAINTENANCE	7,005,196	805,045	7,810,241	576,149	8,386,390	294,193	8,680,583
525								
526	TOTAL TRANSMISSION EXPENSES	35,663,435	(5,063,423)	30,600,012	6,361,199	36,961,211	776,007	37,737,218
527								
528	REGIONAL MARKET EXPENSES							
529	OPERATION							
530	575 / OPER TRANS MKT ADMIN - EIM	686,880	0	686,880	0	686,880	0	686,880
531								
532	TOTAL REGIONAL MARKET EXPENSES	686,880	0	686,880	0	686,880	0	686,880
533								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
534	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							
535	DISTRIBUTION EXPENSES							
536	OPERATION							
537	580 / SUPERVISION & ENGINEERING	5,911,141	3,912	5,915,054	326,853	6,241,907	186,671	6,428,578
538	581 / LOAD DISPATCHING	5,170,071	0	5,170,071	488,757	5,658,828	285,943	5,944,770
539	582 / STATION EXPENSES	1,862,473	(7)	1,862,466	114,459	1,976,925	60,977	2,037,902
540	583 / OVERHEAD LINE EXPENSES	5,421,238	104,989	5,526,227	477,721	6,003,948	214,267	6,218,215
541	584 / UNDERGROUND LINE EXPENSES	4,717,552	4,282	4,721,834	167,229	4,889,062	82,237	4,971,299
542	585 / STREET LIGHTING & SIGNAL SYSTEMS	44,756	0	44,756	2,724	47,479	1,309	48,788
543	586 / METER EXPENSES	5,719,569	(73)	5,719,496	535,125	6,254,621	256,699	6,511,320
544	587 / CUSTOMER INSTALLATIONS EXPENSE	1,095,297	0	1,095,297	88,874	1,184,170	45,823	1,229,993
545	588 / MISCELLANEOUS EXPENSES	4,687,904	(1,010)	4,686,894	323,082	5,009,975	181,825	5,191,800
546	589 / RENTS	741,341	0	741,341	0	741,341	0	741,341
547	TOTAL DISTRIBUTION OPERATION	35,371,341	112,093	35,483,435	2,524,822	38,008,257	1,315,749	39,324,006
548								
549	MAINTENANCE							
550	590 / SUPERVISION & ENGINEERING	11,968	0	11,968	997	12,965	583	13,548
551	591 / STRUCTURES	0	0	0	0	0	0	0
552	592 / STATION EQUIPMENT	4,120,742	(351)	4,120,391	328,264	4,448,655	167,728	4,616,383
553	593 / OVERHEAD LINES	21,931,803	12,695,311	34,627,115	684,800	35,311,914	330,675	35,642,590
554	594 / UNDERGROUND LINES	751,577	18,123	769,700	45,008	814,708	22,649	837,357
555	595 / LINE TRANSFORMERS	94,087	0	94,087	2,717	96,804	1,557	98,361
556	596 / STREET LIGHTING & SIGNAL SYSTEMS	204,924	3,043	207,967	16,003	223,970	7,856	231,826
557	597 / METERS	862,000	0	862,000	77,162	939,163	42,167	981,330
558	598 / MISCELLANEOUS PLANT	123,765	0	123,765	10,116	133,880	5,037	138,917
559	TOTAL DISTRIBUTION MAINTENANCE	28,100,867	12,716,126	40,816,993	1,165,066	41,982,059	578,252	42,560,311
560	TOTAL DISTRIBUTION EXPENSES	63,472,208	12,828,219	76,300,428	3,689,888	79,990,316	1,894,002	81,884,317
561								
562	CUSTOMER ACCOUNTING EXPENSES							
563	901 / SUPERVISION	845,854	0	845,854	75,609	921,463	44,217	965,680
564	902 / METER READING	1,819,788	0	1,819,788	142,617	1,962,406	79,111	2,041,516
565	903 / CUSTOMER RECORDS & COLLECTIONS	15,041,848	0	15,041,848	997,289	16,039,137	569,230	16,608,368
566	904 / UNCOLLECTIBLE ACCOUNTS	3,069,311	198,133	3,267,444	2,514,638	5,782,082	0	5,782,082
567	905 / MISC EXPENSES	(3,031)	0	(3,031)	0	(3,031)	0	(3,031)
568	TOTAL CUSTOMER ACCOUNTING EXPENSES	20,773,771	198,133	20,971,903	3,730,154	24,702,057	692,558	25,394,615
569								
570	CUSTOMER SERVICES & INFORMATION EXPENSES							
571	907 / SUPERVISION	1,009,780	(15,995)	993,785	87,883	1,081,669	51,408	1,133,077
572	908 / CUSTOMER ASSISTANCE						0	
573	SYSTEM CONSERVATION	314,424	0	314,424	0	314,424	0	314,424
574	OTHER	40,168,748	(33,197,948)	6,970,800	4,110,142	11,080,942	291,521	11,372,463
575	TOTAL ACCOUNT 908	40,483,172	(33,197,948)	7,285,224	4,110,142	11,395,366	291,521	11,686,887
576	909 / INFORMATION & INSTRUCTIONAL	295,103	0	295,103	10	295,113	0	295,113
577	910 / MISCELLANEOUS EXPENSES	746,645	(3,166)	743,479	33,938	777,417	19,452	796,869
578	912 / DEMO AND SELLING EXPENSES	0	0	0	0	0	0	0
579	TOTAL CUST SERV & INFORMATN EXPENSES	42,534,700	(33,217,109)	9,317,591	4,231,973	13,549,564	362,381	13,911,945

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
580	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***							
581	ADMINISTRATIVE & GENERAL EXPENSES							
582	920 / ADMINISTRATIVE & GENERAL SALARIES	95,790,672	(26,598,671)	69,192,001	16,597,361	85,789,362	3,836,202	89,625,564
583	921 / OFFICE SUPPLIES	15,137,531	(28,774)	15,108,757	50,701	15,159,457	15,816	15,175,273
584	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-CR	(35,131,943)	0	(35,131,943)	(3,326,773)	(38,458,716)	(1,946,297)	(40,405,013)
585	923 / OUTSIDE SERVICES	8,733,229	0	8,733,229	5	8,733,234	0	8,733,234
586	924 / PROPERTY INSURANCE							
587	PRODUCTION - STEAM	412,596	0	412,596	0	412,596	0	412,596
588	ALL RISK & MISCELLANEOUS	3,513,012	1,277,597	4,790,609	40,547	4,831,156	98,991	4,930,147
589	TOTAL ACCOUNT 924	3,925,608	1,277,597	5,203,205	40,547	5,243,752	98,991	5,342,743
590	925 / INJURIES & DAMAGES	6,544,597	5,309,456	11,854,054	14,295	11,868,349	8,363	11,876,713
591	926 / EMPLOYEE PENSIONS & BENEFITS	36,409,743	(16,837)	36,392,906	3,281,778	39,674,684	1,919,922	41,594,606
592	EMPLOYEE PENSIONS & BENEFITS - OREGON	880,053	0	880,053	0	880,053	0	880,053
593	EMPLOYEE PENSIONS & BENEFITS - IDAHO	17,153,713	0	17,153,713	18,028,665	35,182,378	0	35,182,378
594	EMPLOYEE PENSIONS AND BENEFITS - FERC	0	0	0	0	0	0	0
595	927 / FRANCHISE REQUIREMENTS	0	0	0	0	0	0	0
596	928 / REGULATORY COMMISSION EXPENSES							
597	928.101 / FERC ADMIN ASSESS & SECURITIES							
598	CAPACITY RELATED	2,826,830	0	2,826,830	0	2,826,830	0	2,826,830
599	ENERGY RELATED	963,911	0	963,911	0	963,911	0	963,911
600	FERC RATE CASE	0	0	0	0	0	0	0
601	FERC ORDER 472	963,867	0	963,867	0	963,867	0	963,867
602	FERC OTHER	109,055	0	109,055	0	109,055	0	109,055
603	FERC - OREGON HYDRO FEE	271,717	0	271,717	0	271,717	0	271,717
604	SEC EXPENSES	0	0	0	0	0	0	0
605	IDAHO PUC -RATE CASE	0	0	0	0	0	0	0
606	-OTHER	36,197	0	36,197	296,576	332,773	0	332,773
607	OREGON PUC -RATE CASE	0	0	0	0	0	0	0
608	-OTHER	1,374,230	(65,075)	1,309,155	0	1,309,155	0	1,309,155
609	TOTAL ACCOUNT 928	6,545,807	(65,075)	6,480,732	296,576	6,777,308	0	6,777,308
610	929 / DUPLICATE CHARGES	0	0	0	0	0	0	0
611	930.1 / GENERAL ADVERTISING	491,473	(491,473)	0	0	0	0	0
612	930.2 / MISCELLANEOUS EXPENSES	4,378,924	(365,067)	4,013,857	20,958	4,034,815	12,261	4,047,076
613	931 / RENTS	0	0	0	0	0	0	0
614	TOTAL ADM & GEN OPERATION	160,859,406	(20,978,844)	139,880,562	35,004,113	174,884,676	3,945,258	178,829,934
615	PLUS:			0		0		0
616	935 / GENERAL PLANT MAINTENANCE	7,877,237	(826)	7,876,411	132,761	8,009,173	65,032	8,074,205
617	416 / MERCHANDISING EXPENSE	0	4,701,875	4,701,875	0	4,701,875	0	4,701,875
618	TOTAL OPER & MAINT EXPENSES	1,103,041,646	(392,959,807)	710,081,839	210,696,109	920,777,948	9,636,652	930,414,600

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
619	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***							
620								
621	DEPRECIATION EXPENSE							
622	310-316 / STEAM PRODUCTION	33,503,186	(24,062,614)	9,440,573	(272,656)	9,167,916	436,859	9,604,775
623	330-336 / HYDRAULIC PRODUCTION	23,889,746	0	23,889,746	1,198,104	25,087,850	271,290	25,359,140
624	340-346 / OTHER PRODUCTION-BASELOAD	12,299,790	0	12,299,790	1,286,377	13,586,167	228,635	13,814,802
625	340-346 / OTHER PRODUCTION-PEAKERS	5,496,313	0	5,496,313	574,834	6,071,146	102,168	6,173,315
626	TOTAL PRODUCTION PLANT	75,189,035	(24,062,614)	51,126,421	2,786,659	53,913,080	1,038,951	54,952,032
627								
628	TRANSMISSION PLANT							
629	350 / LAND & LAND RIGHTS	402,759	0	402,759	9,304	412,063	4,292	416,355
630	352 / STRUCTURES & IMPROVEMENTS	1,774,142	(15,531)	1,758,611	150,258	1,908,869	12,023	1,920,891
631	353 / STATION EQUIPMENT	10,539,412	(506,744)	10,032,668	164,793	10,197,461	94,357	10,291,818
632	354 / TOWERS & FIXTURES	2,779,736	0	2,779,736	59,977	2,839,713	50,452	2,890,165
633	355 / POLES & FIXTURES	5,828,633	0	5,828,633	201,372	6,030,005	125,434	6,155,439
634	356 / OVERHEAD CONDUCTORS & DEVICES	3,898,386	0	3,898,386	143,934	4,042,321	56,057	4,098,377
635	359 / ROADS & TRAILS	2,693	0	2,693	(0)	2,693	0	2,693
636	TOTAL TRANSMISSION PLANT	25,225,761	(522,275)	24,703,487	729,638	25,433,125	342,614	25,775,739
637								
638	DISTRIBUTION PLANT							
639	360 / LAND & LAND RIGHTS	29,090	0	29,090	886	29,976	952	30,928
640	361 / STRUCTURES & IMPROVEMENTS	1,184,766	0	1,184,766	143,782	1,328,548	64,736	1,393,285
641	362 / STATION EQUIPMENT	5,922,824	0	5,922,824	568,630	6,491,454	270,474	6,761,927
642	363 / STORAGE BATTERY EQUIPMENT	0	0	0	2,791,254	2,791,254	5,948,773	8,740,027
643	364 / POLES, TOWERS & FIXTURES	6,052,387	0	6,052,387	455,842	6,508,229	144,277	6,652,506
644	365 / OVERHEAD CONDUCTORS & DEVICES	3,444,811	0	3,444,811	177,899	3,622,711	65,113	3,687,824
645	366 / UNDERGROUND CONDUIT	1,243,741	0	1,243,741	53,049	1,296,790	31,029	1,327,818
646	367 / UNDERGROUND CONDUCTORS & DEVICES	7,181,015	0	7,181,015	485,222	7,666,237	264,991	7,931,228
647	368 / LINE TRANSFORMERS	13,453,992	0	13,453,992	833,610	14,287,602	272,764	14,560,366
648	369 / SERVICES	1,123,543	0	1,123,543	32,824	1,156,367	7,443	1,163,810
649	370 / METERS	5,564,490	0	5,564,490	198,384	5,762,874	146,055	5,908,929
650	371 / INSTALLATIONS ON CUSTOMER PREMISES	206,196	0	206,196	(12,893)	193,303	77	193,380
651	373 / STREET LIGHTING SYSTEMS	188,574	0	188,574	20,297	208,871	8,584	217,455
652	TOTAL DISTRIBUTION PLANT	45,595,429	0	45,595,429	5,748,787	51,344,216	7,225,268	58,569,484

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
653	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***							
654								
655	GENERAL PLANT							
656	389 / LAND & LAND RIGHTS	0	0	0	0	0	0	0
657	390 / STRUCTURES & IMPROVEMENTS	3,110,207	0	3,110,207	204,165	3,314,372	52,430	3,366,802
658	391 / OFFICE FURNITURE & EQUIPMENT	6,842,286	0	6,842,286	114,792	6,957,077	35,197	6,992,274
659	392 / TRANSPORTATION EQUIPMENT	72,928	0	72,928	(484)	72,444	0	72,444
660	393 / STORES EQUIPMENT	187,311	0	187,311	27,781	215,091	12,326	227,417
661	394 / TOOLS, SHOP & GARAGE EQUIPMENT	672,473	0	672,473	124,566	797,039	11,606	808,645
662	395 / LABORATORY EQUIPMENT	775,044	0	775,044	(394)	774,650	6,918	781,567
663	396 / POWER OPERATED EQUIPMENT	0	0	0	0	0	0	0
664	397 / COMMUNICATIONS EQUIPMENT	5,434,341	0	5,434,341	58,229	5,492,570	122,498	5,615,068
665	398 / MISCELLANEOUS EQUIPMENT	772,904	0	772,904	51,452	824,356	36,437	860,793
666	TOTAL GENERAL PLANT	17,867,493	0	17,867,493	580,107	18,447,600	277,411	18,725,011
667								
668	TOTAL DEPRECIATION EXPENSE	163,877,718	(24,584,889)	139,292,829	9,845,191	149,138,020	8,884,245	158,022,265
669								
670	DEPRECIATION ON DISALLOWED COSTS	(296,299)	0	(296,299)	0	(296,299)	0	(296,299)
671	TOTAL DEPRECIATION EXPENSE	163,581,418	(24,584,889)	138,996,530	9,845,191	148,841,721	8,884,245	157,725,966
672								
673	AMORTIZATION EXPENSE							
674	302/FRANCHISES AND CONSENTS	1,271,927	0	1,271,927	219,101	1,491,028	52,515	1,543,543
675	303/MISCELLANEOUS INTANGIBLE PLANT	3,979,986	0	3,979,986	399,545	4,379,530	43,225	4,422,755
676	ADJUSTMENTS, GAINS & LOSSES	15,018	0	15,018	0	15,018	0	15,018
677	TOTAL AMORTIZATION EXPENSE	5,266,930	0	5,266,930	618,646	5,885,576	95,740	5,981,316
678								
679	TOTAL DEPRECIATION & AM0RTIZATION EXP	168,848,348	(24,584,889)	144,263,460	10,463,837	154,727,297	8,979,985	163,707,282
680								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
681	***TABLE 7-TAXES OTHER THAN INCOME TAXES***							
682								
683	TAXES OTHER THAN INCOME							
684	FEDERAL TAXES							
685	FICA	18,219,357	(18,219,357)	0	0	0	0	0
686	FUTA	94,333	(94,333)	0	0	0	0	0
687	LESS PAYROLL DEDUCTION	(18,558,238)	18,558,238	0	0	0	0	0
688								
689	STATE TAXES							
690	AD VALOREM TAXES							
691	JIM BRIDGER	1,282,348	(1,282,348)	0	0	0	0	0
692	VALMY	314,445	(314,445)	0	0	0	0	0
693	OTHER-PRODUCTION PLANT	6,670,284	0	6,670,284	1,036,086	7,706,370	454,948	8,161,318
694	OTHER-TRANSMISSION PLANT	5,986,892	0	5,986,892	839,735	6,826,628	0	6,826,628
695	OTHER-DISTRIBUTION PLANT	7,961,398	0	7,961,398	1,221,533	9,182,931	0	9,182,931
696	OTHER-GENERAL PLANT	1,522,499	0	1,522,499	248,508	1,771,006	43,286	1,814,292
697	SUB-TOTAL	23,737,866	(1,596,793)	22,141,073	3,345,862	25,486,936	498,234	25,985,170
698								
699	LICENSES - HYDRO PROJECTS	4,240	0	4,240	0	4,240	0	4,240
700								
701	REGULATORY COMMISSION FEES							
702	STATE OF IDAHO	2,616,251	0	2,616,251	0	2,616,251	0	2,616,251
703	STATE OF OREGON	290,260	0	290,260	95,251	385,511	0	385,511
704								
705	FRANCHISE TAXES							
706	STATE OF OREGON	890,161	0	890,161	62,839	953,000	0	953,000
707								
708	OTHER STATE TAXES							
709	UNEMPLOYMENT TAXES	244,547	(244,547)	0	0	0	0	0
710	HYDRO GENERATION KWH TAX	982,665	0	982,665	907,247	1,889,911	0	1,889,911
711	IRRIGATION-PIC	180,233	0	180,233	148,058	328,291	0	328,291
712								
713	TOTAL TAXES OTHER THAN INCOME	28,701,676	(1,596,793)	27,104,883	4,559,257	31,664,141	498,234	32,162,375

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
714	***TABLE 8-REGULATORY DEBITS & CREDITS***							
715	REGULATORY DEBITS/CREDITS							
716	STATE OF IDAHO	1,450,259	(173,640)	1,276,619	1,865,167	3,141,786	0	3,141,786
717	STATE OF OREGON	303,059	0	303,059	0	303,059	0	303,059
718								
719	TOTAL REGULATORY DEBITS/CREDITS	1,753,318	(173,640)	1,579,678	1,865,167	3,444,845	0	3,444,845
720								
721								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
722	***TABLE 9-INCOME TAXES***							
723								
724	410/411 NET PROVISION FOR DEFERRED INCOME TAXES							
725	ACCOUNT #282 - RELATED	(34,483,220)	0	(34,483,220)	17,879,031	(16,604,189)	0	(16,604,189)
726	ACCOUNT #190 & #283 - RELATED	23,654,934	0	23,654,934	(24,923,968)	(1,269,034)	0	(1,269,034)
727	TOTAL NET PROVISION FOR DEFERRED INCOME TAXES	(10,828,286)	0	(10,828,286)	(7,044,937)	(17,873,223)	0	(17,873,223)
728								
729	411.4 - INVESTMENT TAX CREDIT ADJUSTMENT	5,825,740	0	5,825,740	19,188,438	25,014,178	0	25,014,178
730								
731	SUMMARY OF INCOME TAXES							
732								
733	TOTAL FEDERAL INCOME TAX	32,209,533	4,643,860	36,853,393	6,099,210	42,952,604	(3,773,276)	39,179,328
734								
735	STATE INCOME TAX							
736	STATE OF IDAHO	10,909,865	1,317,407	12,227,272	(15,538,391)	(3,311,119)	(1,070,433)	(4,381,551)
737	STATE OF OREGON	882,355	70,575	952,930	(204,112)	748,818	(57,345)	691,473
738	OTHER STATES	26,941	23,525	50,466	204,705	255,172	(19,115)	236,057
739	TOTAL STATE INCOME TAXES	11,819,161	1,411,508	13,230,668	(15,537,797)	(2,307,129)	(1,146,892)	(3,454,021)

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
740	***TABLE 10-CALCULATION OF FEDERAL INCOME TAX***							0
741	OPERATING REVENUES	1,637,127,982	(344,590,231)	1,292,537,752	172,540,794	1,465,078,546	0	1,465,078,546
742						0		0
743	OPERATING EXPENSES					0		0
744	OPERATION & MAINTENANCE	1,103,041,646	(392,959,807)	710,081,839	210,696,109	920,777,948	9,636,652	930,414,600
745	DEPRECIATION EXPENSE	163,581,418	(24,584,889)	138,996,530	9,845,191	148,841,721	8,884,245	157,725,966
746	AMORTIZATION OF LIMITED TERM PLANT	5,266,930	0	5,266,930	618,646	5,885,576	95,740	5,981,316
747	TAXES OTHER THAN INCOME	28,701,676	(1,596,793)	27,104,883	4,559,257	31,664,141	498,234	32,162,375
748	REGULATORY DEBITS/CREDITS	1,753,318	(173,640)	1,579,678	1,865,167	3,444,845	0	3,444,845
749	TOTAL OPERATING EXPENSES	1,302,344,989	(419,315,129)	883,029,860	227,584,370	1,110,614,231	19,114,872	1,129,729,102
750								0
751	BOOK-TAX ADJUSTMENT	0	0	0	0	0	0	0
752								0
753	INCOME BEFORE TAX ADJUSTMENTS	334,782,994	74,724,898	409,507,891	(55,043,576)	354,464,315	(19,114,872)	335,349,443
754								
755	INCOME STATEMENT ADJUSTMENTS							
756	INTEREST EXPENSE / SYNCHRONIZATION	102,955,312	0	102,955,312	12,936,098	115,891,410	0	115,891,410
757								
758	NET OPERATING INCOME BEFORE TAXES	231,827,681	74,724,898	306,552,579	(67,979,674)	238,572,905	(19,114,872)	219,458,033
759								
760	TOTAL STATE INCOME TAXES (ALLOWED)	13,899,195	1,411,508	15,310,703	(17,617,832)	(2,307,129)	(1,146,892)	(3,454,021)
761								
762	NET FEDERAL INCOME AFTER STATE INCOME TAXES	217,928,486	73,313,390	291,241,876	(50,361,842)	240,880,034	(17,967,979)	222,912,055
763								
764	FEDERAL TAX AT 21 PERCENT	45,764,982	15,395,812	61,160,794	(10,575,987)	50,584,807	(3,773,276)	46,811,531
765	OTHER CURRENT TAX ADJUSTMENTS	(4,913,431)	0	(4,913,431)	4,913,431	0	0	0
766	PRIOR YEAR TAX ADJUSTMENT	(9,831,485)	0	(9,831,485)	9,831,485	0	0	0
767								
768	TOTAL FEDERAL INCOME TAX BEFORE OTHER ADJUSTMENTS	31,020,066	15,395,812	46,415,878	4,168,929	50,584,807	(3,773,276)	46,811,531
769								
770	OTHER TAX ADJUSTMENTS							
771	ALLOWANCE FOR AFUDC	51,199,770	(51,199,770)	0	0	0	0	0
772	FEDERAL INCOME TAX ADJUSTMENTS - PLANT	68,194,087	0	68,194,087	(64,742,865)	3,451,222	0	3,451,222
773	FEDERAL INCOME TAX ADJUSTMENTS - OTHER	(113,729,727)	0	(113,729,727)	123,877,537	10,147,810	0	10,147,810
774	SUM OF OTHER ADJUSTMENTS	5,664,130	(51,199,770)	(45,535,640)	59,134,672	13,599,032	0	13,599,032
775	FEDERAL TAX ON OTHER TAX ADJ AT 21 PERCENT	1,189,467	(10,751,952)	(9,562,484)	12,418,281	2,855,797	0	2,855,797
776	FEDERAL GENERAL BUSINESS CREDITS	0	0	0	10,488,000	10,488,000	0	10,488,000
777								
778	TOTAL FEDERAL INCOME TAX	32,209,533	4,643,860	36,853,393	6,099,210	42,952,604	(3,773,276)	39,179,328

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
779	***TABLE 11-OREGON STATE INCOME TAX***							
780								
781	NET OPERATING INCOME BEFORE TAXES - OREGON	231,827,681	74,724,898	306,552,579	(67,979,674)	238,572,905	(19,114,872)	219,458,033
782								
783	ALLOWANCE FOR AFUDC	51,199,770	(51,199,770)	0	0	0	0	0
784	STATE INCOME TAX ADJUSTMENTS - PLANT	68,194,087	0	68,194,087	(64,742,865)	3,451,222	0	3,451,222
785	STATE INCOME TAX ADJUSTMENTS - OTHER	(113,729,727)	0	(113,729,727)	123,877,537	10,147,810	0	10,147,810
786	ADD: OTHER DEDUCTION	0	0	0	0	0	0	0
787								
788	TOTAL STATE INCOME TAX ADJUSTMENTS - OREGON	5,664,130	(51,199,770)	(45,535,640)	59,134,672	13,599,032	0	13,599,032
789								
790	INCOME SUBJECT TO OREGON TAX	237,491,811	23,525,128	261,016,939	(8,845,002)	252,171,937	(19,114,872)	233,057,065
791								
792	IERCO TAXABLE INCOME	26,216,557	0	26,216,557	(23,216,557)	3,000,000	0	3,000,000
793	BONUS DEPRECIATION & OTHER OREGON ADJ	(5,767,076)	0	(5,767,076)	201,044	(5,566,032)	0	(5,566,032)
794	OTHER	0	0	0	0	0	0	0
795								
796	TOTAL STATE TAXABLE INCOME - OREGON	257,941,292	23,525,128	281,466,420	(31,860,515)	249,605,905	(19,114,872)	230,491,033
797	APPORTIONMENT FACTOR (0.045454550)	11,724,605	1,069,324	12,793,929	(1,448,205)	11,345,724	(868,858)	10,476,866
798	POST APPORTIONMENT M ITEMS	0	0	0	0	0	0	0
799	TOTAL TAXABLE INCOME - OREGON	11,724,605	1,069,324	12,793,929	(1,448,205)	11,345,724	(868,858)	10,476,866
800								
801	OREGON TAX AT 6.6 PERCENT	773,824	70,575	844,399	(95,582)	748,818	(57,345)	691,473
802	LESS: INVESTMENT TAX CREDIT	0	0	0	0	0	0	0
803								
804	STATE INCOME TAX ALLOWED - OREGON	773,824	70,575	844,399	(95,582)	748,818	(57,345)	691,473
805	ADD : OR CAT TAX	274,802	0	274,802	(274,802)	0	0	0
806	PRIOR YEARS' TAX ADJUSTMENT	(166,271)	0	(166,271)	166,271	0	0	0
807								
808	STATE INCOME TAX PAID - OREGON	882,355	70,575	952,930	(204,112)	748,818	(57,345)	691,473

Exhibit No. 34
Case No. IPC-E-23-11
K. Noe, IPC
Page 22 of 29

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
809	***TABLE 12-IDAHO STATE INCOME TAX***							
810								0
811	NET OPERATING INCOME BEFORE TAXES - IDAHO	231,827,681	74,724,898	306,552,579	(67,979,674)	238,572,905	(19,114,872)	219,458,033
812								
813	ALLOWANCE FOR AFUDC	51,199,770	(51,199,770)	0	0	0	0	0
814	STATE INCOME TAX ADJUSTMENTS - PLANT	68,194,087	0	68,194,087	(64,742,865)	3,451,222	0	3,451,222
815	STATE INCOME TAX ADJUSTMENTS - OTHER	(113,729,727)	0	(113,729,727)	123,877,537	10,147,810	0	10,147,810
816								0
817	INCOME SUBJECT TO IDAHO TAX	237,491,811	23,525,128	261,016,939	(8,845,002)	252,171,937	(19,114,872)	233,057,065
818								0
819	IERCO TAXABLE INCOME	26,216,557	0	26,216,557	(23,216,557)	3,000,000	0	3,000,000
820	BONUS DEPRECIATION ADJUSTMENT	(34,035,818)	0	(34,035,818)	4,433,193	(29,602,625)	0	(29,602,625)
821	OTHER	0	0	0	0	0	0	0
822	TOTAL STATE TAXABLE INCOME - IDAHO	229,672,550	23,525,128	253,197,678	(27,628,366)	225,569,312	(19,114,872)	206,454,440
823	APPORTIONMENT FACTOR (.965517241)	221,752,807	22,713,917	244,466,724	(26,675,664)	217,791,060	(18,455,738)	199,335,322
824	POST APPORTIONMENT SCHEDULE M	0	0	0	0	0	0	0
825	TOTAL TAXABLE INCOME - IDAHO	221,752,807	22,713,917	244,466,724	(26,675,664)	217,791,060	(18,455,738)	199,335,322
826	IDAHO TAX AT 5.8 PERCENT	12,861,663	1,317,407	14,179,070	(1,547,189)	12,631,881	(1,070,433)	11,561,449
827	LESS: INVESTMENT TAX CREDIT	0	0	0	15,943,000	15,943,000	0	15,943,000
828								
829	STATE INCOME TAX ALLOWED - IDAHO	12,861,663	1,317,407	14,179,070	(17,490,189)	(3,311,119)	(1,070,433)	(4,381,551)
830	ADD : CURRENT TAX ADJUSTMENT	(1,951,798)	0	(1,951,798)	1,951,798	0	0	0
831	PRIOR YEARS' TAX ADJUSTMENT	0	0	0	0	0	0	0
832	STATE INCOME TAX PAID - IDAHO	10,909,865	1,317,407	12,227,272	(15,538,391)	(3,311,119)	(1,070,433)	(4,381,551)
833								
834	***OTHER STATE INCOME TAX***							
835	INCOME SUBJECT TO TAX	237,491,811	23,525,128	261,016,939	(8,845,002)	252,171,937	(19,114,872)	233,057,065
836								
837	IERCO TAXABLE INCOME	26,216,557	0	26,216,557	(23,216,557)	3,000,000	0	3,000,000
838	BONUS DEPRECIATION ADJUSTMENT	0	0	0	0	0	0	0
839	OTHER	0	0	0	0	0	0	0
840	TOTAL TAXABLE INCOME-OTHER STATES	263,708,368	23,525,128	287,233,496	(32,061,559)	255,171,937	(19,114,872)	236,057,065
841	APPORTIONMENT FACTOR (1.0)	263,708,368	23,525,128	287,233,496	(32,061,559)	255,171,937	(19,114,872)	236,057,065
842	POST APPORTIONMENT M	0	0	0	0	0	0	0
843	TAXABLE INCOME	263,708,368	23,525,128	287,233,496	(32,061,559)	255,171,937	(19,114,872)	236,057,065
844	OTHER TAX AT 0.1 PERCENT	263,708	23,525	287,233	(32,062)	255,172	(19,115)	236,057
845	ADD : CURRENT YEAR'S TAX DEFICIENCY	(236,767)	0	(236,767)	236,767	0	0	0
846	PRIOR YEARS' TAX ADJUSTMENT	0	0	0	0	0	0	0
847	OTHER STATES' INCOME TAX PAID	26,941	23,525	50,466	204,705	255,172	(19,115)	236,057

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
848	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***							
849	STEAM POWER GENERATION							
850	OPERATION							
851	500 / SUPERVISION & ENGINEERING	266,133		266,133		266,133		266,133
852	501 / FUEL	2,559,614		2,559,614		2,559,614		2,559,614
853	502 / STEAM EXPENSES			0				0
854	LABOR	1,607,750		1,607,750		1,607,750		1,607,750
855	OTHER	0		0		0		0
856						1,607,750		1,607,750
857	505 / ELECTRIC EXPENSES			0				0
858	LABOR	626,112		626,112		626,112		626,112
859	OTHER	0		0		0		0
860						626,112		626,112
861	506 / MISCELLANEOUS EXPENSES	3,352,418		3,352,418		3,352,418		3,352,418
862	507 / RENTS	0		0		0		0
863	STEAM OPERATION EXPENSES	8,412,027		8,412,027		8,412,027		8,412,027
864								
865	MAINTENANCE							
866	510 / SUPERVISION & ENGINEERING	0		0		0		0
867	511 / STRUCTURES	658		658		658		658
868	512 / BOILER PLANT			0				0
869	LABOR	3,983,710		3,983,710		3,983,710		3,983,710
870	OTHER	0		0		0		0
871	TOTAL ACCOUNT 512					3,983,710		3,983,710
872	513 / ELECTRIC PLANT			0				0
873	LABOR	1,522,637		1,522,637		1,522,637		1,522,637
874	OTHER	0		0		0		0
875	TOTAL ACCOUNT 513					1,522,637		1,522,637
876	514 / MISCELLANEOUS STEAM PLANT	2,441,874		2,441,874		2,441,874		2,441,874
877	STEAM MAINTENANCE EXPENSES	7,948,879		7,948,879		7,948,879		7,948,879
878	TOTAL STEAM GENERATION EXPENSES	16,360,906		16,360,906		16,360,906	0	16,360,906
879								

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
880	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***							
881	HYDRAULIC POWER GENERATION							
882	OPERATION							
883	535 / SUPERVISION & ENGINEERING	4,235,258		4,235,258		4,235,258		4,235,258
884	536 / WATER FOR POWER	866,414		866,414		866,414		866,414
885	537 / HYDRAULIC EXPENSES	6,262,192		6,262,192		6,262,192		6,262,192
886	538 / ELECTRIC EXPENSES							
887	LABOR	1,510,454		1,510,454		1,510,454		1,510,454
888	OTHER	0		0		0		0
889	TOTAL ACCOUNT 538	1,510,454		1,510,454		1,510,454		1,510,454
890	539 / MISCELLANEOUS EXPENSES	3,401,219		3,401,219		3,401,219		3,401,219
891	540 / RENTS	0		0		0		0
892	HYDRAULIC OPERATION EXPENSES	17,785,991		17,785,991		16,275,537		16,275,537
893								
894	MAINTENANCE							
895	541 / SUPERVISION & ENGINEERING	90,192		90,192		90,192		90,192
896	542 / STRUCTURES	577,669		577,669		577,669		577,669
897	543 / RESERVOIRS, DAMS & WATERWAYS	254,872		254,872		254,872		254,872
898	544 / ELECTRIC PLANT			0				0
899	LABOR	1,799,397		1,799,397		1,799,397		1,799,397
900	OTHER	0		0		0		0
901	TOTAL ACCOUNT 544	1,799,397		1,799,397		1,799,397		1,799,397
902	545 / MISCELLANEOUS HYDRAULIC PLANT	2,163,612		2,163,612		2,163,612		2,163,612
903	HYDRAULIC MAINTENANCE EXPENSES	4,885,742		4,885,742		4,885,742		4,885,742
904	TOTAL HYDRAULIC GENERATION EXPENSES	22,671,733		22,671,733		21,161,279		21,161,279

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
905	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***							
906	OTHER POWER GENERATION							
907	OPERATION							
908	546 / SUPERVISION & ENGINEERING	516,722		516,722		516,722		516,722
909	547 / FUEL	0		0		0		0
910	548 / GENERATING EXPENSES			0				0
911	LABOR	3,234,939		3,234,939		3,234,939		3,234,939
912	OTHER	0		0		0		0
913	TOTAL ACCOUNT 548			0		3,234,939		3,234,939
914	549 / MISCELLANEOUS EXPENSES	370,607		370,607		370,607		370,607
915	550 / RENTS	0		0		0		0
916	OTHER POWER OPER EXPENSES	4,122,267		4,122,267		4,122,267		4,122,267
917								
918	MAINTENANCE							
919	551 / SUPERVISION & ENGINEERING	0		0		0		0
920	552 / STRUCTURES	43,046		43,046		43,046		43,046
921	553 / GENERATING & ELECTRIC PLANT			0				0
922	LABOR	56,825		56,825		56,825		56,825
923	OTHER			0		0		0
924	TOTAL ACCOUNT 553			0		56,825		56,825
925	554 / MISCELLANEOUS EXPENSES	690,424		690,424		690,424		690,424
926	OTHER POWER MAINT EXPENSES	790,295		790,295		790,295		790,295
927	TOTAL OTHER POWER GENERATION EXP	4,912,562		4,912,562		4,912,562		4,912,562
928								
929	OTHER POWER SUPPLY EXPENSE							
930	555.0 / PURCHASED POWER	0		0		0		0
931	555.1 / COGENERATION & SMALL POWER PROD			0				0
932	CAPACITY RELATED	0		0		0		0
933	ENERGY RELATED	0		0		0		0
934	TOTAL 555.1/CSPP							
935	555/TOTAL							
936	556 / LOAD CONTROL & DISPATCHING EXPENSES	0		0		0		0
937	557 / OTHER EXPENSES	4,495,330		4,495,330		4,495,330		4,495,330
938	TOTAL OTHER POWER SUPPLY EXPENSES	4,495,330		4,495,330		4,495,330		4,495,330
939				0				0
940	TOTAL PRODUCTION EXPENSES	48,440,532		48,440,532		46,930,078		46,930,078

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
941	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***							
942	TRANSMISSION EXPENSES							
943	OPERATION							
944	560 / SUPERVISION & ENGINEERING	2,380,639		2,380,639		2,380,639		2,380,639
945	561 / LOAD DISPATCHING	3,053,979		3,053,979		3,053,979		3,053,979
946	562 / STATION EXPENSES	1,883,621		1,883,621		1,883,621		1,883,621
947	563 / OVERHEAD LINE EXPENSES	428,401		428,401		428,401		428,401
948	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	0		0		0		0
949	566 / MISCELLANEOUS EXPENSES	0		0		0		0
950	567 / RENTS	0		0		0		0
951	TOTAL TRANSMISSION OPERATION	7,746,639		7,746,639		7,746,639		7,746,639
952				0				0
953	MAINTENANCE			0				0
954	568 / SUPERVISION & ENGINEERING	90,949		90,949		90,949		90,949
955	569 / STRUCTURES	1,442,019		1,442,019		1,442,019		1,442,019
956	570 / STATION EQUIPMENT	2,327,169		2,327,169		2,327,169		2,327,169
957	571 / OVERHEAD LINES	865,811		865,811		865,811		865,811
958	573 / MISCELLANEOUS PLANT	3,520		3,520		3,520		3,520
959	TOTAL TRANSMISSION MAINTENANCE	4,729,468		4,729,468		4,729,468		4,729,468
960				0				0
961	TOTAL TRANSMISSION EXPENSES	12,476,107		12,476,107		12,476,107		12,476,107

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
962	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***							
963	DISTRIBUTION EXPENSES							
964	OPERATION							
965	580 / SUPERVISION & ENGINEERING	2,995,909		2,995,909		2,995,909		2,995,909
966	581 / LOAD DISPATCHING	4,166,909		4,166,909		4,166,909		4,166,909
967	582 / STATION EXPENSES	983,432		983,432		983,432		983,432
968	583 / OVERHEAD LINE EXPENSES	3,611,849		3,611,849		3,611,849		3,611,849
969	584 / UNDERGROUND LINE EXPENSES	1,372,655		1,372,655		1,372,655		1,372,655
970	585 / STREET LIGHTING & SIGNAL SYSTEMS	20,365		20,365		20,365		20,365
971	586 / METER EXPENSES	4,176,379		4,176,379		4,176,379		4,176,379
972	587 / CUSTOMER INSTALLATIONS EXPENSE	736,676		736,676		736,676		736,676
973	588 / MISCELLANEOUS EXPENSES	2,911,186		2,911,186		2,911,186		2,911,186
974	589 / RENTS	0		0		0		0
975	TOTAL DISTRIBUTION OPERATION	20,975,360		20,975,360		20,975,360		20,975,360
976								
977	MAINTENANCE							
978	590 / SUPERVISION & ENGINEERING	9,353		9,353		9,353		9,353
979	591 / STRUCTURES	0		0		0		0
980	592 / STATION EQUIPMENT	2,716,642		2,716,642		2,716,642		2,716,642
981	593 / OVERHEAD LINES	5,201,009		5,201,009		5,201,009		5,201,009
982	594 / UNDERGROUND LINES	304,799		304,799		304,799		304,799
983	595 / LINE TRANSFORMERS	25,793		25,793		25,793		25,793
984	596 / STREET LIGHTING & SIGNAL SYSTEMS	123,794		123,794		123,794		123,794
985	597 / METERS	678,112		678,112		678,112		678,112
986	598 / MISCELLANEOUS PLANT	79,964		79,964		79,964		79,964
987	TOTAL DISTRIBUTION MAINTENANCE	9,139,466		9,139,466		9,139,466		9,139,466
988	TOTAL DISTRIBUTION EXPENSES	30,114,827		30,114,827		30,114,827		30,114,827
989								
990	CUSTOMER ACCOUNTING EXPENSES							
991	901 / SUPERVISION	705,017		705,017		705,017		705,017
992	902 / METER READING	1,267,888		1,267,888		1,267,888		1,267,888
993	903 / CUSTOMER RECORDS & COLLECTIONS	9,731,713		9,731,713		9,731,713		9,731,713
994	904 / UNCOLLECTIBLE ACCOUNTS	0		0		0		0
995	905 / MISC EXPENSES	0		0		0		0
996	TOTAL CUSTOMER ACCOUNTING EXPENSES	11,704,618		11,704,618		11,704,618		11,704,618
997								
998	CUSTOMER SERVICES & INFORMATION EXPENSES							
999	907 / SUPERVISION	828,671		828,671		828,671		828,671
1000	908 / CUSTOMER ASSISTANCE	4,679,331		4,679,331		4,679,331		4,679,331
1001	908 / DSM RIDER	0		0		0		0
1002	909 / INFORMATION & INSTRUCTIONAL	0		0		0		0
1003	910 / MISCELLANEOUS EXPENSES	308,799		308,799		308,799		308,799
1004	TOTAL CUST SERV & INFORMATN EXPENSES	5,816,801		5,816,801		5,816,801		5,816,801

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2		2022	2022 Actual	2022	Forecast	2023 Unadjusted	Annualizing	2023
3	Description	Actual	Adjustments	Base	Adjustment	Test Year	Adjustment	Test Year
1005	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***							
1006	ADMINISTRATIVE & GENERAL EXPENSES							
1007	920 / ADMINISTRATIVE & GENERAL SALARIES	53,511,744		53,511,744		53,511,744		53,511,744
1008	921 / OFFICE SUPPLIES	228,890		228,890		228,890		228,890
1009	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-CR	0		0		0		0
1010	923 / OUTSIDE SERVICES	0		0		0		0
1011	924 / PROPERTY INSURANCE			0				0
1012	PRODUCTION - STEAM	0		0		0		0
1013	ALL RISK & MISCELLANEOUS	378,934		378,934		378,934		378,934
1014	TOTAL ACCOUNT 924							
1015	925 / INJURIES & DAMAGES	132,355		132,355		132,355		132,355
1016	926 / EMPLOYEE PENSIONS & BENEFITS	0		0		0		0
1017	927 / FRANCHISE REQUIREMENTS	0		0		0		0
1018	928 / REGULATORY COMMISSION EXPENSES							
1019	928.101 / FERC ADMIN ASSESS & SECURITIES							
1020	CAPACITY RELATED	0		0		0		0
1021	ENERGY RELATED	0		0		0		0
1022	928.101 / FERC ORDER 472	0		0		0		0
1023	928.101 / FERC MISCELLANIOUS	0		0		0		0
1024	928.102 FERC RATE CASE	0		0		0		0
1025	928.104 / FERC OREGON HYDRO	0		0		0		0
1026	SEC EXPENSES	0		0		0		0
1027	928.202 / IDAHO PUC -RATE CASE	0		0		0		0
1028	928.203 / IDAHO PUC - OTHER	0		0		0		0
1029	928.301 / OREGON PUC - FILING FEES	0		0		0		0
1030	928.302 / OREGON PUC - RATE CASE	0		0		0		0
1031	928.303 / OREGON PUC - OTHER	0		0		0		0
1032	IPC/PUC JSS TRUE-UP ADJ	0		0		0		0
1033	TOTAL ACCOUNT 928							
1034	929 / DUPLICATE CHARGES	0		0		0		0
1035	930.1 / GENERAL ADVERTISING	0		0		0		0
1036	930.2 / MISCELLANEOUS EXPENSES	214,755		214,755		214,755		214,755
1037	931 / RENTS	0		0		0		0
1038	TOTAL ADM & GEN OPERATION	54,466,679		54,466,679		54,466,679	0	54,466,679
1039	PLUS:			0				0
1040	935 / GENERAL PLANT MAINTENANCE	1,038,440		1,038,440		1,038,440		1,038,440
1041	416 / MERCHANDISING EXPENSE	0		0		0		0
1042	TOTAL OPER & MAINT EXPENSES	164,058,004		164,058,004		162,547,550	0	162,547,550

Exhibit No. 34
Case No. IPC-E-23-11
K. Noe, IPC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

NOE, DI TESTIMONY

EXHIBIT NO. 35

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	IDAHO RETAIL	OTHER
SUMMARY OF RESULTS				
RATE OF RETURN UNDER PRESENT RATES				
TOTAL COMBINED RATE BASE		4,092,522,974	**3,912,569,823**	*179,953,152*
OPERATING REVENUES				
FIRM JURISDICTIONAL SALES		1,346,676,681	**1,293,009,840**	**53,666,841**
SYSTEM OPPORTUNITY SALES		29,035,180	**27,748,563**	*1,286,617*
OTHER OPERATING REVENUES		89,366,685	**85,891,627**	*3,475,058*
TOTAL OPERATING REVENUES		1,465,078,546	**1,406,650,030**	*58,428,516*
OPERATING EXPENSES				
OPERATION & MAINTENANCE EXPENSES		930,414,600	**888,823,963**	*41,590,637*
DEPRECIATION EXPENSE		157,725,966	**150,952,190**	*6,773,776*
AMORTIZATION OF LIMITED TERM PLANT		5,981,316	**5,725,400**	*255,916*
TAXES OTHER THAN INCOME		32,162,375	**29,601,331**	*2,561,044*
REGULATORY DEBITS/CREDITS		3,444,845	**3,141,786**	*303,059*
PROVISION FOR DEFERRED INCOME TAXES		(17,873,223)	**(17,124,938)**	*(748,285)*
INVESTMENT TAX CREDIT ADJUSTMENT		25,014,178	**23,926,476**	*1,087,702*
FEDERAL INCOME TAXES		39,179,328	**39,040,245**	*139,083*
STATE INCOME TAXES		(3,454,021)	**(2,828,435)**	*(625,586)*
TOTAL OPERATING EXPENSES		1,172,595,364	**1,121,258,018**	*51,337,346*
OPERATING INCOME		292,483,181	**285,392,012**	*7,091,169*
ADD: IERCO OPERATING INCOME		1,841,118	**1,759,534**	*81,584*
CONSOLIDATED OPERATING INCOME		294,324,299	**287,151,546**	*7,172,754*
RATE OF RETURN UNDER PRESENT RATES		7.19%	**7.34%**	*3.99%*
DEVELOPMENT OF REVENUE REQUIREMENTS				
RATE OF RETURN @ **10.4%** ROE		7.702%	**7.702%**	*7.702%*
RETURN		315,206,119	**301,346,128**	*13,859,992*
EARNINGS DEFICIENCY		20,881,820	**14,194,582**	*6,687,238*
ADD: CWIP (HELLS CANYON RELICENSING)	D10	6,815,472	**6,537,444**	*278,028*
EARNINGS DEFICIENCY WITH CWIP		27,697,292	**20,732,026**	*6,965,266*
NET-TO-GROSS TAX MULTIPLIER		1.347	**1.347**	*1.347*
REVENUE DEFICIENCY		37,297,728	**27,918,161**	*9,379,567*
ADD: VALMY REVENUE REQUIREMENT	CIDA	36,957,501	**36,957,501**	*0*
ADD: BRIDGER REVENUE REQUIREMENT	CIDA	67,579,174	**67,579,174**	*0*
LESS: BATTERY ADITC MITIGATION	CIDA	21,149,854	**21,149,854**	*0*
REVENUE DEFICIENCY WITH VALMY AND BRIDGER		120,684,548	**111,304,981**	*9,379,567*
FIRM JURISDICTIONAL RETAIL REVENUES		1,346,676,681	**1,293,009,840**	53,666,841
PERCENT INCREASE REQUIRED			**8.61%**	
SALES AND WHEELING REVENUES REQUIRED		1,467,361,229	**1,404,314,821**	*63,046,408*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	IDAHO RETAIL	OTHER
49	***SUMMARY OF RESULTS***				
50	**DEVELOPMENT OF RATE BASE COMPONENTS**				
51	ELECTRIC PLANT IN SERVICE				
52	INTANGIBLE PLANT		105,220,910	**100,787,269**	*4,433,641*
53	PRODUCTION PLANT		2,014,242,607	**1,932,074,232**	*82,168,375*
54	TRANSMISSION PLANT		1,355,473,916	**1,300,089,883**	*55,384,033*
55	DISTRIBUTION PLANT		2,423,399,384	**2,309,047,394**	*114,351,990*
56	GENERAL PLANT		517,244,492	**494,752,941**	*22,491,551*
57	TOTAL ELECTRIC PLANT IN SERVICE		6,415,581,308	**6,136,751,718**	*278,829,591*
58	LESS: ACCUM PROVISION FOR DEPRECIATION		2,085,671,484	**1,994,366,693**	*91,304,791*
59	AMORT OF OTHER UTILITY PLANT		41,915,507	**40,143,386**	*1,772,121*
60	NET ELECTRIC PLANT IN SERVICE		4,287,994,318	**4,102,241,639**	*185,752,678*
61	LESS: CUSTOMER ADV FOR CONSTRUCTION		7,441,965	**7,387,459**	*54,505*
62	LESS: ACCUM DEFERRED INCOME TAXES		382,140,505	**365,461,375**	*16,679,130*
63	ADD : PLT HLD FOR FUTURE+ACQUIS ADJ		8,878,552	**8,585,072**	*293,480*
64	ADD : WORKING CAPITAL		115,290,253	**110,090,091**	*5,200,163*
65	ADD : CONSERVATION+OTHER DFRD PROG.		38,571,563	**34,521,209**	*4,050,354*
66	ADD : SUBSIDIARY RATE BASE		31,370,758	**29,980,646**	*1,390,112*
67	TOTAL COMBINED RATE BASE		4,092,522,974	**3,912,569,823**	*179,953,152*
68					
69	**DEVELOPMENT OF NET INCOME COMPONENTS**				
70	OPERATING REVENUES				
71	SALES REVENUES		1,375,711,861	**1,320,758,403**	*54,953,458*
72	OTHER OPERATING REVENUES		89,366,685	**85,891,627**	*3,475,058*
73	TOTAL OPERATING REVENUES		1,465,078,546	**1,406,650,030**	*58,428,516*
74	OPERATING EXPENSES				
75	OPERATION & MAINTENANCE EXPENSES		930,414,600	**888,823,963**	*41,590,637*
76	DEPRECIATION EXPENSE		157,725,966	**150,952,190**	*6,773,776*
77	AMORTIZATION OF LIMITED TERM PLANT		5,981,316	**5,725,400**	*255,916*
78	TAXES OTHER THAN INCOME		32,162,375	**29,601,331**	*2,561,044*
79	REGULATORY DEBITS/CREDITS		3,444,845	**3,141,786**	*303,059*
80	PROVISION FOR DEFERRED INCOME TAXES		(17,873,223)	**(17,124,938)**	*(748,285)*
81	INVESTMENT TAX CREDIT ADJUSTMENT		25,014,178	**23,926,476**	*1,087,702*
82	FEDERAL INCOME TAXES		39,179,328	**39,040,245**	*139,083*
83	STATE INCOME TAXES		(3,454,021)	**(2,828,435)**	*(625,586)*
84	TOTAL OPERATING EXPENSES		1,172,595,364	**1,121,258,018**	*51,337,346*
85	OPERATING INCOME		292,483,181	**285,392,012**	*7,091,169*
86	ADD: IERCO OPERATING INCOME	E10	1,841,118	**1,759,534**	*81,584*
87	CONSOLIDATED OPERATING INCOME		294,324,299	**287,151,546**	*7,172,754*
88					
89	**NET POWER SUPPLY COSTS:**				
90	ACCT 447/SURPLUS SALES		(29,035,180)	(27,748,563)	(1,286,617)
91	ACCT 501/FUEL-THERMAL PLANTS		65,523,000	62,619,523	2,903,477
92	ACCT 547/FUEL-OTHER		119,653,675	114,351,541	5,302,134
93	ACCT 555/NON-FIRM PURCHASES		99,465,021	95,057,493	4,407,528
94	ACCT 555/DEMAND RESPONSE INCENTIVE		10,240,003	10,240,003	0
95	ACCT 555/CSPP PURCHASES		214,448,755	204,946,028	9,502,726
96	SUBTOTAL		480,295,274	459,466,025	20,829,249
97	ACCT 536/WATER FOR POWER (PCA & OTHER)		0	0	0
98	ACCT 565/TRANS OF ELECTRICTY BY OTHERS		10,263,139	9,808,355	454,784
99	TOTAL NET POWER SUPPLY COSTS		490,558,413	469,274,380	21,284,033
100	**OTHER O&M**				
101	TOTAL O&M EXPENSES		930,414,600	888,823,963	41,590,637
102	LESS: ACCT 501/FUEL - THERMAL PLANTS		(65,523,000)	(62,619,523)	(2,903,477)

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
103	ACCT 547/FUEL - OTHER		(119,653,675)	(114,351,541)	(5,302,134)
104	ACCT 555/NON-FIRM PURCHASES		(99,465,021)	(95,057,493)	(4,407,528)
105	ACCT 555/DEMAND RESPONSE INCENTIVE		(10,240,003)	(10,240,003)	0
106	ACCT 555/CSPP PURCHASES		(214,448,755)	(204,946,028)	(9,502,726)
107	SUBTOTAL		421,084,146	401,609,375	19,474,771
108	ACCT 536/WATER FOR POWER (PCA & OTHER)		0	0	0
109	ACCT 565/TRANS OF ELECTRICTY BY OTHERS		(10,263,139)	(9,808,355)	(454,784)
110	ACCT 416/MERCHANDISING EXPENSE		(4,701,875)	(4,523,796)	(178,079)
111	NET OTHER O&M		406,119,132	387,277,224	18,841,908

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
112	***TABLE 1-ELECTRIC PLANT IN SERVICE***		541,565		
113	INTANGIBLE PLANT				
114	301 - ORGANIZATION	P101P	$ 5,703	**5,455**	*248*
115	302 - FRANCHISES & CONSENTS	D10	52,690,324	**50,540,892**	*2,149,432*
116	303 - MISCELLANEOUS	P101P	52,524,883	**50,240,922**	*2,283,961*
117					
118	TOTAL INTANGIBLE PLANT		105,220,910	**100,787,269**	*4,433,641*
119					
120	PRODUCTION PLANT				
121	310-316 / STEAM PRODUCTION	D10	278,459,274	**267,099,895**	*11,359,379*
122	330-336 / HYDRAULIC PRODUCTION	D10	1,103,982,377	**1,058,946,870**	*45,035,508*
123	340-346 / OTHER PRODUCTION - BASE LOAD	D10	443,280,152	**425,197,122**	*18,083,030*
124	340-346 / OTHER PRODUCTION-PEAKERS	D10	188,520,803	**180,830,345**	*7,690,458*
125					
126	TOTAL PRODUCTION PLANT		2,014,242,607	**1,932,074,232**	*82,168,375*
127					
128	TRANSMISSION PLANT				
129	350 / LAND & LAND RIGHTS - SYSTEM SERVICE	D11	41,039,057	**39,364,923**	*1,674,134*
130	DIRECT ASSIGNMENT	DA350	0	**0**	*0*
131	TOTAL ACCOUNT 350		41,039,057	**39,364,923**	*1,674,134*
132					
133	352 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	D11	100,561,627	**96,459,348**	*4,102,279*
134	DIRECT ASSIGNMENT	DA352	658	**0**	*658*
135	TOTAL ACCOUNT 352		100,562,285	**96,459,348**	*4,102,937*
136					
137	353 / STATION EQUIPMENT - SYSTEM SERVICE	D11	468,388,599	**449,281,302**	*19,107,296*
138	DIRECT ASSIGNMENT	DA353	111,594	**75,100**	*36,494*
139	TOTAL ACCOUNT 353		468,500,193	**449,356,402**	*19,143,790*
140					
141	354 / TOWERS & FIXTURES - SYSTEM SERVICE	D11	237,158,275	**227,483,716**	*9,674,560*
142	DIRECT ASSIGNMENT	DA354	0	**0**	*0*
143	TOTAL ACCOUNT 354		237,158,275	**227,483,716**	*9,674,560*
144					
145	355 / POLES & FIXTURES - SYSTEM SERVICE	D11	236,032,717	**226,404,073**	*9,628,644*
146	DIRECT ASSIGNMENT	DA355	33,842	**0**	*33,842*
147	TOTAL ACCOUNT 355		236,066,559	**226,404,073**	*9,662,486*
148					
149	356 / OVERHEAD CONDUCTORS & DEVICES - SYSTEM SERVICE	D11	271,730,786	**260,645,887**	*11,084,900*
150	DIRECT ASSIGNMENT	DA356	26,495	**1,189**	*25,306*
151	TOTAL ACCOUNT 356		271,757,281	**260,647,076**	*11,110,206*
152					
153	359 / ROADS & TRAILS - SYSTEM SERVICE	D11	390,266	**374,346**	*15,920*
154	DIRECT ASSIGNMENT	DA359	0	**0**	*0*
155	TOTAL ACCOUNT 359		390,266	**374,346**	*15,920*
156					
157	TOTAL TRANSMISSION PLANT		1,355,473,916	**1,300,089,883**	*55,384,033*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
158	***TABLE 1-ELECTRIC PLANT IN SERVICE***				
159					
160	DISTRIBUTION PLANT				
161	360 / LAND & LAND RIGHTS - SYSTEM SERVICE	ACCT360	9,601,720	**9,271,376**	*330,344*
162	PLUS: ADJUSTMENT FOR CIAC	ACCT360CIAC	430,656	**430,355**	*301*
163	DISTRIBUTION PLANT + CIAC		10,032,376	**9,701,731**	*330,645*
164					
165	361 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	ACCT361	62,384,614	**59,436,491**	*2,948,123*
166	PLUS: ADJUSTMENT FOR CIAC	ACCT361CIAC	8,009,324	**7,447,616**	*561,708*
167	DISTRIBUTION PLANT + CIAC		70,393,938	**66,884,107**	*3,509,831*
168					
169	362 / STATION EQUIPMENT - SYSTEM SERVICE	ACCT362	343,076,495	**328,626,219**	*14,450,276*
170	PLUS: ADJUSTMENT FOR CIAC	ACCT362CIAC	38,463,951	**34,892,876**	*3,571,075*
171	DISTRIBUTION PLANT + CIAC		381,540,447	**363,519,096**	*18,021,351*
172					
173	363 / STORAGE BATTERY EQUIPMENT	D10	174,800,536	**167,669,778**	*7,130,758*
174	TOTAL BATTERY STORAGE EQUIPMENT		174,800,536	**167,669,778**	**7,130,758**
175					
176	364 / POLES, TOWERS & FIXTURES	DA364	334,235,525	**308,137,437**	*26,098,088*
177	365 / OVERHEAD CONDUCTORS & DEVICES	DA365	162,758,591	**153,461,377**	*9,297,214*
178	366 / UNDERGROUND CONDUIT	DA366	54,848,113	**53,988,992**	*859,120*
179	367 / UNDERGROUND CONDUCTORS & DEVICES	DA367	338,877,918	**333,844,506**	*5,033,412*
180	368 / LINE TRANSFORMERS	DA368	745,644,817	**704,503,661**	*41,141,155*
181	369 / SERVICES	DA369	69,707,265	**66,979,720**	*2,727,544*
182	370 / METERS	DA370	116,503,219	**112,739,963**	*3,763,256*
183	371 / INSTALLATIONS ON CUSTOMER PREMISES	DA371	4,646,860	**4,326,265**	*320,595*
184	373 / STREET LIGHTING SYSTEMS	DA373	6,313,711	**6,061,607**	*252,104*
185					
186	TOTAL DISTRIBUTION PLANT (without CIAC)		2,423,399,384	**2,309,047,394**	*114,351,990*
187					
188	GENERAL PLANT				
189	389 / LAND & LAND RIGHTS	PTD	20,940,797	**20,030,220**	*910,577*
190	390 / STRUCTURES & IMPROVEMENTS	PTD	177,514,211	**169,795,289**	*7,718,922*
191	391 / OFFICE FURNITURE & EQUIPMENT	PTD	41,438,522	**39,636,634**	*1,801,888*
192	392 / TRANSPORTATION EQUIPMENT	PTD	119,914,591	**114,700,297**	*5,214,295*
193	393 / STORES EQUIPMENT	PTD	5,476,857	**5,238,705**	*238,152*
194	394 / TOOLS, SHOP & GARAGE EQUIPMENT	PTD	15,380,479	**14,711,683**	*668,796*
195	395 / LABORATORY EQUIPMENT	PTD	14,914,034	**14,265,521**	*648,513*
196	396 / POWER OPERATED EQUIPMENT	PTD	27,588,092	**26,388,468**	*1,199,624*
197	397 / COMMUNICATIONS EQUIPMENT	PTD	82,670,542	**79,075,745**	*3,594,797*
198	398 / MISCELLANEOUS EQUIPMENT	PTD	11,406,368	**10,910,380**	*495,988*
199					
200	TOTAL GENERAL PLANT		517,244,492	**494,752,941**	*22,491,551*
201					
202	TOTAL ELECTRIC PLANT IN SERVICE (without CIAC)		6,415,581,308	**6,136,751,718**	*278,829,591*

Exhibit No. 35
Case No. IPC-E-23-11
K. Noe, IPC

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
203	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***				
204					
205	PRODUCTION PLANT				
206	310-316 / STEAM PRODUCTION	L 121	151,132,377	**144,967,130**	*6,165,246*
207	330-336 / HYDRAULIC PRODUCTION	L 122	510,334,076	**489,515,669**	*20,818,407*
208	340-346 / OTHER PRODUCTION - BASE LOAD	L 123	95,989,012	**92,073,267**	*3,915,745*
209	340-346 / OTHER PRODUCTION-PEAKERS	L 124	67,786,643	**65,021,376**	*2,765,267*
210	TOTAL PRODUCTION PLANT		825,242,107	**791,577,442**	*33,664,665*
211					
212	TRANSMISSION PLANT				
213	350 / LAND & LAND RIGHTS	L 131	10,201,355	**9,785,205**	*416,151*
214	352 / STRUCTURES & IMPROVEMENTS	L 135	34,251,518	**32,854,058**	*1,397,461*
215	353 / STATION EQUIPMENT	L 139	123,269,932	**118,232,894**	*5,037,039*
216	354 / TOWERS & FIXTURES	L 143	80,447,813	**77,166,051**	*3,281,763*
217	355 / POLES & FIXTURES	L 147	80,583,039	**77,284,679**	*3,298,360*
218	356 / OVERHEAD CONDUCTORS & DEVICES	L 151	90,332,368	**86,639,325**	*3,693,042*
219	359 / ROADS & TRAILS	L 155	297,401	**285,269**	*12,132*
220	TOTAL TRANSMISSION PLANT		419,383,427	**402,247,480**	*17,135,948*
221					
222	DISTRIBUTION PLANT				
223	360 / LAND & LAND RIGHTS	L 161	239,442	**231,204**	*8,238*
224	361 / STRUCTURES & IMPROVEMENTS	L 165	16,778,902	**15,985,978**	*792,924*
225	362 / STATION EQUIPMENT	L 169	72,249,574	**69,206,444**	*3,043,130*
226	363 / STORAGE BATTERY EQUIPMENT	L 173	3,548,486	**3,403,730**	*144,756*
227	364 / POLES, TOWERS & FIXTURES	L 176	144,727,473	**133,426,728**	*11,300,745*
228	365 / OVERHEAD CONDUCTORS & DEVICES	L 177	56,593,997	**53,361,193**	*3,232,803*
229	366 / UNDERGROUND CONDUIT	L 178	18,880,710	**18,584,970**	*295,740*
230	367 / UNDERGROUND CONDUCTORS & DEVICES	L 179	105,526,973	**103,959,562**	*1,567,410*
231	368 / LINE TRANSFORMERS	L 180	199,797,737	**188,773,843**	*11,023,894*
232	369 / SERVICES	L 181	45,500,962	**43,720,575**	*1,780,387*
233	370 / METERS	L 182	37,281,576	**36,077,317**	*1,204,260*
234	371 / INSTALLATIONS ON CUSTOMER PREMISES	L 183	1,185,775	**1,103,966**	*81,809*
235	373 / STREET LIGHTING SYSTEMS	L 184	33,016	**31,698**	*1,318*
236	TOTAL DISTRIBUTION PLANT		702,344,623	**667,867,210**	*34,477,414*
237					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

		ALLOC/	TOTAL	IDAHO	
2					
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
238	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***				
239					
240	GENERAL PLANT				
241	389 / LAND & LAND RIGHTS	L 189	0	**0**	*0*
242	390 / STRUCTURES & IMPROVEMENTS	L 190	36,044,691	**34,477,345**	*1,567,346*
243	391 / OFFICE FURNITURE & EQUIPMENT	L 191	18,757,637	**17,941,991**	*815,646*
244	392 / TRANSPORTATION EQUIPMENT	L 192	23,975,721	**22,933,175**	*1,042,546*
245	393 / STORES EQUIPMENT	L 193	1,468,592	**1,404,733**	*63,859*
246	394 / TOOLS, SHOP & GARAGE EQUIPMENT	L 194	5,026,782	**4,808,200**	*218,582*
247	395 / LABORATORY EQUIPMENT	L 195	6,860,809	**6,562,478**	*298,331*
248	396 / POWER OPERATED EQUIPMENT	L 196	5,419,822	**5,184,149**	*235,672*
249	397 / COMMUNICATIONS EQUIPMENT	L 197	33,453,398	**31,998,730**	*1,454,668*
250	398 / MISCELLANEOUS EQUIPMENT	L 198	4,396,481	**4,205,307**	*191,174*
251	TOTAL GENERAL PLANT		135,403,933	**129,516,109**	*5,887,824*
252					
253	AMORTIZATION OF DISALLOWED COSTS	L 118	3,297,393	**3,158,453**	*138,941*
254					
255	TOTAL ACCUM PROVISION DEPRECIATION		2,085,671,484	**1,994,366,693**	*91,304,791*
256					
257	AMORTIZATION OF OTHER UTILITY PLANT				
258	302/FRANCHISES AND CONSENTS	L 115	18,778,074	**18,012,048**	*766,027*
259	303/MISCELLANEOUS INTANGIBLE PLANT	L 116	23,137,432	**22,131,338**	*1,006,094*
260					
261	TOTAL AMORT OF OTHER UTILITY PLANT		41,915,507	**40,143,386**	*1,772,121*
262					
263	TOTAL ACCUM PROVISION FOR DEPR				
264	& AMORTIZATION OF OTHER UTILITY PLANT		2,127,586,991	**2,034,510,078**	*93,076,912*
265					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
266	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***				
267					
268	NET ELECTRIC PLANT IN SERVICE		4,287,994,318	**4,102,241,639**	*185,752,678*
269	LESS:				
270	252 CUSTOMER ADVANCES FOR CONSTRUCTION				
271	POWER SUPPLY	D10	0	**0**	*0*
272	OTHER	DA252	7,441,965	**7,387,459**	*54,505*
273	TOTAL CUSTOMER ADV FOR CONSTRUCTION		7,441,965	**7,387,459**	*54,505*
274					
275	ACCUMULATED DEFERRED INCOME TAXES				
276	190 / ACCUMULATED DEFERRED INCOME TAXES				
277	CUSTOMER ADVANCES FOR CONSTUCTION	DA252	(1,806,678)	**(1,793,446)**	*(13,232)*
278	OTHER	LABOR	(18,108,580)	**(17,318,189)**	*(790,391)*
279	TOTAL ACCOUNT 190		(19,915,258)	**(19,111,635)**	*(803,623)*
280	281 / ACCELERATED AMORTIZATION	P101P	0	**0**	*0*
281	282 / OTHER PROPERTY	P101P	395,790,474	**378,580,157**	*17,210,317*
282	283 / OTHER	P101P	6,265,289	**5,992,853**	*272,436*
283	TOTAL ACCUM DEFERRED INCOME TAXES		382,140,505	**365,461,375**	**16,679,130**
284					
285	NET ELECTRIC PLANT IN SERVICE		3,898,411,848	**3,729,392,805**	*169,019,043*
286	ADD:				
287	WORKING CAPITAL				
288	151 / FUEL INVENTORY	E10	24,704,689	**23,609,967**	*1,094,723*
289	154 & 163 / PLANT MATERIALS & SUPPLIES				
290	PRODUCTION - GENERAL	L 126	16,137,028	**15,478,739**	*658,289*
291	TRANSMISSION - GENERAL	L 157	14,694,376	**14,093,970**	*600,405*
292	DISTRIBUTION - GENERAL	L 186+CIAC	55,470,039	**52,809,487**	*2,660,553*
293	OTHER - UNCLASSIFIED	L 202	4,284,121	**4,097,928**	*186,194*
294	TOTAL ACCOUNT 154 & 163		90,585,564	**86,480,124**	*4,105,440*
295	165 / PREPAID ITEMS				
296	AD VALOREM TAXES	L 697	0	**0**	*0*
297	OTHER PROD-RELATED PREPAYMENTS	D10	0	**0**	*0*
298	INSURANCE	L 126	0	**0**	*0*
299	PENSION EXPENSE	L 1039	0	**0**	*0*
300	PREPAID RETIREE BENEFITS	L 1039	0	**0**	*0*
301	MISCELLANEOUS PREPAYMENTS	P101P	0	**0**	*0*
302	TOTAL ACCOUNT 165		0	**0**	*0*
303	WORKING CASH ALLOWANCE	L 618	0	**0**	*0*
304					
305	TOTAL WORKING CAPITAL		115,290,253	**110,090,091**	*5,200,163*
306					
307	NET ELECTRIC PLANT IN SERVICE		4,013,702,101	**3,839,482,895**	*174,219,206*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
308	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***				
309					
310	NET ELECTRIC PLANT IN SERVICE		4,013,702,101	**3,839,482,895**	*174,219,206*
311	ADD:				
312	105 / PLANT HELD FOR FUTURE USE				
313	HYDRAULIC PRODUCTION	L 122	0	**0**	*0*
314	TRANS LAND & LAND RIGHTS	L 131	2,752,506	**2,640,221**	*112,285*
315	TRANS STRUCTURES & IMPROVEMENTS	L 135	0	**0**	*0*
316	TRANS STATION EQUIPMENT	L 139	0	**0**	*0*
317	DIST LAND & LAND RIGHTS	L 163	5,497,799	**5,316,603**	*181,196*
318	DIST STRUCTURES & IMPROVEMENTS	L 167	0	**0**	*0*
319	DIST STATIONS EQUIPMENT		0		
320	GEN LAND & LAND RIGHTS	L 189	0	**0**	*0*
321	GEN STRUCTURES & IMPROVEMENTS	L 190	0	**0**	*0*
322	COMMUNICATION	L 192	0	**0**	*0*
323	TOTAL PLANT HELD FOR FUTURE USE		8,250,305	**7,956,825**	*293,480*
324					
325	114/115 - ASSET EXCHANGE ACQUISITION ADJUSTMENT	CIDA	628,247	**628,247**	*0*
326					
327	DEFERRED PROGRAMS:				
328	182 / CONSERVATION PROGRAMS				
329	IDAHO DEFERRED CONSERVATION PROGRAMS	CIDA	0	**0**	*0*
330	OREGON DEFERRED CONSERVATION PROGRAMS	CODA	0	**0**	*0*
331	TOTAL CONSERVATION PROGRAMS		0	**0**	*0*
332	182&186 / MISC. OTHER REGULATORY ASSETS				
333	CUB FUND INTEREST (OPUC 15-399)	CODA	0	**0**	*0*
334	AM. FALLS BOND REFINANCING	D10	72,977	**70,000**	*2,977*
335	SFAS 87 CAPITALIZED PENSION - OPUC ORDER 10-064	CODA	6,781,181	**0**	*6,781,181*
336	CLOUD COMPUTING - (IPUC Order 34707)	CIDA	1,006,327	**1,006,327**	*0*
337	WILDFIRE MITIGATION (IPUC Order 35077)	CIDA	13,056,171	**13,056,171**	*0*
338	SIEMENS LTP RATE BASE (IPUC Order 33420)	CIDA	12,207,705	**12,207,705**	*0*
339	SIEMENS LTP DEFERRED RATE BASE (IPUC Order 33420)	CIDA	8,181,006	**8,181,006**	*0*
340	SIEMENS LTP RATE BASE (OPUC ORDER 15-387)	CODA	471,789	**0**	*471,789*
341	SIEMENS LTP DEFERRED RATE BASE (OPUC ORDER 15-387)	CODA	94,504	**0**	*94,504*
342	TOTAL OTHER REGULATORY ASSETS		41,871,660	**34,521,209**	*7,350,451*
343	186 / MISC. OTHER DEFERRED PROGRAMS		0	**0**	*0*
344	254 / JIM BRIDGER PLANT END OF LIFE DEPR - OPUC ORD 12-296	CODA	(3,285,386)	**0**	*(3,285,386)*
345	RECONNECT FEES - (OPUC ADV 16-09)	CODA	(14,711)	**0**	*(14,711)*
346	TOTAL DEFERRED PROGRAMS		38,571,563	**34,521,209**	*4,050,354*
347					
348	DEVELOPMENT OF IERCO RATE BASE				
349	INVESTMENT IN IERCO	E10	15,577,838	**14,887,547**	*690,290*
350	PREPAID COAL ROYALTIES	E10	597,770	**571,281**	*26,489*
351	NOTES PAYABLE TO/RECEIVABLE FROM SUBSIDIARY	E10	15,195,150	**14,521,817**	*673,333*
352	TOTAL SUBSIDIARY RATE BASE		31,370,758	**29,980,646**	*1,390,112*
353					
354	TOTAL COMBINED RATE BASE		4,092,522,974	**3,912,569,823**	**179,953,152**

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
355	***TABLE 4-OPERATING REVENUES***				
356	FIRM ENERGY SALES				
357	440-448 / RETAIL	RETREV	1,169,833,173	**1,116,166,332**	*53,666,841*
358	442 / BASE REVENUE TRANSFER - PCA	CIDA	173,368,953	**173,368,953**	*0*
359	442 / BASE REVENUE TRANSFER - EE RIDER	CIDA	3,474,555	**3,474,555**	*0*
360	447 / SYSTEM OPPORTUNITY SALES	E10	19,175,280	**18,325,578**	*849,702*
361	447.050 / FINANCIAL LOSSES	E10	9,859,900	**9,422,985**	*436,915*
362	TOTAL SALES OF ELECTRICITY		1,375,711,861	**1,320,758,403**	*54,953,458*
363					
364	OTHER OPERATING REVENUES				
365	415 / MERCHANDISING REVENUES	D60	3,942,438	**3,793,122**	*149,316*
366					
367	449 / OATT TARIFF REFUND				
368	NETWORK	D11	0	**0**	*0*
369	POINT-TO-POINT	D11	0	**0**	*0*
370	TOTAL ACCOUNT 449		0	0	0
371					
372	451 / MISCELLANEOUS SERVICE REVENUES	DA451	6,208,088	**6,150,427**	*57,660*
373					
374	454 / RENTS FROM ELECTRIC PROPERTY				
375	SUBSTATION EQUIPMENT	L 139	3,215,758	**3,084,356**	*131,402*
376	TRANSFORMER RENTALS	D11	17,330	**16,623**	*707*
377	LINE RENTALS	D11	0	**0**	*0*
378	COGENERATION	L 495	1,892,534	**1,808,672**	**83,863**
379	DARK FIBER PROJECT	CIDA	0	**0**	*0*
380	POLE ATTACHMENTS	L 176	1,634,179	**1,506,578**	*127,601*
381	FACILITIES CHARGES	DA454	10,280,339	**9,859,316**	*421,023*
382	OTHER RENTALS	L 122	1,072,002	**1,028,271**	*43,731*
383	MISCELLANEOUS	PTD	84,248	**80,584**	**3,663**
384	TOTAL ACCOUNT 454		18,196,391	**17,384,400**	*811,990*
385					
386	456 / OTHER ELECTRIC REVENUES				
387	TRANSMISSION NETWORK SERVICES- FIRM DA	D11	11,080,635	**10,628,615**	*452,020*
388	TRANSMISSION NETWORK SERVICES - DIST FACILITIES	D60	792,372	**762,362**	*30,010*
389	TRANSMISSION POINT-TO-POINT	D11	48,333,338	**46,361,643**	*1,971,695*
390	PHOTOVOLTAIC STATION SERVICE	L 186+CIAC	0	**0**	*0*
391	ENERGY EFFICIENCY RIDER	CIDA	0	**0**	*0*
392	STAND-BY SERVICE	DASTNBY	759,997	**759,997**	*0*
393	SIERRA PACIFIC USAGE CHARGE	E10	51,764	**49,471**	*2,294*
394	ANTELOPE	L 515	0	**0**	*0*
395	MISCELLANEOUS	PTD	1,663	**1,590**	**72**
396	TOTAL ACCOUNT 456		61,019,769	**58,563,677**	*2,456,091*
397					
398	TOTAL OTHER OPERATING REVENUES		89,366,685	**85,891,627**	3,475,058
399					
400	TOTAL OPERATING REVENUES		1,465,078,546	**1,406,650,030**	*58,428,516*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
401	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
402	STEAM POWER GENERATION				
403	OPERATION				
404	500 / SUPERVISION & ENGINEERING	D10	(76,495)	**(73,374)**	*(3,120)*
405	501 / FUEL	E10	65,523,000	**62,619,523**	*2,903,477*
406	502 / STEAM EXPENSES				
407	LABOR	D10	1,607,750	**1,542,164**	*65,586*
408	OTHER	E10	(1,145,574)	**(1,094,811)**	*(50,763)*
409	TOTAL ACCOUNT 502		462,176	**447,353**	*14,823*
410	505 / ELECTRIC EXPENSES				
411	LABOR	D10	626,112	**600,571**	*25,541*
412	OTHER	E10	(570,253)	**(544,984)**	*(25,269)*
413	TOTAL ACCOUNT 505		55,859	**55,587**	*272*
414	506 / MISCELLANEOUS EXPENSES	D10	425,042	**407,703**	*17,339*
415	507 / RENTS	L 121	11,358	**10,895**	*463*
416	STEAM OPERATION EXPENSES		66,400,940	**63,467,686**	*2,933,254*
417					
418	MAINTENANCE				
419	510 / SUPERVISION & ENGINEERING	D10	(250,725)	**(240,497)**	*(10,228)*
420	511 / STRUCTURES	D10	125,730	**120,601**	*5,129*
421	512 / BOILER PLANT				
422	LABOR	D10	3,983,710	**3,821,200**	*162,510*
423	OTHER	E10	(3,549,393)	**(3,392,111)**	*(157,282)*
424	TOTAL ACCOUNT 512		434,317	**429,089**	*5,228*
425	513 / ELECTRIC PLANT				
426	LABOR	D10	1,522,637	**1,460,523**	*62,114*
427	OTHER	E10	(1,408,464)	**(1,346,052)**	*(62,412)*
428	TOTAL ACCOUNT 513		114,173	**114,471**	*(298)*
429	514 / MISCELLANEOUS STEAM PLANT	D10	474,809	**455,440**	*19,369*
430	STEAM MAINTENANCE EXPENSES		898,305	**879,105**	*19,200*
431	TOTAL STEAM GENERATION EXPENSES		67,299,245	**64,346,791**	*2,952,455*
432					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
433	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
434	HYDRAULIC POWER GENERATION				
435	OPERATION				
436	535 / SUPERVISION & ENGINEERING	L 892	6,476,728	**6,210,878**	*265,850*
437	536 / WATER FOR POWER				
438	WATER FOR POWER/WCLOUD SEEDING	D10	6,481,689	**6,217,277**	*264,412*
439	WATER LEASE	D10	0	**0**	*0*
440	536 TOTAL ACCOUNT 536		6,481,689	**6,217,277**	264,412
441	537 / HYDRAULIC EXPENSES	D10	20,190,100	**19,366,472**	*823,629*
442	538 / ELECTRIC EXPENSES				
443	LABOR	D10	1,605,926	**1,540,414**	*65,512*
444	OTHER	E10	629,979	**602,063**	*27,916*
445	TOTAL ACCOUNT 538		2,235,905	**2,142,477**	*93,427*
446	539 / MISCELLANEOUS EXPENSES	D10	5,730,483	**5,496,716**	*233,768*
447	540 / RENTS	D10	303,402	**291,025**	*12,377*
448	HYDRAULIC OPERATION EXPENSES		41,418,307	**39,724,845**	**1,693,462**
449					
450	MAINTENANCE				
451	541 / SUPERVISION & ENGINEERING	L 903	125,939	**120,801**	*5,138*
452	542 / STRUCTURES	D10	1,033,666	**991,499**	*42,167*
453	543 / RESERVOIRS, DAMS & WATERWAYS	D10	508,487	**487,743**	*20,743*
454	544 / ELECTRIC PLANT				
455	LABOR	D10	1,910,981	**1,833,025**	*77,956*
456	OTHER	E10	1,011,361	**966,545**	*44,816*
457	TOTAL ACCOUNT 544		2,922,342	**2,799,570**	*122,772*
458	545 / MISCELLANEOUS HYDRAULIC PLANT	L 122	4,310,252	**4,134,421**	*175,831*
459	HYDRAULIC MAINTENANCE EXPENSES		8,900,686	**8,534,035**	*366,650*
460	TOTAL HYDRAULIC GENERATION EXPENSES		50,318,993	**48,258,881**	*2,060,112*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
461	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
462	OTHER POWER GENERATION				
463	OPERATION				
464	546 / SUPERVISION & ENGINEERING	L 916	714,692	**685,537**	*29,155*
465	547 / FUEL				
466	DIESEL FUEL	E10	10,499	**10,034**	*465*
467	OTHER	E10	119,653,675	**114,351,541**	*5,302,134*
468	TOTAL ACCOUNT 547		119,664,175	**114,361,575**	**5,302,600**
469	548 / GENERATING EXPENSES				
470	LABOR	D10	3,433,099	**3,293,050**	*140,049*
471	OTHER	E10	2,011,042	**1,921,928**	*89,114*
472	TOTAL ACCOUNT 548		5,444,141	**5,214,978**	*229,163*
473	549 / MISCELLANEOUS EXPENSES	D10	75,953	**72,854**	*3,098*
474	550 / RENTS	D10	0	**0**	*0*
475	OTHER POWER OPER EXPENSES		125,898,960	**120,334,945**	**5,564,016**
476					
477	MAINTENANCE				
478	551 / SUPERVISION & ENGINEERING	L 926	0	**0**	*0*
479	552 / STRUCTURES	D10	167,178	**160,358**	*6,820*
480	553 / GENERATING & ELECTRIC PLANT				
481	LABOR	D10	60,498	**58,030**	*2,468*
482	OTHER	E10	877,633	**838,743**	*38,890*
483	TOTAL ACCOUNT 553		938,132	**896,774**	*41,358*
484	554 / MISCELLANEOUS EXPENSES	L 124	3,387,334	**3,249,153**	*138,182*
485	OTHER POWER MAINT EXPENSES		4,492,644	**4,306,284**	*186,360*
486	TOTAL OTHER POWER GENERATION EXP		130,391,604	**124,641,229**	*5,750,375*
487					
488	OTHER POWER SUPPLY EXPENSE				
489	555.0 / PURCHASED POWER				
490	POWER EXPENSE	E10	99,465,021	**95,057,493**	*4,407,528*
491	OTHER	CIDA	0	**0**	*0*
492	TRANSMISSION LOSSES	E10	0	**0**	*0*
493	DEMAND RESPONSE INCENTIVE	CIDA	10,240,003	**10,240,003**	*0*
494	TOTAL 555.0/PURCHASED POWER		109,705,024	**105,297,496**	*4,407,528*
495	555.1 / COGENERATION & SMALL POWER PROD	E10	214,448,755	**204,946,028**	*9,502,726*
496	555/TOTAL		324,153,778	**310,243,524**	*13,910,254*
497	556 / LOAD CONTROL & DISPATCHING EXPENSES	D10	0	**0**	*0*
498	557 / OTHER EXPENSES				
499	PCA/ EPC ACCOUNTS	CIDA	0	**0**	*0*
500	OREGON POWER COST-RELATED EXPENSES	CODA	0	**0**	*0*
501	OTHER	D10	7,029,991	**6,743,211**	*286,779*
502	557/TOTAL		7,029,991	**6,743,211**	**286,779**
503	TOTAL OTHER POWER SUPPLY EXPENSES		331,183,769	**316,986,736**	**14,197,033**
504					
505	TOTAL PRODUCTION EXPENSES		579,193,611	**554,233,636**	*24,959,975*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

Line	Description	Alloc/ Source	Total System	Idaho Retail	Other
2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
506	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
507	TRANSMISSION EXPENSES				
508	OPERATION				
509	560 / SUPERVISION & ENGINEERING	L 157	3,593,025	**3,446,215**	*146,809*
510	561 / LOAD DISPATCHING	D12	6,017,285	**5,771,817**	*245,467*
511	562 / STATION EXPENSES	L 139	3,122,087	**2,994,513**	*127,574*
512	563 / OVERHEAD LINE EXPENSES	L 143+147+151	1,205,690	**1,156,414**	*49,276*
513	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	E10	10,263,139	**9,808,355**	*454,784*
514	566 / MISCELLANEOUS EXPENSES	L 157	8	**7**	*0*
515	567 / RENTS	L 157	4,855,402	**4,657,012**	*198,389*
516	TOTAL TRANSMISSION OPERATION		29,056,635	**27,834,335**	*1,222,301*
517					
518	MAINTENANCE				
519	568 / SUPERVISION & ENGINEERING	L 157	222,008	**212,937**	*9,071*
520	569 / STRUCTURES	L 135	2,147,917	**2,060,282**	*87,635*
521	570 / STATION EQUIPMENT	L 139	3,052,711	**2,927,971**	*124,739*
522	571 / OVERHEAD LINES	L 143+147+151	3,252,166	**3,119,250**	*132,915*
523	573 / MISCELLANEOUS PLANT	L 157	5,781	**5,545**	*236*
524	TOTAL TRANSMISSION MAINTENANCE		8,680,583	**8,325,986**	*354,597*
525					
526	TOTAL TRANSMISSION EXPENSES		37,737,218	**36,160,321**	*1,576,898*
527					
528	REGIONAL MARKET EXPENSES				
529	OPERATION				
530	575 / OPER TRANS MKT ADMIN - EIM	L 157	686,880	**658,814**	*28,066*
531					
532	TOTAL REGIONAL MARKET EXPENSES		686,880	**658,814**	*28,066*
533					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
534	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
535	DISTRIBUTION EXPENSES				
536	OPERATION				
537	580 / SUPERVISION & ENGINEERING	L 186	6,428,578	**6,125,235**	*303,343*
538	581 / LOAD DISPATCHING	D60	5,944,770	**5,719,617**	*225,153*
539	582 / STATION EXPENSES	L 171	2,037,902	**1,941,646**	*96,257*
540	583 / OVERHEAD LINE EXPENSES	L 176+177	6,218,215	**5,775,361**	*442,854*
541	584 / UNDERGROUND LINE EXPENSES	L 178+179	4,971,299	**4,896,899**	*74,401*
542	585 / STREET LIGHTING & SIGNAL SYSTEMS	L 184	48,788	**46,840**	*1,948*
543	586 / METER EXPENSES	L 182	6,511,320	**6,300,993**	*210,327*
544	587 / CUSTOMER INSTALLATIONS EXPENSE	L 183	1,229,993	**1,145,133**	*84,859*
545	588 / MISCELLANEOUS EXPENSES	L 186	5,191,800	**4,946,817**	*244,983*
546	589 / RENTS	L 186	741,341	**706,360**	*34,981*
547	TOTAL DISTRIBUTION OPERATION		39,324,006	**37,604,900**	*1,719,105*
548					
549	MAINTENANCE				
550	590 / SUPERVISION & ENGINEERING	L 186	13,548	**12,909**	*639*
551	591 / STRUCTURES	L 167	0	**0**	*0*
552	592 / STATION EQUIPMENT	L 171	4,616,383	**4,398,336**	*218,046*
553	593 / OVERHEAD LINES	L 176+177	35,642,590	**33,104,169**	*2,538,421*
554	594 / UNDERGROUND LINES	L 178+179	837,357	**824,825**	*12,532*
555	595 / LINE TRANSFORMERS	L 180	98,361	**92,933**	*5,427*
556	596 / STREET LIGHTING & SIGNAL SYSTEMS	L 184	231,826	**222,570**	*9,257*
557	597 / METERS	L 182	981,330	**949,631**	*31,699*
558	598 / MISCELLANEOUS PLANT	L 186	138,917	**132,362**	*6,555*
559	TOTAL DISTRIBUTION MAINTENANCE		42,560,311	**39,737,736**	*2,822,576*
560	TOTAL DISTRIBUTION EXPENSES		81,884,317	**77,342,636**	*4,541,681*
561					
562	CUSTOMER ACCOUNTING EXPENSES				
563	901 / SUPERVISION	L 996	965,680	**917,533**	*48,148*
564	902 / METER READING	CW902	2,041,516	**1,768,247**	*273,270*
565	903 / CUSTOMER RECORDS & COLLECTIONS	CW903	16,608,368	**16,063,116**	*545,252*
566	904 / UNCOLLECTIBLE ACCOUNTS	CW904	5,782,082	**5,389,398**	*392,683*
567	905 / MISC EXPENSES	L 564+565+566	(3,031)	**(2,881)**	*(150)*
568	TOTAL CUSTOMER ACCOUNTING EXPENSES		25,394,615	**24,135,413**	*1,259,202*
569					
570	CUSTOMER SERVICES & INFORMATION EXPENSES				
571	907 / SUPERVISION	L 1004	1,133,077	**1,103,115**	*29,962*
572	908 / CUSTOMER ASSISTANCE				
573	SYSTEM CONSERVATION	E10	314,424	**300,491**	*13,933*
574	OTHER CUSTOMER ASSISTANCE	DA908	11,372,463	**11,077,363**	*295,100*
575	TOTAL ACCOUNT 908		11,686,887	**11,377,854**	**309,033**
576	909 / INFORMATION & INSTRUCTIONAL	DA909	295,113	**285,588**	*9,524*
577	910 / MISCELLANEOUS EXPENSES	L 575+576	796,869	**775,684**	*21,186*
578	912 / DEMO AND SELLING EXPENSES	E10	0	**0**	*0*
579	TOTAL CUST SERV & INFORMATN EXPENSES		13,911,945	**13,542,241**	**369,704**

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		**ALLOC/**	TOTAL	**IDAHO**	
3	**DESCRIPTION**	**SOURCE**	SYSTEM	**RETAIL**	**OTHER**
580	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
581	ADMINISTRATIVE & GENERAL EXPENSES				
582	920 / ADMINISTRATIVE & GENERAL SALARIES	LABOR	89,625,564	**85,713,649**	*3,911,915*
583	921 / OFFICE SUPPLIES	LABOR	15,175,273	**14,512,913**	*662,360*
584	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-CR	LABOR	(40,405,013)	**(38,641,443)**	*(1,763,570)*
585	923 / OUTSIDE SERVICES	LABOR	8,733,234	**8,352,051**	*381,182*
586	924 / PROPERTY INSURANCE				
587	PRODUCTION - STEAM	D10	412,596	**395,764**	*16,831*
588	ALL RISK & MISCELLANEOUS	P110P	4,930,147	**4,725,542**	*204,605*
589	TOTAL ACCOUNT 924		5,342,743	**5,121,307**	*221,436*
590	925 / INJURIES & DAMAGES	LABOR	11,876,713	**11,358,326**	*518,387*
591	926 / EMPLOYEE PENSIONS & BENEFITS	LABOR	41,594,606	**39,779,114**	*1,815,493*
592	EMPLOYEE PENSIONS & BENEFITS - OREGON	CODA	880,053	**0**	*880,053*
593	EMPLOYEE PENSIONS & BENEFITS - IDAHO	CIDA	35,182,378	**35,182,378**	*0*
594	EMPLOYEE PENSIONS & BENEFITS -CAPITALIZED OREGON	CODA	0	**0**	*0*
595	927 / FRANCHISE REQUIREMENTS	CIDA	0	**0**	*0*
596	928 / REGULATORY COMMISSION EXPENSES				
597	928.101 / FERC ADMIN ASSESS & SECURITIES				
598	CAPACITY RELATED	D10	2,826,830	**2,711,513**	*115,317*
599	ENERGY RELATED	E10	963,911	**921,198**	*42,713*
600	FERC RATE CASE	E99	0	**0**	*0*
601	FERC ORDER 472	D11	963,867	**924,547**	*39,320*
602	FERC OTHER	D11	109,055	**104,606**	*4,449*
603	FERC - OREGON HYDRO FEE	D11	271,717	**260,632**	*11,084*
604	SEC EXPENSES	CIDA	0	**0**	*0*
605	IDAHO PUC -RATE CASE	CIDA	0	**0**	*0*
606	-OTHER	CIDA	332,773	**332,773**	*0*
607	OREGON PUC -RATE CASE	CODA	0	**0**	*0*
608	-OTHER	CODA	1,309,155	**0**	*1,309,155*
609	TOTAL ACCOUNT 928		6,777,308	**5,255,269**	*1,522,038*
610	929 / DUPLICATE CHARGES	LABOR	0	**0**	*0*
611	930.1 / GENERAL ADVERTISING	LABOR	0	**0**	*0*
612	930.2 / MISCELLANEOUS EXPENSES	LABOR	4,047,076	**3,870,432**	*176,644*
613	931 / RENTS	L 200	0	**0**	*0*
614	TOTAL ADM & GEN OPERATION		178,829,934	**170,503,996**	*8,325,937*
615	PLUS:				
616	935 / GENERAL PLANT MAINTENANCE	L 200	8,074,205	**7,723,111**	*351,094*
617	416 / MERCHANDISING EXPENSE	D60	4,701,875	**4,523,796**	*178,079*
618	TOTAL OPER & MAINT EXPENSES		930,414,600	**888,823,963**	**41,590,637**

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

		ALLOC/	TOTAL	IDAHO	
2					
3	**DESCRIPTION**	**SOURCE**	SYSTEM	**RETAIL**	**OTHER**
619	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***				
620					
621	DEPRECIATION EXPENSE				
622	310-316 / STEAM PRODUCTION	L 121	9,604,775	**9,212,961**	*391,814*
623	330-336 / HYDRAULIC PRODUCTION	L 122	25,359,140	**24,324,647**	*1,034,493*
624	340-346 / OTHER PRODUCTION-BASELOAD	L 123	13,814,802	**13,251,245**	*563,557*
625	340-346 / OTHER PRODUCTION-PEAKERS	L 124	6,173,315	**5,921,482**	*251,832*
626	TOTAL PRODUCTION PLANT		54,952,032	**52,710,336**	*2,241,696*
627					
628	TRANSMISSION PLANT				
629	350 / LAND & LAND RIGHTS	L 131	416,355	**399,371**	*16,985*
630	352 / STRUCTURES & IMPROVEMENTS	L 135	1,920,891	**1,842,519**	*78,372*
631	353 / STATION EQUIPMENT	L 139	10,291,818	**9,871,275**	*420,543*
632	354 / TOWERS & FIXTURES	L 143	2,890,165	**2,772,265**	*117,900*
633	355 / POLES & FIXTURES	L 147	6,155,439	**5,903,489**	*251,949*
634	356 / OVERHEAD CONDUCTORS & DEVICES	L 151	4,098,377	**3,930,824**	*167,553*
635	359 / ROADS & TRAILS	L 155	2,693	**2,583**	*110*
636	TOTAL TRANSMISSION PLANT		25,775,739	**24,722,326**	*1,053,413*
637					
638	DISTRIBUTION PLANT				
639	360 / LAND & LAND RIGHTS	L 163	30,928	**29,909**	*1,019*
640	361 / STRUCTURES & IMPROVEMENTS	L 167	1,393,285	**1,323,816**	*69,469*
641	362 / STATION EQUIPMENT	L 171	6,761,927	**6,442,540**	*319,387*
642	363 / STORAGE BATTERY EQUIPMENT	L 173	8,740,027	**8,383,489**	*356,538*
643	364 / POLES, TOWERS & FIXTURES	L 176	6,652,506	**6,133,059**	*519,447*
644	365 / OVERHEAD CONDUCTORS & DEVICES	L 177	3,687,824	**3,477,165**	*210,659*
645	366 / UNDERGROUND CONDUIT	L 178	1,327,818	**1,307,020**	*20,798*
646	367 / UNDERGROUND CONDUCTORS & DEVICES	L 179	7,931,228	**7,813,424**	*117,804*
647	368 / LINE TRANSFORMERS	L 180	14,560,366	**13,756,994**	*803,372*
648	369 / SERVICES	L 181	1,163,810	**1,118,272**	*45,538*
649	370 / METERS	L 182	5,908,929	**5,718,060**	*190,869*
650	371 / INSTALLATIONS ON CUSTOMER PREMISES	L 183	193,380	**180,039**	*13,342*
651	373 / STREET LIGHTING SYSTEMS	L 184	217,455	**208,773**	*8,683*
652	TOTAL DISTRIBUTION PLANT		58,569,484	**55,892,559**	*2,676,925*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

Line	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	IDAHO RETAIL	OTHER
653	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***				
654					
655	GENERAL PLANT				
656	389 / LAND & LAND RIGHTS	L 189	0	**0**	*0*
657	390 / STRUCTURES & IMPROVEMENTS	L 190	3,366,802	**3,220,402**	*146,400*
658	391 / OFFICE FURNITURE & EQUIPMENT	L 191	6,992,274	**6,688,226**	*304,048*
659	392 / TRANSPORTATION EQUIPMENT	L 192	72,444	**69,294**	*3,150*
660	393 / STORES EQUIPMENT	L 193	227,417	**217,528**	*9,889*
661	394 / TOOLS, SHOP & GARAGE EQUIPMENT	L 194	808,645	**773,482**	*35,163*
662	395 / LABORATORY EQUIPMENT	L 195	781,567	**747,582**	*33,985*
663	396 / POWER OPERATED EQUIPMENT	L 196	0	**0**	*0*
664	397 / COMMUNICATIONS EQUIPMENT	L 197	5,615,068	**5,370,906**	*244,162*
665	398 / MISCELLANEOUS EQUIPMENT	L 198	860,793	**823,363**	*37,430*
666	TOTAL GENERAL PLANT		18,725,011	**17,910,784**	*814,227*
667					
668	TOTAL DEPRECIATION EXPENSE		158,022,265	**151,236,005**	*6,786,261*
669					
670	DEPRECIATION ON DISALLOWED COSTS	L 118	(296,299)	**(283,814)**	*(12,485)*
671	TOTAL DEPRECIATION EXPENSE		157,725,966	**150,952,190**	*6,773,776*
672					
673	AMORTIZATION EXPENSE				
674	302/FRANCHISES AND CONSENTS	L 115	1,543,543	**1,480,576**	*62,967*
675	303/MISCELLANEOUS INTANGIBLE PLANT	L 116	4,422,755	**4,230,438**	*192,316*
676	ADJUSTMENTS, GAINS & LOSSES	L 118	15,018	**14,385**	*633*
677	TOTAL AMORTIZATION EXPENSE		5,981,316	**5,725,400**	*255,916*
678					
679	TOTAL DEPRECIATION & AM0RTIZATION EXP		163,707,282	**156,677,590**	*7,029,692*
680					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

Line	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	IDAHO RETAIL	OTHER
681	***TABLE 7-TAXES OTHER THAN INCOME TAXES***				
682					
683	TAXES OTHER THAN INCOME				
684	FEDERAL TAXES				
685	FICA	LABOR	0	**0**	*0*
686	FUTA	LABOR	0	**0**	*0*
687	LESS PAYROLL DEDUCTION	LABOR	0	**0**	*0*
688					
689	STATE TAXES				
690	AD VALOREM TAXES				
691	JIM BRIDGER STATION	L 121	0	**0**	*0*
692	VALMY	L 121	0	**0**	*0*
693	OTHER-PRODUCTION PLANT	L 126	8,161,318	**7,828,388**	*332,930*
694	OTHER-TRANSMISSION PLANT	L 157	6,826,628	**6,547,695**	*278,933*
695	OTHER-DISTRIBUTION PLANT	L 186	9,182,931	**8,749,620**	*433,311*
696	OTHER-GENERAL PLANT	L 200	1,814,292	**1,735,401**	*78,892*
697	SUB-TOTAL		25,985,170	**24,861,103**	*1,124,066*
698					
699	LICENSES - HYDRO PROJECTS	L 122	4,240	**4,067**	*173*
700					
701	REGULATORY COMMISSION FEES				
702	STATE OF IDAHO	CIDA	2,616,251	**2,616,251**	*0*
703	STATE OF OREGON	CODA	385,511	**0**	*385,511*
704					
705	FRANCHISE TAXES				
706	STATE OF OREGON	CODA	953,000	**0**	*953,000*
707					
708	OTHER STATE TAXES				
709	UNEMPLOYMENT TAXES	LABOR	0	**0**	*0*
710	HYDRO GENERATION KWH TAX	E10	1,889,911	**1,806,165**	*83,746*
711	IRRIGATION-PIC	E10	328,291	**313,744**	*14,547*
712					
713	TOTAL TAXES OTHER THAN INCOME		32,162,375	**29,601,331**	*2,561,044*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
714	***TABLE 8-REGULATORY DEBITS & CREDITS***				
715	REGULATORY DEBITS/CREDITS				
716	STATE OF IDAHO	CIDA	3,141,786	**3,141,786**	*0*
717	STATE OF OREGON	CODA	303,059	**0**	*303,059*
718					
719	TOTAL REGULATORY DEBITS/CREDITS		3,444,845	**3,141,786**	*303,059*
720					
721					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

		ALLOC/	TOTAL	IDAHO	
3	**DESCRIPTION**	**SOURCE**	SYSTEM	**RETAIL**	**OTHER**
722	***TABLE 9-INCOME TAXES***				
723					
724	410/411 NET PROVISION FOR DEFERRED INCOME TAXES				
725	ACCOUNT #282 - RELATED	P101P	(16,604,189)	**(15,882,182)**	*(722,007)*
726	ACCOUNTS #190 & #283 - RELATED	L 753	(1,269,034)	**(1,242,756)**	*(26,278)*
727	TOTAL NET PROVISION FOR DEFERRED INCOME TAXES		(17,873,223)	**(17,124,938)**	*(748,285)*
728					
729	411.4 - INVESTMENT TAX CREDIT ADJUSTMENT	P101P	25,014,178	**23,926,476**	*1,087,702*
730					
731	SUMMARY OF INCOME TAXES				
732					
733	TOTAL FEDERAL INCOME TAX		39,179,328	**39,040,245**	*139,083*
734					
735	STATE INCOME TAX				
736	STATE OF IDAHO		(4,381,551)	**(3,747,326)**	*(634,225)*
737	STATE OF OREGON		691,473	**685,175**	*6,298*
738	OTHER STATES		236,057	**233,716**	*2,341*
739	TOTAL STATE INCOME TAXES		(3,454,021)	**(2,828,435)**	*(625,586)*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

		ALLOC/	TOTAL	IDAHO	
2					
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
740	***TABLE 10-CALCULATION OF FEDERAL INCOME TAX***				
741	OPERATING REVENUES		1,465,078,546	**1,406,650,030**	*58,428,516*
742					
743	OPERATING EXPENSES				
744	OPERATION & MAINTENANCE		930,414,600	**888,823,963**	*41,590,637*
745	DEPRECIATION EXPENSE		157,725,966	**150,952,190**	*6,773,776*
746	AMORTIZATION OF LIMITED TERM PLANT		5,981,316	**5,725,400**	*255,916*
747	TAXES OTHER THAN INCOME		32,162,375	**29,601,331**	*2,561,044*
748	REGULATORY DEBITS/CREDITS		3,444,845	**3,141,786**	*303,059*
749	TOTAL OPERATING EXPENSES		1,129,729,102	**1,078,244,670**	*51,484,432*
750					
751	BOOK-TAX ADJUSTMENT	L 749	0	**0**	*0*
752					
753	INCOME BEFORE TAX ADJUSTMENTS (NOI Before Interest)		335,349,443	**328,405,360**	*6,944,084*
754					
755	INCOME STATEMENT ADJUSTMENTS				
756	INTEREST EXPENSE SYNCHRONIZATION	L 354	115,891,410	**110,795,525**	*5,095,885*
757					
758	NET OPERATING INCOME BEFORE TAXES		219,458,033	**217,609,834**	*1,848,199*
759					
760	TOTAL STATE INCOME TAXES (ALLOWED)		(3,454,021)	**(2,828,435)**	*(625,586)*
761					
762	NET FEDERAL INCOME AFTER STATE INCOME TAXES		222,912,055	**220,438,269**	*2,473,785*
763					
764	FEDERAL TAX AT 21 PERCENT	@ **21%**	46,811,531	**46,292,037**	*519,495*
765	OTHER CURRENT TAX ADJUSTMENTS	L 764	0	**0**	*0*
766	PRIOR YEAR TAX ADJUSTMENT	L 764	0	**0**	*0*
767					
768	TOTAL FEDERAL INCOME TAX BEFORE OTHER ADJUSTMENTS		46,811,531	**46,292,037**	*519,495*
769					
770	OTHER TAX ADJUSTMENTS				
771	ALLOWANCE FOR AFUDC	P101P	0	**0**	*0*
772	FEDERAL INCOME TAX ADJUSTMENTS - PLANT	P101P	3,451,222	**3,301,151**	*150,071*
773	FEDERAL INCOME TAX ADJUSTMENTS - OTHER	L 753	10,147,810	**9,937,679**	*210,131*
774	SUM OF OTHER ADJUSTMENTS		13,599,032	**13,238,830**	*360,202*
775	FEDERAL TAX ON OTHER TAX ADJ AT 21 PERCENT	@ **21%**	2,855,797	**2,780,154**	*75,642*
776	FEDERAL GENERAL BUSINESS CREDITS	P101P	10,488,000	**10,031,946**	*456,054*
777					
778	TOTAL FEDERAL INCOME TAX		39,179,328	**39,040,245**	*139,083*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		**ALLOC/**	TOTAL	**IDAHO**	
3	**DESCRIPTION**	**SOURCE**	SYSTEM	**RETAIL**	**OTHER**
779	***TABLE 11-OREGON STATE INCOME TAX***				
780					
781	NET OPERATING INCOME BEFORE TAXES - OREGON	L 758	219,458,033	**217,609,834**	*1,848,199*
782					
783	ALLOWANCE FOR AFUDC	P101P	0	**0**	*0*
784	STATE INCOME TAX ADJUSTMENTS - PLANT	P101P	3,451,222	**3,301,151**	*150,071*
785	STATE INCOME TAX ADJUSTMENTS - OTHER	L 753	10,147,810	**9,937,679**	*210,131*
786	ADD: OTHER	L 753	0	**0**	*0*
787					
788	TOTAL STATE INCOME TAX ADJUSTMENTS - OREGON		13,599,032	**13,238,830**	*360,202*
789					
790	INCOME SUBJECT TO OREGON TAX		233,057,065	**230,848,665**	*2,208,401*
791					
792	IERCO TAXABLE INCOME	E10	3,000,000	**2,867,063**	*132,937*
793	BONUS DEPRECIATION & OTHER OREGON ADJ	P101P	(5,566,032)	**(5,324,002)**	*(242,030)*
794	OTHER	L 753	0	**0**	*0*
795					
796	TOTAL STATE TAXABLE INCOME - OREGON		230,491,033	**228,391,726**	*2,099,308*
797	APPORTIONMENT FACTOR (0.045454550)	@ **0.045454550**	10,476,866	**10,381,443**	*95,423*
798	POST APPORTIONMENT M ITEMS	L 753	0	**0**	*0*
799	TOTAL TAXABLE INCOME - OREGON		10,476,866	**10,381,443**	*95,423*
800					
801	OREGON TAX AT 6.6 PERCENT	@ **6.60%**	691,473	**685,175**	*6,298*
802	LESS: INVESTMENT TAX CREDIT	P101P	0	**0**	*0*
803					
804	STATE INCOME TAX ALLOWED - OREGON		691,473	**685,175**	*6,298*
805	ADD : OR CAT TAX	L 785	0	**0**	*0*
806	PRIOR YEARS' TAX ADJUSTMENT	L 785	0	**0**	*0*
807					
808	STATE INCOME TAX PAID - OREGON		691,473	**685,175**	*6,298*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
809	***TABLE 12-IDAHO STATE INCOME TAX***				
810					
811	NET OPERATING INCOME BEFORE TAXES - IDAHO	L 744	219,458,033	**217,609,834**	*1,848,199*
812					
813	ALLOWANCE FOR AFUDC	P101P	0	**0**	*0*
814	STATE INCOME TAX ADJUSTMENTS - PLANT	P101P	3,451,222	**3,301,151**	*150,071*
815	STATE INCOME TAX ADJUSTMENTS - OTHER	L 753	10,147,810	**9,937,679**	*210,131*
816					
817	INCOME SUBJECT TO IDAHO TAX		233,057,065	**230,848,665**	*2,208,401*
818					
819	IERCO TAXABLE INCOME	E10	3,000,000	**2,867,063**	*132,937*
820	BONUS DEPRECIATION ADJUSTMENT	P101P	(29,602,625)	**(28,315,402)**	*(1,287,223)*
821	OTHER	L 753	0	**0**	*0*
822	TOTAL STATE TAXABLE INCOME - IDAHO		206,454,440	**205,400,326**	*1,054,115*
823	APPORTIONMENT FACTOR (.965517241)	@ **0.965517241**	199,335,322	**198,317,556**	***1,017,766***
824	POST APPORTIONMENT SCHEDULE M	L 753	0	**0**	*0*
825	TOTAL TAXABLE INCOME - IDAHO		199,335,322	**198,317,556**	*1,017,766*
826	IDAHO TAX AT 5.8 PERCENT	@ **5.80%**	11,561,449	**11,502,418**	*59,030*
827	LESS: INVESTMENT TAX CREDIT	P101P	15,943,000	**15,249,744**	*693,256*
828					
829	STATE INCOME TAX ALLOWED - IDAHO		(4,381,551)	**(3,747,326)**	**(634,225)**
830	ADD : CURRENT TAX ADJUSTMENT	L 826	0	**0**	*0*
831	PRIOR YEARS' TAX ADJUSTMENT	826	0	**0**	*0*
832	STATE INCOME TAX PAID - IDAHO		(4,381,551)	**(3,747,326)**	*(634,225)*
833					
834	***OTHER STATE INCOME TAX***				
835	INCOME SUBJECT TO TAX		233,057,065	**230,848,665**	*2,208,401*
836					
837	IERCO TAXABLE INCOME	E10	3,000,000	**2,867,063**	*132,937*
838	BONUS DEPRECIATION ADJUSTMENT	P101P	0	**0**	**0**
839	OTHER	L 753	0	**0**	*0*
840	TOTAL TAXABLE INCOME-OTHER STATES		236,057,065	**233,715,728**	*2,341,338*
841	APPORTIONMENT FACTOR (1.0)		236,057,065	**233,715,728**	*2,341,338*
842	POST APPORTIONMENT SCHEDULE M	L 756	0	**0**	*0*
843	TAXABLE INCOME		236,057,065	**233,715,728**	**2,341,338**
844	OTHER TAX AT 0.1 PERCENT		236,057	233,716	2,341
845	ADD : CURRENT YEAR'S TAX DEFICIENCY	L 829	0	**0**	*0*
846	PRIOR YEARS' TAX ADJUSTMENT	L 829	0	**0**	*0*
847	OTHER STATES' INCOME TAX PAID		236,057	**233,716**	**2,341**

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		**ALLOC/**	TOTAL	**IDAHO**	
3	**DESCRIPTION**	**SOURCE**	SYSTEM	**RETAIL**	**OTHER**
848	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
849	STEAM POWER GENERATION				
850	OPERATION				
851	500 / SUPERVISION & ENGINEERING	L 852-862	266,133	**255,277**	*10,857*
852	501 / FUEL	D10	2,559,614	**2,455,198**	*104,416*
853	502 / STEAM EXPENSES				
854	LABOR	D10	1,607,750	**1,542,164**	*65,586*
855	OTHER	D10	0	**0**	*0*
856	TOTAL ACCOUNT 502		1,607,750	**1,542,164**	*65,586*
857	505 / ELECTRIC EXPENSES				
858	LABOR	D10	626,112	**600,571**	*25,541*
859	OTHER	D10	0	**0**	*0*
860	TOTAL ACCOUNT 505		626,112	**600,571**	*25,541*
861	506 / MISCELLANEOUS EXPENSES	D10	3,352,418	**3,215,661**	*136,757*
862	507 / RENTS	D10	0	**0**	*0*
863	STEAM OPERATION EXPENSES		8,412,027	**8,068,870**	*343,158*
864					
865	MAINTENANCE				
866	510 / SUPERVISION & ENGINEERING	L 867-876	0	**0**	*0*
867	511 / STRUCTURES	D10	658	**631**	*27*
868	512 / BOILER PLANT				
869	LABOR	D10	3,983,710	**3,821,200**	*162,510*
870	OTHER	D10	0	**0**	*0*
871	TOTAL ACCOUNT 512		3,983,710	**3,821,200**	*162,510*
872	513 / ELECTRIC PLANT				
873	LABOR	D10	1,522,637	**1,460,523**	*62,114*
874	OTHER	D10	0	**0**	*0*
875	TOTAL ACCOUNT 513		1,522,637	**1,460,523**	*62,114*
876	514 / MISCELLANEOUS STEAM PLANT	D10	2,441,874	**2,342,261**	*99,613*
877	STEAM MAINTENANCE EXPENSES		7,948,879	**7,624,615**	*324,264*
878	TOTAL STEAM GENERATION EXPENSES		16,360,906	**15,693,485**	*667,422*
879					

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
880	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
881	HYDRAULIC POWER GENERATION				
882	OPERATION				
883	535 / SUPERVISION & ENGINEERING	L 884-891	4,235,258	**4,061,414**	*173,844*
884	536 / WATER FOR POWER	E10	866,414	**828,021**	*38,393*
885	537 / HYDRAULIC EXPENSES	D10	6,262,192	**6,006,734**	*255,458*
886	538 / ELECTRIC EXPENSES				
887	LABOR	D10	1,510,454	**1,448,837**	*61,617*
888	OTHER	D10	0	**0**	*0*
889	TOTAL ACCOUNT 538		1,510,454	**1,448,837**	*61,617*
890	539 / MISCELLANEOUS EXPENSES	D10	3,401,219	**3,262,471**	*138,748*
891	540 / RENTS	D10	0	**0**	*0*
892	HYDRAULIC OPERATION EXPENSES		16,275,537	**15,607,477**	*668,060*
893					
894	MAINTENANCE				
895	541 / SUPERVISION & ENGINEERING	L 896-902	90,192	**86,513**	*3,679*
896	542 / STRUCTURES	D10	577,669	**554,103**	*23,565*
897	543 / RESERVOIRS, DAMS & WATERWAYS	D10	254,872	**244,475**	*10,397*
898	544 / ELECTRIC PLANT				
899	LABOR	D10	1,799,397	**1,725,993**	*73,404*
900	OTHER	D10	0	**0**	*0*
901	TOTAL ACCOUNT 544		1,799,397	**1,725,993**	*73,404*
902	545 / MISCELLANEOUS HYDRAULIC PLANT	D10	2,163,612	**2,075,350**	*88,262*
903	HYDRAULIC MAINTENANCE EXPENSES		4,885,742	**4,686,434**	*199,307*
904	TOTAL HYDRAULIC GENERATION EXPENSES		21,161,279	**20,293,911**	*867,367*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		**ALLOC/**	TOTAL	**IDAHO**	
3	**DESCRIPTION**	**SOURCE**	SYSTEM	**RETAIL**	**OTHER**
905	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
906	OTHER POWER GENERATION				
907	OPERATION				
908	546 / SUPERVISION & ENGINEERING	L 909-915	516,722	**495,643**	*21,079*
909	547 / FUEL	E10	0	**0**	*0*
910	548 / GENERATING EXPENSES				
911	LABOR	D10	3,234,939	**3,102,974**	*131,965*
912	OTHER	D10	0	**0**	*0*
913	TOTAL ACCOUNT 548		3,234,939	**3,102,974**	*131,965*
914	549 / MISCELLANEOUS EXPENSES	D10	370,607	**355,488**	*15,118*
915	550 / RENTS	D10	0	**0**	*0*
916	OTHER POWER OPER EXPENSES		4,122,267	**3,954,105**	*168,162*
917					
918	MAINTENANCE				
919	551 / SUPERVISION & ENGINEERING	L 920-925	0	**0**	*0*
920	552 / STRUCTURES	D10	43,046	**41,290**	*1,756*
921	553 / GENERATING & ELECTRIC PLANT				
922	LABOR	D10	56,825	**54,507**	*2,318*
923	OTHER	D10	0	**0**	*0*
924	TOTAL ACCOUNT 553		56,825	**54,507**	*2,318*
925	554 / MISCELLANEOUS EXPENSES	D10	690,424	**662,259**	*28,165*
926	OTHER POWER MAINT EXPENSES		790,295	**758,056**	*32,239*
927	TOTAL OTHER POWER GENERATION EXP		4,912,562	**4,712,161**	*200,402*
928					
929	OTHER POWER SUPPLY EXPENSE				
930	555.0 / PURCHASED POWER	E10	0	**0**	*0*
931	555.1 / COGENERATION & SMALL POWER PROD				
932	CAPACITY RELATED	D10	0	**0**	*0*
933	ENERGY RELATED	E10	0	**0**	*0*
934	TOTAL 555.1/CSPP			**0**	*0*
935	555/TOTAL			**0**	*0*
936	556 / LOAD CONTROL & DISPATCHING EXPENSES	D10	0	**0**	*0*
937	557 / OTHER EXPENSES	D10	4,495,330	**4,311,949**	*183,381*
938	TOTAL OTHER POWER SUPPLY EXPENSES		4,495,330	**4,311,949**	*183,381*
939					
940	TOTAL PRODUCTION EXPENSES		46,930,078	**45,011,506**	*1,918,572*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

		ALLOC/	TOTAL	IDAHO	
2					
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
941	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
942	TRANSMISSION EXPENSES				
943	OPERATION				
944	560 / SUPERVISION & ENGINEERING	L 157	2,380,639	**2,283,367**	*97,272*
945	561 / LOAD DISPATCHING	D12	3,053,979	**2,929,396**	*124,583*
946	562 / STATION EXPENSES	L 139	1,883,621	**1,806,653**	*76,968*
947	563 / OVERHEAD LINE EXPENSES	L 143+147+151	428,401	**410,892**	*17,509*
948	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	E10	0	**0**	*0*
949	566 / MISCELLANEOUS EXPENSES	L 526	0	**0**	*0*
950	567 / RENTS	L 157	0	**0**	*0*
951	TOTAL TRANSMISSION OPERATION		7,746,639	**7,430,307**	*316,332*
952					
953	MAINTENANCE				
954	568 / SUPERVISION & ENGINEERING	L 157	90,949	**87,233**	*3,716*
955	569 / STRUCTURES	L 135	1,442,019	**1,383,185**	*58,834*
956	570 / STATION EQUIPMENT	L 139	2,327,169	**2,232,077**	*95,092*
957	571 / OVERHEAD LINES	L 143+147+151	865,811	**830,425**	*35,385*
958	573 / MISCELLANEOUS PLANT	L 157	3,520	**3,376**	*144*
959	TOTAL TRANSMISSION MAINTENANCE		4,729,468	**4,536,296**	*193,172*
960					
961	TOTAL TRANSMISSION EXPENSES		12,476,107	**11,966,603**	*509,504*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

		ALLOC/	TOTAL	IDAHO	
2					
3	**DESCRIPTION**	**SOURCE**	SYSTEM	**RETAIL**	**OTHER**
962	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
963	DISTRIBUTION EXPENSES				
964	OPERATION				
965	580 / SUPERVISION & ENGINEERING	L 186	2,995,909	**2,854,543**	*141,367*
966	581 / LOAD DISPATCHING	D60	4,166,909	**4,009,091**	*157,818*
967	582 / STATION EXPENSES	L 171	983,432	**936,981**	*46,451*
968	583 / OVERHEAD LINE EXPENSES	L 176+177	3,611,849	**3,354,617**	*257,231*
969	584 / UNDERGROUND LINE EXPENSES	L 178+179	1,372,655	**1,352,112**	*20,543*
970	585 / STREET LIGHTING & SIGNAL SYSTEMS	L 184	20,365	**19,552**	*813*
971	586 / METER EXPENSES	L 182	4,176,379	**4,041,475**	*134,904*
972	587 / CUSTOMER INSTALLATIONS EXPENSE	L 183	736,676	**685,851**	*50,825*
973	588 / MISCELLANEOUS EXPENSES	L 560	2,911,186	**2,749,719**	*161,468*
974	589 / RENTS	L 186	0	**0**	*0*
975	TOTAL DISTRIBUTION OPERATION		20,975,360	**20,003,940**	*971,420*
976					
977	MAINTENANCE				
978	590 / SUPERVISION & ENGINEERING	L 186	9,353	**8,912**	*441*
979	591 / STRUCTURES	L 167	0	**0**	*0*
980	592 / STATION EQUIPMENT	L 171	2,716,642	**2,588,326**	*128,316*
981	593 / OVERHEAD LINES	L 176+177	5,201,009	**4,830,600**	*370,409*
982	594 / UNDERGROUND LINES	L 178+179	304,799	**300,238**	*4,562*
983	595 / LINE TRANSFORMERS	L 180	25,793	**24,370**	*1,423*
984	596 / STREET LIGHTING & SIGNAL SYSTEMS	L 184	123,794	**118,851**	*4,943*
985	597 / METERS	L 182	678,112	**656,208**	*21,904*
986	598 / MISCELLANEOUS PLANT	L 186	79,964	**76,191**	*3,773*
987	TOTAL DISTRIBUTION MAINTENANCE		9,139,466	**8,603,695**	*535,771*
988	TOTAL DISTRIBUTION EXPENSES		30,114,827	**28,607,635**	*1,507,191*
989					
990	CUSTOMER ACCOUNTING EXPENSES				
991	901 / SUPERVISION	L 992	705,017	**610,646**	*94,371*
992	902 / METER READING	CW902	1,267,888	**1,098,173**	*169,715*
993	903 / CUSTOMER RECORDS & COLLECTIONS	CW903	9,731,713	**9,412,221**	*319,492*
994	904 / UNCOLLECTIBLE ACCOUNTS	CW904	0	**0**	*0*
995	905 / MISC EXPENSES	L 992-994	0	**0**	*0*
996	TOTAL CUSTOMER ACCOUNTING EXPENSES		11,704,618	**11,121,040**	*583,577*
997					
998	CUSTOMER SERVICES & INFORMATION EXPENSES				
999	907 / SUPERVISION	L 1003	828,671	**806,758**	*21,912*
1000	908 / CUSTOMER ASSISTANCE	L 572	4,679,331	**4,555,597**	*123,734*
1001	908 / ENERGY EFFICIENCY RIDER	CIDA	0	**0**	*0*
1002	909 / INFORMATION & INSTRUCTIONAL	L 576	0	**0**	*0*
1003	910 / MISCELLANEOUS EXPENSES	L 1000+1002	308,799	**300,634**	*8,165*
1004	TOTAL CUST SERV & INFORMATN EXPENSES		5,816,801	**5,662,989**	*153,812*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

			ALLOC/	TOTAL	IDAHO	
2						
3	DESCRIPTION		SOURCE	SYSTEM	RETAIL	OTHER
1005	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***					
1006	ADMINISTRATIVE & GENERAL EXPENSES					
1007	920 / ADMINISTRATIVE & GENERAL SALARIES		PTDCAS	53,511,744	**51,175,830**	*2,335,915*
1008	921 / OFFICE SUPPLIES		PTDCAS	228,890	**218,898**	*9,992*
1009	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-CR		SUBEX	0	**0**	*0*
1010	923 / OUTSIDE SERVICES		PTDCAS	0	**0**	*0*
1011	924 / PROPERTY INSURANCE			0		
1012	PRODUCTION - STEAM	L	121	0	**0**	*0*
1013	ALL RISK & MISCELLANEOUS		P110P	378,934	**363,208**	*15,726*
1014						
1015	925 / INJURIES & DAMAGES		LABOR	132,355	**126,578**	*5,777*
1016	926 / EMPLOYEE PENSIONS & BENEFITS		LABOR	0	**0**	*0*
1017	927 / FRANCHISE REQUIREMENTS		CIDA	0	**0**	*0*
1018	928 / REGULATORY COMMISSION EXPENSES					
1019	928.101 / FERC ADMIN ASSESS & SECURITIES					
1020	CAPACITY RELATED		D10	0	**0**	*0*
1021	ENERGY RELATED		E10	0	**0**	*0*
1022	928.101 / FERC ORDER 472		E99	0	**0**	*0*
1023	928.101 / FERC MISCELLANIOUS	L	RESREV	0	**0**	*0*
1024	928.102 FERC RATE CASE		RESREV	0	**0**	*0*
1025	928.104 / FERC OREGON HYDRO		RESREV	0	**0**	*0*
1026	SEC EXPENSES	L	202	0	**0**	*0*
1027	928.202 / IDAHO PUC -RATE CASE		CIDA	0	**0**	*0*
1028	928.203 / IDAHO PUC - OTHER		CIDA	0	**0**	*0*
1029	928.301 / OREGON PUC - FILING FEES		CODA	0	**0**	*0*
1030	928.302 / OREGON PUC - RATE CASE		CODA	0	**0**	*0*
1031	928.303 / OREGON PUC - OTHER		CODA	0	**0**	*0*
1032	IPC/PUC JSS TRUE-UP ADJ		PTD	0	**0**	*0*
1033	TOTAL ACCOUNT 928				**0**	*0*
1034	929 / DUPLICATE CHARGES		SUBEX	0	**0**	*0*
1035	930.1 / GENERAL ADVERTISING		RELAB	0	**0**	*0*
1036	930.2 / MISCELLANEOUS EXPENSES		PTDCAS	214,755	**205,380**	*9,375*
1037	931 / RENTS	L	200	0	**0**	*0*
1038	TOTAL ADM & GEN OPERATION			54,466,679	**52,089,895**	*2,376,784*
1039	PLUS:					
1040	935 / GENERAL PLANT MAINTENANCE		P3908	1,038,440	**993,286**	*45,155*
1041	416 / MERCHANDISING EXPENSE		E10	0	**0**	*0*
1042	TOTAL OPER & MAINT EXPENSES			162,547,550	**155,452,955**	*7,094,595*
1043	**TOTAL LABOR - RATIO (%)**			100.00%	**95.64%**	*4.36%*
1044						

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
1045	***TABLE 14-ALLOCATION FACTORS***				
1046					
1047	CAPACITY RELATED KW				
1048	PRODUCTION RELATED COINCIDENT PEAKS @ GEN LEVEL	D10	2,585,316	**2,479,852**	*105,465*
1049	SYSTEM TRANSMISSION SERVICE @ GENERATION LEVEL	D11	2,585,316	**2,479,852**	*105,465*
1050	RETAIL TRANSMISSION SERVICE @ GENERATION LEVEL	D12	2,585,316	**2,479,852**	*105,465*
1051	DISTRIBUTION SERVICE @ GENERATION LEVEL	D60	2,431,714	**2,339,615**	*92,099*
1052					
1053	ENERGY RELATED MWH				
1054	GENERATION LEVEL (PSP)	E10	16,783,429	**16,039,716**	*743,713*
1055	CUSTOMER LEVEL	E99	15,740,718	**15,039,426**	*701,292*
1056					
1057	CUSTOMER RELATED FACTORS				
1058	902-CUSTOMER WEIGHTED	CW902	1,819,788	**1,576,198**	*243,590*
1059	903-CUSTOMER WEIGHTED	CW903	15,041,849	**14,548,026**	*493,823*
1060	904-CUSTOMER WEIGHTED	CW904	2,751,851	**2,564,962**	*186,889*
1061	909-DIRECT ASSIGN-AVG.NO.CUST.	DA909	610,567	**590,862**	*19,705*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
1062	***TABLE 14-ALLOCATION FACTORS***				
1063					
1064	DIRECT ASSIGNMENTS (red font denotes allocator comes from Plant E				
1065	252-CUSTOMER ADVANCES	DA252	13,139,360	**13,043,126**	*96,234*
1066	350-LAND & LAND RIGHTS	DA350	0	**0**	*0*
1067	352-STRUCTURES & IMPROVEMENTS	DA352	658	**0**	*658*
1068	353-STATION EQUIPMENT	DA353	111,594	**75,100**	*36,494*
1069	354-TOWERS & FIXTURES	DA354	0	**0**	*0*
1070	355-POLES & FIXTURES	DA355	33,842	**0**	*33,842*
1071	356-OVERHEAD CONDUCTORS & DEVICES	DA356	26,495	**1,189**	*25,306*
1072	359-ROADS & TRAILS	DA359	0	**0**	*0*
1073	360LAND & LAND RIGHTS	ACCT360	7,818,143	**7,549,162**	268,981
1074	360LAND & LAND RIGHTS-CIAC	ACCT360CIAC	430,656	**430,355**	*301*
1075	361-STRUCTURES & IMPROVEMENTS	ACCT361	52,245,201	**49,776,238**	2,468,963
1076	361-STRUCTURES & IMPROVEMENTS-CIAC	ACCT361CIAC	8,009,324	**7,447,616**	*561,708*
1077	362-STATION EQUIPMENT	ACCT362	300,357,806	**287,706,828**	12,650,978
1078	362-STATION EQUIPMENT-CIAC	ACCT362CIAC	38,463,951	**34,892,876**	*3,571,075*
1079	364-POLES, TOWERS & FIXTURES-NET	DA364	313,204,206	**288,748,305**	24,455,901
1080	365-OVERHEAD CONDUCTORS & DEVICES-NET	DA365	155,253,318	**146,384,826**	8,868,492
1081	366-UNDERGROUND CONDUIT-NET	DA366	52,785,315	**51,958,505**	826,810
1082	367-UNDERGROUND CONDUCTORS & DEVICES-NET	DA367	318,155,073	**313,429,461**	4,725,612
1083	368- LINE TRANSFORMERS	DA368	704,959,938	**666,063,582**	38,896,356
1084	369-DIRECT ASSIGNMENT	DA369	67,920,301	**65,262,678**	*2,657,623*
1085	370-METERS	DA370	112,940,727	**109,292,546**	*3,648,181*
1086	371-INSTALLATIONS ON CUSTOMER PREMISES-NET	DA371	4,931,439	**4,591,211**	340,228
1087	373-STREET LIGHTING SYSTEMS-NET	DA373	5,706,749	**5,478,881**	227,868
1088	451-REVENUE - MISCELLANEOUS SERVICE	DA451	4,936,204	**4,890,357**	45,847
1089	454-REVENUE - FACILITIES CHARGE	DA454	10,470,031	**10,041,240**	428,792
1090	908-OTHER CUSTOMER ASSISTANCE	DA908	6,971,635	**6,790,730**	*180,904*
1091	440-RETAIL SALES REVENUE	RETREV	1,169,833,173	**1,116,166,332**	*53,666,841*
1092	447-WHOLESALE SALES REVENUE	RESREV	0	**0**	*0*
1093	456-REVENUE - STANDBY SERVICE	DASTNBY	1	**1**	*0*
1094	440-REVENUE OFFSET FOR PLANT ADDITIONS	DAREV	1	**1**	*0*
1095	IDAHO	CIDA	1	**1**	*0*
1096	OREGON	CODA	1	**0**	*1*
1097	NET TO GROSS TAX MULTIPLIER	DA990	1.347	**1.347**	*1.347*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		**ALLOC/**	TOTAL	**IDAHO**	
3	**DESCRIPTION**	**SOURCE**	SYSTEM	**RETAIL**	**OTHER**
1098	***TABLE 14-ALLOCATION FACTORS***				
1099					
1100	INTERNALLY DEVELOPED ALLOCATION FACTORS				
1101	PLANT - PROD,TRANS&DIST	PTD	5,793,115,906	**5,541,211,508**	*251,904,398*
1102	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	PTDCAS	107,042,430	**102,369,774**	*4,672,656*
1103	PLANT - HYDRO,OTHER,TSUBS,DSUBS&GP	P110P	3,227,551,412	**3,093,605,738**	133,945,674
1104	PLANT - GEN PLT (390,391,397&398)	P3908	313,029,643	**299,418,048**	*13,611,594*
1105	PLANT - PROD,TRANS,DIST&GEN	P101P	6,310,360,398	**6,035,964,449**	*274,395,950*
1106	O&M - PROD,TRANS,DIST,CUST ACCT&CSIS	SUBEX	738,121,707	**705,414,246**	*32,707,461*
1107	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	RELAB	3,227,551,412	**3,093,605,738**	*133,945,674*
1108	LAB - ALL LABOR WITHOUT 925-6 "CIRC"	LABOR	161,161,999	**154,127,711**	*7,034,288*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

2		ALLOC/	TOTAL	IDAHO	
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
1109	***TABLE 15-ALLOCATION FACTORS-RATIOS***				
1110					
1111	CAPACITY RELATED KW				
1112	PRODUCTION RELATED COINCIDENT PEAKS @ GEN LEVEL	D10	100.00%	**95.92%**	*4.08%*
1113	SYSTEM TRANSMISSION SERVICE @ GENERATION LEVEL	D11	100.00%	**95.92%**	*4.08%*
1114	RETAIL TRANSMISSION SERVICE @ GENERATION LEVEL	D12	100.00%	**95.92%**	*4.08%*
1115	DISTRIBUTION SERVICE @ GENERATION LEVEL	D60	100.00%	**96.21%**	*3.79%*
1116					
1117	ENERGY RELATED MWH				
1118	GENERATION LEVEL (PSP)	E10	100.00%	**95.57%**	*4.43%*
1119	CUSTOMER LEVEL	E99	100.00%	**95.54%**	*4.46%*
1120					
1121	CUSTOMER RELATED FACTORS				
1122	369-DIRECT ASSIGNMENT	DA369	100.00%	**96.09%**	*3.91%*
1123	370-METERS	DA370	100.00%	**96.77%**	*3.23%*
1124	902-CUSTOMER WEIGHTED	CW902	100.00%	**86.61%**	*13.39%*
1125	903-CUSTOMER WEIGHTED	CW903	100.00%	**96.72%**	*3.28%*
1126	904-CUSTOMER WEIGHTED	CW904	100.00%	**93.21%**	*6.79%*
1127	909-DIRECT ASSIGN-AVG.NO.CUST.	DA909	100.00%	**96.77%**	*3.23%*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	IDAHO RETAIL	OTHER
1128	***TABLE 15-ALLOCATION FACTORS-RATIOS***				
1129					
1130	DIRECT ASSIGNMENTS				
1131	252-CUSTOMER ADVANCES	DA252	100.00%	**99.27%**	*0.73%*
1132	350-LAND & LAND RIGHTS	DA350	#DIV/0!	**#DIV/0!**	*#DIV/0!*
1133	352-STRUCTURES & IMPROVEMENTS	DA352	100.00%	**0.00%**	*100.00%*
1134	353-STATION EQUIPMENT	DA353	100.00%	**67.30%**	*32.70%*
1135	354-TOWERS & FIXTURES	DA354	#DIV/0!	**#DIV/0!**	*#DIV/0!*
1136	355-POLES & FIXTURES	DA355	100.00%	**0.00%**	*100.00%*
1137	356-OVERHEAD CONDUCTORS & DEVICES	DA356	100.00%	**4.49%**	*95.51%*
1138	359-ROADS & TRAILS	DA359	#DIV/0!	**#DIV/0!**	*#DIV/0!*
1139	360LAND & LAND RIGHTS-DA	DA360	100.00%	**96.56%**	*3.44%*
1140	360LAND & LAND RIGHTS-CIAC	DA360C	100.00%	**99.93%**	*0.07%*
1141	361-STRUCTURES & IMPROVEMENTS-DA	DA361	100.00%	**95.27%**	*4.73%*
1142	361-STRUCTURES & IMPROVEMENTS-CIAC	DA361C	100.00%	**92.99%**	*7.01%*
1143	362-STATION EQUIPMENT-DA	DA362	100.00%	**95.79%**	*4.21%*
1144	362-STATION EQUIPMENT-CIAC	DA362C	100.00%	**90.72%**	*9.28%*
1145	364-POLES, TOWERS & FIXTURES-NET	DA364	100.00%	**92.19%**	*7.81%*
1146	365-OVERHEAD CONDUCTORS & DEVICES-NET	DA365	100.00%	**94.29%**	*5.71%*
1147	366-UNDERGROUND CONDUIT-NET	DA366	100.00%	**98.43%**	*1.57%*
1148	367-UNDERGROUND CONDUCTORS & DEVICES-NET	DA367	100.00%	**98.51%**	*1.49%*
1149	368- LINE TRANSFORMERS	DA368	100.00%	**94.48%**	*5.52%*
1150	371-INSTALLATIONS ON CUSTOMER PREMISES-NET	DA371	100.00%	**93.10%**	*6.90%*
1151	373-STREET LIGHTING SYSTEMS-NET	DA373	100.00%	**96.01%**	*3.99%*
1152	451-REVENUE - MISCELLANEOUS SERVICE	DA451	100.00%	**99.07%**	*0.93%*
1153	454-REVENUE - FACILITIES CHARGE	DA454	100.00%	**95.90%**	*4.10%*
1154	908-OTHER CUSTOMER ASSISTANCE	DA908	100.00%	**97.41%**	*2.59%*
1155	440-RETAIL SALES REVENUE	RETREV	100.00%	**95.41%**	*4.59%*
1156	447-WHOLESALE SALES REVENUE	RESREV	#DIV/0!	**#DIV/0!**	*#DIV/0!*
1157	456-REVENUE - STANDBY SERVICE	DASTNBY	100.00%	**100.00%**	*0.00%*
1158	440-REVENUE OFFSET FOR PLANT ADDITIONS	DAREV	100.00%	**100.00%**	*0.00%*
1159	IDAHO	CIDA	100.00%	**100.00%**	*0.00%*
1160	OREGON	CODA	100.00%	**0.00%**	*100.00%*
1161	NET TO GROSS TAX MULTIPLIER	DA990	1.347	**1.347**	*1.347*

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
IDAHO REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2023

		ALLOC/	TOTAL	IDAHO	
2					
3	DESCRIPTION	SOURCE	SYSTEM	RETAIL	OTHER
1162	***TABLE 15-ALLOCATION FACTORS-RATIOS***				
1163					
1164	INTERNALLY DEVELOPED ALLOCATION FACTORS				
1165	PLANT - PROD,TRANS&DIST	PTD	100.00%	**95.65%**	*4.35%*
1166	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	PTDCAS	100.00%	**95.63%**	*4.37%*
1167	PLANT - HYDRO,OTHER,TSUBS,DSUBS&GP	P110P	100.00%	**95.85%**	*4.15%*
1168	PLANT - GEN PLT (390,391,397&398)	P3908	100.00%	**95.65%**	*4.35%*
1169	PLANT - PROD,TRANS,DIST&GEN	P101P	100.00%	**95.65%**	*4.35%*
1170	O&M - PROD,TRANS,DIST,CUST ACCT&CSIS	SUBEX	100.00%	**95.57%**	*4.43%*
1171	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	RELAB	100.00%	**95.85%**	*4.15%*
1172	LAB - ALL LABOR WITHOUT 925-6 "CIRC"	LABOR	100.00%	**95.64%**	*4.36%*

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

CONNIE G. ASCHENBRENNER

Q. Please state your name, business address, and present position with Idaho Power Company (“Idaho Power” or “Company”).

A. My name is Connie G. Aschenbrenner. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Rate Design Senior Manager in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 2006, I received a Bachelor of Business Administration degree in Finance from Boise State University in Boise, Idaho. In December of 2011, I earned a Master of Business Administration degree from Boise State University. In addition, I have attended the electric utility ratemaking course The Basics: Practical Regulatory Training for the Electric Industry, a course offered through New Mexico State University’s Center for Public Utilities.

Q. Please describe your work experience with Idaho Power.

A. In 2012, I was hired as a Regulatory Analyst in the Company’s Regulatory Affairs Department. My primary responsibilities included support of the Company’s Commercial and Industrial customer class’s rate design and general support of tariff rules and regulations. In my time as a Regulatory Analyst, I also provided support for

Residential and Small General Service rate design, as well as regulatory support associated with demand-side management (“DSM”) activities. In 2017, I was promoted to Rate Design Manager for Idaho Power, and in 2019 I was promoted to my current role as Rate Design Senior Manager. I am currently responsible for the management of the rate design strategies of the Company, as well as oversight of all tariff administration. In my current role, I am also one of the Company representatives at its Energy Efficiency Advisory Group (“EEAG”) meetings.

Q. What is the purpose of your testimony in this matter?

A. In my testimony, I will describe generally how customer rates are developed and the Company’s approach to rate design strategy as well as the policy basis for the rate design proposals being made in this case. I will also describe the overall objectives I provided to the Regulatory Consultants and Analysts for the development of the Company’s proposed rate designs and general tariff updates. I will also present an overview of the Company’s approach to developing pricing for its on-site generation customers, specifically considering interdependencies between this case and Case No. IPC-E-23-14, which is currently pending before the Idaho Public Utilities Commission (“Commission”). Finally, I will describe the approach the Company took to updating its tariff schedules and rules to ensure the language in the tariff reflects current business practices.

Q. Please provide a witness overview for the Company’s CCOS, rate design, and general tariff revision proposals.

A. Company Witness Mr. Paul Goralski will present the Company’s recommendation as it relates to class cost-of-service (“CCOS”) in this case and will also present rate design recommendations for the Company’s existing Special Contract customers (Micron, Simplot – Pocatello, and INL) as well as pending and prospective Special Contract customers (Brisbie, Lamb Weston, and Simplot – Caldwell). Mr. Goralski will also present the rate design proposal for Schedule 20, Speculative High-Density Load as well as the proposed Fixed Cost Adjustment rates and the corresponding modifications to Schedule 54.

Company Witness Mr. Grant Anderson will explain the proposed rate design and resulting prices for the residential classes, including standard service (Schedule 1), time-of-use (“TOU”) (Schedule 5), and residential on-site generation (Schedule 6) and will explain the Company’s Residential Price Modernization Plan. Mr. Anderson will also present the rate design proposals for Small General Service On-Site Generation (Schedule 8), Large General

Service – Primary and Transmission (Schedule 9P/T) and Large Power customers (Schedule 19).

Company Witness Mr. Zack Thompson will present the rate design proposals for Small General Service (Schedule 7), Large General Service – Secondary (Schedule 9S), Agricultural Irrigation Service (Schedule 24), Dusk to Dawn Customer Lighting (Schedule 15), Street Lighting Service (Schedule 41), Traffic Control Signal Lighting Service (Schedule 42), and Non-Metered General Service (Schedule 40).

Finally, Company Witness Mr. Riley Maloney will present the recommendation for the Company’s Standby Service schedules (Schedules 31 and 45) and Alternate Distribution Service schedule (Schedule 46). Mr. Maloney will also present several proposed modifications to the Company’s tariff.

I. RATE DESIGN OVERVIEW AND OBJECTIVES

Q. How are customer rates developed?

A. After the Idaho jurisdictional revenue requirement is determined, the Company develops a class cost-of-service study (“CCOS Study”) whereby it allocates the revenue requirement to each customer class based on their specific utilization of the system. The methodology for separating costs among classes consists of a three-step process generally referred to as classification, functionalization, and allocation. In all three steps, recognition is given to the way in which the costs are incurred by relating these costs to the way in which the utility is operated to provide electrical service. Once individual costs have been allocated to the various classes of service, it is possible to total these costs as allocated and arrive at a breakdown of functionalized and classified unit costs which can be relied on to inform rate design.

Q. Please describe the objectives underlying the Company's rate design strategy.

A. The Company's primary rate design objective is to establish rate structures and prices that will recover the revenue requirement targets for each customer class. Additionally, the Company seeks to design rates that assign costs to those customers that cause the Company to incur the costs, a principle known as "cost causation," and to incorporate price signals to encourage wise and efficient use of energy.

Q. How can rate design influence customer behavior?

A. The rate design itself – or structure – and the prices set by these designs can impact the amount of electricity customers consume and either encourage or discourage usage at certain times. The Company believes that rates should be designed in a manner such that changes in a customer’s consumption (both the timing or quantity of usage) will result in decreases or increases to the customer’s bill that track with overall decreases or increases in costs incurred by the utility to provide service.

Q. How effective are the Company’s current rate structures in achieving its rate design objectives?

A. Current rate structures fall short of achieving the Company’s long-term objectives in a number of key areas. A large portion of the fixed costs to serve customers is collected through volumetric energy charges. In other words, the rate structure does not align well with how costs are incurred, and as a result, the price signals sent to these customers are inconsistent with the nature of the costs of providing electricity. Further, the rates offer little incentive for customers to use electricity cost-effectively.

Q. Why does the Company believe it is important to align prices with the underlying cost structure?

A. Customers respond to price signals. If the Company’s rate structures are not aligned with the underlying cost drivers, customers do not have access to information that will allow them to make decisions based on the economics from their perspective or for the broader utility system. This dynamic is increasingly important to Idaho Power’s system. Over the last several years, advancements in technology have influenced customer adoption of several behind-the-meter energy solutions, including energy efficiency, smart appliances, on-site generation, and energy storage systems. The Company believes that structuring rates in a manner that will more equitably collect fixed costs, while also sending price signals to promote efficiencies, is important to the long-term management of system costs.

In addition to sending the right price signal to influence behavior, cost-informed rates help to limit cross subsidies within a given class.

Q. Are there any other policy objectives to consider regarding rate design?

A. Yes. There are several other important ratemaking objectives the Commission has historically relied upon when ultimately establishing rates. These include evaluating customers’ ability to pay, understandability of the rate structure and rates themselves, and to what extent the rates provide some stability for customers. While the Company believes each of these objectives is important and should factor into an ultimate decision, it also believes that the best starting point for Commission deliberations is an economic one.

II. RATE DESIGN RECOMMENDATIONS

Q. Has the Company identified opportunities for improving the current rate design applicable to its major customer classes?

A. Yes. Generally, the Company is proposing to adjust each of the billing components within its existing structures to move incrementally closer to their cost-of-service, while targeting collection of the revenue assigned to each class. Accordingly, I have directed each of the Company witnesses who have prepared rate design recommendations to prioritize movements in collection towards cost-of-service, which includes moving away from tiered rate designs and shifting fixed cost collection into the appropriate charges, while balancing the magnitude of those changes with the resulting customer impacts. Table 1 shows a summary of the requested rate design changes for the Company's existing service schedules and identifies the Company witness who developed the proposed rates.

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Table 1

Summary of Existing Rate Designs & Proposed Modifications

	Current Structure	Proposed Modifications	Witness
Residential (Schedules 1 & 6)	• Service Charge • 3 Inclining Block Tiers	• Increase fixed cost collection through the Service Charge • Flatten the tiers	Anderson
Residential Time-of-Use ("TOU") (Schedule 5)	• Service Charge • Summer On & Off-Peak • Non-Summer Mid & Off-Peak	• Shorten on-peak hours to align with IRP-informed hours of highest risk • Introduce larger differentials	Anderson
Small Commercial (Schedules 7 & 8)	• Service Charge • 2 Inclining Block Tiers	• Increase fixed cost collection through the Service Charge and flatten tiers	Thompson; Anderson
Large Commercial Secondary (Schedule 9S)	• Service Charge • Two-Block Demand/BLC • 2 Declining Block Tiers	• Increase fixed cost collection through the Service Charge • Replace Two-Block Demand/BLC and Declining Tiers with a seasonal, flat rate • Introduce an optional TOU offering	Thompson
Irrigation (Schedule 24)	• Service Charge • In-Season Demand • Load-Factor Pricing	• Increase fixed cost collection through the Service Charge • Replace Load-Factor Pricing with a flat energy rate	Thompson
Large Commercial Primary & Transmission (Schedules 9P/T)	• Service Charge • Demand, BLC, and On-Peak Demand • TOU Energy Rates	• Better align existing elements with underlying cost drivers as informed by CCOS	Anderson
Large Power (Schedule 19)	• Service Charge • Demand, BLC, and On-Peak Demand • TOU Energy Rates	• Better align existing elements with underlying cost drivers as informed by CCOS	Anderson
Special Contracts (Schedules 26, 29, 30, & 32)	• Varied	• Better align existing elements with underlying cost drivers as informed by CCOS	Goralski

Q. Please describe the Company’s general goals/strategies for addressing the weaknesses in existing rate designs in this case.

A. In this case, the Company intends to establish rate structures that are more in line with cost causation, while balancing customer understandability and bill impact. Overall, the Company is seeking to implement changes that will take a step towards correcting a long-standing inequity within the residential class by implementing a plan to establish better price signals within that class. Further, the Company’s proposal will continue to better align the commercial and irrigation rate designs with cost-causation, providing for more economic price signals to those customer classes.

A. <u>Eliminate Tiered Rate Design</u>

Q. What rate classes currently rely on some form of tiered rates?

A. Schedules 1, 6, 7, 8, 9S and 24 all rely on a form of tiered rates. Currently, Idaho Power’s tiered rates include inclining block rates, whereby the prices associated with each defined block of energy usage is higher than the proceeding block, and declining block rates, whereby the prices associated with each block of energy usage is lower than the proceeding block.

Inclining Block Rates

Q. What rate classes currently have an inclining-block tiered rate design?

A. Schedules 1, 6, 7, and 8. Schedules 1 and 6 rely on a three-tiered inclining block structure while Schedules 7 and 8 rely on a two-tiered inclining block structure.

Q. What is the purpose of an inclining-block rate?

A. A primary goal of an inclining tiered structure is to encourage conservation by charging a higher rate as energy consumption increases over a billing period. Once a threshold of energy consumption is exceeded within a billing period, the rate becomes higher to send a price signal intended to encourage efficiency and/or conservation. Historically, the inclining block rate structure has been used as a tool for encouraging customers to use less energy. The theory underlying this concept is that the first block covers some basic level of usage at a lower rate to help keep the overall bill affordable for customers and sequential blocks with higher rates make incremental energy usage more expensive to encourage energy efficiency.

Q. Are there downsides to this type of a rate design?

A. Yes. The tiered rate structure has potential to unfavorably impact bills of customers who reside in older, less efficient homes, or those homes with all-electric heat. These customers may be unable to safely reduce their energy beyond a certain threshold or may not be able to efficiently reduce their energy usage in response to the established price signals. The most significant downside is that the tiered rate structure does not reflect how costs are incurred throughout the billing period and therefore does not send a price signal related to the differing costs to produce or procure energy throughout the billing period.

Proponents of inclining block rates believe they provide customers with greater control over their electric charges. However, it is important to note that high-end energy use is often electric heating and cooling, and while customers can elect to turn off or lower their heating requirements to lower their bill, this could compromise basic health and safety. The Company does not believe an inclining block structure is the right way to promote energy efficiency for residential customers over the long-term, and, as explained more fully below, proposes to transition to a rate design that will better enable efficiencies on its system.

In short, tiered rates are not cost-based and serve to penalize higher usage customers.

Q. Why are tiered rates not cost-based?

A. There is no cost-based reason why after using 800 kilowatt hours (“kWh”) or 2,000 kWh in a billing period the next kWh consumed by a customer should cost more. Conversely, the timing of energy consumption, both seasonally and during different hours, can affect the utility’s cost of providing service to the customer. The load factor or the effective utilization of kWh consumption relative to peak kilowatt (“kW”) demand can also change the average cost of providing energy. However, additional overall usage in a customer’s billing period does not make it incrementally more expensive for the utility to produce the next kWh of electricity when both fixed and variable costs are considered.

Q. Why do tiered rates unduly penalize customers?

A. Charging higher prices for greater usage in each billing period generally causes large users to subsidize smaller users. Under a tiered rate structure, customers who heat their homes with natural gas benefit and those who use electric heat are penalized. A household with several people living under one roof will be more likely to have usage in the higher second and third block rate than a person living alone. Effectively, inclining block rates unfairly reward some customers and penalize others, often for reasons outside the customer’s control. For those reasons, the Company is proposing to eliminate this type of rate structure for its residential customers over time.

Q. Are there any other reasons why the Company believes that eliminating tiers from Schedule 1 is advantageous?

A. Yes. Eliminating tiers for Schedule 1 makes the comparison to Schedule 5, which does not have tiers, easier for customers to assess regarding the potential benefits of time-variant pricing.

Additionally, moving away from an inclining block tiered structure to a seasonally flat structure would better position residential customers for future pricing structure changes. For example, a change from a seasonal flat rate to an introductory or mandatory TOU rate would cause less customer confusion – whereas a change from the existing inclining block structure to TOU rates may be more volatile and cause a varying degree of bill impacts to individual customers.

Declining Block Rates

Q. What rate classes currently have a declining - block tiered rate design?

A. Schedules 9S and 24.

Q. Please describe the details of the declining block tiered rate that applies to Schedule 9S.

A. The Schedule 9S rate design includes a two-tier declining block energy charge and a two-block demand and basic load capacity ("BLC") charge. In this rate design, the first block of kWh consumption is billed at a higher rate than all other consumption.

Q. Is the Company proposing changes to the Schedule 9S rate design?

A. Yes. Under the Schedule 9S rate design, the higher first block energy charge is intended to collect costs that are classified as demand and would otherwise be collected through a demand charge. As described by Mr. Thompson in this case, the Company is proposing to "unwind" the declining block Schedule 9S rate design and replace it with a rate structure more in line with other large general service customers, containing a billing demand and BLC applied to all kW and seasonal energy charges.

Q. Please explain the considerations in evaluating the change to Schedule 9S.

A. The Schedule 9S rate design was initially implemented in the 2005 general rate case[1] primarily to ease impacts on customer bills as a customer's usage made them

[1] *In the Matter of the Application of Idaho Power Company for Authority to Increase its Base Rates and Charges for Electric Service in the State of Idaho,* Case No. IPC-E-05-28, Order No. 30035 (May 12, 2006).

ineligible for Schedule 7 service and where they instead qualified for service under Schedule 9S. At that time, customers were experiencing a “pain point” when they transitioned back and forth between Schedule 7 and Schedule 9 due to the differences in the rate designs. Several changes were made to the address that pain point, including modifying the eligibility criteria so that once a customer qualifies for Schedule 9 service, they will continue to take service under that schedule. At the time, the Company signaled that combining the Schedule 7 and Schedule 9S class may be most appropriate in the long term.

Q. Did the Company consider providing additional customer options to help improve understandability or provide a price signal to promote system efficiency?

A. Yes. As more fully described below, the Company is proposing to implement an optional TOU rate structure where time-differentiated volumetric energy rates would give a better price signal to prioritize the more critical times when customers could shift load. It costs more to serve load during summer and non-summer peak times and an on-peak summer rate encourages more efficient use of the system as well as fairly charging customers based on their load profiles.

Q. Is the Company proposing to combine the small and large general secondary rate classes in this case?

A. No. In this case, the Company is proposing to slightly modify the Schedule 7 design, as more fully described in the Direct Testimony of Mr. Thompson, to collect more fixed costs through the Service Charge and commensurately reduce the reliance on volumetric rates for fixed cost collection. The Schedule 7 class has a disproportionate number of small users (nearly 60 percent of the class uses less than 300 kWh per month), and the Company determined that, at this point, it would not propose combining the classes.

However, in evaluating its proposed rates, the Company did consider how Schedule 7 customers transitioning onto Schedule 9 would be impacted, which in part influenced the proposed level of collection through the Service Charge for both Schedules 7 and 9S.

Q. What rate design currently applies to Schedule 24?

A. Schedule 24 relies on “load factor pricing” which is like a declining block, where the price of the first tier is higher than that of the second tier. The first block charges irrigation customers a monthly rate per kWh for the first 164 kWh per kW of demand, where the second block charges customers a lower monthly energy rate per kWh of all other energy use.

Q. Is this rate design cost based?

A. No. Like the Schedule 9S rate design, this rate design collects costs otherwise classified as demand through the first block; however, unlike the Schedule 9S design, customers are charged for all units of billing demand during the in-season time period. The Company has found this rate design tends to be complex to explain to customers. As a result, and as described in the Direct Testimony of Mr. Thompson, the Company is proposing to move the demand-classified costs out of the first tier and collect those costs through the demand charge, which the Company believes would be a more straightforward rate design for Schedule 24 customers to understand.

B. Expanded Summer Season & TOU Rates

Q. Do the Company's current rate structures reflect the time-variant nature of electricity?

A. Only to an extent. The rate designs applicable to most of the Company's service schedules include a seasonal component. Additionally, the large users, Schedules 9 P/T and 19, have mandatory time-differentiated energy charges.

Q. What is the Company's view on seasonal rates?

A. The cost to provide service to customers varies throughout different times of the year. For Idaho Power's system, it is generally more expensive to meet customer energy requirements in the summer and seasonal rates are an effective tool to promote reduced consumption during those higher cost months. Acknowledging this, the Company implemented seasonal rates for Schedules 1, 7, 9, and 19 in its 2003 General Rate Case ("GRC"). Since that time, the summer season for purposes of ratemaking has remained unchanged – that is, for most customers, the summer season is defined as June 1 through August 31.

Q. What is the Company's proposed summer season in this case and how did it develop that recommendation?

A. The Company is proposing to expand the summer season by one month to include September. Over the last several years, the Company's Integrated Resource Plan ("IRP") has identified high-risk hours are more frequently occurring later in the summer, often showing up in September. Shifting to a four-month summer season better aligns with current and future high-risk hours.

Q. What is the Company's view on TOU rates?

A. TOU rates can be an effective way to send a price signal to customers to encourage them to shift energy usage to specific hours in the day that are less costly to serve. This price signal can be effective to promote energy efficiency and system efficiency rather than strictly a conservation signal, as the tiered rates do. As more fully described by Mr. Anderson and Mr. Thompson, the Company is proposing to expand its TOU offerings for both residential and commercial customers and to establish a basis for potential opt-out or mandatory TOU rates for those classes.

Residential TOU

Q. Is the Company proposing to expand its TOU offering for residential customers as part of this GRC?

A. Yes. The Company has had an optional TOU offering in place for its residential customers since 2005; however, only a small number of customers (currently less than 1,000) opt to take that service from Idaho Power. The Company is proposing to redesign its optional residential TOU offering in a few ways: (1) modify and shorten the on-peak windows to align with the Company’s highest risk hours as informed by the 2023 IRP and (2) introduce a larger differential between on- and off-peak times.

Q. Please generally describe how the TOU offering was designed.

A. First, the Company relied on the analysis performed by the power supply planning team in preparation of the 2023 IRP to determine which hours are currently considered highest risk. These hours were used to inform the summer and non-summer on- and off-peak price periods utilized in the Schedule 5 rate design. I then directed Mr. Anderson to rely on the results of that analysis to inform his rate proposal.

Q. How is the Company proposing to set the differentials between on-, mid-, and off-peak?

A. The Company's approach varied slightly by customer class. For Schedule 5 customers, I directed Mr. Anderson to develop the offering in a manner that would be most effective at promoting a response to the price signal.

Q. Please describe how system efficiencies may be gained under this type of a rate structure.

A. TOU pricing (including Critical Peak Pricing) was identified as having the potential to manage customer demand in a recently completed Demand Response Potential Study, which will be relied on in the 2023 IRP. For the residential class, the total potential from TOU pricing programs amounted to approximately 8 MW. To the extent customers respond to this type of a rate design, the Company may be able to delay building traditional supply-side resources.

Q. Did the Company consider making TOU a default or mandatory rate offering for residential customers?

A. Yes, however, while the Company believes TOU is a more efficient and effective way to send energy and system efficiency price signals, it is aware that a change in a single year – from the current tiered rate structure to a mandatory or even a default TOU program – would be a significant impact to many of its residential customers that may be unfamiliar with this type of rate design, or who are otherwise unable to respond to the price signal.

Based on these considerations, in this case, the Company is proposing a three-year transition whereby it will gradually increase the Service Charge while eliminating the inclining block tier rates, which, at the end of the transition period, will better position the Company to consider proposing mandatory or default TOU for all customers in the future. This will also provide the Company an opportunity to evaluate the impacts and effectiveness of the on-peak to off-peak price ratio of 4.0x proposed in this case.

Commercial and Industrial TOU

Q. Is the Company proposing to modify or expand TOU for its commercial and industrial customers?

A. Yes. Schedules 19 and 9P/T already have TOU rates in place. The Company is aware that many of its Schedule 9S customers would like to take service under a time-differentiated rate design as this type of a design will better enable customers with discretionary load to manage their energy bills.

Q. Why is the Company proposing only an optional TOU service offering for Schedule 9S customers as opposed to making it a mandatory service?

A. The Company is proposing the optional Schedule 9S TOU offering at this time to incentivize customers, who have the ability, to shift load to off-peak periods by sending cost-based price signals informed by the Company’s high-risk hours identified in preparation of the 2023 IRP. This encourages customers to use the system more efficiently and economically based on both how the Company incurs cost and the high-risk time periods.

For example, if a customer with electric vehicle charging stations selected the TOU offering, they would be encouraged to charge their vehicles during off-peak hours. This would lessen the burden on the system during on-peak time periods as well as save the customer money compared to if they were on the standard service offering.

Q. How is the Company proposing to set the differentials between on- and off-peak?

A. I directed both Mr. Anderson and Mr. Thompson to develop a proposal to isolate both the variable and fixed cost components of the volumetric charge and only apply a differential to the energy classified portion of the rate. By developing the rates this way and having the fixed cost component of the volumetric rate remain constant for all kWh within a given season, the principles of cost-causation are maintained. That is, when a customer shifts usage to another time period, the underlying costs are expected to increase or decrease commensurately.

C. <u>Residential Price Modernization Plan</u>

Q. Please explain the Company's Residential Price Modernization Plan.

A. As more fully described in the Direct Testimony of Mr. Anderson, the Company is proposing a three-year transition period to modify the structure of its residential rates whereby it will increase the Service Charge and lower the energy charges commensurately over that period.

Q. Why is Idaho Power requesting to implement the Residential Price Modernization Plan?

A. The current residential rate structure does not align with Idaho Power's embedded cost structure. Providing electric service requires a significant amount of capital infrastructure, which is largely a fixed cost once infrastructure goes into service. The current residential rate structure is comprised of the Service Charge, which is a monthly fixed charge, and Energy Charges, which are usage-based or volumetric charges.

The Service Charge does not cover the fixed costs incurred by residential customers and those fixed costs are instead recovered through the volumetric Energy Charges. As I explained above, the Energy Charges in Schedule 1 are also tiered, so that usage over a specific threshold in a billing period are priced at a higher rate.

Q. What is the downside to this rate structure?

A. The Company's current rate structure for residential customers recovers a high proportion of fixed costs through the volumetric Energy Charges instead of through fixed charges. This relationship results in higher energy use customers subsidizing lower energy use customers and generally leads to customers believing the value of a kWh of energy is much higher than it is.

Q. What costs does the Company propose are reasonably recovered through the Service Charge?

A. The Company proposes to recover all costs related to the distribution system and customer-related costs like metering, billing, and customer service through the Service Charge. It is appropriate to include these costs in the fixed monthly charges that residential customers pay because they represent the fixed costs to deliver power over the distribution system and provide customer service and billing functions. These costs are fixed in nature and do not vary with changes in volumetric energy usage. If a residential customer uses less energy, the fixed costs of distribution facilities that have been installed to serve that customer do not decrease. These costs are therefore appropriately recovered through the fixed Service Charge. The Company proposes to continue to recover all other costs – fixed generation and transmission costs as well as variable energy costs – through Energy Charges.

Q. Will this structure remove the energy efficiency price signal?

A. No. As I mentioned, the Company is proposing to continue to collect fixed charges associated with generation and transmission through seasonal energy charges, which will continue to promote energy efficiency. As shown in Tables 6 and 7 of the Direct Testimony of Mr. Anderson, in the first year of the change, the energy rates are higher than they currently are – by the end of the transition plan, the energy charges remain seasonally differentiated, ensuring an efficiency signal remains.

Q. Did the Company consider the impact this rate design would have on low-income customers?

A. Yes. As discussed in greater detail in the Direct Testimony of Mr. Anderson, the Company evaluated the impact of this rate design on those customers in its service area known to be eligible for income-qualified energy assistance and found the proposed rate design would not disproportionally impact those customers in a negative way. In fact, at the end of the transition period, these customers are more likely to see a *savings* when compared to the residential customer class in total.

Q. Why is the Company proposing that these changes occur over a three-year transition?

A. Essentially, the Company is mindful of the impacts this type of a rate design will have on lower-usage customers and with gradualism in mind, has proposed a multi-year timeframe to moderate bill impacts on individual customers. The three-year transition provides a mechanism to make changes that better align rates with cost-of-service while also balancing how these changes affect some customers. Mr. Anderson presents a bill impact analysis to show the bill impact for customers once the plan is implemented.

III. ON-SITE GENERATION

Q. Please summarize the Company's request presented in Case No. IPC-E-23-14.

A. On May 1, 2023, Idaho Power filed Case No. IPC-E-23-14 ("ECR Case").[2] The Company filed the case in response to Commission Order No. 35631 directing the Company to file a new case to implement changes to its on-

[2] *In the Matter of Idaho Power's Application for Authority to Implement Changes to the Compensation Structure Applicable to Customer On-Site Generation Under Schedules 6, 8, and 84 and to Establish an Export Credit Rate Methodology,* Case No. IPC-E-23-14 (filed May 1, 2023).

site generation offering. Specifically, the Company requested the Commission implement: (1) real-time net billing with an avoided cost-based financial credit rate for exported energy, (2) a methodology for determining annual updates to the ECR, (3) a modified project eligibility cap for commercial, industrial, and irrigation (“CI&I”) customers, (4) related changes to the accounting for and transferability of excess net energy financial credits, and (5) updated tariff schedules necessary to administer the modified on-site generation offering.

Q. Are there any interdependencies between the General Rate Case and Case No. IPC-E-23-14?

A. Yes. The Company is addressing a variety of issues related to Idaho Power’s on-site generation offering in the ECR Case. However, because a GRC is an appropriate venue to address CCOS and rate design, the Company did not present any recommendations related to those items in Case No. IPC-E-23-14. Rather, those topics have been addressed within this case. Further, the Company believes it is appropriate to address transitional considerations in the context of rates and rate design within this docket as this GRC is the first opportunity to evaluate how closely revenue collection for the on-site generation customers aligns with the allocation of costs to those classes.

Q. How did the Company approach CCOS cost-allocation for on-site generation customers?

A. I requested load research statistics be developed based on on-site generation customers' utilization of the system. I then directed Mr. Goralski to rely on those statistics to complete cost-allocation to the on-site generation customers. This required relying on only a "delivered channel" of meter data for allocating generation, transmission, and energy related costs and looking at the maximum of both the "delivered channel" and "received channel" in determining the allocation of distribution plant. This is consistent with the real-time measurement interval presented in the ECR Case.

Q. Did legacy status[3] impact cost allocation?

A. No; the Company evaluated the cost to serve all customers with on-site generation in the same manner, regardless of legacy status. The type of compensation structure applied to the billings for customers has no bearing on measuring those customer's utilization of the system. In all cases, for all classes, the Company assessed the classes' energy and demand requirements in determining cost allocation. The approach I described ensures on-site

[3] The Company uses the term legacy to refer to those systems that the Commission has previously determined would continue to take NEM, under certain conditions, for a period of 25 years (also known as "grandfathered" systems).

generation customers are not treated any different than standard service customers.

Q. Are there any other areas related to on-site generation that are being addressed in this docket rather than in the ECR Case?

A. Yes. In Order No. 34046, the Commission directed Idaho Power to evaluate rate design and specifically “transitional rates.” In the ECR Case, the Company proposed that any transitional considerations be better addressed when evaluating the reasonableness of pricing proposals in the GRC versus the ECR Case, which is focused on the modification of the measurement interval applied to excess net energy and the valuation of that excess energy.

Q. What were the results of the CCOS for Schedules 6 and 8?

A. The study, prior to the cap and spread process described by Mr. Goralski, showed that the Schedule 6 and 8 classes should receive a 52 percent and 111 percent increase, respectively, in their class revenue requirement. These results demonstrate a large revenue deficiency for Schedules 6 and 8 under current rates, relative to other classes.

Q. Is the Company proposing rates for those classes to target the CCOS revenue requirement?

A. No. The Company believes it is reasonable to consider transitioning Schedule 6 and 8 customers to cost of service over a period of time. If the Company were to rely on the underlying CCOS as a basis for revenue allocation, those customers would experience relatively large increases in this case.

Q. How did the Company establish revenue targets for Schedules 6 and 8 for rate design purposes?

A. As a mitigation measure, the Company combined the Schedule 6 class with all residential customers (and Schedule 8 with all small general service customers) to complete both the cap and spread and the rate design process. That is, in this case Idaho Power proposes that on-site generation customers take service from Idaho Power under the same rates that all standard service customers pay.

Q. Will this result in a subsidy?

A. Yes. Any class whose assigned revenue requirement is more than the amount authorized will be subsidized by other customer classes.

Q. Does the Company believe its proposal results provides a reasonable and fair transition period for Schedule 6 and 8 customers?

A. Yes. The Company believes this approach results in a reasonable transition period for on-site generation customers and aligns with prior Commission orders where the Commission has directed the Company to evaluate transitional considerations as it proposes changes that will impact on-site generation customers.

Q. How will Schedule 6 customers be impacted by the Residential Price Modernization Plan?

A. Schedule 6 customers were included in the determination of the revenue neutral rates developed as part of the Residential Price Modernization Plan. It is important to note that even at the end of the three-year plan, Schedule 6 customers will still be contributing well below their cost to serve. Idaho Power is not recommending future changes be approved as part of this case, rather, the Company will evaluate further rate design considerations for on-site generation customers, as may be necessary, in future rate proceedings.

IV. TARIFF ADMINISTRATION

Q. Is the Company proposing changes to its tariff as part of this case?

A. Yes. The Company is requesting several administrative and housekeeping edits to many of the rules and schedules contained within its tariff. Additionally, I directed Mr. Maloney to work with field and customer-facing representatives to develop recommendations for updates and additions necessary to administer the tariff in a manner that ensures equitable treatment and is transparent to customers.

Attachment Nos. 1 and 2 to the application contains the legislative and clean versions of the requested tariff.

V. CONCLUSION

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF CONNIE G. ASCHENBRENNER

I, Connie G. Aschenbrenner, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Connie G. Aschenbrenner. I am employed by Idaho Power Company as the Senior Manager of Rate Design in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Connie Aschenbrenner

Signed: ____________________________
CONNIE G. ASCHENBRENNER

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	)	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

PAWEL P. GORALSKI

Q. Please state your name, business address, and present position with Idaho Power Company (“Idaho Power” or “Company”).

A. My name is Pawel (“Paul”) P. Goralski. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as a Regulatory Consultant in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 2007, I received a Bachelor of Business Administration degree in Finance from Boise State University in Boise, Idaho. I have also attended “The Basics: Practical Regulatory Training for the Electric Industry,” an electric utility ratemaking course offered through the New Mexico State University’s Center for Public Utilities, “Electric Utility Fundamentals and Insights,” an electric utility course offered by Western Energy Institute, and “Electric Rates Advanced Course,” an electric utility ratemaking course offered through the Edison Electric Institute.

Q. Please describe your work experience with Idaho Power.

A. In 2017, I was hired as a Regulatory Analyst in the Company’s Regulatory Affairs Department, and in 2020 I was promoted to my current position of Regulatory

Consultant. My primary responsibilities include supporting the Company’s class cost-of-service (“CCOS”) activities, developing pricing for special contract customers and other large load pricing analysis, supporting the Company’s annual Fixed Cost Adjustment (“FCA”) calculation, and serving as the Company witness in that matter. I have also been its witness for the Company’s annual Demand-Side Management (“DSM”) prudency filings.

Q. What is the purpose of your testimony in this matter?

A. My testimony will address derivation of the Company’s 2023 CCOS study and the resulting recommendations for customer pricing components. Specifically, my testimony covers the following six areas: 1) CCOS - overview, proposed modifications to methodology, description, and study results, 2) allocation of CCOS-informed revenue requirement to customer classes, 3) computation of the Sales Based Adjustment Rate (“SBAR”) consistent with the methodology described in the Settlement Agreement in Case No. IPC-E-15-15,[1] 4) update to FCA components as informed by the 2023 CCOS study and related rate design proposals, 5) Special Contract pricing and rate design, and, 6) Schedule

[1] *In the Matter of Idaho Power Company’s Application for Approval of Computational Modifications to the True-Up Portion of the Power Cost Adjustment*, Case No. IPC-E-15-15 (filed April 28, 2015; Final Order No. 33307 issued May 28, 2015).

20 – High-Density Load (“Schedule 20”) pricing and update on Schedule 20 customers and interruption compensation.

I. **<u>CLASS COST-OF-SERVICE OVERVIEW</u>**

Q. Please describe in general terms the process used to prepare the class cost-of-service study.

A. There are two general steps used in preparing a class cost-of-service study. The first step is to determine the total costs of providing electric service, adjusted for normal weather and water conditions. These costs have been provided to me by Company Witness Ms. Kelley Noe on Exhibit No. 35. The next step is to establish a methodology for the separation of those costs among customer classes.

Q. What methodology is used to separate costs among customer classes?

A. The methodology for separating costs among classes consists of a three-step process generally referred to as functionalization, classification, and allocation. In all three steps, recognition is given to the way in which the costs are incurred by relating these costs to the way in which the utility is operated to provide electrical service.

Q. Please explain the meaning of functionalization.

A. Costs must be functionalized; that is, identified with utility operating functions. Operating functions recognize the different roles played by the various facilities in the electric utility system. In the Company’s accounts, these various roles are already recognized to some degree, particularly in the recording of plant costs as production-, transmission-, or distribution-related. However, this functional breakdown is not sufficiently detailed for cost-of-service purposes. Individual plant items are examined and, where possible, the associated investment costs are assigned to one or more operating functions, such as substations, primary lines, secondary lines, and meters. This level of functionalization allows costs to be more equitably allocated among classes of customers.

Q. Please explain the meaning of classification.

A. In addition to functionalization, classification refers to the identification of a cost as being either customer-related, demand-related, or energy-related. These three cost components are used to reflect the fact that an electric utility makes service available to customers on a continuous basis, provides as much service, or capacity, as the customer desires at any point in time, and supplies energy, which provides the customer the ability to do useful work over an extended period of time. These three concepts of availability, capacity, and energy are related to the three components of cost designated as customer, demand, and energy, respectively. In order to classify a particular cost by component, primary attention is given to whether the cost varies as a result of changes in the number of customers, changes in demand imposed by the customers, or changes in energy used by the customers.

Q. What are some examples of customer-, demand- and energy-related costs?

A. Examples of customer-related costs are the plant investments and expenses that are associated with meters and service drops, meter reading, billing and collection, and customer information and services, as well as a portion of the investment in the distribution system. These investments and expenses are made and incurred based on the number of customers, regardless of the amount of energy used, and are, therefore, generally considered to be fixed costs. Demand-related costs are the fixed costs associated with investments in generation, transmission, and a portion of the distribution plant and the associated operation and maintenance expenses necessary to accommodate the maximum demand imposed on the Company’s system. Energy-related costs are generally the variable costs associated with the operation of the generating plants, such as fuel.

Q. What did you use as your primary guide in classifying costs as either customer-, demand-, or energy-related?

A. I used the *Electric Utility Cost Allocation Manual*, published January 1992, by the National Association of Regulatory Utility Commissioners as my primary guide to the classification of customer-, demand-, and energy-related costs.

Q. Please explain the process of allocation.

A. The process of allocation is one of apportioning the total jurisdictional cost among classes by introducing allocation factors into the process. An allocation factor is nothing more than an array of numbers that specifies the class value or share of a total jurisdictional quantity.

Once individual costs have been allocated to the various classes of service, it is possible to total these costs as allocated and arrive at a breakdown of utility rate base and expenses by class. The results are stated in a summary form to measure adequacy of revenues for each class. The measure of adequacy is typically the rate of return earned on rate base compared to the requested rate of return.

Q. Have you provided separate documentation describing in detail the methodology used to prepare the Company's class cost-of-service study?

A. Yes. Exhibit No. 36, the Class Cost-of-Service Process Guide, describes in detail the methodology used in the preparation of the Company's class cost-of-service study.

II. PROPOSED MODIFICATIONS TO THE COMPANY'S COST-OF-SERVICE METHODOLOGY

Q. Is the Company proposing modifications to the CCOS study methodology most recently approved by the Idaho Public Utilities Commission ("Commission") in the 2008 general rate case ("GRC") and that was also utilized in the 2011 GRC?

A. Yes. I am proposing two modifications to the CCOS methodology most recently approved by the Commission. However, much of the study's methodology remains consistent with the 2008 and 2011 GRC CCOS studies.[2]

Q. Please describe the primary elements that remain consistent between the 2023 CCOS and the study prepared for the 2011 GRC.

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[2] *In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service to its Customers in the State of Idaho*, Case No. IPC-E-11-08, Larkin DI (filed June 1, 2011).

In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service, Case No. IPC-E-08-10, Tatum DI (filed June 27, 2008).

A. Generally, the 2023 CCOS remains consistent with the 2011 CCOS study, including, but not limited to:

- Demand-classified base-load serving generation plant is allocated based on a monthly system coincidence peak ("12CP") allocator;
- The Company's hydro and coal-fueled generation plants are functionalized as base-load serving generation resources, while the Danskin and Bennett Mountain natural gas-fueled generation plants are functionalized as peak-load serving generation resources;
- Transmission plant is 100 percent demand-classified and allocated based on a 12CP, marginal-cost weighted allocator;
- Energy-related cost allocators continue to be derived based on an averaging approach inclusive of marginal-cost weighting;
- The Company's 12CP values, and each class's share of that value, is adjusted to add back the impact of Demand Response, that is, system load is representative of load as if no Demand Response events had been called; and
- Classification of distribution plant between demand and customer is based on a three-year load duration curve.

Q. Please describe the first modification made to CCOS methodology.

A. As described by Company Witness Ms. Aschenbrenner, analysis completed in support of the Company's upcoming 2023 Integrated Resource Plan indicates there is a probability that high-risk hours occur into the month of September. As a result, I recommend allocation of peak-load serving resources be based on a summer period June through September 4CP allocator, updated from the June through August 3CP allocator utilized in the 2011 CCOS. The four-month summer season better aligns with current and future high-risk hours and the need to rely on peak-load serving resources to meet those high-risk hours.

Q. Did the CCOS modification to extend the summer season to include September impact all customer classes?

A. No. Idaho Power's Irrigation class service schedule, Schedule 24, has previously utilized a different seasonal definition than other rate schedules. While all other Idaho Power rate schedules with seasonal rates have previously defined the summer season as June through August, the Irrigation customer class has historically received a portion of cost allocation and rates based on a summer period definition including September. The proposed CCOS modification for summer-season baseload serving generation resources to be allocated on a June through September period aligns cost allocation for the summer season for all customer classes.

Q. Please describe the second recommended CCOS modification.

A. In past studies, classification of Idaho Power's cost of generation - with respect to base-load serving generation plant rate base, expenses, and power supply expenses - has included both energy and demand classification based on a jurisdictional load factor. That is, if the Idaho jurisdictional load factor was 55 percent, 55 percent of baseload generation plant was classified as energy, with amounts exceeding the jurisdictional load factor classified as demand-related.

Idaho Power proposes to change classification methodology such that energy and demand classification follow a more "accounting-like" fixed cost versus variable cost approach. All base-load serving generation fixed accounting costs would be 100 percent demand classified, and all variable expenses, such as fuel and purchased power expenses, would be 100 percent energy classified.

Q. How does this impact the classification of generation and power supply by FERC account?

A. Please see Table 1 for a comparison of main FERC account classification under the recommended methodology and the Company's previous methodology. Peak-load generation plant continues to be 100 percent demand-classified and fuel expense continues to be 100 percent energy classified. For base-load serving generation plant: hydro, steam, and natural-gas fueled, 100 percent of generation plant is demand-classified. Power supply expense, including account 555.0 purchased power, and 555.1 – PURPA are 100 percent energy classified. It should be noted that while Table 1 is not a comprehensive list of impacted FERC accounts (there are also impacts to composite allocators that include the FERC accounts below), the list identifies the primary accounts that drive changes in cost assignment.

Table 1
Primary Production & Power Supply Expense FERC Account Classification Comparison

FERC Account	Description	Prior Classification	Recommended Classification
501	Steam Plant - Fuel	100% Energy	100% Energy
536	**Water lease & Other**	**Demand/Energy**	**100% Energy**
547	Other Generation - Diesel	100% Energy	100% Energy
547	Other Generation - Other Fuel	100% Energy	100% Energy
555.1	**Purchased Power**	**Demand/Energy**	**100% Energy**
555.1	Purchased Power - Demand Response Incentives	100% Demand	100% Demand
555.2	**Purchased Power - PURPA**	**Demand/Energy**	**100% Energy**
310-316	**Steam Production**	**Demand/Energy**	**100% Demand**
330-336	**Hydraulic Production**	**Demand/Energy**	**100% Demand**
340-346	**Other Production - Langley**	**Demand/Energy**	**100% Demand**

Q. Why is the Company proposing this change in classifying costs?

A. Idaho Power has used, and the Commission has approved, the use of a jurisdictional load factor to classify base-load generation expense since the early 1980s. As explained by Ms. Aschenbrenner, the Company seeks to modernize rate design to better align cost-causation with fixed and variable components of Idaho Power's cost structures. Because the results of classification are used to inform rate design, I am proposing a method to align with the Company's rate design objectives.

Q. What additional changes are incorporated in the 2023 CCOS study?

A. There are several cost categories that are new to the CCOS study since the Company's 2011 GRC. The more recent cost categories are described in detail in Mr. Larkin's testimony, and are allocated in the CCOS study in the following manner:

- Other Production – Langley: base-load serving generation; 100 percent demand-classified;
- 120 megawatt ("MW") battery storage: base-load generation; 100 percent demand-classified;
- Jackpot Power Purchase Agreement ("PPA"):[3] 100 percent energy classified;

[3] The Jackpot PPA is described in the Direct Testimony of Company Witness Ms. Jessica Brady.

- Energy Imbalance Market expenses: follows transmission plant allocation as the ability for Idaho Power to access the market is determined by transmission capacity;
- Western Resource Adequacy Program: also follows transmission plant allocation for FERC account 561 – Transmission – Load Dispatching;
- Wildfire mitigation: wildfire mitigation supports the Company's overall electrical system and is allocated based on a composite allocator for generation, transmission, and distribution plant.

Q. Are there any other major changes to the 2023 CCOS study from the CCOS filed in the 2011 GRC?

A. Yes, the 2023 CCOS study separately allocates costs to the on-site generation class for Residential, Schedule 6, and Small-General service, Schedule 8, as independent rate classes for cost assignment. The Commission approved the creation of Schedule 6 and 8 in 2018.[4] These load statistics were developed by the Company's Load Research and Forecasting Department and are described in workpapers filed by Mr. Larkin.

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[4] *In the Matter of the Application of Idaho Power Company for Authority to Establish New Schedules for Residential and Small General Service Customers with On-Site Generation*, Case No. IPC-E-17-13, Order No. 34046 (May 9, 2018).

Q. How are the clean energy aspects of Micron's Special Contract accounted for in the CCOS?

A. As described in Mr. Larkin's testimony, because costs and revenues from Micron's payment for the Black Mesa PPA are offsetting, they are excluded from the Idaho jurisdictional revenue requirement, and are also excluded from CCOS. While costs and revenues were excluded from CCOS, derivation of the energy-allocator for Micron was adjusted to exclude energy met by the Black Mesa resource. That is, the energy service Micron requires from Idaho Power is reduced by the forecast generation of the Black Mesa PPA, consistent with the Special Contract billing construct. This modification ensures Micron receives its fair, allocable share of power supply expense for the portion of load met by Idaho Power.

III. **COST-OF-SERVICE STUDY DESCRIPTION**

Q. Have you prepared a table that summarizes the basis by which each of the major functionalized cost categories has been classified and subsequently allocated to customer classes under the CCOS?

A. Yes. The Table 2 summarizes the basis by which each of the major functionalized cost categories is classified and subsequently allocated to customer classes under the CCOS:

Table 2

CCOS Classification and Functionalization Summary

Cost Category	Classification Basis
Generation Plant	
Hydro and Steam Production	Demand
Other Production (Langley & Peaking Units)	Demand
Transmission Plant	Demand
Distribution Plant	Demand and Customer
Other Expenses	
Fuel	Energy
Purchased Power	Energy
Demand Response Incentive Payments	Demand
Cost Category	**Allocation Basis**
Generation Demand	
Hydro and Steam Production	12CP without Marginal Generation Cost Weighting
Other Production (Langley)	12CP without Marginal Generation Cost Weighting
Other Production (Peaking Units)	4CP without Marginal Generation Cost Weighting
Demand Response Incentive Payments	4CP without Marginal Generation Cost Weighting
Generation Energy	12 Months Energy with Marginal Energy Cost Weighting (averaged w/ un-weighted values)
Transmission	12CP with Marginal Transmission Cost Weighting
Distribution	1NCP / No. of Customers / Direct Assignment

Q. Please identify the exhibits that comprise the cost-of-service study.

A. The cost-of-service study is comprised of the following exhibits:

1. Exhibit No. 37, Functionalization and Classification of Costs;
2. Exhibit No. 38, Summary of Functionalized Costs;
3. Exhibit No. 39, Allocation to Classes;
4. Exhibit No. 40, Summary of Class Allocations;
5. Exhibit No. 41, Transfer Adjustment;
6. Exhibit No. 42, Revenue Requirement Summary;
7. Exhibit No. 43, Class Cost-of-Service Unit Costs;
8. Exhibit No. 44, Marginal Cost Study
9. Exhibit No. 45, Development of Weighted Demand and Energy Allocators;
10. Exhibit No. 46, Revenue Requirement Adjustments.

Q. Please describe Exhibit No. 37.

A. Exhibit No. 37 contains 145 pages and consists of 11 Cost Functionalization and Classification Tables. The functionalization and classification of each component of rate base, operating revenue, and expense are treated in detail in these tables. The tables are shown in the following sequence:

- Table 1 - Electric Plant in Service;

- Table 2 - Accumulated Provision for Depreciation;
- Table 3 - Additions and Deletions to Rate Base;
- Table 4 - Operating Revenues;
- Table 5 - Operation and Maintenance Expenses;
- Table 6 - Depreciation and Amortization Expense;
- Table 7 - Taxes Other Than Income Taxes;
- Table 8 - Regulatory Debits/Credits;
- Table 9 - Income Taxes;
- Table 10 - Development of Labor-Related Allocator; and
- Table 11 - Functionalization Allocators.

Q. What is the significance of the column header "Allocator" on Exhibit No. 37?

A. This column identifies, by symbol, the basis for each allocation. For example, for Accounts 310 through 316, Steam Production, shown at line 20 on page 1, the constant "PI-S" is used to allocate the total investment in steam production plant to the production function and to the demand cost classifications. The resultant functionalization of costs may itself serve as a basis for subsequent allocations. This use is illustrated at line 119 on page 21 where the accumulated depreciation for steam production plant is allocated according to the same allocator “PI-S” used at line 20.

Q. Please describe Exhibit No. 38.

A. Exhibit No. 38 summarizes in row format the functionalized costs for each component of rate base and expenses shown across the columns on Exhibit No. 37.

Q. Please describe Exhibit No. 39.

A. Exhibit No. 39 details the allocation of the summarized costs shown on Exhibit No. 38 to each customer class, including the Special Contract customers. The exhibit also includes a summary of results showing the actual rate of return earned for each customer class and Special Contract customer. The exhibit includes the following tables:

- Table 1 - Plant in Service;
- Table 2 - Accumulated Reserve for Depreciation;
- Table 3 - Amortization Reserve;
- Table 4 – Substation Contributions in Aid of Construction;
- Table 5 - Customer Advances for Construction;
- Table 6 - Accumulated Deferred Income Taxes;
- Table 7 - Acquisition Adjustment;
- Table 8 - Working Capital;

- Table 9 - Deferred Programs;
- Table 10 - Subsidiary Rate Base;
- Table 11 - Plant Held for Future Use;
- Table 12 - Other Revenues;
- Table 13 - Operation & Maintenance Expenses;
- Table 14 - Depreciation Expense;
- Table 15 - Amortization of Limited Term Plant;
- Table 16 - Taxes Other Than Income;
- Table 17 - Regulatory Debits/Credits;
- Table 18 - Provisions for Deferred Income Taxes;
- Table 19 - Investment Tax Credit Adjustment;
- Table 20 - Construction Work In Progress;
- Table 21 - State Income Taxes;
- Table 22 - Federal Income Taxes; and
- Table 23 - Allocation Factor Summary.

Q. Does the Class Cost-of-Service Process Guide, Exhibit No. 36, detail the manner in which you allocated the summarized costs shown on Exhibit No. 38 to each class of service as shown on Tables 1 through 22 of Exhibit No. 39?

A. Yes. Exhibit No. 36, the Class Cost-of-Service Process Guide, details the majority of the allocation methodology that was applied to produce the results shown on Tables 1 through 22 of Exhibit No. 39.

Q. What additional allocation methodology was included in the CCOS to produce the summarized costs shown on Exhibit No. 42?

A. As described by Mr. Larkin, the Jurisdictional Separation Study includes three additional revenue requirement line items: 1) Bridger revenue requirement, 2) Valmy revenue requirement, and 3) revenue requirement offset for battery projects to be installed in 2023. Revenue requirements for those three items were allocated to customer classes consistent with other base-load serving generation plant. Please see Exhibit No. 46 Revenue Requirement Adjustments for each class’s calculated allocable share. The result of that class allocation for the three revenue requirement items is listed by customer class on row 45 of Exhibit No. 42 Revenue Requirement Summary.

A second allocation was included to spread to customer classes the transfer adjustment described by Mr. Larkin. The total value of the Energy Efficiency Rider labor adjustment and update to Power Cost Adjustment (“PCA”)-related items were allocated to customer classes in the same manner as they would be incurred. Exhibit No. 41, Transfer Adjustment, computes the base revenue transfer for each customer class.

Q. Does Exhibit No. 39 include a listing of the allocation factors used to allocate to classes the various costs shown on Tables 1 through 22?

A. Yes. Table 23 of Exhibit No. 39 includes a listing of each allocation factor.

Q. Have you included information regarding the derivation of the Company’s updated marginal costs with your testimony?

A. Yes. I have included a copy of the Company’s 2023 Marginal Cost Analysis Study as Exhibit No. 44.

Q. Have the marginal costs been used to develop the Company’s revenue requirement?

A. No. The marginal costs have been used solely for purposes of developing allocation factors and not for purposes of developing the Company’s revenue requirement.

Q. Have you prepared an exhibit that details the derivation of the demand and energy allocation factors used in the cost-of-service study?

A. Yes. Exhibit No. 45 details the derivation of the allocation factors D10S, D10NS, D10P, D13, E10S, and E10NS used in the CCOS.

IV. COST-OF-SERVICE STUDY RESULTS

Q. Please describe Exhibit No. 42.

A. Exhibit No. 42 is the revenue requirement summary based on the results of the proposed CCOS study. The section headed “Revenue Requirement for Rate Design” details the sales revenue required from each customer class and special contract customer. The sales revenue required includes return on rate base, total operating expenses, and incremental taxes computed using the net-to-gross multiplier of 1.347 provided by Ms. Noe.

Q. Have you prepared an exhibit quantifying the impact from the recommended CCOS modifications?

A. Yes, Exhibit No. 47 to my testimony includes the results of the 2023 CCOS study and the three supplemental CCOS studies. The exhibit is presented with the first section representing a CCOS study consistent with the 2011 GRC methodology; the two subsequent sections independently list the incremental change to revenue requirement by class from that respective modification. Finally, the combined impact of the modifications and the 2023 CCOS class revenue requirement results are listed in the fourth section.

Q. Please summarize the major impacts to customer classes from the recommendations.

A. The greatest impact is to the Irrigation customer class, which is primarily driven by shifting to a four-month summer season for all customer classes, and results in a reduction in revenue deficiency of $3.7 million (as compared to the 2011 GRC methodology) from this modification. However, while each class experiences a slight change to revenue requirement from the two proposed changes, the greatest percentage total impact is a 2.65 percent reduction in revenue deficiency for the Irrigation class, nearly all due to the four-month summer season, with almost all other classes experiencing less than 1 percent impact to revenue requirement from the proposed methodology changes.

Q. Please summarize the results of the class cost-of-service study that are detailed on Exhibit No. 42.

A. The results shown on Exhibit No. 42 indicate that the Residential (“Schedule 1”), Residential On-Site Generation (“Schedule 6”), Small General Service (“Schedule 7”), Small General Service On-Site Generation (“Schedule 8”) Irrigation Service (“Schedule 24”), and Traffic Control Lighting Service (“Schedule 42”) should have an increase in rates that is greater than the overall average increase requested by the Company. In addition, the results indicate that Large General Service – Primary & Transmission (“Schedules 9P and 9T”), Dusk to Dawn Lighting (“Schedule

15”), Municipal Street Lighting (“Schedule 41”), and Special Contract customer J. R. Simplot Company Pocatello, Idaho (“Simplot Pocatello”) (“Schedule 29”) should have a decrease in rates from the current level.

V. **REVENUE REQUIREMENT ALLOCATION**

Q. What is the Company’s general ratemaking philosophy on determining class-specific revenue requirement and the resulting customer rates?

A. The Company’s primary approach to ratemaking in the last several GRCs has been to establish rates that reflect costs as accurately as possible. Accordingly, the Company’s ratemaking proposals usually advocate movement toward cost-of-service results, which assign costs to those customer classes that cause the Company to incur the costs.

Q. Are there other objectives that may be considered in the ratemaking process?

A. Yes. The Commission may consider a number of other objectives, such as rate stability, in the determination of rates.

Q. How did you approach the determination of the revenue requirement for each customer class?

A. As I described above, a pure cost-of-service revenue requirement spread would result in larger increases for certain classes relative to the overall average increase. In order to mitigate the magnitude of the maximum rate increase any class would experience, the Company is proposing to cap the percentage increase to any customer class at one and one-half times the overall average requested increase, or 12.91 percent (8.61 percent X 1.5 = 12.91 percent). As proposed, Large General Service – Primary & Secondary, Dusk to Dawn Lighting, Municipal Street Lighting and the Simplot Pocatello Special Contract receive neither a decrease nor an increase in rates.

Q. Did you discuss the results of the CCOS study internally before deciding to apply the 12.91 percent caps to the specified customer classes?

A. Yes. I discussed the results of the CCOS and potential rate spread scenarios with Company Witness Mr. Timothy Tatum, who is responsible for the overall preparation of this case. My revenue allocation is the result of those discussions.

Q. Was the revenue allocation process affected by the clean energy aspects of Micron’s Special Contract?

A. No. Micron’s revenue targets were developed for the portion of service Idaho Power provides.

Q. Does the overall 12.91 percent cap also apply to new customer classes Schedule 6 and 8?

A. Not explicitly. However, consistent with the direction provided by Ms. Aschenbrenner, the Residential and Residential On-Site Generation customer classes were combined prior to determining the revenue target. The same occurred for Small General Service and its On-Site Generation counterpart. As further discussed in the Direct Testimony of Company Witness Mr. Grant Anderson and Company Witness Mr. Zack Thompson, respectively, rate design was developed such that Schedule 1 and Schedule 6 share the same service charge and energy rates, with that also being the case for Schedule 7 and Schedule 8.

Q. Do you have an exhibit that details the class revenue requirement determination?

A. Yes. Exhibit No. 48 is a five-page exhibit that steps through the revenue requirement allocation process from the CCOS results to the ultimate proposal for each customer class. Page 1 of Exhibit No. 48 presents the proformed normalized test year sales and revenues and transfer adjustment by customer class. Page 2 details the results from the CCOS study and illustrates the revenue changes that would be made to each customer class to obtain the CCOS results. Page 3 shows the revenue shortfall that resulted by applying the 12.91 percent cap to combined Small General Service classes, Irrigation, and Traffic Control Lighting, and no decrease to Large General Service – Primary & Secondary, Dusk to Dawn Lighting, Municipal Street Lighting, or Simplot Pocatello Special Contract.

Page 5 shows the final proposed increase to customer classes that resulted from spreading the revenue shortfall created by the 12.91 percent cap, no increase or decrease to Large General Service – Primary & Secondary, Dusk to Dawn Lighting, Municipal Street Lighting, or Simplot Pocatello Special Contract. The results from page 5 were utilized in determining the individual rates for the Company's general tariff and special contract customers.

Q. Did you also provide the results of the CCOS to the Company's rate design witnesses for use in the Company's rate design proposals along with the revenue targets from Exhibit No. 48?

A. Yes. I provided the CCOS unit costs, detailed on Exhibit No. 43, to Mr. Anderson, Mr. Thompson, and Company Witness Mr. Riley Maloney for use in determining the rates for their respective service schedules.

Q. Please describe Exhibit No. 43.

A. Exhibit No. 43 shows the unit cost for each function for metered service schedules as determined through the CCOS study. The billing units shown in the column labeled "(F)" reflect the billing demands, normalized billing energy, basic load capacity, and number of billings.

Q. Are you proposing any other changes to cost recovery?

A. Yes, As discussed by Mr. Tatum, the Company is proposing to reduce the Energy Efficiency Rider (“Rider”) collection percentage to 2.25 percent from 3.10 percent. Exhibit No. 41 includes derivation of the proposed 2.25 percent Rider collection percentage, with Rider collection projected to be $31.6 million, just slightly above the current funding level when also considering the $3.5 million of labor-related cost that will be collected in base rates.

VI. SALES BASED ADJUSTMENT RATE

Q. Please describe in general terms the purpose of the SBAR?

A. The SBAR is a part of the PCA mechanism that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns.

Q. Please describe the SBAR methodology approved by the Commission in Order No. 33307.

A. Commission Order No. 33307 directs the Company to calculate the SBAR based on the energy classified portion of embedded production revenue requirement as established in the CCOS. The final SBAR is calculated by dividing this portion of revenue requirement by the Idaho kilowatt-hour (“kWh”) sales for the test year.

Q. Are any additional modifications to calculate the SBAR necessary as part of the 2023 CCOS determination?

A. Yes. The Commission's Order adopted Commission Staff's ("Staff") recommendations for the PCA treatment of the renewable portion of Micron's billing construct,[5] which accepted the proposed treatment described in Ms. Aschenbrenner's testimony filed in Case No. IPC-E-22-06:[6]

> Further, any energy requirements met by the Renewable Resource will not be included in the PCA sales based adjustment (SBA) and will not be used in the derivation of the future PCA rates. All Supplemental Energy supplied to Micron will be included in the PCA, SBA and used for PCA rate derivation purposes.

Accordingly, the Black Mesa PPA power supply expense is excluded as part of the SBAR energy-related generation function revenue requirement, and the portion of Micron's energy that Black Mesa meets under the Special Contract billing construct is also excluded from test year retail sales.

Q. What is the resulting SBAR?

A. By applying the methodology established by

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[5] *In the Matter of Idaho Power Company's Application for Approval of a Replacement Special Contract with Micron Technology, Inc. and a Power Purchase Agreement with Black Mesa Energy, LLC.*, Case No. IPC-E-22-06, Order No. 35482 (August 1, 2022); Staff Comments pg. 18.

[6] Case No. IPC-E-22-06, Aschenbrenner DI, pg. 20.

Commission Order No. 33307 in Case No. IPC-E-15-15, and for the Micron clean energy component of their Special Contract components by Order No. 35482, the SBAR should be increased from the requested level of $26.72 in Case No. IPC-E-15-15 to $31.29 per megawatt-hour.

Q. Have you prepared an exhibit that details the derivation of the revised SBAR?

A. Yes. Exhibit No. 49, details the derivation of the $31.29 SBAR amount.

VII. FIXED COST ADJUSTMENT RATES

Q. Please describe the FCA mechanism.

A. The FCA is a rate mechanism that is designed to remove the financial disincentive to utility acquisition of demand-side management resources. The mechanism accomplishes this goal by severing the link between energy sales and the recovery of fixed costs. The FCA applies to customer classes that only include energy and service charges in their retail billing components, Residential Service (Schedules 1, 3, 5, and 6) and Small General Service (Schedule 7, and 8). The annual FCA amount is determined according to the following formula:

FCA = (CUST X FCC) – (ACTUAL X FCE)

Where:

FCA = Fixed Cost Adjustment;

CUST = Actual number of customers, by class;

FCC = Fixed Cost per Customer, by class;

ACTUAL = Actual Billed kWh Energy Sales, by class; and

FCE = Fixed Cost per Energy, by class.

Q. What values are required to calculate the FCA amount annually?

A. As outlined in the above formula, for each class (Residential Service and Small General Service), the actual number of customers (“CUST”), the fixed cost per customer (“FCC”), actual energy (“ACTUAL”), and the Fixed Cost per Energy (“FCE”) are required to determine the FCA amount. Two of these variables (CUST and ACTUAL) are determined at the end of each year based upon the Company’s actual billing records. The other two variables (FCC and FCE) are updated each time the Company files a GRC and are based on the results of the CCOS study.

Q. Since granting permanency for the FCA mechanism in Order No. 32505 in 2012,[7] has the Commission authorized any additional changes?

A. Yes. First, the Commission approved a Settlement Stipulation in 2015 that replaced the use of weather-normalized data with actual sales in determination

[7] *In the Matter of the Application of Idaho Power Company for Authority to Convert Schedule 54 – Fixed Cost Adjustment – from a Pilot Schedule to an Ongoing Schedule*, Case No. IPC-E-11-19, Order No. 32505 (March 30, 2012).

of the FCA deferral.[8] Second, in 2021 the Commission approved separate, and reduced fixed cost tracking for customers considered “new,” defined in the Order to be customers added after January 1, 2022.[9] The Commission’s rationale stated that the modification “eliminates fixed cost recovery due to new customer growth for investments best determined in a general rate case.”[10]

Q. Beginning with the 2024 FCA deferral, who will be considered a “new” customer?

A. The FCC and FCE rates will be reset based on outcomes of this GRC, as such, “new” customers will also be reset to be those customers added starting January 1, 2024, when proposed GRC rates go into effect.

Q. Are you proposing any additional modifications to the FCA as part of this proceeding?

A. Yes, I am proposing two additional modifications. First, because Schedule 6 and Schedule 8 are now separate rate classes in the CCOS study with individual cost assignment and independent class statistics, I recommend separate determination of use per customer (“UPC”), FCC, and FCE for these customer classes.

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[8] *In the Matter of the Commission’s Inquiry into Idaho Power Company’s Fixed Cost Adjustment Mechanism*, Case No. IPC-E-14-17, Order No. 33295 (May 6, 2015).
[9] *Idaho Power Company’s Application for Modification of the Fixed Power Cost Adjustment*, Case No. IPC-E-21-39, Order No. 35273 (Dec. 28, 2021).
[10] Order No. 35273, pg. 4.

Next, I am proposing separate determination for the UPC and FCE applied to customers taking service under the Proposed Schedule 5, Residential Service Time-of-Use Plan (“Schedule 5”). Cost assignment for Residential customers is completed on a composite group including Schedule 1, 3, and 5 customers and the FCC is calculated based on class statistics from this composite group. However, UPC for Schedule 5 is approximately 50 percent higher than the average Residential Service (Schedule 1) standard service customer. To appropriately track actual sales against a UPC basis, a class-specific UPC basis should be utilized.

For the FCE, derivation independent from composite Residential FCE rates should be utilized because of the proposed Schedule 5 rate design. As detailed in Mr. Anderson’s testimony, the Company is pursuing an update to Schedule 5 time-of-use rates such that on- and off-peak energy rates maintain a four-to-one price differential in the summer season, and 1.5-to-one price differential in the non-summer season. That is, the summer on-peak energy rate will be four times the summer off-peak energy rate, and the non-summer on-peak energy rate will be 1.5 times the non-summer off-peak energy rate. Neither differential aligns with CCOS-informed rates, thus the FCE for Schedule 5 incorporates a matching four-to-one differential for summer, and 1.5-to-one differential for non-summer consumption, such that changes to Schedule 5 energy consumption in response to price signals between on- and off-peak periods recognize the embedded level of fixed costs in each time period. Schedule 5 customers who shift use from the on-peak period to the off-peak period do not receive an under- or over-collection of fixed costs between energy rates and the FCA mechanism because the FCE includes a four-to-one, and 1.5-to-one differential, respectively.

Q. Is the Company proposing changes to how annual FCA rates that recover the FCA deferral are set and applied to customer classes?

A. No. Annually, the FCA deferral will be tracked for five customer segments: Schedule 1 & 3, Schedule 5, Schedule 6, Schedule 7, and Schedule 8. The determination of annual FCA rates combines the Residential and Small General Service customer segments first, and sets the percentage change on an overall basis, not on a class-segment basis. FCA rates will continue to be set only at the total Residential (Schedule 1, 3, 5, and 6) segment, and Small General Service (Schedule 7, and 8) segment.

Q. Have you updated the FCC and FCE rates as part of this GRC proceeding?

A. Yes. I have updated the new and existing customer FCC and the FCE rates using the functionalized and classified revenue requirement from the 2023 CCOS, and proposed Service Charge collection effective January 1, 2024. The updated FCC and FCE rates have been included in the revised Schedule 54, Fixed Cost Adjustment.

Q. Please describe the process used to determine the FCC and FCE rates for the FCA mechanism, which have been submitted as part of this GRC proceeding.

A. The FCC and FCE rates submitted as part of this GRC proceeding are based upon the 2023 test year. These rates most accurately represent the Company's current fixed costs. Exhibit No. 50, Tables I, II, III, IV, and the Schedule 5 FCE derivation detail the computational process that was used to determine these class-specific fixed-cost amounts.

The first step in this process is a determination of the 2023 test year fixed cost recovery embedded in the energy charges for Residential Service and Small General Service customers. As can be seen on Exhibit No. 50, Table III, column J, for Residential Service, $367,032,962 of fixed costs are to be recovered from residential customers through energy charges, and $8,715,991 for Residential On-Site Generation customers. For Small General Service, $8,266,319 of fixed costs are to be recovered from the energy charges, and $27,218 for Small General Service On-Site Generation customers.

Q. Do these fixed cost amounts for the

Residential class include more than their actual class cost of service?

A. Yes. There is a difference between the class cost of service numbers and the amount of requested revenue requirement. This difference is a result of the cross-class subsidies that are currently present in the Company's rate structure. The total cross-class subsidies, as well as the fixed cost portion of those subsidies, are identified on Exhibit No. 50, Table II.

Q. Why is it important to include these fixed cost subsidies for the Residential class?

A. When fixed costs are recovered through a volumetric rate, the effects of any energy efficiency program that reduces energy consumption result in lost recovery of those fixed costs. In the case of the Residential classes, the reduction of energy consumption through energy efficiency not only prevents the Company from recovering the fixed costs associated with those classes, but in addition, prevents the fixed cost recovery of the other inter-class subsidies that are embedded in Residential energy rates.

Q. How are the class-specific fixed cost amounts established in the initial step used to derive the updated FCC rates?

A. The determination of the FCC rate utilizes the annual average number of customers for the Residential customer class and Small General Service customer class. As can be seen on Exhibit No. 50, Table III, column A, the 2023 average number of customers are 492,481 for the Residential customer class, 13,288 for the Residential On-Site Generation class, 30,401 for the Small General Service customer class, and 88 for the Small General Service On-Site Generation class.

With these two principal base level values, the FCC rate can be determined. The annual fixed costs recovered through the energy charges divided by the 2023 average number of customers results in an annual fixed cost recovery per customer, or the FCC rate, shown on Exhibit No. 50, Table III, column K. For the Residential class, the annual fixed cost recovery per customer is $745.27 ($367,032,692 / 492,481), and $655.94 for the Residential On-Site Generation class ($8,715,991 / 13,288). For the Small General Service class, the annual fixed cost recovery per customer is $271.91 ($8,266,319 / 30,401), and $311.07 for the Small General Service On-Site Generation class ($27,218 / 88).

For new customers, those added starting January 1, 2024, the Fixed Cost per Customer – Distribution (“FCC-DIST”) only includes distribution function fixed costs. The table below lists the corresponding FCC-DIST for each of the FCA classes.

Table 3
New Customer FCC-DIST

Customer Group	Total Distribution & Customer Fixed Cost Revenue from Energy Charges	2023 Avg. Customers	FCC-DIST
Residential	125,476,059	492,481	$254.78
Residential On-Site Generation	3,620,717	13,288	$272.49
Small General Service	3,257,318	30,401	$107.15
Small General Service On-Site Generation	12,337	88	$140.99

Q. How are the class-specific fixed cost amounts established in the initial step used to derive the updated FCE values?

A. The determination of the FCE rate utilizes the Residential and Small General Service weather-normalized energy consumption for the 2023 test year. As can be seen on Exhibit No. 50, Table III, column B, the 2023 weather-normalized annual energy consumption for the Residential customer class is 5,425,559,433 kWh, 122,912,496 kWh for Residential On-Site Generation customers, 138,285,160 kWh for the Small General Service class, and 370,708 kWh for the Small General Service On-Site Generation class.

The annual fixed cost recovered through the energy charges divided by the normalized energy results in an annual fixed cost recovery per kWh, or the FCE rate, shown on Exhibit No. 50, Table III, column L. Matching FCC-DIST determination for new customers, the FCE-DIST determination for new customers added starting January 1, 2024, only includes distribution-related fixed costs. Existing customer FCE and new customer FCE-DIST are listed in Table No. 4 for each of the FCA classes. Derivation of FCE-DIST is shown on Exhibit No. 50, Table IV.

Table 4

FCE and FCE-DIST

Customer Group	Total Fixed Cost Revenue from Energy Charges	2023 kWh	FCE
Residential (Schedule 1, and 3)	367,032,962	5,425,559,433	$0.067649
Residential On-Site Generation	8,715,991	122,912,496	$0.070912
Small General Service	8,266,319	138,285,160	$0.059777
Small General Service On-Site Generation	27,218	370,708	$0.073423
Customer Group	**Total Distribution & Customer Fixed Cost Revenue from Energy Charges**	**2023 kWh**	**FCE-DIST**
Residential (Schedule 1, and 3)	125,476,059	5,425,559,433	$0.023127
Residential On-Site Generation	3,620,717	122,912,496	$0.029458
Small General Service	3,257,318	138,285,160	$0.023555
Small General Service On-Site Generation	12,337	370,708	$0.033278

Q. Please describe Schedule 5 FCE and FCE-DIST derivation.

A. The kWh sales forecast for Schedule 5 customers is multiplied by the Residential FCE to determine the actual fixed cost collection through the energy charge in the forecast. That resulting value is removed from the amount of energy sales revenue forecast for Schedule 5, with the amount remaining considered to be the energy cost in energy revenue. Energy cost in energy revenue is seasonalized based on CCOS-informed summer/non-summer energy cost ratio. Finally, the energy cost in energy revenue for that season is allocated to the on-peak and off-peak period based on the time-of-use billing determinants, with the per-energy unit cost retaining a four-to-one differential in the summer, and 1.5-to-one differential in the non-summer season. The proposed energy rates from Mr. Anderson’s workpapers are reduced for the corresponding per-energy unit seasonal energy cost in energy revenue to calculate a matching differential Schedule 5 FCE rate. The process is replicated for the FCE-DIST for new Schedule 5 customers. Page 5 of Exhibit No. 50 is the workpaper supporting derivation of Schedule 5 FCE and FCE-DIST rates.

Q. How do the FCC and FCE computed in this filing compare to the FCC and FCE established in the Company’s last general rate case, IPC-E-11-08?

A. Both the FCC and FCE rates are greater than those currently in effect, which were established using the functionalized classified revenue requirement data in the Company’s last filed general rate case, Case No. IPC-E-11-08. The Company has made significant investments in its infrastructure since that time, and the newly calculated FCC and FCE rates reflect those fixed costs that are being recovered through the Residential and Small General Service energy charges.

VIII. SPECIAL CONTRACT CUSTOMERS

Q. Please provide an overview of the Company’s Special Contract customers and how rate design was developed.

A. There are six Special Contract customers and associated rate design proposals included in my testimony. First, I will review rate design proposals for Idaho Power’s three long-standing Special Contract customers, Micron, Simplot Pocatello (Schedule 29), and the United States Department of Energy (“DOE”). Second, I will discuss development of rates for J. R. Simplot Company Caldwell, Idaho (“Simplot Caldwell”) (Schedule 32), whose 2015 Special Contract became active at the end of April 2023 when it exceeded the 20 MW threshold for it to become effective. Finally, I will describe CCOS methodology and rate design for future Special Contract customers Brisbie, LLC (“Brisbie”) and Lamb Weston.

Q. What are the Company’s rate design proposals for the long-standing Special Contract customers, Micron, Simplot Pocatello, and the DOE?

A. The Company is proposing to maintain the current rate structures for the active Special Contract customers Micron, Simplot Pocatello, and DOE, but move the rate design components toward CCOS-informed amounts when increasing forecast collections to recover the revenue requirement shown on Exhibit No. 48. This includes reestablishing the Contract Demand charge for Micron and Simplot Pocatello based on the same methodology the Company recently included in the Brisbie[11] and Lamb Weston contracts.

Q. Please describe the derivation of Micron's and Simplot's Pocatello Contract Demand rates.

A. Consistent with the method most-recently reviewed by the Commission as a reasonable basis for Contract Demand rates approved for Brisbie, and proposed for new Special Contract customer Lamb Weston, I propose Micron and Simplot Pocatello's Contract Demand rate is based on costs derived from the Company's Open Access Transmission Tariff ("OATT") rate effective October 1, 2022. The OATT-based Contract Demand reflects the reservation cost that any other customer would pay on Idaho Power's system. To account for collection of costs by the Contract Demand charge, the Billing Demand rate is adjusted to collect any remaining fixed costs not collected through the Contract Demand charge.

Q. What other rate design elements for Micron, Simplot Pocatello, and DOE are proposed to be updated based on CCOS results?

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[11] *In the Matter of Idaho Power's Application for Approval of Special Contract and Tariff Schedule 33 to Provide Electric Service to Brisbie, LLC's Data Center Facility*, Case No. IPC-E-21-42, Goralski DI, p. 13.

A. I propose that the energy rate for Micron, Simplot Pocatello, and DOE match the CCOS-informed energy rate. This proposed change aligns rate design with cost causation by recovering only variable costs through the energy charge.

Q. Have you included rate design workpapers for Micron, Simplot Pocatello, and DOE?

A. Yes, Exhibit No. 51 includes rate design workpapers for all six Special Contract customers, current and future.

Q. Please describe the Simplot Caldwell Special Contract pricing and CCOS analysis.

A. As noted earlier, in late April 2023 Simplot Caldwell crossed the 20 MW customer load threshold to activate their Special Contract. Idaho Power endeavors that the GRC test year uses the best information available to the Company at the time of development. For Simplot Caldwell, while their Special Contract was approved in 2015, prior to April, Simplot Caldwell had not previously exceeded the threshold to begin taking service under their Special Contract rates. Because historical customer usage has remained slightly below their forecast usage and they remained a Schedule 19 customer since approval of the Special Contract, Idaho Power included Simplot Caldwell as part of the Schedule 19 customer class in the 2023 GRC test year load forecast, consistent with customer load until late April 2023.

For Simplot Caldwell, I completed pricing analysis by first removing their Schedule 19 load statistics from the CCOS study, and then added back their customer-provided Special Contract forecast load as an individual customer to complete cost assignment. This is similar to the approach Idaho Power has utilized when pricing new Special Contract customers between GRC, which is in alignment with the Commission's direction provided in Case No. IPC-E-13-23.[12]

Q. Was additional consideration required as part of developing Simplot Caldwell’s proposed rate design?

A. Yes. It’s important to distinguish the rates and revenue collection forecast for Simplot Caldwell in the 2023 GRC test year, which are based on Schedule 19 rates and a lower, historical usage profile, versus the higher load forecast assumptions for cost assignment as a Special Contract. In the CCOS analysis, the historical basis Simplot Caldwell collections under Schedule 19 are approximately $6.7 million, while the revenue requirement based on their higher, Special Contract load forecast is

[12] *In the Matter of the Application of Idaho Power Company for Approval of a Special Contract with J.R. Simplot Company*, Case No. IPC-E-13-23, Order No. 33038 at 12 (May 19, 2014) (". . . we find that a rate utilizing cost-of-service as a starting point for negotiation is consistent with prior Commission Orders and is fair, just and reasonable.")

$9.97 million. However, because Simplot Caldwell has existing Schedule 32 rates, rate design was evaluated by using current Schedule 32 rates applied to the higher, Simplot Caldwell load forecast used in the completion of the Special Contract CCOS cost assignment.

Q. What is the resulting revenue requirement change and proposed rate design for Simplot Caldwell?

A. I propose to increase Simplot Caldwell’s revenue requirement by $6,518 to bring them up to CCOS results, as revenue collection under existing Schedule 32 rates and the forecast Special Contract load are nearly aligned with Simplot Caldwell’s cost assignment. Consistent with rate design proposed for Micron and Simplot Pocatello, I propose to update Simplot Caldwell’s Contract Demand rate to be OATT-based, and for the energy rate to match CCOS.

Q. How was pricing developed for future Special Contract customer Lamb Weston, which is an Idaho Power tariff Schedule 19P customer today?

A. Idaho Power recently filed an application to enter into a Special Contract with Lamb Weston in recognition of their forecast load exceeding 20 MW in July 2023.[13] However, Lamb Weston’s current load is less than 20 MW, and the 2023 CCOS test year data includes Lamb Weston

[13] *In the Matter of Idaho Power’s Application for Approval of Special Contract and Tariff Schedule 34 to Provide Electric Service to Lamb Weston, Inc.*, Case No. IPC-E-23-18, filed May 23, 2023.

as part of Schedule 19 load statistics, consistent with the level of service they currently receive from Idaho Power.

Similar to Simplot Caldwell, I completed pricing analysis by first removing Lamb Weston's Schedule 19 load statistics from the CCOS study, and then added back their future, customer-provided Special Contract steady-state forecast load as an individual customer to complete cost assignment.

Q. Why didn't the Company include Lamb Weston as a Special Contract customer in the GRC test year to develop rates?

A. Lamb Weston is in the process of a plant expansion at its facility in American Falls and is forecast to exceed the Schedule 19 service eligibility threshold in the second half of 2023 but not complete expansion until mid-2024. Due to uncertainty associated with the exact timing of that expansion, it is appropriate to include Lamb Weston's forecast Special Contract system utilization in a future GRC test year once that usage has been achieved.

If Lamb Weston was removed from the Schedule 19 test year load statistics but remained a Schedule 19 customer after the GRC, the total Schedule 19 class would be under-assigned costs, which would instead be allocated to all other Idaho Power customer classes. There is inherent regulatory lag when pricing new, proposed Special Contract customers and the future point in time when all customer rates are re-balanced. The process Idaho Power followed to price Lamb Weston's Special Contract rates incorporates the best-known, historical information for this customer at the time of GRC filing.

Q. Please describe Lamb Weston's rate design components.

A. As described in more detail in the Company's recent filing for Commission approval of the Lamb Weston Special Contract, Case No. IPC-E-23-18, Lamb Weston's Special Contract rates incorporate a two-block, embedded and marginal-cost-based pricing structure. Block 1 represents the first 20 MW of Lamb Weston's load and is priced at Schedule 19 – Primary retail rates, and Lamb Weston' load exceeding 20 MW is priced on an embedded cost basis for capacity and marginal cost basis for energy. Because block 1 references Schedule 19 rates, I propose mirroring the rates proposed by Mr. Anderson for Schedule 19. The marginal energy cost portion of Lamb Weston's second block is based on an annual power supply cost forecast consistent with the PCA test year, with proposed marginal cost rate updates to occur at an annual interval in the spring with updated effective marginal energy rate each June 1st. My rate design focuses on the block 2 demand charge, which is the sole component that is determined by

CCOS for Lamb Weston as a class of one.

Q. What is the resulting proposed block 2 Billing Demand Charge for Lamb Weston?

A. Lamb Weston’s block 2 Billing Demand is proposed to be $23.80 per kW. This represents recovery of Lamb Weston’s CCOS revenue requirement, which will not be recovered under either block 1 rate components or the Contract Demand charge.

Q. How was pricing for Brisbie developed for their Special Contract rates?

A. Brisbie is forecast to come online beyond the test year period and as a result, no 2023 CCOS customer class adjustment was necessary to remove test year load for Brisbie. Similar to the methodology described in my testimony in the case to establish the current Brisbie, Schedule 33 rates,[14] for the loads that fall under the embedded portion of Brisbie’s second block, Brisbie received their load ratio share of embedded capacity costs for a 30 MW steady-state operation assumption.

Brisbie’s block 1 rates are fully-embedded and based on Schedule 19 – Transmission retail rates, which have been updated to match the proposed rates for Schedule 19

[14] *In the Matter of Idaho Power’s Application for Approval of Special Contract and Tariff Schedule 33 to Provide Electric Service to Brisbie, LLC’s Data Center Facility*, Case No. IPC-E-21-42, Goralski DI, p. 21-42.

provided by Mr. Anderson. Following the terms of the Brisbie Special Contract, the Contract Demand Charge, and Daily Excess Demand Charge have been updated based on the OATT rates in effect October 1, 2022. The remainder of Brisbie's block 2 rates are contractually established in the Brisbie Special Contract and follow an update schedule independent of updates to the Company's CCOS study.

Q. What is the resulting proposed block 2 Billing Demand Charge for Brisbie?

A. Brisbie's block 2 Billing Demand is proposed to be $22.07 per kW. This represents recovery of Brisbie's CCOS revenue requirement which will not be recovered under either block 1 rate components or the Contract Demand charge.

IX. SCHEDULE 20 PRICING

Q. Does the Company currently have any Schedule 20 customers, or are any included in the 2023 test year?

A. No. While Idaho Power continues to respond to prospective customers that are exploring service under Schedule 20, there are no active customers taking service under Schedule 20, thus none were included in the 2023 test year.

Q. Please provide an update on any Schedule 20-related active Commission proceedings.

A. As directed by the Commission, on December

28, 2022, Idaho Power filed an Application recommending two proposals for the Commission's consideration on what, if any, compensation for mandatory interruption should be applicable to Schedule 20 customers.[15] The case is currently ongoing with a deadline for Staff and public comments of June 7, 2023, and a June 21, 2023, Company Reply Comment deadline.

Q. Is the Company proposing any changes to Schedule 20 rates as part of this GRC?

A. Yes. While the Company believes embedded rate components should remain based on underlying Schedule 9 and 19 rates as designed until sufficient Schedule 20 customers have joined Idaho Power's system to complete class-specific cost assignment, Idaho Power recommends updating the marginal energy component basis of Schedule 20, and aligning to the time-of-use periods with those proposed for Schedule 9 and 19.

As recommended by Staff,[16] and adopted by the Commission,[17] the Company agreed[18] that evaluation and comparison of methods other than DSM Avoided Cost Averages

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[15] *In the Matter of Idaho Power's Application for Authority to Establish Compensation for the Mandatory Interruption Requirement of Schedule 20 – Speculative High-Density Load*, Case No. IPC-E-22-30.
[16] *In the Matter of the Application of Idaho Power Company for Authority to Establish a New Schedule to Serve Speculative High-Density Load Customers*, Case No. 21-37, Staff Comments, p. 6.
[17] Case No. IPC-E-21-37, Order 35428, p. 7.
[18] Case No. IPC-E-21-37, Idaho Power Reply Comments, p. 5.

for setting the Schedule 20 energy rates should be completed prior to filing the Company’s next (this) GRC. An evaluation is critical to ensure that referenced marginal prices best reflect costs the Company is actually incurring and are recovered through the PCA, which would not be collectable from Schedule 20 as the PCA rate does not apply to Schedule 20 energy sales priced at a marginal rate.

Idaho Power met with Staff on January 20, 2023, and again on February 2, 2023, to discuss the results of Idaho Power’s evaluation and to solicit Staff’s feedback. Subsequent to the two discussions, Staff provided a memo, included as Exhibit No. 52, outlining five general criteria that should be considered when developing marginal cost-based customer energy rates:

- The resources used in a model for determining marginal cost should be based on the resources that are highly likely to exist during the rate period.
- The amount of incremental load used to determine the marginal cost rate should reflect the amount of incremental load for the portion of load that will be priced at marginal cost.
- The marginal cost rates should have enough granularity to reflect time difference (e.g. seasonality, time of day) value of Marginal

Cost within the Company’s system to provide accurate price signals.

- If the marginal cost rates are based on a forecast, due to the lack of marginal costs being trued-up in the PCA, they should be updated often enough that they reflect current conditions or find a way to true up the marginal cost to actual marginal cost.
- If market costs are used, cost of transmission transaction and wheeling costs should be included.

Q. What marginal cost basis does Idaho Power propose for Schedule 20’s energy rates?

A. In replacement of the current DSM Avoided Cost Average-based marginal rates, the Company proposes to use an AURORA-based method. This achieves several of the criteria noted in Staff’s memo including granularity to reflect time differences, costs based on resources likely to exist during the rate period, and more frequent updates to reflect more current market conditions than DSM Avoided Cost Averages.

The marginal cost of energy is determined from the simulated hourly operation of the Company’s power supply system over forecast hydro conditions. Net power supply expenses are first quantified using the Company’s expected load for the test year, then an incremental load increase is added to determine the resulting increase in power supply expenses and generation. The difference in monthly power supply expenses between the initial and subsequent simulation is divided by the difference in generation to produce a marginal cost per kWh.

Q. What are the resulting marginal energy rates, and at what interval does the Company propose to make updates?

A. The proposed seasonal, time-of-use marginal rates are as follows:

TABLE 6

Proposed Seasonal – Time of use Marginal Rates

SONP ($/kWh)	$ 0.068108
SMP ($/kWh)	$ 0.095308
SOFP ($/kWh)	$ 0.050374
NSONP ($/kWh)	$ 0.048629
NSMP ($/kWh)	$ 0.068321
NSOFP ($/kWh)	$ 0.057180

The Company proposes Schedule 20 energy rates be updated annually on June 1 using a forward test year consisting of the 12-month period April through the subsequent March, consistent with power cost spring filings.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF PAWEL P. GORALSKI

I, Pawel P. Goralski, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Pawel P. Goralski. I am employed by Idaho Power Company as a Regulatory Consultant in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 36 through 52 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: Pawel P. Goralski
PAWEL P. GORALSKI

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI
TESTIMONY

EXHIBIT NO. 36

Class Cost-of-Service Process Guide

The following document is a technical description of Idaho Power Company's Class Cost-of-Service study. The methodology for separating costs among classes consists of three steps, generally referred to as classification, functionalization, and allocation. In all three steps, recognition is given to how costs are incurred by relating these costs to how the utility operates to provide electrical service.

I. PROCESS OVERVIEW

A. Classification

The *Electric Utility Cost Allocation Manual*, published in January 1992 by the National Association of Regulatory Utility Commissioners, serves as the basis for the company's classification process. Classification refers to identifying a cost as being either customer-related, demand-related, or energy-related. These three cost components are used to reflect that an electric utility makes service available to customers continuously; provides as much service, or capacity, as the customer desires at any point in time; and supplies energy to provide customers the ability to do useful work over an extended period of time. These three concepts of availability, capacity, and energy are related to the three components of cost, designated as customer, demand, and energy components, respectively. To classify a particular cost by component, focus is given to whether the cost varies because of changes in the number of customers, changes in demand imposed by the customers, or changes in energy used by the customers.

Examples of customer-related costs include the following:

- Plant investments and expenses associated with meters and service drops
- Meter reading
- Billing and collection
- Customer information and services
- Investment in the distribution system

These cost are based on the number of customers, regardless of the amount of energy used, and are generally considered to be fixed costs.

Demand-related costs are investments in generation, transmission, and a portion of the distribution plant and the associated operation and maintenance (O&M) expenses necessary to accommodate the maximum demand imposed on the company's system.

Energy-related costs are generally the variable costs associated with operating generating plants, such as fuel.

B. Functionalization

In addition to classification, costs must be functionalized; that is, identified with utility operating functions. Operating functions recognize different roles played by various facilities in the electric utility system. In the company's accounts, these roles are recognized to some degree, particularly in recording plant costs as production-, transmission-, or distribution-related. However, this functional breakdown is not sufficient for cost-of-service purposes. Individual plant items are examined and, where possible, associated investment costs are assigned to one or more operating functions, such as substations, primary lines, secondary lines, and meters. This level of functionalization allows costs to be more equitably allocated among classes of customers.

C. Allocation and Summarization of Results

Once costs are classified and functionalized, they are allocated to rate classes based on the appropriate allocation factors. After individual costs are allocated to the various classes of service, to the company totals these costs as allocated and arrive at a breakdown of utility rate base and expenses by class. The results are summarized to measure adequacy of revenues for each class. The measure of adequacy is typically the rate of return earned on rate base compared to the requested rate of return.

II. ASSIGN MODULE AND FUNCTIONALIZED COST MODULE

The class cost-of-service model is made of two separate Microsoft® Excel workbooks. The first workbook, called the Assign Module (AS Module), performs the previously described classification and functionalization processes. This module categorizes the Idaho jurisdictional costs identified by the Federal Energy Regulatory Commission (FERC) account into operating functions, such as production, transmission, distribution, metering, customer service, etc. It also categorizes the functional costs into demand-, energy-, and customer-related classifications. For example, the AS Module categorizes the company's investment in steam plant into the production function and the demand- and energy-related classifications.

The second workbook, called the Functionalized Cost Module (FC Module), performs the class allocation process. This module allocates the classified and functionalized costs developed in the AS Module to various customer classes. For example, the FC Module allocates the demand- and energy-related production costs identified in the AS Module to each of the company's customer classes and special contract customers. Each operation performed by this module is shown as a separate worksheet to make the allocation process transparent and easier to understand.

III. CLASSIFICATION

A. Steam and Hydro Production

In this Class Cost-of-Service study all production plants (steam, hydro, other [including natural-gas fueled and battery-storage capacity], and diesel) have been classified as 100% demand-related, as capital investment in production plants may be considered *fixed* from a traditional accounting definition. Transmission plants are also classified as demand-related, which is consistent with prior cost-of-service studies.

B. PURPA and Purchased-Power Expenses

PURPA and purchased-power expenses booked to FERC Account 555 are classified as 100% energy-related as costs may be considered variable from a traditional accounting definition as they vary based on the amount of energy provided.

C. Distribution Plant

Distribution substation plant accounts 360, 361, and 362 are classified as demand-related. Distribution plant accounts 364, 365, 366, 367, and 368 are classified as either demand-related or customer-related using the same fixed and variable ratio computation method used in the company's prior general rate case proceedings. The fixed-to-variable ratio is updated according to a system capacity utilization measurement based on a three-year average load duration curve.

IV. FUNCTIONALIZATION

A. General Plant

General plant is functionalized based on total production, transmission, and distribution plant. As a result, a portion of general plant is assigned to each production, transmission, and distribution function based on each function's proportion to the total.

B. Accumulated Provision for Depreciation

The accumulated provision for depreciation is functionalized using the resulting functionalization of costs for the appropriate plant item. For example, the accumulated depreciation for steam production plant shown is functionalized based on the functionalization of steam production plant in service.

C. Additions to and Reductions from Rate Base

Deductions from rate base include customer advances for construction and accumulated deferred income taxes. Customer advances are functionalized based on the distribution plant investment against which the advances apply. Accumulated deferred taxes are functionalized based on total plant investment. Additions to rate base consist of 1) fuel inventory, which is functionalized based on energy production and 2) materials and supplies, which are functionalized based on the appropriate plant function. Energy efficiency program expenses are functionalized consistent with baseload production resources as demand-side management may be considered similar to a supply-side resource.

D. Other Operating Revenue

Other operating revenue is functionalized based on either the functionalization of the related rate base item or, in the situation where a particular revenue item may be identified with a specific service, the functionalization of the specific service item.

E. O&M Expense

In general, the basis for the functionalization of O&M expense is the same as that for the associated plant.

F. Labor Components

For each applicable expense account in each functional group, the labor component is separately functionalized. For example, for Account 535 the labor-related supervision and engineering expense is functionalized based on the cumulative labor as functionalized for accounts 536 through 540. Similarly, the allocation of supervision and engineering associated with hydraulic maintenance expense, Account 541, is based on the composite labor expense for accounts 542 through 545. Total functionalized labor expense serves the additional purpose of functionalizing employee pensions and other labor-related taxes and expenses.

G. Depreciation Expense, Taxes Other than Income, and Income Taxes

Depreciation expense is functionalized based on the function of the associated plant. Taxes, other than income, are also functionalized based on the function of the source of the tax. Deferred income taxes are functionalized based on plant investment. The functionalization of federal and state income taxes is based on the functionalization of total rate base and expenses.

V. ALLOCATION

A. Derivation of Peak Demands

For customers taking service through Advanced Metering Infrastructure (AMI) and interval meters, system coincident demands are taken directly from their meter read data, as this represents 99.8% of Idaho Power's customers it is significant enough to average and apply to any non-AMI or non-interval customer. Coincident demands are estimated through the use of system coincident demand factors. These factors are defined as the ratio of the system coincident demand to the population's average demand. To determine the monthly system coincident peak demands by rate class, each class's monthly system coincident demand factors from load research are applied to the test-year monthly average demand values for each class. Similarly, a non-coincident (group) demand factor is defined as the ratio of a population's non-coincident peak demand to the population's average demand. To determine the monthly non-coincident peak demands by rate class, each class's monthly non-coincident demand factors from load research are applied to the test-year monthly average demand values for each class.

Customers are billed throughout each month and billing periods (cycles). These cycles typically include portions of more than one calendar month. Billing period data is converted into calendar month data using a nonlinear method based on load research data that uses actual daily usage patterns. Total daily consumption is assumed to fluctuate in proportion to the fluctuations in the daily consumption of the load research customers. This methodology captures the effects of weather on energy consumption and improves the process of determining coincident peak demand responsibility.

To account for the partial requirement nature of on-site generation customers, measurement of the energy delivered to customers is the basis of energy and system coincident load statistics. On-site generation exports are independently valued outside the Class Cost-of-Service study.

B. Marginal Cost Usage

While the four coincident peak demands (4CP)/12 monthly coincident demands (12CP) methodology eliminates the need for marginal cost weighting in the allocation of production plant costs, this weighting is necessary to properly seasonalize energy- and transmission-related costs. The use of marginal cost weighting balances costs already incurred and costs to be incurred in the future, and injects into the allocation process recognition of the influence seasonal load profiles have on cost causation.

The marginal costs associated with new resource integration are seasonalized based on the monthly peak-hour generation deficiencies that the company expects to encounter during the next five years of the planning period based on the 50th percentile water plus and 50th percentile plus 15.5% reserve margin load criteria used for planning purposes. The relative sizes of the five-year average monthly peak-hour deficiencies identified in the *2021 Integrated Resource Report* (IRP) are used to define the share of the annual capacity cost assigned to each month. The marginal costs associated with planned system expansions are seasonalized based on the monthly share of projected peak-hour load growth. The total demand-related transmission marginal costs for each month are then derived by adding the monthly values for both categories of transmission costs.

Updated marginal energy costs are calculated by quantifying the difference in net power supply costs resulting from the addition of 50 megawatts (MW) of load to all hours of the company's base case system simulation run for the five-year planning period. It should be noted that the marginal costs have been used solely for purposes of developing allocation factors and not for purposes of developing the company's revenue requirement.

C. Production Plant Cost Allocation

The class cost-of-service study allocates the costs of the company's generation peaking facilities differently than its base-load resources. Rather than allocating all production plant based on the same allocation factor, this method allocates production plant costs based on the nature of the load being served. Under this approach, production plant costs associated with serving summer peak load are allocated separately from costs associated with serving the base and intermediate load. That is, the costs associated with building and operating the simple cycle combustion turbines, which are used primarily to serve summer peak loads, have been allocated to customers differently than the costs associated with the company's other generation resources, including the Langley Gulch combined-cycle combustion plant (CCCP). This method allocates production plant costs associated with serving base and intermediate load using an average of 12CP, without marginal cost weighting. Using an un-weighted 12CP allocator is appropriate in this case given that fixed base and intermediate generation costs do not vary greatly between the summer and non-summer seasons. Furthermore, the study allocates fixed generation costs associated with serving peak load using an average of the 4CP occurring in June, July, August, and September. This method of allocation isolates the costs associated with peaking resources and allocates those costs according to the load that is causing the investment.

The cost allocation method used in the study is based on the concept that the costs associated with each of the company's generation resources can be categorized according to the type of loads being served. Utilities typically experience three distinct time-based production costing periods that are driven by customer loads. The costing periods are normally identified as base, intermediate, and peak. The base period is equivalent to a low load or off-peak time period where loads are at the lowest, normally during the nighttime hours. The intermediate time period represents the shoulder hours which are driven by the mid-peak loads that typically occur throughout the winter daytime and in the early morning and late evening during the summer months. The peak category is driven by the peak loads that occur during summer afternoons and evenings. The base and intermediate loads on the company's system are typically served by the same generation resources. Those two categories have been combined for cost allocation purposes. The generation resources that serve the peak loads (i.e., combustion turbines) are normally only used for that purpose. Consistent with that concept, the costs associated with peak-related resources have been segmented into a second category for cost-allocation purposes. Using this methodology, there is no need for marginal cost weighting because the seasonal nature of the loads is reflected in the allocation factors.

The production plant costs that have been classified as serving base and intermediate load are captured in accounts 310 through 316, Steam Production and accounts 330 through 336, Hydraulic Production. Accounts 340-346, Other Production, for the Langley Gulch CCCP, and the Account 363 where the company's battery storage system is recorded. The costs identified under the Steam Production category represent the company's investment in coal-fired generation facilities, and the costs identified under the Hydraulic Production category represent the company's investment in its hydroelectric generation facilities. The majority of costs associated with the company's coal-fired facilities have been removed from the test year as there are cost recovery mechanisms in place based on the announcement of upcoming retirement.

Utilities typically use generation resources to serve customer loads by operating the resources with the lowest operating cost first, and as demand grows, more costly resources are then dispatched. This is no different for Idaho Power. However, since hydroelectric generation is such a significant portion of the company's resource stack, stream-flow conditions and economics can influence the proportionate share of output provided by steam and hydro resources throughout the year. Since hydroelectric output is highly dependent on stream flows, steam production is ramped up or down according to the production capability of hydro generation. Therefore, throughout the year, hydro- and steam-production plants are used at varying proportions to serve base and intermediate loads according to the production capabilities of the hydro plants. However, the combined monthly output of these two resources does not vary significantly between the summer and non-summer months as does the output of the combustion turbines.

Accounts 340 through 346, Other Production, contain the company's investment in gas-fueled production plant. The production plant investment captured in accounts 340 through 346 represents both the company's investment in simple-cycle combustion plants (SCCP), and CCCPs. Because these resources are dispatched to meet different types of customer load, they are listed independently between the Langley Gulch CCCP that serves base and intermediate load, while Bennett Mountain and Danksin SCCPs are peak-load serving resources. The investment identified as peaking plant is the investment in combustion-turbine generation resources that were constructed specifically to meet the summer peak loads.

In the Functionalized Cost Module, D10BS and D10BNS describe the factors used to allocate the production plant associated with serving the base and intermediate loads. D10P describes the allocation factor used to allocate the production plant associated with serving the peak loads. The D10BS and

D10BNS represent the non-weighted average 12 coincident peak demands for the summer and non-summer seasons respectively. D10P represents the non-weighted average four coincident peak demands for June, July, August and September.

D. Transmission and Distribution Cost Allocation

The company's approach to cost allocation for transmission and distribution facilities is an effective method for equitably assigning costs to customer classes. Under this method, transmission and distribution (T&D) costs are properly segmented according how costs are imposed on the system. As a result, the cost responsibility of each class can be effectively identified through a combination of direct cost assignment and cost allocation based on the appropriate demand- or customer-based factors.

D13 is used to allocate transmission costs to customer classes. The first step in deriving this factor is to calculate ratios based on the sum of the actual coincident peak demands for each customer class. Second, weighted coincident peak demand values are derived by multiplying the actual monthly coincident peak demands by the monthly transmission marginal costs. Corresponding weighted ratios are then calculated for each customer class. Finally, the actual ratios are averaged with the weighted ratios to derive the non-seasonalized transmission allocation factor D13. The company applies this averaging approach as a rate stability measure intended to mitigate any extreme impacts that the marginal costs may have on cost allocation.

The capacity components of distribution plant, both primary and secondary, are allocated by the non-coincident group peak demands for each customer class identified as demand allocation factors D20, D30, D50, and D60.

The customer components of distribution plant, both primary and secondary, are allocated by the average number of customers identified as customer allocation factors C20, C30, C50 and C60.

E. Energy-Related Cost Allocation

The energy-related cost allocators, E10S and E10NS, are derived by averaging the normalized energy values for each customer class with the normalized energy values weighted by the marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next, summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the E10S and E10NS allocators used in this study. This averaging approach is consistent with the methodology used in the derivation of the demand-related allocation factor D13.

The principal customer accounting expenses which require allocation are meter reading expenses, customer records and collections, and uncollectible accounts. The meter reading and customer records and collection expenses are allocated based upon a review of actual practices of the company in reading meters and preparing monthly bills. The allocation of uncollectible amounts is similarly based upon a review of actual company data. Customer assistance expenses are allocated based on the average number of customers in each class.

F. State and Federal Income Tax Allocation

The state and federal income taxes for the Idaho jurisdiction are allocated to each customer class and special contract customer according to each class's allocated share of rate base. Once the state and federal income taxes are allocated to each customer class, they are functionalized based on the functionalization of total rate base and expenses for each class.

VI. REVENUE REQUIREMENT AND APPLICATION

Once all costs have been properly functionalized, classified, and allocated, the company is able to determine the revenue requirement for each customer class. The sales revenue required includes return on rate base, total operating expenses, and incremental taxes computed using the net-to-gross multiplier.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 37

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
10	***** TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***											
11												
12	INTANGIBLE PLANT											
13	301	ORGANIZATION	P101P	5,455	1,875	177				1,270		0
14	302	FRANCHISES & CONSENTS	P101P	50,540,892	17,368,179	1,636,704				11,766,485		690
15	303	MISCELLANEOUS	P101P	50,240,922	17,265,096	1,626,990				11,696,649		686
16												
17		TOTAL INTANGIBLE PLANT		100,787,269								
18												
19	PRODUCTION PLANT											
20	310-316	STEAM PRODUCTION	PI-S	267,099,895	267,099,895							
21	330-336	HYDRAULIC PRODUCTION	PI-H	1,058,946,870	1,058,946,870							
22	340-346 / OTHER PRODUCTION-BASELOAD		PI-S	425,197,122	425,197,122							
23	340-346 / OTHER PRODUCTION-PEAKERS		PI-O	180,830,345		180,830,345						
24												
25		TOTAL PRODUCTION PLANT		1,932,074,232								
26												
27	TRANSMISSION PLANT											
28	350	LAND & LAND RIGHTS										
29		TRANSMISSION SERVICE	T-100	39,364,923						39,364,923		
30		DIRECT ASSIGNMENT	T-Direct									
31		TOTAL ACCOUNT 350		39,364,923								
32												
33	352	STRUCTURES & IMPROVEMENTS										
34		TRANSMISSION SERVICE	T-100	96,459,348						96,459,348		
35		DIRECT ASSIGNMENT	T-Direct									
36		TOTAL ACCOUNT 352		96,459,348								

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
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		(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			* *			DISTRIBUTION FUNCTION	* *					
		ALLOCATOR	SUBSTATION GENERAL	SUBSTATION DIRECT	SUBSTATION CIAC	PRI LINES DEMAND	PRI LINES CUSTOMER	SEC LINES DIRECT	LINE TRANS PRI DMD	LINE TRANS PRI CUST	LINE TRANS PRI DIRECT	LINE TRANS SEC DMD
**** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ****												
INTANGIBLE PLANT												
301	ORGANIZATION	P101P	411	19		502	249	31	113	56	31	326
302	FRANCHISES & CONSENTS	P101P	3,805,916	177,495		4,648,412	2,303,818	290,482	1,045,627	518,227	289,784	3,024,081
303	MISCELLANEOUS	P101P	3,783,327	176,442		4,620,823	2,290,145	288,758	1,039,421	515,152	288,064	3,006,133
	TOTAL INTANGIBLE PLANT											
PRODUCTION PLANT												
310-316	STEAM PRODUCTION	PI-S										
330-336	HYDRAULIC PRODUCTION	PI-H										
340-346 / OTHER PRODUCTION-BASELOAD		PI-S										
340-346 / OTHER PRODUCTION-PEAKERS		PI-O										
	TOTAL PRODUCTION PLANT											
TRANSMISSION PLANT												
350	LAND & LAND RIGHTS											
	TRANSMISSION SERVICE	T-100										
	DIRECT ASSIGNMENT	T-Direct										
	TOTAL ACCOUNT 350											
352	STRUCTURES & IMPROVEMENTS											
	TRANSMISSION SERVICE	T-100										
	DIRECT ASSIGNMENT	T-Direct										
	TOTAL ACCOUNT 352											

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

		(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
			* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
		ALLOCATOR	LINE TRANS SEC CUST	SEC LINES DEMAND	SEC LINES CUSTOMER	SERVICES	METERS	STREET LIGHTS	INSTALLATION CUST PREM
**** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ****									
INTANGIBLE PLANT									
301	ORGANIZATION	P101P	162	32	16	65	110	6	4
302	FRANCHISES & CONSENTS	P101P	1,498,777	297,898	147,642	606,237	1,020,415	54,864	39,157
303	MISCELLANEOUS	P101P	1,489,881	296,130	146,766	602,639	1,014,358	54,538	38,925
	TOTAL INTANGIBLE PLANT								
PRODUCTION PLANT									
310-316	STEAM PRODUCTION	PI-S							
330-336	HYDRAULIC PRODUCTION	PI-H							
340-346 / OTHER PRODUCTION-BASELOAD		PI-S							
340-346 / OTHER PRODUCTION-PEAKERS		PI-O							
	TOTAL PRODUCTION PLANT								
TRANSMISSION PLANT									
350	LAND & LAND RIGHTS								
	TRANSMISSION SERVICE	T-100							
	DIRECT ASSIGNMENT	T-Direct							
	TOTAL ACCOUNT 350								
352	STRUCTURES & IMPROVEMENTS								
	TRANSMISSION SERVICE	T-100							
	DIRECT ASSIGNMENT	T-Direct							
	TOTAL ACCOUNT 352								

IDAHO POWER COMPANY
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FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

		(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
			- - - CUSTOMER ACCOUNTING FUNCTION - - -				***** CUSTOMER INFORMATION FUNCTION *****			
		ALLOCATOR	METER READING	CUSTOMER RECORDS	UNCOLLECT ACCOUNTS	OTHER	CUSTOMER ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
***** TABLE 1 - ELECTRIC PLANT IN SERVICE *****										
INTANGIBLE PLANT										
301	ORGANIZATION	P101P								
302	FRANCHISES & CONSENTS	P101P								
303	MISCELLANEOUS	P101P								
	TOTAL INTANGIBLE PLANT									
PRODUCTION PLANT										
310-316	STEAM PRODUCTION	PI-S								
330-336	HYDRAULIC PRODUCTION	PI-H								
340-346 /	OTHER PRODUCTION-BASELOAD	PI-S								
340-346 /	OTHER PRODUCTION-PEAKERS	PI-O								
	TOTAL PRODUCTION PLANT									
TRANSMISSION PLANT										
350	LAND & LAND RIGHTS									
	TRANSMISSION SERVICE	T-100								
	DIRECT ASSIGNMENT	T-Direct								
	TOTAL ACCOUNT 350									
352	STRUCTURES & IMPROVEMENTS									
	TRANSMISSION SERVICE	T-100								
	DIRECT ASSIGNMENT	T-Direct								
	TOTAL ACCOUNT 352									

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

		(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
			- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
		ALLOCATOF						& REVENUES
			DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
**** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ****								
INTANGIBLE PLANT								
301	ORGANIZATION	P101P						
302	FRANCHISES & CONSENTS	P101P						
303	MISCELLANEOUS	P101P						
	TOTAL INTANGIBLE PLANT							
PRODUCTION PLANT								
310-316	STEAM PRODUCTION	PI-S						
330-336	HYDRAULIC PRODUCTION	PI-H						
340-346 / OTHER PRODUCTION-BASELOAD		PI-S						
340-346 / OTHER PRODUCTION-PEAKERS		PI-O						
	TOTAL PRODUCTION PLANT							
TRANSMISSION PLANT								
350	LAND & LAND RIGHTS							
	TRANSMISSION SERVICE	T-100						
	DIRECT ASSIGNMENT	T-Direct						
	TOTAL ACCOUNT 350							
352	STRUCTURES & IMPROVEMENTS							
	TRANSMISSION SERVICE	T-100						
	DIRECT ASSIGNMENT	T-Direct						
	TOTAL ACCOUNT 352							

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Line	Acct	Description	(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
37												
38	353	STATION EQUIPMENT										
39		TRANSMISSION SERVICE	T-100	449,281,302						449,281,302		
40		DIRECT ASSIGNMENT	T-Direct	75,100								75,100
41		TOTAL ACCOUNT 353		449,356,402								
42												
43												
44	354	TOWERS & FIXTURES										
45		TRANSMISSION SERVICE	T-100	227,483,716						227,483,716		
46		DIRECT ASSIGNMENT	T-Direct									
47		TOTAL ACCOUNT 354		227,483,716								
48												
49	355	POLES & FIXTURES										
50		TRANSMISSION SERVICE	T-100	226,404,073						226,404,073		
51		DIRECT ASSIGNMENT	T-Direct									
52		TOTAL ACCOUNT 355		226,404,073								
53												
54	356	OVERHEAD CONDUCTORS & DEVICES										
55		TRANSMISSION SERVICE	T-100	260,645,887						260,645,887		
56		DIRECT ASSIGNMENT	T-Direct	1,189								1,189
57		TOTAL ACCOUNT 356		260,647,076								

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Acct	Description	(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* DISTRIBUTION FUNCTION *									
8			ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
37													
38	353	STATION EQUIPMENT											
39		TRANSMISSION SERVICE	T-100										
40		DIRECT ASSIGNMENT	T-Direct										
41		TOTAL ACCOUNT 353											
42													
43													
44	354	TOWERS & FIXTURES											
45		TRANSMISSION SERVICE	T-100										
46		DIRECT ASSIGNMENT	T-Direct										
47		TOTAL ACCOUNT 354											
48													
49	355	POLES & FIXTURES											
50		TRANSMISSION SERVICE	T-100										
51		DIRECT ASSIGNMENT	T-Direct										
52		TOTAL ACCOUNT 355											
53													
54	356	OVERHEAD CONDUCTORS & DEVICES											
55		TRANSMISSION SERVICE	T-100										
56		DIRECT ASSIGNMENT	T-Direct										
57		TOTAL ACCOUNT 356											

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Acct	Description	(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
8			ALLOCATOR	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
37										
38	353	STATION EQUIPMENT								
39		TRANSMISSION SERVICE	T-100							
40		DIRECT ASSIGNMENT	T-Direct							
41		TOTAL ACCOUNT 353								
42										
43										
44	354	TOWERS & FIXTURES								
45		TRANSMISSION SERVICE	T-100							
46		DIRECT ASSIGNMENT	T-Direct							
47		TOTAL ACCOUNT 354								
48										
49	355	POLES & FIXTURES								
50		TRANSMISSION SERVICE	T-100							
51		DIRECT ASSIGNMENT	T-Direct							
52		TOTAL ACCOUNT 355								
53										
54	356	OVERHEAD CONDUCTORS & DEVICES								
55		TRANSMISSION SERVICE	T-100							
56		DIRECT ASSIGNMENT	T-Direct							
57		TOTAL ACCOUNT 356								

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Acct	Description	(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
37											
38	353	STATION EQUIPMENT									
39		TRANSMISSION SERVICE	T-100								
40		DIRECT ASSIGNMENT	T-Direct								
41		TOTAL ACCOUNT 353									
42											
43											
44	354	TOWERS & FIXTURES									
45		TRANSMISSION SERVICE	T-100								
46		DIRECT ASSIGNMENT	T-Direct								
47		TOTAL ACCOUNT 354									
48											
49	355	POLES & FIXTURES									
50		TRANSMISSION SERVICE	T-100								
51		DIRECT ASSIGNMENT	T-Direct								
52		TOTAL ACCOUNT 355									
53											
54	356	OVERHEAD CONDUCTORS & DEVICES									
55		TRANSMISSION SERVICE	T-100								
56		DIRECT ASSIGNMENT	T-Direct								
57		TOTAL ACCOUNT 356									

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
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FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Acct	Description	(A) ALLOCATOR	(AH) DEMAND	(AI) ENERGY	(AJ) - - - MISCELLANEOUS - - - CUSTOMER	(AK) REVENUE	(AL) OTHER	(AM) INC TAXES & REVENUES TRANSFER
37									
38	353	STATION EQUIPMENT							
39		TRANSMISSION SERVICE	T-100						
40		DIRECT ASSIGNMENT	T-Direct						
41		TOTAL ACCOUNT 353							
42									
43									
44	354	TOWERS & FIXTURES							
45		TRANSMISSION SERVICE	T-100						
46		DIRECT ASSIGNMENT	T-Direct						
47		TOTAL ACCOUNT 354							
48									
49	355	POLES & FIXTURES							
50		TRANSMISSION SERVICE	T-100						
51		DIRECT ASSIGNMENT	T-Direct						
52		TOTAL ACCOUNT 355							
53									
54	356	OVERHEAD CONDUCTORS & DEVICES							
55		TRANSMISSION SERVICE	T-100						
56		DIRECT ASSIGNMENT	T-Direct						
57		TOTAL ACCOUNT 356							

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4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Acct	Description	(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOR		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
58	*** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***											
59												
60	359	ROADS & TRAILS										
61		TRANSMISSION SERVICE	T-100	374,346						374,346		
62		DIRECT ASSIGNMENT	T-Direct									
63		TOTAL ACCOUNT 359		374,346								
64		TOTAL TRANSMISSION PLANT		1,300,089,883								
65												
66												
67	DISTRIBUTION PLANT											
68	360	LAND & LAND RIGHTS										
69		DISTRIBUTION FUNCTION	D360	9,701,731								
70		LESS CIAC	CIAC	(430,355)								
71		TOTAL ACCOUNT 360		9,271,376								
72												
73	361	STRUCTURES & IMPROVEMENTS										
74		DISTRIBUTION FUNCTION	D361	66,884,107								
75		LESS CIAC	CIAC	(7,447,616)								
76		TOTAL ACCOUNT 361		59,436,491								
77												
78	362	STATION EQUIPMENT										
79		DISTRIBUTION FUNCTION	D362	363,519,096								
80		LESS CIAC	CIAC	(34,892,876)								
81		TOTAL ACCOUNT 362		328,626,219								
82												
83	363	STORAGE BATTERY EQUIPMENT										
84		TOTAL BATTERY STORAGE EQUIPMENT	PI-S	167,669,778	167,669,778							
85												
86												
87	364	POLES, TOWERS & FIXTURES	D364	308,137,437								
88	365	OVERHEAD CONDUCTORS & DEVICES	D365	153,461,377								
89	366	UNDERGROUND CONDUIT	D366	53,988,992								
90	367	UNDERGROUND CONDUCTORS & DEVIC	D367	333,844,506								
91	368	LINE TRANSFORMERS	D368	704,503,661								
92	369	SERVICES	SERVICE	66,979,720								
93	370	METERS	METER	112,739,963								
94	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST	4,326,265								
95	373	STREET LIGHTING SYSTEMS	STLIGHT	6,061,607								
96												
97		TOTAL DISTRIBUTION PLANT		2,309,047,394								

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Acct	Description	(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *			DISTRIBUTION FUNCTION		* *				
8			ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
58	*** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***												
59													
60	359	ROADS & TRAILS											
61		TRANSMISSION SERVICE	T-100										
62		DIRECT ASSIGNMENT	T-Direct										
63		TOTAL ACCOUNT 359											
64		TOTAL TRANSMISSION PLANT											
65													
66													
67	DISTRIBUTION PLANT												
68	360	LAND & LAND RIGHTS											
69		DISTRIBUTION FUNCTION	D360	9,701,676	55								
70		LESS CIAC	CIAC			(430,355)							
71		TOTAL ACCOUNT 360											
72													
73	361	STRUCTURES & IMPROVEMENTS											
74		DISTRIBUTION FUNCTION	D361	62,888,583	3,995,524								
75		LESS CIAC	CIAC			(7,447,616)							
76		TOTAL ACCOUNT 361											
77													
78	362	STATION EQUIPMENT											
79		DISTRIBUTION FUNCTION	D362	347,904,235	15,614,861								
80		LESS CIAC	CIAC			(34,892,876)							
81		TOTAL ACCOUNT 362											
82													
83	363	STORAGE BATTERY EQUIPMENT											
84		TOTAL BATTERY STORAGE EQUIPMENT	PI-S										
85													
86													
87	364	POLES, TOWERS & FIXTURES	D364				192,956,701	95,632,049	2,148,004				
88	365	OVERHEAD CONDUCTORS & DEVICES	D365				92,154,627	45,673,126	1,417,325				
89	366	UNDERGROUND CONDUIT	D366				25,677,526	12,726,142	6,542,372				
90	367	UNDERGROUND CONDUCTORS & DEVIC	D367				202,788,361	100,504,758	21,986,065				
91	368	LINE TRANSFORMERS	D368							115,525,520	57,256,069	32,016,611	334,113,916
92	369	SERVICES	SERVICE										
93	370	METERS	METER										
94	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST										
95	373	STREET LIGHTING SYSTEMS	STLIGHT										
96													
97		TOTAL DISTRIBUTION PLANT											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *	DISTRIBUTION FUNCTION	* * * * * * * * * * * * * * *				
8			ALLOCATOR	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
58	*** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***									
59										
60	359	ROADS & TRAILS								
61		TRANSMISSION SERVICE	T-100							
62		DIRECT ASSIGNMENT	T-Direct							
63		TOTAL ACCOUNT 359								
64		TOTAL TRANSMISSION PLANT								
65										
66										
67	DISTRIBUTION PLANT									
68	360	LAND & LAND RIGHTS								
69		DISTRIBUTION FUNCTION	D360							
70		LESS CIAC	CIAC							
71		TOTAL ACCOUNT 360								
72										
73	361	STRUCTURES & IMPROVEMENTS								
74		DISTRIBUTION FUNCTION	D361							
75		LESS CIAC	CIAC							
76		TOTAL ACCOUNT 361								
77										
78	362	STATION EQUIPMENT								
79		DISTRIBUTION FUNCTION	D362							
80		LESS CIAC	CIAC							
81		TOTAL ACCOUNT 362								
82										
83	363	STORAGE BATTERY EQUIPMENT								
84		TOTAL BATTERY STORAGE EQUIPMENT	PI-S							
85										
86										
87	364	POLES, TOWERS & FIXTURES	D364		11,634,473	5,766,208				
88	365	OVERHEAD CONDUCTORS & DEVICES	D365		9,505,326	4,710,973				
89	366	UNDERGROUND CONDUIT	D366		6,046,314	2,996,638				
90	367	UNDERGROUND CONDUCTORS & DEVIC	D367		5,726,960	2,838,362				
91	368	LINE TRANSFORMERS	D368	165,591,546						
92	369	SERVICES	SERVICE				66,979,720			
93	370	METERS	METER					112,739,963		
94	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST							4,326,265
95	373	STREET LIGHTING SYSTEMS	STLIGHT						6,061,607	
96										
97		TOTAL DISTRIBUTION PLANT								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - -	CUSTOMER ACCOUNTING FUNCTION		- - -	* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
58	*** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***										
59											
60	359	ROADS & TRAILS									
61		TRANSMISSION SERVICE	T-100								
62		DIRECT ASSIGNMENT	T-Direct								
63		TOTAL ACCOUNT 359									
64		TOTAL TRANSMISSION PLANT									
65											
66											
67	DISTRIBUTION PLANT										
68	360	LAND & LAND RIGHTS									
69		DISTRIBUTION FUNCTION	D360								
70		LESS CIAC	CIAC								
71		TOTAL ACCOUNT 360									
72											
73	361	STRUCTURES & IMPROVEMENTS									
74		DISTRIBUTION FUNCTION	D361								
75		LESS CIAC	CIAC								
76		TOTAL ACCOUNT 361									
77											
78	362	STATION EQUIPMENT									
79		DISTRIBUTION FUNCTION	D362								
80		LESS CIAC	CIAC								
81		TOTAL ACCOUNT 362									
82											
83	363	STORAGE BATTERY EQUIPMENT									
84		TOTAL BATTERY STORAGE EQUIPMENT	PI-S								
85											
86											
87	364	POLES, TOWERS & FIXTURES	D364								
88	365	OVERHEAD CONDUCTORS & DEVICES	D365								
89	366	UNDERGROUND CONDUIT	D366								
90	367	UNDERGROUND CONDUCTORS & DEVIC	D367								
91	368	LINE TRANSFORMERS	D368								
92	369	SERVICES	SERVICE								
93	370	METERS	METER								
94	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST								
95	373	STREET LIGHTING SYSTEMS	STLIGHT								
96											
97		TOTAL DISTRIBUTION PLANT									

Line	Acct	Description							
1						**IDAHO POWER COMPANY**			
2						**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**			
3						**CLASS COST OF SERVICE STUDY**			
4						**FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**			
5						**FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**			
6			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - -		MISCELLANEOUS	- - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
58	*** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***								
59									
60	359	ROADS & TRAILS							
61		TRANSMISSION SERVICE	T-100						
62		DIRECT ASSIGNMENT	T-Direct						
63		TOTAL ACCOUNT 359							
64		TOTAL TRANSMISSION PLANT							
65									
66									
67	DISTRIBUTION PLANT								
68	360	LAND & LAND RIGHTS							
69		DISTRIBUTION FUNCTION	D360						
70		LESS CIAC	CIAC						
71		TOTAL ACCOUNT 360							
72									
73	361	STRUCTURES & IMPROVEMENTS							
74		DISTRIBUTION FUNCTION	D361						
75		LESS CIAC	CIAC						
76		TOTAL ACCOUNT 361							
77									
78	362	STATION EQUIPMENT							
79		DISTRIBUTION FUNCTION	D362						
80		LESS CIAC	CIAC						
81		TOTAL ACCOUNT 362							
82									
83	363	STORAGE BATTERY EQUIPMENT							
84		TOTAL BATTERY STORAGE EQUIPMENT	PI-S						
85									
86									
87	364	POLES, TOWERS & FIXTURES	D364						
88	365	OVERHEAD CONDUCTORS & DEVICES	D365						
89	366	UNDERGROUND CONDUIT	D366						
90	367	UNDERGROUND CONDUCTORS & DEVIC	D367						
91	368	LINE TRANSFORMERS	D368						
92	369	SERVICES	SERVICE						
93	370	METERS	METER						
94	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST						
95	373	STREET LIGHTING SYSTEMS	STLIGHT						
96									
97		TOTAL DISTRIBUTION PLANT							

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Row			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
98	*** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***											
99												
100	GENERAL PLANT											
101	389	LAND & LAND RIGHTS	P-PTD	20,030,220	6,883,307	648,654				4,663,259		274
102	390	STRUCTURES & IMPROVEMENTS	P-PTD	169,795,289	58,349,486	5,498,610				39,530,244		2,320
103	391	OFFICE FURNITURE & EQUIPMENT	P-PTD	39,636,634	13,620,974	1,283,583				9,227,852		542
104	392	TRANSPORTATION EQUIPMENT	P-PTD	114,700,297	39,416,308	3,714,427				26,703,513		1,567
105	393	STORES EQUIPMENT	P-PTD	5,238,705	1,800,260	169,649				1,219,629		72
106	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD	14,711,683	5,055,612	476,420				3,425,045		201
107	395	LABORATORY EQUIPMENT	P-PTD	14,265,521	4,902,290	461,971				3,321,173		195
108	396	POWER OPERATED EQUIPMENT	P-PTD	26,388,468	9,068,294	854,558				6,143,531		361
109	397	COMMUNICATIONS EQUIPMENT	P-PTD	79,075,745	27,174,070	2,560,770				18,409,719		1,080
110	398	MISCELLANEOUS EQUIPMENT	P-PTD	10,910,380	3,749,309	353,319				2,540,059		149
111												
112		TOTAL GENERAL PLANT		494,752,941								
113												
114	TOTAL ELECTRIC PLANT IN SERVICE			6,136,751,718	2,123,568,725	200,116,177				1,438,662,020		84,425
115												

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *				DISTRIBUTION FUNCTION *					
8			ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
98	*** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***												
99													
100	GENERAL PLANT												
101	389	LAND & LAND RIGHTS	P-PTD	1,508,350	70,344		1,842,245	913,043	115,123	414,400	205,382	114,846	1,198,495
102	390	STRUCTURES & IMPROVEMENTS	P-PTD	12,786,212	596,306		15,616,631	7,739,821	975,893	3,512,849	1,741,017	973,547	10,159,590
103	391	OFFICE FURNITURE & EQUIPMENT	P-PTD	2,984,785	139,200		3,645,512	1,806,767	227,810	820,032	406,419	227,263	2,371,632
104	392	TRANSPORTATION EQUIPMENT	P-PTD	8,637,356	402,817		10,549,363	5,228,413	659,236	2,373,004	1,176,094	657,652	6,863,017
105	393	STORES EQUIPMENT	P-PTD	394,494	18,398		481,821	238,797	30,109	108,382	53,716	30,037	313,454
106	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD	1,107,844	51,666		1,353,082	670,606	84,555	304,366	150,848	84,352	880,264
107	395	LABORATORY EQUIPMENT	P-PTD	1,074,246	50,099		1,312,047	650,269	81,991	295,136	146,273	81,794	853,568
108	396	POWER OPERATED EQUIPMENT	P-PTD	1,987,149	92,674		2,427,034	1,202,872	151,667	545,944	270,577	151,302	1,578,937
109	397	COMMUNICATIONS EQUIPMENT	P-PTD	5,954,696	277,707		7,272,856	3,604,530	454,485	1,635,977	810,813	453,393	4,731,445
110	398	MISCELLANEOUS EQUIPMENT	P-PTD	821,592	38,316		1,003,464	497,331	62,707	225,722	111,871	62,556	652,815
111													
112		TOTAL GENERAL PLANT											
113													
114	TOTAL ELECTRIC PLANT IN SERVICE			465,340,871	21,701,923	(42,770,847)	568,351,006	281,682,735	35,516,616	127,846,492	63,362,516	35,431,232	369,747,673
115													

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
8			ALLOCATOR	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
98	*** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***									
99										
100	GENERAL PLANT									
101	389	LAND & LAND RIGHTS	P-PTD	593,991	118,062	58,513	240,262	404,408	21,744	15,519
102	390	STRUCTURES & IMPROVEMENTS	P-PTD	5,035,235	1,000,806	496,014	2,036,690	3,428,147	184,319	131,551
103	391	OFFICE FURNITURE & EQUIPMENT	P-PTD	1,175,414	233,626	115,788	475,440	800,259	43,027	30,709
104	392	TRANSPORTATION EQUIPMENT	P-PTD	3,401,407	676,066	335,068	1,375,827	2,315,786	124,511	88,866
105	393	STORES EQUIPMENT	P-PTD	155,352	30,878	15,304	62,838	105,769	5,687	4,059
106	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD	436,271	86,714	42,976	176,466	297,027	15,970	11,398
107	395	LABORATORY EQUIPMENT	P-PTD	423,040	84,084	41,673	171,115	288,019	15,486	11,052
108	396	POWER OPERATED EQUIPMENT	P-PTD	782,543	155,539	77,087	316,529	532,780	28,646	20,445
109	397	COMMUNICATIONS EQUIPMENT	P-PTD	2,344,971	466,088	231,000	948,511	1,596,530	85,839	61,265
110	398	MISCELLANEOUS EQUIPMENT	P-PTD	323,544	64,308	31,872	130,870	220,279	11,844	8,453
111										
112		TOTAL GENERAL PLANT								
113										
114	TOTAL ELECTRIC PLANT IN SERVICE			183,252,136	36,423,303	18,051,900	74,123,210	124,763,852	6,708,087	4,787,668
115										

Line											
1		**IDAHO POWER COMPANY**									
2		**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**									
3		**CLASS COST OF SERVICE STUDY**									
4		**FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**									
5		**FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**									
6			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
98	*** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***										
99											
100	GENERAL PLANT										
101	389	LAND & LAND RIGHTS	P-PTD								
102	390	STRUCTURES & IMPROVEMENTS	P-PTD								
103	391	OFFICE FURNITURE & EQUIPMENT	P-PTD								
104	392	TRANSPORTATION EQUIPMENT	P-PTD								
105	393	STORES EQUIPMENT	P-PTD								
106	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD								
107	395	LABORATORY EQUIPMENT	P-PTD								
108	396	POWER OPERATED EQUIPMENT	P-PTD								
109	397	COMMUNICATIONS EQUIPMENT	P-PTD								
110	398	MISCELLANEOUS EQUIPMENT	P-PTD								
111											
112		TOTAL GENERAL PLANT									
113											
114	TOTAL ELECTRIC PLANT IN SERVICE										
115											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line									
6			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOR						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
98	*** * * TABLE 1 - ELECTRIC PLANT IN SERVICE * * ***								
99									
100	GENERAL PLANT								
101	389	LAND & LAND RIGHTS	P-PTD						
102	390	STRUCTURES & IMPROVEMENTS	P-PTD						
103	391	OFFICE FURNITURE & EQUIPMENT	P-PTD						
104	392	TRANSPORTATION EQUIPMENT	P-PTD						
105	393	STORES EQUIPMENT	P-PTD						
106	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD						
107	395	LABORATORY EQUIPMENT	P-PTD						
108	396	POWER OPERATED EQUIPMENT	P-PTD						
109	397	COMMUNICATIONS EQUIPMENT	P-PTD						
110	398	MISCELLANEOUS EQUIPMENT	P-PTD						
111									
112		TOTAL GENERAL PLANT							
113									
114	TOTAL ELECTRIC PLANT IN SERVICE								
115									

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Acct	Description	(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
116	**** * * TABLE 2 - ACCUMULATED PROVISION FOR DEPRECIATION * * ****											
117												
118	PRODUCTION PLANT											
119	310-316	STEAM PRODUCTION	PI-S	144,967,130	144,967,130							
120	330-336	HYDRAULIC PRODUCTION	PI-H	489,515,669	489,515,669							
121	340-346	OTHER PRODUCTION (BASELOAD)	PI-S	92,073,267	92,073,267							
122	340-346	OTHER PRODUCTION (PEAKERS)	PI-O	65,021,376		65,021,376						
123		TOTAL PRODUCTION PLANT		791,577,442								
124												
125	TRANSMISSION PLANT											
126	350	LAND & LAND RIGHTS	T-350	9,785,205						9,785,205		
127	352	STRUCTURES & IMPROVEMENTS	T-352	32,854,058						32,854,058		
128	353	STATION EQUIPMENT	T-353	118,232,894						118,213,134		19,760
129	354	TOWERS & FIXTURES	T-354	77,166,051						77,166,051		
130	355	POLES & FIXTURES	T-355	77,284,679						77,284,679		
131	356	OVERHEAD CONDUCTORS & DEVICES	T-356	86,639,325						86,638,930		395
132	359	ROADS & TRAILS	T-359	285,269						285,269		
133		TOTAL TRANSMISSION PLANT		402,247,480								
134												
135	DISTRIBUTION PLANT											
136	360	LAND & LAND RIGHTS	D360N	231,204								
137	361	STRUCTURES & IMPROVEMENTS	D361N	15,985,978								
138	362	STATION EQUIPMENT	D362N	69,206,444								
139	363	STORAGE BATTERY EQUIPMENT	PI-S	3,403,730	3,403,730							
140	364	POLES, TOWERS & FIXTURES	D364	133,426,728								
141	365	OVERHEAD CONDUCTORS & DEVICES	D365	53,361,193								
142	366	UNDERGROUND CONDUIT	D366	18,584,970								
143	367	UNDERGROUND CONDUCTORS & DEVIC	D367	103,959,562								
144	368	LINE TRANSFORMERS	D368	188,773,843								
145	369	SERVICES	SERVICE	43,720,575								
146	370	METERS	METER	36,077,317								
147	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST	1,103,966								
148	373	STREET LIGHTING SYSTEMS	STLIGHT	31,698								
149		TOTAL DISTRIBUTION PLANT		667,867,210								
150												

1 IDAHO POWER COMPANY
2 BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
3 COST OF SERVICE STUDY
4 FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
5 FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

6			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *				DISTRIBUTION FUNCTION *					
8			ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
116	**** * * TABLE 2 - ACCUMULATED PROVISION FOR DEPRECIATI***												
117													
118	PRODUCTION PLANT												
119	310-316	STEAM PRODUCTION	PI-S										
120	330-336	HYDRAULIC PRODUCTION	PI-H										
121	340-346	OTHER PRODUCTION (BASELOAD)	PI-S										
122	340-346	OTHER PRODUCTION (PEAKERS)	PI-O										
123		TOTAL PRODUCTION PLANT											
124													
125	TRANSMISSION PLANT												
126	350	LAND & LAND RIGHTS	T-350										
127	352	STRUCTURES & IMPROVEMENTS	T-352										
128	353	STATION EQUIPMENT	T-353										
129	354	TOWERS & FIXTURES	T-354										
130	355	POLES & FIXTURES	T-355										
131	356	OVERHEAD CONDUCTORS & DEVICES	T-356										
132	359	ROADS & TRAILS	T-359										
133		TOTAL TRANSMISSION PLANT											
134													
135	DISTRIBUTION PLANT												
136	360	LAND & LAND RIGHTS	D360N	231,203	1								
137	361	STRUCTURES & IMPROVEMENTS	D361N	15,835,296	150,682								
138	362	STATION EQUIPMENT	D362N	68,442,087	764,358								
139	363	STORAGE BATTERY EQUIPMENT	PI-S										
140	364	POLES, TOWERS & FIXTURES	D364				83,552,267	41,409,676	930,108				
141	365	OVERHEAD CONDUCTORS & DEVICES	D365				32,043,769	15,881,341	492,829				
142	366	UNDERGROUND CONDUIT	D366				8,839,136	4,380,800	2,252,122				
143	367	UNDERGROUND CONDUCTORS & DEVIC	D367				63,148,528	31,297,297	6,846,486				
144	368	LINE TRANSFORMERS	D368							30,955,405	15,341,933	8,578,946	89,526,813
145	369	SERVICES	SERVICE										
146	370	METERS	METER										
147	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST										
148	373	STREET LIGHTING SYSTEMS	STLIGHT										
149		TOTAL DISTRIBUTION PLANT											
150													

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Acct	Description	(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *	DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *				
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
116	**** * * TABLE 2 - ACCUMULATED PROVISION FOR DEPRECIATI***									
117										
118	PRODUCTION PLANT									
119	310-316	STEAM PRODUCTION	PI-S							
120	330-336	HYDRAULIC PRODUCTION	PI-H							
121	340-346	OTHER PRODUCTION (BASELOAD)	PI-S							
122	340-346	OTHER PRODUCTION (PEAKERS)	PI-O							
123		TOTAL PRODUCTION PLANT								
124										
125	TRANSMISSION PLANT									
126	350	LAND & LAND RIGHTS	T-350							
127	352	STRUCTURES & IMPROVEMENTS	T-352							
128	353	STATION EQUIPMENT	T-353							
129	354	TOWERS & FIXTURES	T-354							
130	355	POLES & FIXTURES	T-355							
131	356	OVERHEAD CONDUCTORS & DEVICES	T-356							
132	359	ROADS & TRAILS	T-359							
133		TOTAL TRANSMISSION PLANT								
134										
135	DISTRIBUTION PLANT									
136	360	LAND & LAND RIGHTS	D360N							
137	361	STRUCTURES & IMPROVEMENTS	D361N							
138	362	STATION EQUIPMENT	D362N							
139	363	STORAGE BATTERY EQUIPMENT	PI-S							
140	364	POLES, TOWERS & FIXTURES	D364		5,037,848	2,496,828				
141	365	OVERHEAD CONDUCTORS & DEVICES	D365		3,305,167	1,638,087				
142	366	UNDERGROUND CONDUIT	D366		2,081,361	1,031,552				
143	367	UNDERGROUND CONDUCTORS & DEVIC	D367		1,783,382	883,869				
144	368	LINE TRANSFORMERS	D368	44,370,745						
145	369	SERVICES	SERVICE				43,720,575			
146	370	METERS	METER					36,077,317		
147	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST							1,103,966
148	373	STREET LIGHTING SYSTEMS	STLIGHT						31,698	
149		TOTAL DISTRIBUTION PLANT								
150										

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOF	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
116	**** * * TABLE 2 - ACCUMULATED PROVISION FOR DEPRECIATI***										
117											
118	PRODUCTION PLANT										
119	310-316	STEAM PRODUCTION	PI-S								
120	330-336	HYDRAULIC PRODUCTION	PI-H								
121	340-346	OTHER PRODUCTION (BASELOAD)	PI-S								
122	340-346	OTHER PRODUCTION (PEAKERS)	PI-O								
123		TOTAL PRODUCTION PLANT									
124											
125	TRANSMISSION PLANT										
126	350	LAND & LAND RIGHTS	T-350								
127	352	STRUCTURES & IMPROVEMENTS	T-352								
128	353	STATION EQUIPMENT	T-353								
129	354	TOWERS & FIXTURES	T-354								
130	355	POLES & FIXTURES	T-355								
131	356	OVERHEAD CONDUCTORS & DEVICES	T-356								
132	359	ROADS & TRAILS	T-359								
133		TOTAL TRANSMISSION PLANT									
134											
135	DISTRIBUTION PLANT										
136	360	LAND & LAND RIGHTS	D360N								
137	361	STRUCTURES & IMPROVEMENTS	D361N								
138	362	STATION EQUIPMENT	D362N								
139	363	STORAGE BATTERY EQUIPMENT	PI-S								
140	364	POLES, TOWERS & FIXTURES	D364								
141	365	OVERHEAD CONDUCTORS & DEVICES	D365								
142	366	UNDERGROUND CONDUIT	D366								
143	367	UNDERGROUND CONDUCTORS & DEVIC	D367								
144	368	LINE TRANSFORMERS	D368								
145	369	SERVICES	SERVICE								
146	370	METERS	METER								
147	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST								
148	373	STREET LIGHTING SYSTEMS	STLIGHT								
149		TOTAL DISTRIBUTION PLANT									
150											

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
116	*** TABLE 2 - ACCUMULATED PROVISION FOR DEPRECIATI***								
117									
118	PRODUCTION PLANT								
119	310-316	STEAM PRODUCTION	PI-S						
120	330-336	HYDRAULIC PRODUCTION	PI-H						
121	340-346	OTHER PRODUCTION (BASELOAD)	PI-S						
122	340-346	OTHER PRODUCTION (PEAKERS)	PI-O						
123		TOTAL PRODUCTION PLANT							
124									
125	TRANSMISSION PLANT								
126	350	LAND & LAND RIGHTS	T-350						
127	352	STRUCTURES & IMPROVEMENTS	T-352						
128	353	STATION EQUIPMENT	T-353						
129	354	TOWERS & FIXTURES	T-354						
130	355	POLES & FIXTURES	T-355						
131	356	OVERHEAD CONDUCTORS & DEVICES	T-356						
132	359	ROADS & TRAILS	T-359						
133		TOTAL TRANSMISSION PLANT							
134									
135	DISTRIBUTION PLANT								
136	360	LAND & LAND RIGHTS	D360N						
137	361	STRUCTURES & IMPROVEMENTS	D361N						
138	362	STATION EQUIPMENT	D362N						
139	363	STORAGE BATTERY EQUIPMENT	PI-S						
140	364	POLES, TOWERS & FIXTURES	D364						
141	365	OVERHEAD CONDUCTORS & DEVICES	D365						
142	366	UNDERGROUND CONDUIT	D366						
143	367	UNDERGROUND CONDUCTORS & DEVIC	D367						
144	368	LINE TRANSFORMERS	D368						
145	369	SERVICES	SERVICE						
146	370	METERS	METER						
147	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST						
148	373	STREET LIGHTING SYSTEMS	STLIGHT						
149		TOTAL DISTRIBUTION PLANT							
150									

Line	Acct	Description	(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
1								IDAHO POWER COMPANY				
2								BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION				
3								CLASS COST OF SERVICE STUDY				
4								FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023				
5								FUNCTIONALIZATION AND CLASSIFICATION OF COSTS				
6			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
151	***** TABLE 2 - ACCUMULATED PROVISION FOR DEPRECIATION * * ***											
152												
153	GENERAL PLANT											
154	389	LAND & LAND RIGHTS	P-PTD									
155	390	STRUCTURES & IMPROVEMENTS	P-PTD	34,477,345	11,848,004	1,116,506				8,026,712		471
156	391	OFFICE FURNITURE & EQUIPMENT	P-PTD	17,941,991	6,165,695	581,029				4,177,096		245
157	392	TRANSPORTATION EQUIPMENT	P-PTD	22,933,175	7,880,896	742,662				5,339,100		313
158	393	STORES EQUIPMENT	P-PTD	1,404,733	482,731	45,491				327,038		19
159	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD	4,808,200	1,652,319	155,708				1,119,403		66
160	395	LABORATORY EQUIPMENT	P-PTD	6,562,478	2,255,170	212,518				1,527,818		90
161	396	POWER OPERATED EQUIPMENT	P-PTD	5,184,149	1,781,513	167,882				1,206,928		71
162	397	COMMUNICATIONS EQUIPMENT	P-PTD	31,998,730	10,996,238	1,036,239				7,449,663		437
163	398	MISCELLANEOUS EQUIPMENT	P-PTD	4,205,307	1,445,137	136,184				979,043		57
164		TOTAL GENERAL PLANT		129,516,109								
165												
166	AMORTIZATION OF DISALLOWED COSTS		P101P	3,158,453	1,085,390	102,283				735,323		43
167												
168		TOTAL ACCUM PROVISION DEPRECIATION		1,994,366,693	775,552,890	69,317,877				433,115,447		21,968
169												
170	AMORTIZATION OF OTHER UTILITY PLANT											
171		302/FRANCHISES AND CONSENTS	P101P	18,012,048	6,189,770	583,298				4,193,406		246
172		303/MISCELLANEOUS INTANGIBLE PLAN	PI-H	22,131,338	22,131,338							
173												
174		TOTAL AM0RT OF OTHER UTILITY PLANT		40,143,386	28,321,108	583,298				4,193,406		246
175												
176		TOTAL ACCUM PROVISION FOR DEPR										
177		& AMORTIZATION OF OTHER UTILITY PLANT		2,034,510,078	803,873,997	69,901,175				437,308,854		22,214
178												

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* DISTRIBUTION FUNCTION *									
8			ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
151	***** * * TABLE 2 - ACCUMULATED PROVISION FOR DEPRECIATI***												
152													
153	GENERAL PLANT												
154	389	LAND & LAND RIGHTS	P-PTD										
155	390	STRUCTURES & IMPROVEMENTS	P-PTD	2,596,271	121,081		3,170,995	1,571,589	198,157	713,293	353,518	197,681	2,062,929
156	391	OFFICE FURNITURE & EQUIPMENT	P-PTD	1,351,098	63,011		1,650,184	817,854	103,121	371,197	183,970	102,873	1,073,547
157	392	TRANSPORTATION EQUIPMENT	P-PTD	1,726,953	80,539		2,109,240	1,045,369	131,808	474,458	235,148	131,491	1,372,191
158	393	STORES EQUIPMENT	P-PTD	105,782	4,933		129,198	64,032	8,074	29,062	14,404	8,054	84,051
159	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD	362,075	16,886		442,226	219,173	27,635	99,476	49,301	27,569	287,695
160	395	LABORATORY EQUIPMENT	P-PTD	494,179	23,047		603,573	299,139	37,718	135,769	67,289	37,627	392,662
161	396	POWER OPERATED EQUIPMENT	P-PTD	390,386	18,206		476,803	236,310	29,796	107,253	53,156	29,724	310,190
162	397	COMMUNICATIONS EQUIPMENT	P-PTD	2,409,623	112,377		2,943,028	1,458,606	183,912	662,013	328,103	183,470	1,914,623
163	398	MISCELLANEOUS EQUIPMENT	P-PTD	316,675	14,769		386,776	191,692	24,170	87,002	43,120	24,112	251,622
164		TOTAL GENERAL PLANT											
165													
166	AMORTIZATION OF DISALLOWED COSTS		P101P	237,843	11,092		290,493	143,973	18,153	65,344	32,386	18,109	188,984
167													
168		TOTAL ACCUM PROVISION DEPRECIATION		94,499,470	1,380,982		199,786,215	99,016,852	11,284,088	33,700,274	16,702,329	9,339,656	97,465,309
169													
170	AMORTIZATION OF OTHER UTILITY PLANT												
171		302/FRANCHISES AND CONSENTS	P101P	1,356,374	63,257		1,656,627	821,048	103,524	372,646	184,689	103,275	1,077,739
172		303/MISCELLANEOUS INTANGIBLE PLAN	PI-H										
173													
174		TOTAL AM0RT OF OTHER UTILITY PLANT		1,356,374	63,257		1,656,627	821,048	103,524	372,646	184,689	103,275	1,077,739
175													
176		TOTAL ACCUM PROVISION FOR DEPR											
177		& AMORTIZATION OF OTHER UTILITY PLANT		95,855,844	1,444,239		201,442,843	99,837,900	11,387,611	34,072,920	16,887,017	9,442,930	98,543,048
178													

Line			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
1						IDAHO POWER COMPANY				
2						BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION				
3						CLASS COST OF SERVICE STUDY				
4						FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023				
5						FUNCTIONALIZATION AND CLASSIFICATION OF COSTS				
6			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *		DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *			
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
151	**** * * TABLE 2 - ACCUMULATED PROVISION FOR DEPRECIATI***									
152										
153	GENERAL PLANT									
154	389	LAND & LAND RIGHTS	P-PTD							
155	390	STRUCTURES & IMPROVEMENTS	P-PTD	1,022,417	203,216	100,717	413,555	696,094	37,426	26,712
156	391	OFFICE FURNITURE & EQUIPMENT	P-PTD	532,065	105,754	52,413	215,214	362,247	19,477	13,901
157	392	TRANSPORTATION EQUIPMENT	P-PTD	680,077	135,173	66,993	275,083	463,018	24,895	17,768
158	393	STORES EQUIPMENT	P-PTD	41,657	8,280	4,104	16,850	28,361	1,525	1,088
159	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD	142,586	28,340	14,046	57,674	97,077	5,219	3,725
160	395	LABORATORY EQUIPMENT	P-PTD	194,609	38,681	19,171	78,717	132,496	7,124	5,084
161	396	POWER OPERATED EQUIPMENT	P-PTD	153,735	30,556	15,144	62,184	104,667	5,628	4,016
162	397	COMMUNICATIONS EQUIPMENT	P-PTD	948,914	188,607	93,476	383,824	646,051	34,736	24,791
163	398	MISCELLANEOUS EQUIPMENT	P-PTD	124,707	24,787	12,285	50,443	84,905	4,565	3,258
164		TOTAL GENERAL PLANT								
165										
166	AMORTIZATION OF DISALLOWED COSTS		P101P	93,663	18,617	9,227	37,886	63,769	3,429	2,447
167										
168		TOTAL ACCUM PROVISION DEPRECIATION		48,305,175	12,989,768	6,437,911	45,312,003	38,756,001	175,721	1,206,758
169										
170	AMORTIZATION OF OTHER UTILITY PLANT									
171		302/FRANCHISES AND CONSENTS	P101P	534,143	106,166	52,618	216,054	363,661	19,553	13,955
172		303/MISCELLANEOUS INTANGIBLE PLAN	PI-H							
173										
174		TOTAL AM0RT OF OTHER UTILITY PLANT		534,143	106,166	52,618	216,054	363,661	19,553	13,955
175										
176		TOTAL ACCUM PROVISION FOR DEPR								
177		& AMORTIZATION OF OTHER UTILITY PLANT		48,839,317	13,095,935	6,490,529	45,528,057	39,119,662	195,273	1,220,713
178										

1 **IDAHO POWER COMPANY**

2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

3 **CLASS COST OF SERVICE STUDY**

4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**

5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line											
6			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
151	**** * * TABLE 2 - ACCUMULATED PROVISION FOR DEPRECIATI***										
152											
153	GENERAL PLANT										
154	389	LAND & LAND RIGHTS	P-PTD								
155	390	STRUCTURES & IMPROVEMENTS	P-PTD								
156	391	OFFICE FURNITURE & EQUIPMENT	P-PTD								
157	392	TRANSPORTATION EQUIPMENT	P-PTD								
158	393	STORES EQUIPMENT	P-PTD								
159	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD								
160	395	LABORATORY EQUIPMENT	P-PTD								
161	396	POWER OPERATED EQUIPMENT	P-PTD								
162	397	COMMUNICATIONS EQUIPMENT	P-PTD								
163	398	MISCELLANEOUS EQUIPMENT	P-PTD								
164		TOTAL GENERAL PLANT									
165											
166	AMORTIZATION OF DISALLOWED COSTS		P101P								
167											
168		TOTAL ACCUM PROVISION DEPRECIATION									
169											
170	AMORTIZATION OF OTHER UTILITY PLANT										
171		302/FRANCHISES AND CONSENTS	P101P								
172		303/MISCELLANEOUS INTANGIBLE PLAN	PI-H								
173											
174		TOTAL AM0RT OF OTHER UTILITY PLANT									
175											
176		TOTAL ACCUM PROVISION FOR DEPR									
177		& AMORTIZATION OF OTHER UTILITY PLANT									
178											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
151	**** * * TABLE 2 - ACCUMULATED PROVISION FOR DEPRECIATI***								
152									
153	GENERAL PLANT								
154	389	LAND & LAND RIGHTS	P-PTD						
155	390	STRUCTURES & IMPROVEMENTS	P-PTD						
156	391	OFFICE FURNITURE & EQUIPMENT	P-PTD						
157	392	TRANSPORTATION EQUIPMENT	P-PTD						
158	393	STORES EQUIPMENT	P-PTD						
159	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD						
160	395	LABORATORY EQUIPMENT	P-PTD						
161	396	POWER OPERATED EQUIPMENT	P-PTD						
162	397	COMMUNICATIONS EQUIPMENT	P-PTD						
163	398	MISCELLANEOUS EQUIPMENT	P-PTD						
164		TOTAL GENERAL PLANT							
165									
166	AMORTIZATION OF DISALLOWED COSTS		P101P						
167									
168		TOTAL ACCUM PROVISION DEPRECIATION							
169									
170	AMORTIZATION OF OTHER UTILITY PLANT								
171		302/FRANCHISES AND CONSENTS	P101P						
172		303/MISCELLANEOUS INTANGIBLE PLAN	PI-H						
173									
174		TOTAL AM0RT OF OTHER UTILITY PLANT							
175									
176		TOTAL ACCUM PROVISION FOR DEPR							
177		& AMORTIZATION OF OTHER UTILITY PLANT							
178									

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line		Allocator	Totals	Production				Transmission			
6		(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7			TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8		ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9				Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
179	**** * * TABLE 3 - ADDITIONS & DELETIONS TO RATE BASE * * ****										
180											
181	NET ELECTRIC PLANT IN SERVICE		4,102,241,639	1,319,694,727	130,215,002				1,001,353,167		62,211
182	LESS:										
183	252 CUSTOMER ADVANCES FOR CONSTRUCTION										
184	POWER SUPPLY	PI-SHO									
185	OTHER	CUSTADV	7,387,459								
186	TOTAL CUST ADV FOR CONSTRUCTION		7,387,459								
187											
188	ACCUMULATED DEFERRED INCOME TAXES										
189	ADIT - CUST ADVANCE RELATED	CUSTADV	(1,793,446)								
190	ADIT - OTHER	P111P	(17,318,189)	(6,010,954)	(566,447)				(4,072,263)		(239)
191	281 ACCELERATED AMORTIZATION	P111P									
192	282 OTHER PROPERTY	P111P	378,580,157	131,401,024	12,382,679				89,020,742		5,224
193	283 OTHER	P111P	5,992,853	2,080,054	196,015				1,409,182		83
194	TOTAL ACCUMULATED DEFERRED INCOME TAXES		365,461,375	127,470,124	12,012,248				86,357,660		5,068
195											
196	NET ELECTRIC PLANT IN SERVICE		3,729,392,805	1,192,224,603	118,202,754				914,995,506		57,144
197	ADD:										
198	WORKING CAPITAL										
199	151 FUEL INVENTORY	KWH-S	23,609,967				23,609,967				
200	154 PLANT MATERIALS & SUPPLIES										
201	PRODUCTION - GENERAL	PI-SHO	15,478,739	14,145,707	1,333,032						
202	TRANSMISSION - GENERAL	T-PLT	14,093,970						14,093,143		827
203	DISTRIBUTION - GENERAL	D3601	52,809,487								
204	OTHER-UNCLASSIFIED	P110P	4,097,928	1,408,237	132,706				954,043		56
205	TOTAL ACCOUNT 154		86,480,124								
206	165 PREPAID ITEMS										
207	AD VALOREM TAXES	LABOR									
208	OTHER PROD-RELATED PP	LABOR									
209	INSURANCE	LABOR									
210	PENSION EXPENSE	LABOR									
211	PREPAID RETIREE BENEFITS	LABOR									
212	MISC PREPAYMENTS	LABOR									
213	TOTAL ACCOUNT 165	LABOR									
214	WORKING CASH ALLOWANCE	O&M-T	0	0	0		0		0		0
215											
216	TOTAL WORKING CAPITAL		110,090,091	15,553,944	1,465,738		23,609,967		15,047,187		883
217											
218	NET ELECTRIC PLANT IN SERVICE		3,839,482,895	1,207,778,547	119,668,492		23,609,967		930,042,693		58,027

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7			* DISTRIBUTION FUNCTION *									
8		ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9			GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
179	**** * * TABLE 3 - ADDITIONS & DELETIONS TO RATE BASE * * ****											
180												
181	NET ELECTRIC PLANT IN SERVICE		369,485,027	20,257,685	(42,770,847)	366,908,163	181,844,835	24,129,005	93,773,572	46,475,498	25,988,301	271,204,625
182	LESS:											
183	252 CUSTOMER ADVANCES FOR CONSTRUCTION											
184	POWER SUPPLY	PI-SHO										
185	OTHER	CUSTADV				3,181,235	1,576,665		128,427	63,650		395,224
186	TOTAL CUST ADV FOR CONSTRUCTION					3,181,235	1,576,665		128,427	63,650		395,224
187												
188	ACCUMULATED DEFERRED INCOME TAXES											
189	ADIT - CUST ADVANCE RELATED	CUSTADV				(772,305)	(382,765)		(31,178)	(15,452)		(95,948)
190	ADIT - OTHER	P111P	(1,188,578)	(16,532)		(1,608,769)	(797,329)	(100,533)	(361,881)	(179,353)	(100,291)	(1,046,604)
191	281 ACCELERATED AMORTIZATION	P111P										
192	282 OTHER PROPERTY	P111P	25,982,622	361,384		35,168,113	17,429,810	2,197,678	7,910,815	3,920,711	2,192,394	22,879,044
193	283 OTHER	P111P	411,300	5,721		556,705	275,911	34,789	125,227	62,064	34,705	362,171
194	TOTAL ACCUMULATED DEFERRED INCOME TAXES		25,205,345	350,573		33,343,743	16,525,627	2,131,934	7,642,983	3,787,970	2,126,808	22,098,663
195												
196	NET ELECTRIC PLANT IN SERVICE		344,279,682	19,907,111	(42,770,847)	330,383,185	163,742,544	21,997,071	86,002,162	42,623,878	23,861,493	248,710,738
197	ADD:											
198	WORKING CAPITAL											
199	151 FUEL INVENTORY	KWH-S										
200	154 PLANT MATERIALS & SUPPLIES											
201	PRODUCTION - GENERAL	PI-SHO										
202	TRANSMISSION - GENERAL	T-PLT										
203	DISTRIBUTION - GENERAL	D3601	10,166,936	474,152		12,417,539	6,154,307	775,980	2,793,237	1,384,367	774,114	8,078,381
204	OTHER-UNCLASSIFIED	P110P	308,589	14,392		376,900	186,797	23,553	84,781	42,019	23,496	245,197
205	TOTAL ACCOUNT 154											
206	165 PREPAID ITEMS											
207	AD VALOREM TAXES	LABOR										
208	OTHER PROD-RELATED PP	LABOR										
209	INSURANCE	LABOR										
210	PENSION EXPENSE	LABOR										
211	PREPAID RETIREE BENEFITS	LABOR										
212	MISC PREPAYMENTS	LABOR										
213	TOTAL ACCOUNT 165	LABOR										
214	WORKING CASH ALLOWANCE	O&M-T	0	0		0	0	0	0	0	0	0
215												
216	TOTAL WORKING CAPITAL		10,475,525	488,543		12,794,439	6,341,104	799,533	2,878,018	1,426,386	797,611	8,323,578
217												
218	NET ELECTRIC PLANT IN SERVICE		354,755,208	20,395,655	(42,770,847)	343,177,624	170,083,647	22,796,604	88,880,179	44,050,264	24,659,103	257,034,316

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Description	(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7			* * * * * * * * * * * * * *		DISTRIBUTION FUNCTION		* * * * * * * * * * * * * *		
8		ALLOCATOR	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9			SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
179	**** * * TABLE 3 - ADDITIONS & DELETIONS TO RATE BASE * * ****								
180									
181	NET ELECTRIC PLANT IN SERVICE		134,412,819	23,327,369	11,561,371	28,595,152	85,644,190	6,512,814	3,566,955
182	LESS:								
183	252 CUSTOMER ADVANCES FOR CONSTRUCTION								
184	POWER SUPPLY	PI-SHO							
185	OTHER	CUSTADV	195,879	536,323	265,809	1,032,307	706	10,184	1,051
186	TOTAL CUST ADV FOR CONSTRUCTION		195,879	536,323	265,809	1,032,307	706	10,184	1,051
187									
188	ACCUMULATED DEFERRED INCOME TAXES								
189	ADIT - CUST ADVANCE RELATED	CUSTADV	(47,553)	(130,202)	(64,530)	(250,612)	(171)	(2,472)	(255)
190	ADIT - OTHER	P111P	(518,712)	(103,099)	(51,098)	(209,812)	(353,155)	(18,988)	(13,552)
191	281 ACCELERATED AMORTIZATION	P111P							
192	282 OTHER PROPERTY	P111P	11,339,175	2,253,781	1,117,006	4,586,555	7,720,069	415,079	296,249
193	283 OTHER	P111P	179,497	35,677	17,682	72,604	122,207	6,571	4,690
194	TOTAL ACCUMULATED DEFERRED INCOME TAXES		10,952,407	2,056,156	1,019,060	4,198,735	7,488,950	400,190	287,131
195									
196	NET ELECTRIC PLANT IN SERVICE		123,264,532	20,734,890	10,276,502	23,364,110	78,154,534	6,102,439	3,278,773
197	ADD:								
198	WORKING CAPITAL								
199	151 FUEL INVENTORY	KWH-S							
200	154 PLANT MATERIALS & SUPPLIES								
201	PRODUCTION - GENERAL	PI-SHO							
202	TRANSMISSION - GENERAL	T-PLT							
203	DISTRIBUTION - GENERAL	D3601	4,003,759	795,790	394,404	1,619,471	2,725,886	146,561	104,603
204	OTHER-UNCLASSIFIED	P110P	121,523	24,154	11,971	49,155	82,737	4,448	3,175
205	TOTAL ACCOUNT 154								
206	165 PREPAID ITEMS								
207	AD VALOREM TAXES	LABOR							
208	OTHER PROD-RELATED PP	LABOR							
209	INSURANCE	LABOR							
210	PENSION EXPENSE	LABOR							
211	PREPAID RETIREE BENEFITS	LABOR							
212	MISC PREPAYMENTS	LABOR							
213	TOTAL ACCOUNT 165	LABOR							
214	WORKING CASH ALLOWANCE	O&M-T	0	0	0	0	0	0	0
215									
216	TOTAL WORKING CAPITAL		4,125,282	819,944	406,376	1,668,625	2,808,623	151,009	107,778
217									
218	NET ELECTRIC PLANT IN SERVICE		127,389,815	21,554,833	10,682,878	25,032,735	80,963,156	6,253,449	3,386,550

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4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7			- - - CUSTOMER ACCOUNTING FUNCTION			- - -	* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8		ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9			READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
179	**** * * TABLE 3 - ADDITIONS & DELETIONS TO RATE BASE * * ****									
180										
181	NET ELECTRIC PLANT IN SERVICE									
182	LESS:									
183	252 CUSTOMER ADVANCES FOR CONSTRUCTION									
184	POWER SUPPLY	PI-SHO								
185	OTHER	CUSTADV								
186	TOTAL CUST ADV FOR CONSTRUCTION									
187										
188	ACCUMULATED DEFERRED INCOME TAXES									
189	ADIT - CUST ADVANCE RELATED	CUSTADV								
190	ADIT - OTHER	P111P								
191	281 ACCELERATED AMORTIZATION	P111P								
192	282 OTHER PROPERTY	P111P								
193	283 OTHER	P111P								
194	TOTAL ACCUMULATED DEFERRED INCOME TAXES									
195										
196	NET ELECTRIC PLANT IN SERVICE									
197	ADD:									
198	WORKING CAPITAL									
199	151 FUEL INVENTORY	KWH-S								
200	154 PLANT MATERIALS & SUPPLIES									
201	PRODUCTION - GENERAL	PI-SHO								
202	TRANSMISSION - GENERAL	T-PLT								
203	DISTRIBUTION - GENERAL	D3601								
204	OTHER-UNCLASSIFIED	P110P								
205	TOTAL ACCOUNT 154									
206	165 PREPAID ITEMS									
207	AD VALOREM TAXES	LABOR								
208	OTHER PROD-RELATED PP	LABOR								
209	INSURANCE	LABOR								
210	PENSION EXPENSE	LABOR								
211	PREPAID RETIREE BENEFITS	LABOR								
212	MISC PREPAYMENTS	LABOR								
213	TOTAL ACCOUNT 165	LABOR								
214	WORKING CASH ALLOWANCE	O&M-T	0	0	0		0			
215										
216	TOTAL WORKING CAPITAL		0	0	0		0			
217										
218	NET ELECTRIC PLANT IN SERVICE		0	0	0		0			

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Row		(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7			- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8		ALLOCATOR						& REVENUES
9			DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
179	**** * * TABLE 3 - ADDITIONS & DELETIONS TO RATE BASE * * ****							
180								
181	NET ELECTRIC PLANT IN SERVICE							
182	LESS:							
183	252 CUSTOMER ADVANCES FOR CONSTRUCTION							
184	POWER SUPPLY	PI-SHO						
185	OTHER	CUSTADV						
186	TOTAL CUST ADV FOR CONSTRUCTION							
187								
188	ACCUMULATED DEFERRED INCOME TAXES							
189	ADIT - CUST ADVANCE RELATED	CUSTADV						
190	ADIT - OTHER	P111P						
191	281 ACCELERATED AMORTIZATION	P111P						
192	282 OTHER PROPERTY	P111P						
193	283 OTHER	P111P						
194	TOTAL ACCUMULATED DEFERRED INCOME TAXES							
195								
196	NET ELECTRIC PLANT IN SERVICE							
197	ADD:							
198	WORKING CAPITAL							
199	151 FUEL INVENTORY	KWH-S						
200	154 PLANT MATERIALS & SUPPLIES							
201	PRODUCTION - GENERAL	PI-SHO						
202	TRANSMISSION - GENERAL	T-PLT						
203	DISTRIBUTION - GENERAL	D3601						
204	OTHER-UNCLASSIFIED	P110P						
205	TOTAL ACCOUNT 154							
206	165 PREPAID ITEMS							
207	AD VALOREM TAXES	LABOR						
208	OTHER PROD-RELATED PP	LABOR						
209	INSURANCE	LABOR						
210	PENSION EXPENSE	LABOR						
211	PREPAID RETIREE BENEFITS	LABOR						
212	MISC PREPAYMENTS	LABOR						
213	TOTAL ACCOUNT 165	LABOR						
214	WORKING CASH ALLOWANCE	O&M-T					0	
215								
216	TOTAL WORKING CAPITAL						0	
217								
218	NET ELECTRIC PLANT IN SERVICE						0	

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7			TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8		ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9				Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
219	**** * * TABLE 3 - ADDITIONS & DELETIONS TO RATE BASE * * ****										
220											
221	NET ELECTRIC PLANT IN SERVICE		3,839,482,895	1,207,778,547	119,668,492		23,609,967		930,042,693		58,027
222	ADD:										
223	105 PLANT HELD FOR FUTURE USE										
224	HYDRAULIC PRODUCTION	PI-H	0	0							
225	TRANS LAND & LAND RIGHTS	T-350	2,640,221						2,640,221		
226	TRANS STRUCTURES & IMPROVEMENTS	T-352									
227	TRANS STATION EQUIPMENT	T-353									
228	DIST LAND & LAND RIGHTS	D360	5,316,603								
229	DIST STRUCTURES & IMPROVEMENTS	D361									
230	DIST STATIONS EQUIPMENT	D362									
231	GEN LAND & LAND RIGHTS	P-PTD									
232	GEN STRUCTURES & IMPROVEMENTS	P-PTD									
233	COMMUNICATIONS EQUIPMENT	P-PTD									
234	TOTAL PLANT HELD FOR FUTURE USE		7,956,825	0					2,640,221		
235											
236	ELECTRIC PLANT ACQUISITION ADJUSTMENT	T-100	628,247						628,247		
237											
238	DEFERRED PROGRAMS										
239	182 / CONSERVATION PROGRAMS										
240	IDAHO DEFERRED CONSERVATION	PI-H									
241	OREGON DEFERRED CONSERVATION	PI-H									
242	OTHER DEFERRED CONSERVATION	PI-H									
243	TOTAL CONSERVATION										
244	182 / MISC. OTHER REGULATORY ASSETS										
245	CUB FUND INTEREST (OPUC 15-399)	NONE									
246	AM. FALLS BOND REFINANCING	PI-H	70,000	70,000							
247	SFAS 87 CAPITALIZED PENSION - OPUC	NONE									
248	CLOUD COMPUTING - (IPUC Order 34707	P101P	1,006,327	345,820	32,589				234,284		14
249	WILDFIRE MITIGATION (IPUC Order 3507	P-PTD	13,056,171	4,486,702	422,808				3,039,623		178
250	SIEMENS LTP RATE BASE (IPUC Order 3	PI-OS	12,207,705	8,565,092	3,642,613						
251	SIEMENS LTP DEFERRED RATE BASE (I	PI-OS	8,181,006	5,739,905	2,441,101						
252	SIEMENS LTP RATE BASE (OPUC ORDE	NONE									
253	SIEMENS LTP DEFERRED RATE BASE (O	NONE									
254	TOTAL OTHER REG ASSETS		34,521,209								
255	186 / MISC. OTHER DEFERRED PROGRAMS	T-PLT									
256	254 / JIM BRIDGER PLANT END OF LIFE DEPR - OP	NONE									
257	RECONNECT FEES - (OPUC ADV 16-09)	NONE									
258	TOTAL DEFERRED PROGRAMS		34,521,209	19,207,519	6,539,110				3,273,907		192
259											
260	DEVELOPMENT OF SUBSIDIARY RATE BASE										
261	123 INVESTMENT IN IERCO	KWH-S	14,887,547				14,887,547				
262	186 PREPAID COAL ROYALTIES	KWH-S	571,281				571,281				
263	233 NOTES PAYABLE TO SUBSIDIARY	KWH-S	14,521,817				14,521,817				
264	TOTAL SUBSIDIARY RATE BASE		29,980,646				29,980,646				
265											
266	TOTAL COMBINED RATE BASE		3,912,569,823	1,226,986,067	126,207,603		53,590,613		936,585,068		58,219

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7			* * * * * * * * * * *	* * * * * * *	* * * * * * *	* * DISTRIBUTION FUNCTION		* * * * * *	* * * * * *	* * * * * *	* * * * * *	* * * * * *
8		ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9			GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
219	**** * * TABLE 3 - ADDITIONS & DELETIONS TO RATE BASE * * ****											
220												
221	NET ELECTRIC PLANT IN SERVICE		354,755,208	20,395,655	(42,770,847)	343,177,624	170,083,647	22,796,604	88,880,179	44,050,264	24,659,103	257,034,316
222	ADD:											
223	105 PLANT HELD FOR FUTURE USE											
224	HYDRAULIC PRODUCTION	PI-H										
225	TRANS LAND & LAND RIGHTS	T-350										
226	TRANS STRUCTURES & IMPROVEMENTS	T-352										
227	TRANS STATION EQUIPMENT	T-353										
228	DIST LAND & LAND RIGHTS	D360	5,316,573	30								
229	DIST STRUCTURES & IMPROVEMENTS	D361										
230	DIST STATIONS EQUIPMENT	D362										
231	GEN LAND & LAND RIGHTS	P-PTD										
232	GEN STRUCTURES & IMPROVEMENTS	P-PTD										
233	COMMUNICATIONS EQUIPMENT	P-PTD										
234	TOTAL PLANT HELD FOR FUTURE USE		5,316,573	30								
235												
236	ELECTRIC PLANT ACQUISITION ADJUSTMENT	T-100										
237												
238	DEFERRED PROGRAMS											
239	182 / CONSERVATION PROGRAMS											
240	IDAHO DEFERRED CONSERVATION	PI-H										
241	OREGON DEFERRED CONSERVATION	PI-H										
242	OTHER DEFERRED CONSERVATION	PI-H										
243	TOTAL CONSERVATION											
244	182 / MISC. OTHER REGULATORY ASSETS											
245	CUB FUND INTEREST (OPUC 15-399)	NONE										
246	AM. FALLS BOND REFINANCING	PI-H										
247	SFAS 87 CAPITALIZED PENSION - OPUC	NONE										
248	CLOUD COMPUTING - (IPUC Order 34707	P101P	75,780	3,534		92,555	45,872	5,784	20,820	10,319	5,770	60,213
249	WILDFIRE MITIGATION (IPUC Order 3507	P-PTD	983,178	45,852		1,200,819	595,143	75,040	270,116	133,873	74,860	781,207
250	SIEMENS LTP RATE BASE (IPUC Order 3	PI-OS										
251	SIEMENS LTP DEFERRED RATE BASE (I	PI-OS										
252	SIEMENS LTP RATE BASE (OPUC ORDE	NONE										
253	SIEMENS LTP DEFERRED RATE BASE (O	NONE										
254	TOTAL OTHER REG ASSETS											
255	186 / MISC. OTHER DEFERRED PROGRAMS	T-PLT										
256	254 / JIM BRIDGER PLANT END OF LIFE DEPR - OP	NONE										
257	RECONNECT FEES - (OPUC ADV 16-09)	NONE										
258	TOTAL DEFERRED PROGRAMS		1,058,958	49,386		1,293,374	641,014	80,824	290,935	144,192	80,629	841,420
259												
260	DEVELOPMENT OF SUBSIDIARY RATE BASE											
261	123 INVESTMENT IN IERCO	KWH-S										
262	186 PREPAID COAL ROYALTIES	KWH-S										
263	233 NOTES PAYABLE TO SUBSIDIARY	KWH-S										
264	TOTAL SUBSIDIARY RATE BASE											
265												
266	TOTAL COMBINED RATE BASE		361,130,739	20,445,071	(42,770,847)	344,470,998	170,724,661	22,877,428	89,171,115	44,194,456	24,739,733	257,875,737

1 IDAHO POWER COMPANY
2 BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
3 CLASS COST OF SERVICE STUDY
4 FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
5 FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line		(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7			* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
8		ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9			SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
219	***** TABLE 3 - ADDITIONS & DELETIONS TO RATE BASE * * ***								
220									
221	NET ELECTRIC PLANT IN SERVICE		127,389,815	21,554,833	10,682,878	25,032,735	80,963,156	6,253,449	3,386,550
222	ADD:								
223	105 PLANT HELD FOR FUTURE USE								
224	HYDRAULIC PRODUCTION	PI-H							
225	TRANS LAND & LAND RIGHTS	T-350							
226	TRANS STRUCTURES & IMPROVEMENTS	T-352							
227	TRANS STATION EQUIPMENT	T-353							
228	DIST LAND & LAND RIGHTS	D360							
229	DIST STRUCTURES & IMPROVEMENTS	D361							
230	DIST STATIONS EQUIPMENT	D362							
231	GEN LAND & LAND RIGHTS	P-PTD							
232	GEN STRUCTURES & IMPROVEMENTS	P-PTD							
233	COMMUNICATIONS EQUIPMENT	P-PTD							
234	TOTAL PLANT HELD FOR FUTURE USE								
235									
236	ELECTRIC PLANT ACQUISITION ADJUSTMENT	T-100							
237									
238	DEFERRED PROGRAMS								
239	182 / CONSERVATION PROGRAMS								
240	IDAHO DEFERRED CONSERVATION	PI-H							
241	OREGON DEFERRED CONSERVATION	PI-H							
242	OTHER DEFERRED CONSERVATION	PI-H							
243	TOTAL CONSERVATION								
244	182 / MISC. OTHER REGULATORY ASSETS								
245	CUB FUND INTEREST (OPUC 15-399)	NONE							
246	AM. FALLS BOND REFINANCING	PI-H							
247	SFAS 87 CAPITALIZED PENSION - OPUC	NONE							
248	CLOUD COMPUTING - (IPUC Order 34707	P101P	29,842	5,931	2,940	12,071	20,318	1,092	780
249	WILDFIRE MITIGATION (IPUC Order 3507	P-PTD	387,177	76,956	38,140	156,608	263,603	14,173	10,115
250	SIEMENS LTP RATE BASE (IPUC Order 3	PI-OS							
251	SIEMENS LTP DEFERRED RATE BASE (I	PI-OS							
252	SIEMENS LTP RATE BASE (OPUC ORDE	NONE							
253	SIEMENS LTP DEFERRED RATE BASE (	NONE							
254	TOTAL OTHER REG ASSETS								
255	186 / MISC. OTHER DEFERRED PROGRAMS	T-PLT							
256	254 / JIM BRIDGER PLANT END OF LIFE DEPR - OP	NONE							
257	RECONNECT FEES - (OPUC ADV 16-09)	NONE							
258	TOTAL DEFERRED PROGRAMS		417,020	82,887	41,080	168,679	283,920	15,265	10,895
259									
260	DEVELOPMENT OF SUBSIDIARY RATE BASE								
261	123 INVESTMENT IN IERCO	KWH-S							
262	186 PREPAID COAL ROYALTIES	KWH-S							
263	233 NOTES PAYABLE TO SUBSIDIARY	KWH-S							
264	TOTAL SUBSIDIARY RATE BASE								
265									
266	TOTAL COMBINED RATE BASE		127,806,834	21,637,720	10,723,958	25,201,414	81,247,077	6,268,714	3,397,445

1					**IDAHO POWER COMPANY**					
2					**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**					
3					**CLASS COST OF SERVICE STUDY**					
4					**FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**					
5					**FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**					
6		(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7			- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8		ALLOCATOF	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9			READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
219	**** * * TABLE 3 - ADDITIONS & DELETIONS TO RATE BASE * * ****									
220										
221	NET ELECTRIC PLANT IN SERVICE		0	0	0		0			
222	ADD:									
223	105 PLANT HELD FOR FUTURE USE									
224	HYDRAULIC PRODUCTION	PI-H								
225	TRANS LAND & LAND RIGHTS	T-350								
226	TRANS STRUCTURES & IMPROVEMENTS	T-352								
227	TRANS STATION EQUIPMENT	T-353								
228	DIST LAND & LAND RIGHTS	D360								
229	DIST STRUCTURES & IMPROVEMENTS	D361								
230	DIST STATIONS EQUIPMENT	D362								
231	GEN LAND & LAND RIGHTS	P-PTD								
232	GEN STRUCTURES & IMPROVEMENTS	P-PTD								
233	COMMUNICATIONS EQUIPMENT	P-PTD								
234	TOTAL PLANT HELD FOR FUTURE USE									
235										
236	ELECTRIC PLANT ACQUISITION ADJUSTMENT	T-100								
237										
238	DEFERRED PROGRAMS									
239	182 / CONSERVATION PROGRAMS									
240	IDAHO DEFERRED CONSERVATION	PI-H								
241	OREGON DEFERRED CONSERVATION	PI-H								
242	OTHER DEFERRED CONSERVATION	PI-H								
243	TOTAL CONSERVATION									
244	182 / MISC. OTHER REGULATORY ASSETS									
245	CUB FUND INTEREST (OPUC 15-399)	NONE								
246	AM. FALLS BOND REFINANCING	PI-H								
247	SFAS 87 CAPITALIZED PENSION - OPUC	NONE								
248	CLOUD COMPUTING - (IPUC Order 34707	P101P								
249	WILDFIRE MITIGATION (IPUC Order 3507	P-PTD								
250	SIEMENS LTP RATE BASE (IPUC Order 3	PI-OS								
251	SIEMENS LTP DEFERRED RATE BASE (I	PI-OS								
252	SIEMENS LTP RATE BASE (OPUC ORDE	NONE								
253	SIEMENS LTP DEFERRED RATE BASE (C	NONE								
254	TOTAL OTHER REG ASSETS									
255	186 / MISC. OTHER DEFERRED PROGRAMS	T-PLT								
256	254 / JIM BRIDGER PLANT END OF LIFE DEPR - OP	NONE								
257	RECONNECT FEES - (OPUC ADV 16-09)	NONE								
258	TOTAL DEFERRED PROGRAMS									
259										
260	DEVELOPMENT OF SUBSIDIARY RATE BASE									
261	123 INVESTMENT IN IERCO	KWH-S								
262	186 PREPAID COAL ROYALTIES	KWH-S								
263	233 NOTES PAYABLE TO SUBSIDIARY	KWH-S								
264	TOTAL SUBSIDIARY RATE BASE									
265										
266	TOTAL COMBINED RATE BASE		0	0	0		0			

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Description	(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7			- - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8		ALLOCATOF						& REVENUES
9			DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
219	**** * * TABLE 3 - ADDITIONS & DELETIONS TO RATE BASE * * ****							
220								
221	NET ELECTRIC PLANT IN SERVICE						0	
222	ADD:							
223	105 PLANT HELD FOR FUTURE USE							
224	HYDRAULIC PRODUCTION	PI-H						
225	TRANS LAND & LAND RIGHTS	T-350						
226	TRANS STRUCTURES & IMPROVEMENTS	T-352						
227	TRANS STATION EQUIPMENT	T-353						
228	DIST LAND & LAND RIGHTS	D360						
229	DIST STRUCTURES & IMPROVEMENTS	D361						
230	DIST STATIONS EQUIPMENT	D362						
231	GEN LAND & LAND RIGHTS	P-PTD						
232	GEN STRUCTURES & IMPROVEMENTS	P-PTD						
233	COMMUNICATIONS EQUIPMENT	P-PTD						
234	TOTAL PLANT HELD FOR FUTURE USE							
235								
236	ELECTRIC PLANT ACQUISITION ADJUSTMENT	T-100						
237								
238	DEFERRED PROGRAMS							
239	182 / CONSERVATION PROGRAMS							
240	IDAHO DEFERRED CONSERVATION	PI-H						
241	OREGON DEFERRED CONSERVATION	PI-H						
242	OTHER DEFERRED CONSERVATION	PI-H						
243	TOTAL CONSERVATION							
244	182 / MISC. OTHER REGULATORY ASSETS							
245	CUB FUND INTEREST (OPUC 15-399)	NONE						
246	AM. FALLS BOND REFINANCING	PI-H						
247	SFAS 87 CAPITALIZED PENSION - OPUC	NONE						
248	CLOUD COMPUTING - (IPUC Order 34707	P101P						
249	WILDFIRE MITIGATION (IPUC Order 3507	P-PTD						
250	SIEMENS LTP RATE BASE (IPUC Order 3	PI-OS						
251	SIEMENS LTP DEFERRED RATE BASE (I	PI-OS						
252	SIEMENS LTP RATE BASE (OPUC ORDE	NONE						
253	SIEMENS LTP DEFERRED RATE BASE (C	NONE						
254	TOTAL OTHER REG ASSETS							
255	186 / MISC. OTHER DEFERRED PROGRAMS	T-PLT						
256	254 / JIM BRIDGER PLANT END OF LIFE DEPR - OP	NONE						
257	RECONNECT FEES - (OPUC ADV 16-09)	NONE						
258	TOTAL DEFERRED PROGRAMS							
259								
260	DEVELOPMENT OF SUBSIDIARY RATE BASE							
261	123 INVESTMENT IN IERCO	KWH-S						
262	186 PREPAID COAL ROYALTIES	KWH-S						
263	233 NOTES PAYABLE TO SUBSIDIARY	KWH-S						
264	TOTAL SUBSIDIARY RATE BASE							
265								
266	TOTAL COMBINED RATE BASE						0	

1								IDAHO POWER COMPANY				
2								BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION				
3								CLASS COST OF SERVICE STUDY				
4								FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023				
5								FUNCTIONALIZATION AND CLASSIFICATION OF COSTS				
6			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
267	**** * * TABLE 4 - OPERATING REVENUES * * ****											
268												
269	OPERATING REVENUES											
270	SALES OF ELECTRICITY											
271		FIRM ENERGY SALES										
272	440-448	RETAIL	TAX-REV	1,116,166,332								
273	442	CLEAN ENERGY YOUR WAY PPA REVEN	TAX-REV	173,368,953								
274	447	FIRM SALES FOR RESALE	TAX-REV	3,474,555								
275	447	SYSTEM OPPORTUNITY SALES	KWH-O	18,325,578				18,325,578				
276	447	FINANCIAL LOSSES	KWH-O	9,422,985				9,422,985				
277		TOTAL SALES OF ELECTRICITY		1,320,758,403				27,748,563				
278												
279	OTHER OPERATING REVENUES											
280	415	MERCHANDISING REVENUES	M-REV	3,793,122				641				
281	449 / OATT TARIFF REFUND											
282		NETWORK	NONE									
283		POINT-TO-POINT	NONE									
284		TOTAL ACCOUNT 449										
285												
286												
287	451	MISCELLANEOUS SERVICE REVENUES	MISC-REV	6,150,427								
288												
289	454	RENTS FROM ELECTRIC PROPERTY	`									
290		SUBSTATION EQUIPMENT	T-353	3,084,356						3,083,841		515
291		TRANSFORMER RENTALS	T-PLT	16,623						16,622		1
292		LINE RENTALS	P-PTD									
293		COGENERATION	COGEN-E	1,808,672				1,808,672				
294		DARK FIBER PROJECT	D-FIBER									
295		POLE ATTACHMENTS	D364	1,506,578								
296		FACILITIES CHARGES	OTH-REV	9,859,316								
297		OTHER RENTALS	PI-H	1,028,271	1,028,271							
298		MISCELLANEOUS	P-PTD	80,584	27,692	2,610				18,761		1
299		TOTAL ACCOUNT 454		17,384,400								
300												
301	456	OTHER ELECTRIC REVENUES										
302		TRANSMISSION NETWORK SERVICES-	T-100	10,628,615						10,628,615		
303		TRANSMISSION NETWORK SERVICES -	D3601	762,362								
304		TRANSMISSION POINT-TO-POINT	T-100	46,361,643						46,361,643		
305		PHOTOVOLTAIC STATION SERVICE	D3601									
306		ENERGY EFFICIENCY RIDER	NONE									
307		STAND-BY SERVICE	D3601	759,997								
308		SIERRA PACIFIC USAGE CHARGE	PI-H	49,471	49,471							
309		ANTELOPE	T-PLT									
310		MISCELLANEOUS	P-PTD	1,590	547	52				370		0
311		TOTAL ACCOUNT 456		58,563,677	49,471					56,990,258		
312												
313		TOTAL OTHER OPERATING REVENUES		85,891,627	1,105,981	2,661		1,809,313		60,109,852		518
314												
315		TOTAL OPERATING REVENUES		1,406,650,030	1,105,981	2,661		29,557,875		60,109,852		518

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Acct	Description	(A) ALLOCATOR	(I) SUBSTATION GENERAL	(J) SUBSTATION DIRECT	(K) SUBSTATION CIAC	(L) PRI LINES DEMAND	(M) PRI LINES CUSTOMER	(N) SEC LINES DIRECT	(O) LINE TRANS PRI DMD	(P) LINE TRANS PRI CUST	(Q) LINE TRANS PRI DIRECT	(R) LINE TRANS SEC DMD
				* *			DISTRIBUTION FUNCTION	* *					
267		**** * * TABLE 4 - OPERATING REVENUES * * ****											
268													
269		OPERATING REVENUES											
270		SALES OF ELECTRICITY											
271		FIRM ENERGY SALES											
272	440-448	RETAIL	TAX-REV										
273	442	CLEAN ENERGY YOUR WAY PPA REVEN	TAX-REV										
274	447	FIRM SALES FOR RESALE	TAX-REV										
275	447	SYSTEM OPPORTUNITY SALES	KWH-O										
276	447	FINANCIAL LOSSES	KWH-O										
277		TOTAL SALES OF ELECTRICITY											
278													
279		OTHER OPERATING REVENUES											
280	415	MERCHANDISING REVENUES	M-REV				1,193,973	591,750	74,612	268,576	133,110	74,433	776,753
281	449 / OATT	TARIFF REFUND											
282		NETWORK	NONE										
283		POINT-TO-POINT	NONE										
284		TOTAL ACCOUNT 449											
285													
286													
287	451	MISCELLANEOUS SERVICE REVENUES	MISC-REV										
288													
289	454	RENTS FROM ELECTRIC PROPERTY											
290		SUBSTATION EQUIPMENT	T-353										
291		TRANSFORMER RENTALS	T-PLT										
292		LINE RENTALS	P-PTD										
293		COGENERATION	COGEN-E										
294		DARK FIBER PROJECT	D-FIBER										
295		POLE ATTACHMENTS	D364				943,424	467,574	10,502				
296		FACILITIES CHARGES	OTH-REV										
297		OTHER RENTALS	PI-H										
298		MISCELLANEOUS	P-PTD	6,068	283		7,412	3,673	463	1,667	826	462	4,822
299		TOTAL ACCOUNT 454											
300													
301	456	OTHER ELECTRIC REVENUES											
302		TRANSMISSION NETWORK SERVICES-	T-100										
303		TRANSMISSION NETWORK SERVICES -	D3601	146,771	6,845		179,261	88,844	11,202	40,323	19,985	11,175	116,620
304		TRANSMISSION POINT-TO-POINT	T-100										
305		PHOTOVOLTAIC STATION SERVICE	D3601										
306		ENERGY EFFICIENCY RIDER	NONE										
307		STAND-BY SERVICE	D3601	146,315	6,824		178,704	88,568	11,167	40,198	19,923	11,141	116,258
308		SIERRA PACIFIC USAGE CHARGE	PI-H										
309		ANTELOPE	T-PLT										
310		MISCELLANEOUS	P-PTD	120	6		146	72	9	33	16	9	95
311		TOTAL ACCOUNT 456		293,086	13,669		357,965	177,412	22,369	80,522	39,908	22,316	232,878
312													
313		TOTAL OTHER OPERATING REVENUES		299,274	13,957		2,502,919	1,240,482	107,956	350,797	173,860	97,220	1,014,549
314													
315		TOTAL OPERATING REVENUES		299,274	13,957		2,502,919	1,240,482	107,956	350,797	173,860	97,220	1,014,549

1						IDAHO POWER COMPANY				
2						BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION				
3						CLASS COST OF SERVICE STUDY				
4						FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023				
5						FUNCTIONALIZATION AND CLASSIFICATION OF COSTS				
6			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *			DISTRIBUTION FUNCTION * * * * * * * * * * * * * *			
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
267	**** * * TABLE 4 - OPERATING REVENUES * * ******									
268										
269	OPERATING REVENUES									
270	SALES OF ELECTRICITY									
271		FIRM ENERGY SALES								
272	440-448	RETAIL	TAX-REV							
273	442	CLEAN ENERGY YOUR WAY PPA REVEN	TAX-REV							
274	447	FIRM SALES FOR RESALE	TAX-REV							
275	447	SYSTEM OPPORTUNITY SALES	KWH-O							
276	447	FINANCIAL LOSSES	KWH-O							
277		TOTAL SALES OF ELECTRICITY								
278										
279	OTHER OPERATING REVENUES									
280	415	MERCHANDISING REVENUES	M-REV	384,970	76,517	37,923	155,716		14,092	10,058
281	449 / OATT TARIFF REFUND									
282		NETWORK	NONE							
283		POINT-TO-POINT	NONE							
284		TOTAL ACCOUNT 449								
285										
286										
287	451	MISCELLANEOUS SERVICE REVENUES	MISC-REV							
288										
289	454	RENTS FROM ELECTRIC PROPERTY								
290		SUBSTATION EQUIPMENT	T-353							
291		TRANSFORMER RENTALS	T-PLT							
292		LINE RENTALS	P-PTD							
293		COGENERATION	COGEN-E							
294		DARK FIBER PROJECT	D-FIBER							
295		POLE ATTACHMENTS	D364		56,884	28,193				
296		FACILITIES CHARGES	OTH-REV							
297		OTHER RENTALS	PI-H							
298		MISCELLANEOUS	P-PTD	2,390	475	235	967	1,627	87	62
299		TOTAL ACCOUNT 454								
300										
301	456	OTHER ELECTRIC REVENUES								
302		TRANSMISSION NETWORK SERVICES-	T-100							
303		TRANSMISSION NETWORK SERVICES -	D3601	57,799	11,488	5,694	23,379	39,351	2,116	1,510
304		TRANSMISSION POINT-TO-POINT	T-100							
305		PHOTOVOLTAIC STATION SERVICE	D3601							
306		ENERGY EFFICIENCY RIDER	NONE							
307		STAND-BY SERVICE	D3601	57,619	11,452	5,676	23,306	39,229	2,109	1,505
308		SIERRA PACIFIC USAGE CHARGE	PI-H							
309		ANTELOPE	T-PLT							
310		MISCELLANEOUS	P-PTD	47	9	5	19	32	2	1
311		TOTAL ACCOUNT 456		115,418	22,941	11,370	46,685	78,580	4,225	3,015
312										
313		TOTAL OTHER OPERATING REVENUES		502,825	156,826	77,725	203,386	80,239	18,406	13,137
314										
315		TOTAL OPERATING REVENUES		502,825	156,826	77,725	203,386	80,239	18,406	13,137

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Acct	Description	(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				***** CUSTOMER INFORMATION FUNCTION *****			
8			ALLOCATOF	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
267	**** * * TABLE 4 - OPERATING REVENUES * * ****										
268											
269	OPERATING REVENUES										
270	SALES OF ELECTRICITY										
271		FIRM ENERGY SALES									
272	440-448	RETAIL	TAX-REV								
273	442	CLEAN ENERGY YOUR WAY PPA REVEN	TAX-REV								
274	447	FIRM SALES FOR RESALE	TAX-REV								
275	447	SYSTEM OPPORTUNITY SALES	KWH-O								
276	447	FINANCIAL LOSSES	KWH-O								
277		TOTAL SALES OF ELECTRICITY									
278											
279	OTHER OPERATING REVENUES										
280	415	MERCHANDISING REVENUES	M-REV								
281	449 / OATT TARIFF REFUND										
282		NETWORK	NONE								
283		POINT-TO-POINT	NONE								
284		TOTAL ACCOUNT 449									
285											
286											
287	451	MISCELLANEOUS SERVICE REVENUES	MISC-REV								
288											
289	454	RENTS FROM ELECTRIC PROPERTY									
290		SUBSTATION EQUIPMENT	T-353								
291		TRANSFORMER RENTALS	T-PLT								
292		LINE RENTALS	P-PTD								
293		COGENERATION	COGEN-E:								
294		DARK FIBER PROJECT	D-FIBER								
295		POLE ATTACHMENTS	D364								
296		FACILITIES CHARGES	OTH-REV								
297		OTHER RENTALS	PI-H								
298		MISCELLANEOUS	P-PTD								
299		TOTAL ACCOUNT 454									
300											
301	456	OTHER ELECTRIC REVENUES									
302		TRANSMISSION NETWORK SERVICES-	T-100								
303		TRANSMISSION NETWORK SERVICES -	D3601								
304		TRANSMISSION POINT-TO-POINT	T-100								
305		PHOTOVOLTAIC STATION SERVICE	D3601								
306		ENERGY EFFICIENCY RIDER	NONE								
307		STAND-BY SERVICE	D3601								
308		SIERRA PACIFIC USAGE CHARGE	PI-H								
309		ANTELOPE	T-PLT								
310		MISCELLANEOUS	P-PTD								
311		TOTAL ACCOUNT 456									
312											
313		TOTAL OTHER OPERATING REVENUES									
314											
315		TOTAL OPERATING REVENUES									

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Acct	Description	(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
267		**** * * TABLE 4 - OPERATING REVENUES * * ****							
268									
269		OPERATING REVENUES							
270		SALES OF ELECTRICITY							
271		FIRM ENERGY SALES							
272	440-448	RETAIL	TAX-REV						1,116,166,332
273	442	CLEAN ENERGY YOUR WAY PPA REVEN	TAX-REV						173,368,953
274	447	FIRM SALES FOR RESALE	TAX-REV						3,474,555
275	447	SYSTEM OPPORTUNITY SALES	KWH-O						
276	447	FINANCIAL LOSSES	KWH-O						
277		TOTAL SALES OF ELECTRICITY							1,293,009,840
278									
279		OTHER OPERATING REVENUES							
280	415	MERCHANDISING REVENUES	M-REV						
281	449 / OATT	TARIFF REFUND							
282		NETWORK	NONE						
283		POINT-TO-POINT	NONE						
284		TOTAL ACCOUNT 449							
285									
286									
287	451	MISCELLANEOUS SERVICE REVENUES	MISC-REV				6,150,427		
288									
289	454	RENTS FROM ELECTRIC PROPERTY							
290		SUBSTATION EQUIPMENT	T-353						
291		TRANSFORMER RENTALS	T-PLT						
292		LINE RENTALS	P-PTD						
293		COGENERATION	COGEN-E						
294		DARK FIBER PROJECT	D-FIBER						
295		POLE ATTACHMENTS	D364						
296		FACILITIES CHARGES	OTH-REV					9,859,316	
297		OTHER RENTALS	PI-H						
298		MISCELLANEOUS	P-PTD						
299		TOTAL ACCOUNT 454							
300									
301	456	OTHER ELECTRIC REVENUES							
302		TRANSMISSION NETWORK SERVICES-	T-100						
303		TRANSMISSION NETWORK SERVICES -	D3601						
304		TRANSMISSION POINT-TO-POINT	T-100						
305		PHOTOVOLTAIC STATION SERVICE	D3601						
306		ENERGY EFFICIENCY RIDER	NONE						
307		STAND-BY SERVICE	D3601						
308		SIERRA PACIFIC USAGE CHARGE	PI-H						
309		ANTELOPE	T-PLT						
310		MISCELLANEOUS	P-PTD						
311		TOTAL ACCOUNT 456							
312									
313		TOTAL OTHER OPERATING REVENUES					6,150,427	9,859,316	
314									
315		TOTAL OPERATING REVENUES					6,150,427	9,859,316	1,293,009,840

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Account	Description	(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
316	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****											
317					Base-load	Peak						
318	STEAM POWER GENERATION											
319	OPERATION											
320	500-OP	SUPERVISION & ENGINEERING	PI-S	(73,374)	(73,374)							
321	501-OP	FUEL	KWH-S	62,619,523				62,619,523				
322												
323	502-OP	STEAM EXPENSES										
324		LABOR	PI-S	1,542,164	1,542,164							
325		OTHER	KWH-S	(1,094,811)				(1,094,811)				
326		TOTAL ACCOUNT 502		447,353								
327	505-OP	ELECTRIC EXPENSES										
328		LABOR	PI-S	600,571	600,571							
329		OTHER	KWH-S	(544,984)				(544,984)				
330		TOTAL ACCOUNT 505		55,587								
331	506-OP	MISCELLANEOUS EXPENSES	PI-S	407,703	407,703							
332	507-OP	RENTS	PI-S	10,895	10,895							
333		TOTAL STEAM OPERATION EXPENSES		63,467,686								
334												
335	MAINTENANCE											
336	510-MT	SUPERVISION & ENGINEERING	PI-S	(240,497)	(240,497)							
337	511-MT	STRUCTURES	PI-S	120,601	120,601							
338	512-MT	BOILER PLANT										
339		LABOR	PI-S	3,821,200	3,821,200							
340		OTHER	KWH-S	(3,392,111)				(3,392,111)				
341		TOTAL ACCOUNT 512		429,089								
342	513-MT	ELECTRIC PLANT										
343		LABOR	PI-S	1,460,523	1,460,523							
344		OTHER	KWH-S	(1,346,052)				(1,346,052)				
345		TOTAL ACCOUNT 513		114,471								
346	514-MT	MISCELLANEOUS STEAM PLANT	PI-S	455,440	455,440							
347		TOTAL STEAM MAINTENANCE EXPENSES		879,105								
348												
349		TOTAL STEAM GENERATION EXPENSES		64,346,791								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *				DISTRIBUTION FUNCTION *						
8			ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
316	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****												
317													
318	STEAM POWER GENERATION												
319	OPERATION												
320	500-OP	SUPERVISION & ENGINEERING	PI-S										
321	501-OP	FUEL	KWH-S										
322													
323	502-OP	STEAM EXPENSES											
324		LABOR	PI-S										
325		OTHER	KWH-S										
326		TOTAL ACCOUNT 502											
327	505-OP	ELECTRIC EXPENSES											
328		LABOR	PI-S										
329		OTHER	KWH-S										
330		TOTAL ACCOUNT 505											
331	506-OP	MISCELLANEOUS EXPENSES	PI-S										
332	507-OP	RENTS	PI-S										
333		TOTAL STEAM OPERATION EXPENSES											
334													
335	MAINTENANCE												
336	510-MT	SUPERVISION & ENGINEERING	PI-S										
337	511-MT	STRUCTURES	PI-S										
338	512-MT	BOILER PLANT											
339		LABOR	PI-S										
340		OTHER	KWH-S										
341		TOTAL ACCOUNT 512											
342	513-MT	ELECTRIC PLANT											
343		LABOR	PI-S										
344		OTHER	KWH-S										
345		TOTAL ACCOUNT 513											
346	514-MT	MISCELLANEOUS STEAM PLANT	PI-S										
347		TOTAL STEAM MAINTENANCE EXPENSES											
348													
349		TOTAL STEAM GENERATION EXPENSES											

1 **IDAHO POWER COMPANY**
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3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Acct	Description	(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *	DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *				
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
316	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****									
317										
318	STEAM POWER GENERATION									
319	OPERATION									
320	500-OP	SUPERVISION & ENGINEERING	PI-S							
321	501-OP	FUEL	KWH-S							
322										
323	502-OP	STEAM EXPENSES								
324		LABOR	PI-S							
325		OTHER	KWH-S							
326		TOTAL ACCOUNT 502								
327	505-OP	ELECTRIC EXPENSES								
328		LABOR	PI-S							
329		OTHER	KWH-S							
330		TOTAL ACCOUNT 505								
331	506-OP	MISCELLANEOUS EXPENSES	PI-S							
332	507-OP	RENTS	PI-S							
333		TOTAL STEAM OPERATION EXPENSES								
334										
335	MAINTENANCE									
336	510-MT	SUPERVISION & ENGINEERING	PI-S							
337	511-MT	STRUCTURES	PI-S							
338	512-MT	BOILER PLANT								
339		LABOR	PI-S							
340		OTHER	KWH-S							
341		TOTAL ACCOUNT 512								
342	513-MT	ELECTRIC PLANT								
343		LABOR	PI-S							
344		OTHER	KWH-S							
345		TOTAL ACCOUNT 513								
346	514-MT	MISCELLANEOUS STEAM PLANT	PI-S							
347		TOTAL STEAM MAINTENANCE EXPENSES								
348										
349		TOTAL STEAM GENERATION EXPENSES								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Account	Description	(A) ALLOCATOR	(Z) METER READING	(AA) CUSTOMER RECORDS	(AB) UNCOLLECT ACCOUNTS	(AC) OTHER	(AD) CUSTOMER ASSISTANCE	(AE) DEMONSTR	(AF) ADVERTISING	(AG) OTHER
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				***** CUSTOMER INFORMATION FUNCTION *****			
316	***** TABLE 5 - OPERATION & MAINTENANCE EXPENSES *****										
317											
318	STEAM POWER GENERATION										
319	OPERATION										
320	500-OP	SUPERVISION & ENGINEERING	PI-S								
321	501-OP	FUEL	KWH-S								
322											
323	502-OP	STEAM EXPENSES									
324		LABOR	PI-S								
325		OTHER	KWH-S								
326		TOTAL ACCOUNT 502									
327	505-OP	ELECTRIC EXPENSES									
328		LABOR	PI-S								
329		OTHER	KWH-S								
330		TOTAL ACCOUNT 505									
331	506-OP	MISCELLANEOUS EXPENSES	PI-S								
332	507-OP	RENTS	PI-S								
333		TOTAL STEAM OPERATION EXPENSES									
334											
335	MAINTENANCE										
336	510-MT	SUPERVISION & ENGINEERING	PI-S								
337	511-MT	STRUCTURES	PI-S								
338	512-MT	BOILER PLANT									
339		LABOR	PI-S								
340		OTHER	KWH-S								
341		TOTAL ACCOUNT 512									
342	513-MT	ELECTRIC PLANT									
343		LABOR	PI-S								
344		OTHER	KWH-S								
345		TOTAL ACCOUNT 513									
346	514-MT	MISCELLANEOUS STEAM PLANT	PI-S								
347		TOTAL STEAM MAINTENANCE EXPENSES									
348											
349		TOTAL STEAM GENERATION EXPENSES									

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Account	Description	(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
316	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****								
317									
318	STEAM POWER GENERATION								
319	OPERATION								
320	500-OP	SUPERVISION & ENGINEERING	PI-S						
321	501-OP	FUEL	KWH-S						
322									
323	502-OP	STEAM EXPENSES							
324		LABOR	PI-S						
325		OTHER	KWH-S						
326		TOTAL ACCOUNT 502							
327	505-OP	ELECTRIC EXPENSES							
328		LABOR	PI-S						
329		OTHER	KWH-S						
330		TOTAL ACCOUNT 505							
331	506-OP	MISCELLANEOUS EXPENSES	PI-S						
332	507-OP	RENTS	PI-S						
333		TOTAL STEAM OPERATION EXPENSES							
334									
335	MAINTENANCE								
336	510-MT	SUPERVISION & ENGINEERING	PI-S						
337	511-MT	STRUCTURES	PI-S						
338	512-MT	BOILER PLANT							
339		LABOR	PI-S						
340		OTHER	KWH-S						
341		TOTAL ACCOUNT 512							
342	513-MT	ELECTRIC PLANT							
343		LABOR	PI-S						
344		OTHER	KWH-S						
345		TOTAL ACCOUNT 513							
346	514-MT	MISCELLANEOUS STEAM PLANT	PI-S						
347		TOTAL STEAM MAINTENANCE EXPENSES							
348									
349		TOTAL STEAM GENERATION EXPENSES							

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A) ALLOCATOF	(B) TOTALS	(C) DEMAND Base-load	(CC) Peak	(CCC)	(D) ENERGY	(E) DEMAND POWER SUP	(F) DEMAND TRANS	(G) DEMAND SUBTRANS	(H) DEMAND DIRECT
					** PRODUCTION FUNCTION **				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
350												
351	HYDRAULIC POWER GENERATION											
352	535-OP	SUPERVISION & ENGINEERING	L-535	6,210,878	6,210,878							
353	536-OP	WATER FOR POWER										
354		WATER FOR POWER/WCLOUD SEED	KWH-H	6,217,277				6,217,277				
355		WATER LEASE	KWH-H									
356		TOTAL ACCOUNT 536		6,217,277								
357												
358	537-OP	HYDRAULIC EXPENSES	PI-H	19,366,472	19,366,472							
359	538-OP	ELECTRIC EXPENSES										
360		LABOR	PI-H	1,540,414	1,540,414							
361		OTHER	KWH-H	602,063				602,063				
362		TOTAL ACCOUNT 538		2,142,477								
363												
364	539-OP	MISCELLANEOUS EXPENSES	PI-H	5,496,716	5,496,716							
365	540-OP	RENTS	PI-H	291,025	291,025							
366		TOTAL HYDRAULIC OPERATION EXPENSES		39,724,845								

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

6			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* DISTRIBUTION FUNCTION *									
8			ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
350													
351	HYDRAULIC POWER GENERATION												
352	535-OP	SUPERVISION & ENGINEERING	L-535										
353	536-OP	WATER FOR POWER											
354		WATER FOR POWER/WCLOUD SEED	KWH-H										
355		WATER LEASE	KWH-H										
356		TOTAL ACCOUNT 536											
357													
358	537-OP	HYDRAULIC EXPENSES	PI-H										
359	538-OP	ELECTRIC EXPENSES											
360		LABOR	PI-H										
361		OTHER	KWH-H										
362		TOTAL ACCOUNT 538											
363													
364	539-OP	MISCELLANEOUS EXPENSES	PI-H										
365	540-OP	RENTS	PI-H										
366		TOTAL HYDRAULIC OPERATION EXPENSES											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Acct	Description	(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *	DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *				
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
350										
351	HYDRAULIC POWER GENERATION									
352	535-OP	SUPERVISION & ENGINEERING	L-535							
353	536-OP	WATER FOR POWER								
354		WATER FOR POWER/WCLOUD SEED	KWH-H							
355		WATER LEASE	KWH-H							
356		TOTAL ACCOUNT 536								
357										
358	537-OP	HYDRAULIC EXPENSES	PI-H							
359	538-OP	ELECTRIC EXPENSES								
360		LABOR	PI-H							
361		OTHER	KWH-H							
362		TOTAL ACCOUNT 538								
363										
364	539-OP	MISCELLANEOUS EXPENSES	PI-H							
365	540-OP	RENTS	PI-H							
366		TOTAL HYDRAULIC OPERATION EXPENSES								

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3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - -	CUSTOMER ACCOUNTING FUNCTION		- - -	* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
350											
351	HYDRAULIC POWER GENERATION										
352	535-OP	SUPERVISION & ENGINEERING	L-535								
353	536-OP	WATER FOR POWER									
354		WATER FOR POWER/WCLOUD SEED	KWH-H								
355		WATER LEASE	KWH-H								
356		TOTAL ACCOUNT 536									
357											
358	537-OP	HYDRAULIC EXPENSES	PI-H								
359	538-OP	ELECTRIC EXPENSES									
360		LABOR	PI-H								
361		OTHER	KWH-H								
362		TOTAL ACCOUNT 538									
363											
364	539-OP	MISCELLANEOUS EXPENSES	PI-H								
365	540-OP	RENTS	PI-H								
366		TOTAL HYDRAULIC OPERATION EXPENSES									

1 **IDAHO POWER COMPANY**
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3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Account	Description	(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
350									
351	HYDRAULIC POWER GENERATION								
352	535-OP	SUPERVISION & ENGINEERING	L-535						
353	536-OP	WATER FOR POWER							
354		WATER FOR POWER/WCLOUD SEED	KWH-H						
355		WATER LEASE	KWH-H						
356		TOTAL ACCOUNT 536							
357									
358	537-OP	HYDRAULIC EXPENSES	PI-H						
359	538-OP	ELECTRIC EXPENSES							
360		LABOR	PI-H						
361		OTHER	KWH-H						
362		TOTAL ACCOUNT 538							
363									
364	539-OP	MISCELLANEOUS EXPENSES	PI-H						
365	540-OP	RENTS	PI-H						
366		TOTAL HYDRAULIC OPERATION EXPENSES							

1 **IDAHO POWER COMPANY**
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3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Account	Description	(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
367	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***											
368												
369	MAINTENANCE											
370	541-MT	SUPERVISION & ENGINEERING	L-541	120,801	120,801							
371	542-MT	STRUCTURES	PI-H	991,499	991,499							
372	543-MT	RESERVOIRS, DAMS & WATERWAYS	PI-H	487,743	487,743							
373	544-MT	ELECTRIC PLANT										
374		LABOR	PI-H	1,833,025	1,833,025							
375		OTHER	KWH-H	966,545				966,545				
376		TOTAL ACCOUNT 544		2,799,570								
377												
378	545-MT	MISCELLANEOUS HYDRAULIC PLANT	PI-H	4,134,421	4,134,421							
379												
380		TOTAL HYDRAULIC MAINTENANCE EXPENSES		8,534,035								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* DISTRIBUTION FUNCTION *									
8			ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
367	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***												
368													
369	MAINTENANCE												
370	541-MT	SUPERVISION & ENGINEERING	L-541										
371	542-MT	STRUCTURES	PI-H										
372	543-MT	RESERVOIRS, DAMS & WATERWAYS	PI-H										
373	544-MT	ELECTRIC PLANT											
374		LABOR	PI-H										
375		OTHER	KWH-H										
376		TOTAL ACCOUNT 544											
377													
378	545-MT	MISCELLANEOUS HYDRAULIC PLANT	PI-H										
379													
380		TOTAL HYDRAULIC MAINTENANCE EXPENSES											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *		DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *			
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
367	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***									
368										
369	MAINTENANCE									
370	541-MT	SUPERVISION & ENGINEERING	L-541							
371	542-MT	STRUCTURES	PI-H							
372	543-MT	RESERVOIRS, DAMS & WATERWAYS	PI-H							
373	544-MT	ELECTRIC PLANT								
374		LABOR	PI-H							
375		OTHER	KWH-H							
376		TOTAL ACCOUNT 544								
377										
378	545-MT	MISCELLANEOUS HYDRAULIC PLANT	PI-H							
379										
380		TOTAL HYDRAULIC MAINTENANCE EXPENSES								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION			- - -	* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
367	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***										
368											
369	MAINTENANCE										
370	541-MT	SUPERVISION & ENGINEERING	L-541								
371	542-MT	STRUCTURES	PI-H								
372	543-MT	RESERVOIRS, DAMS & WATERWAYS	PI-H								
373	544-MT	ELECTRIC PLANT									
374		LABOR	PI-H								
375		OTHER	KWH-H								
376		TOTAL ACCOUNT 544									
377											
378	545-MT	MISCELLANEOUS HYDRAULIC PLANT	PI-H								
379											
380		TOTAL HYDRAULIC MAINTENANCE EXPENSES									

1						**IDAHO POWER COMPANY**			
2						**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**			
3						**CLASS COST OF SERVICE STUDY**			
4						**FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**			
5						**FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**			
6			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
367	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***								
368									
369	MAINTENANCE								
370	541-MT	SUPERVISION & ENGINEERING	L-541						
371	542-MT	STRUCTURES	PI-H						
372	543-MT	RESERVOIRS, DAMS & WATERWAYS	PI-H						
373	544-MT	ELECTRIC PLANT							
374		LABOR	PI-H						
375		OTHER	KWH-H						
376		TOTAL ACCOUNT 544							
377									
378	545-MT	MISCELLANEOUS HYDRAULIC PLANT	PI-H						
379									
380		TOTAL HYDRAULIC MAINTENANCE EXPENSES							

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Acct	Description	(A) ALLOCATOF	(B) TOTALS	(C) * * PRODUCTION FUNCTION * * DEMAND Base-load	(CC) Peak	(CCC)	(D) ENERGY	(E) - - - TRANSMISSION FUNCTION - - - DEMAND POWER SUP	(F) DEMAND TRANS	(G) DEMAND SUBTRANS	(H) DEMAND DIRECT
381												
382		TOTAL HYDRAULIC GENERATION EXPENSES		48,258,881								
383												
384	OTHER POWER GENERATION											
385	OPERATION											
386	546-OP	SUPERVISION & ENGINEERING	L-546	685,537	480,982	204,555						
387	547-OP	FUEL										
388		DIESEL FUEL	KWH-O	10,034				10,034				
389		OTHER	KWH-O	114,351,541				114,351,541				
390		TOTAL ACCOUNT 547		114,361,575								
391												
392	548-OP	GENERATING EXPENSES										
393		LABOR	PI-OS	3,293,050	2,310,449	982,601						
394		OTHER	KWH-O	1,921,928				1,921,928				
395		TOTAL ACCOUNT 548		5,214,978								
396												
397	549-OP	MISCELLANEOUS EXPENSES	PI-OS	72,854	51,116	21,739						
398	550-OP	RENTS	PI-OS									
399												
400		TOTAL OTHER POWER OPER EXPENSES		120,334,945								
401												
402	MAINTENANCE											
403	551-MT	SUPERVISION & ENGINEERING	L-551									
404	552-MT	STRUCTURES	PI-OS	160,358	112,509	47,849						
405	553-MT	GENERATING & ELECTRIC PLANT										
406		LABOR	PI-OS	58,030	40,715	17,315						
407		OTHER	KWH-O	838,743				838,743				
408		TOTAL ACCOUNT 553		896,774								
409												
410	554-MT	MISCELLANEOUS EXPENSES	PI-OS	3,249,153	2,279,650	969,503						
411		TOTAL OTHER POWER MAINT EXPENSES		4,306,284								
412												
413		TOTAL OTHER POWER GEN EXPENSES		124,641,229								

Line			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
1							**IDAHO POWER COMPANY**						
2							**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**						
3							**COST OF SERVICE STUDY**						
4							**FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**						
5							**FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**						
6			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* DISTRIBUTION FUNCTION *										
8			ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
381													
382		TOTAL HYDRAULIC GENERATION EXPENSES											
383													
384	OTHER POWER GENERATION												
385	OPERATION												
386	546-OP	SUPERVISION & ENGINEERING	L-546										
387	547-OP	FUEL											
388		DIESEL FUEL	KWH-O										
389		OTHER	KWH-O										
390		TOTAL ACCOUNT 547											
391													
392	548-OP	GENERATING EXPENSES											
393		LABOR	PI-OS										
394		OTHER	KWH-O										
395		TOTAL ACCOUNT 548											
396													
397	549-OP	MISCELLANEOUS EXPENSES	PI-OS										
398	550-OP	RENTS	PI-OS										
399													
400		TOTAL OTHER POWER OPER EXPENSES											
401													
402	MAINTENANCE												
403	551-MT	SUPERVISION & ENGINEERING	L-551										
404	552-MT	STRUCTURES	PI-OS										
405	553-MT	GENERATING & ELECTRIC PLANT											
406		LABOR	PI-OS										
407		OTHER	KWH-O										
408		TOTAL ACCOUNT 553											
409													
410	554-MT	MISCELLANEOUS EXPENSES	PI-OS										
411		TOTAL OTHER POWER MAINT EXPENSES											
412													
413		TOTAL OTHER POWER GEN EXPENSES											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Account	Description	(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
381										
382		TOTAL HYDRAULIC GENERATION EXPENSES								
383										
384	OTHER POWER GENERATION									
385	OPERATION									
386	546-OP	SUPERVISION & ENGINEERING	L-546							
387	547-OP	FUEL								
388		DIESEL FUEL	KWH-O							
389		OTHER	KWH-O							
390		TOTAL ACCOUNT 547								
391										
392	548-OP	GENERATING EXPENSES								
393		LABOR	PI-OS							
394		OTHER	KWH-O							
395		TOTAL ACCOUNT 548								
396										
397	549-OP	MISCELLANEOUS EXPENSES	PI-OS							
398	550-OP	RENTS	PI-OS							
399										
400		TOTAL OTHER POWER OPER EXPENSES								
401										
402	MAINTENANCE									
403	551-MT	SUPERVISION & ENGINEERING	L-551							
404	552-MT	STRUCTURES	PI-OS							
405	553-MT	GENERATING & ELECTRIC PLANT								
406		LABOR	PI-OS							
407		OTHER	KWH-O							
408		TOTAL ACCOUNT 553								
409										
410	554-MT	MISCELLANEOUS EXPENSES	PI-OS							
411		TOTAL OTHER POWER MAINT EXPENSES								
412										
413		TOTAL OTHER POWER GEN EXPENSES								

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Account	Description	(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION			- - -	***** CUSTOMER INFORMATION FUNCTION *****			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
381											
382		TOTAL HYDRAULIC GENERATION EXPENSES									
383											
384	OTHER POWER GENERATION										
385	OPERATION										
386	546-OP	SUPERVISION & ENGINEERING	L-546								
387	547-OP	FUEL									
388		DIESEL FUEL	KWH-O								
389		OTHER	KWH-O								
390		TOTAL ACCOUNT 547									
391											
392	548-OP	GENERATING EXPENSES									
393		LABOR	PI-OS								
394		OTHER	KWH-O								
395		TOTAL ACCOUNT 548									
396											
397	549-OP	MISCELLANEOUS EXPENSES	PI-OS								
398	550-OP	RENTS	PI-OS								
399											
400		TOTAL OTHER POWER OPER EXPENSES									
401											
402	MAINTENANCE										
403	551-MT	SUPERVISION & ENGINEERING	L-551								
404	552-MT	STRUCTURES	PI-OS								
405	553-MT	GENERATING & ELECTRIC PLANT									
406		LABOR	PI-OS								
407		OTHER	KWH-O								
408		TOTAL ACCOUNT 553									
409											
410	554-MT	MISCELLANEOUS EXPENSES	PI-OS								
411		TOTAL OTHER POWER MAINT EXPENSES									
412											
413		TOTAL OTHER POWER GEN EXPENSES									

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
			ALLOCATOF						& REVENUES
				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
381									
382		TOTAL HYDRAULIC GENERATION EXPENSES							
383									
384	OTHER POWER GENERATION								
385	OPERATION								
386	546-OP	SUPERVISION & ENGINEERING	L-546						
387	547-OP	FUEL							
388		DIESEL FUEL	KWH-O						
389		OTHER	KWH-O						
390		TOTAL ACCOUNT 547							
391									
392	548-OP	GENERATING EXPENSES							
393		LABOR	PI-OS						
394		OTHER	KWH-O						
395		TOTAL ACCOUNT 548							
396									
397	549-OP	MISCELLANEOUS EXPENSES	PI-OS						
398	550-OP	RENTS	PI-OS						
399									
400		TOTAL OTHER POWER OPER EXPENSES							
401									
402	MAINTENANCE								
403	551-MT	SUPERVISION & ENGINEERING	L-551						
404	552-MT	STRUCTURES	PI-OS						
405	553-MT	GENERATING & ELECTRIC PLANT							
406		LABOR	PI-OS						
407		OTHER	KWH-O						
408		TOTAL ACCOUNT 553							
409									
410	554-MT	MISCELLANEOUS EXPENSES	PI-OS						
411		TOTAL OTHER POWER MAINT EXPENSES							
412									
413		TOTAL OTHER POWER GEN EXPENSES							

Line	Acct	Description	(A) ALLOCATOF	(B) TOTALS	(C) DEMAND Base-load	(CC) Peak	(CCC)	(D) ENERGY	(E) DEMAND POWER SUP	(F) DEMAND TRANS	(G) DEMAND SUBTRANS	(H) DEMAND DIRECT
1		IDAHO POWER COMPANY										
2		BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION										
3		CLASS COST OF SERVICE STUDY										
4		FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023										
5		FUNCTIONALIZATION AND CLASSIFICATION OF COSTS										
6			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
414		**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****										
415												
416		OTHER POWER SUPPLY EXPENSE										
417	555.0	PURCHASED POWER										
418		POWER EXPENSE	PP-KWH	95,057,493				95,057,493				
419		CLEAN ENERGY YOUR WAY PPA COS	PP-KWH									
420		TRANSMISSION LOSSES	PP-KWH									
421		DEMAND RESPONSE INCENTIVE	PI-O	10,240,003		10,240,003						
422		TOTAL 555.0/PURCHASED POWER		105,297,496								
423												
424	555.1	COGENERATION & SMALL POWER PROI	PP-KWH	204,946,028				204,946,028				
425		TOTAL COGEN & SMALL POWER PROD		204,946,028								
426												
427		TOTAL ACCOUNT 555		310,243,524								
428												
429	556	LOAD CONTROL & DISPATCHING EXPEN	PP-KW									
430	557	PCA/ EPC ACCOUNTS	NONE									
431	557	OTHER	PI-SHO	6,743,211	6,162,485	580,727						
432												
433		TOTAL OTHER POWER SUPPLY EXPENSES		316,986,736								
434												
435		TOTAL PRODUCTION EXPENSES		554,233,636								
436												
437												
438		TRANSMISSION EXPENSES										
439												
440		OPERATION										
441	560-OP	SUPERVISION & ENGINEERING	L-560	3,446,215						3,445,898		318
442	561-OP	LOAD DISPATCHING	T-PLT	5,771,817						5,771,479		339
443	562-OP	STATION EXPENSES	T-353	2,994,513						2,994,013		500
444	563-OP	OVERHEAD LINE EXPENSES	T-354-356	1,156,414						1,156,412		2
445	565-OP	TRANSMISSION OF ELECTRICITY BY OT	KWH-T	9,808,355				9,808,355				
446	566-OP	MISCELLANEOUS EXPENSES	T-PLT	7						7		0
447	567-OP	RENTS	T-354-359	4,657,012						4,657,005		8
448												
449		TOTAL TRANSMISSION OPERATION		27,834,335								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *	DISTRIBUTION FUNCTION	* *							
8			ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
414	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****												
415													
416	OTHER POWER SUPPLY EXPENSE												
417	555.0	PURCHASED POWER											
418		POWER EXPENSE	PP-KWH										
419		CLEAN ENERGY YOUR WAY PPA COS	PP-KWH										
420		TRANSMISSION LOSSES	PP-KWH										
421		DEMAND RESPONSE INCENTIVE	PI-O										
422		TOTAL 555.0/PURCHASED POWER											
423													
424	555.1	COGENERATION & SMALL POWER PROI	PP-KWH										
425		TOTAL COGEN & SMALL POWER PROD											
426													
427		TOTAL ACCOUNT 555											
428													
429	556	LOAD CONTROL & DISPATCHING EXPEN	PP-KW										
430	557	PCA/ EPC ACCOUNTS	NONE										
431	557	OTHER	PI-SHO										
432													
433		TOTAL OTHER POWER SUPPLY EXPENSES											
434													
435		TOTAL PRODUCTION EXPENSES											
436													
437													
438	TRANSMISSION EXPENSES												
439													
440	OPERATION												
441	560-OP	SUPERVISION & ENGINEERING	L-560										
442	561-OP	LOAD DISPATCHING	T-PLT										
443	562-OP	STATION EXPENSES	T-353										
444	563-OP	OVERHEAD LINE EXPENSES	T-354-356										
445	565-OP	TRANSMISSION OF ELECTRICITY BY OT	KWH-T										
446	566-OP	MISCELLANEOUS EXPENSES	T-PLT										
447	567-OP	RENTS	T-354-359										
448													
449		TOTAL TRANSMISSION OPERATION											

Line	Account	Description	(A) ALLOCATOR	(S) LINE TRANS SEC CUST	(T) SEC LINES DEMAND	(U) SEC LINES CUSTOMER	(V) SERVICES	(W) METERS	(X) STREET LIGHTS	(Y) INSTALLATION CUST PREM
1		**IDAHO POWER COMPANY**								
2		**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**								
3		**CLASS COST OF SERVICE STUDY**								
4		**FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**								
5		**FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**								
6			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
414		**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****								
415										
416	OTHER POWER SUPPLY EXPENSE									
417	555.0	PURCHASED POWER								
418		POWER EXPENSE	PP-KWH							
419		CLEAN ENERGY YOUR WAY PPA COS	PP-KWH							
420		TRANSMISSION LOSSES	PP-KWH							
421		DEMAND RESPONSE INCENTIVE	PI-O							
422		TOTAL 555.0/PURCHASED POWER								
423										
424	555.1	COGENERATION & SMALL POWER PROI	PP-KWH							
425		TOTAL COGEN & SMALL POWER PROD								
426										
427		TOTAL ACCOUNT 555								
428										
429	556	LOAD CONTROL & DISPATCHING EXPEN	PP-KW							
430	557	PCA/ EPC ACCOUNTS	NONE							
431	557	OTHER	PI-SHO							
432										
433		TOTAL OTHER POWER SUPPLY EXPENSES								
434										
435		TOTAL PRODUCTION EXPENSES								
436										
437										
438	TRANSMISSION EXPENSES									
439										
440	OPERATION									
441	560-OP	SUPERVISION & ENGINEERING	L-560							
442	561-OP	LOAD DISPATCHING	T-PLT							
443	562-OP	STATION EXPENSES	T-353							
444	563-OP	OVERHEAD LINE EXPENSES	T-354-356							
445	565-OP	TRANSMISSION OF ELECTRICITY BY OT	KWH-T							
446	566-OP	MISCELLANEOUS EXPENSES	T-PLT							
447	567-OP	RENTS	T-354-359							
448										
449		TOTAL TRANSMISSION OPERATION								

Line	Acct	Description	(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
1											
2											
3											
4											
5											
6			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOF	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
414	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****										
415											
416	OTHER POWER SUPPLY EXPENSE										
417	555.0	PURCHASED POWER									
418		POWER EXPENSE	PP-KWH								
419		CLEAN ENERGY YOUR WAY PPA COS	PP-KWH								
420		TRANSMISSION LOSSES	PP-KWH								
421		DEMAND RESPONSE INCENTIVE	PI-O								
422		TOTAL 555.0/PURCHASED POWER									
423											
424	555.1	COGENERATION & SMALL POWER PROI	PP-KWH								
425		TOTAL COGEN & SMALL POWER PROD									
426											
427		TOTAL ACCOUNT 555									
428											
429	556	LOAD CONTROL & DISPATCHING EXPEN	PP-KW								
430	557	PCA/ EPC ACCOUNTS	NONE								
431	557	OTHER	PI-SHO								
432											
433		TOTAL OTHER POWER SUPPLY EXPENSES									
434											
435		TOTAL PRODUCTION EXPENSES									
436											
437											
438	TRANSMISSION EXPENSES										
439											
440	OPERATION										
441	560-OP	SUPERVISION & ENGINEERING	L-560								
442	561-OP	LOAD DISPATCHING	T-PLT								
443	562-OP	STATION EXPENSES	T-353								
444	563-OP	OVERHEAD LINE EXPENSES	T-354-356								
445	565-OP	TRANSMISSION OF ELECTRICITY BY OT	KWH-T								
446	566-OP	MISCELLANEOUS EXPENSES	T-PLT								
447	567-OP	RENTS	T-354-359								
448											
449		TOTAL TRANSMISSION OPERATION									

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Account	Description	(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
414	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****								
415									
416	OTHER POWER SUPPLY EXPENSE								
417	555.0	PURCHASED POWER							
418		POWER EXPENSE	PP-KWH						
419		CLEAN ENERGY YOUR WAY PPA COS	PP-KWH						
420		TRANSMISSION LOSSES	PP-KWH						
421		DEMAND RESPONSE INCENTIVE	PI-O						
422		TOTAL 555.0/PURCHASED POWER							
423									
424	555.1	COGENERATION & SMALL POWER PROI	PP-KWH						
425		TOTAL COGEN & SMALL POWER PROD							
426									
427		TOTAL ACCOUNT 555							
428									
429	556	LOAD CONTROL & DISPATCHING EXPEN	PP-KW						
430	557	PCA/ EPC ACCOUNTS	NONE						
431	557	OTHER	PI-SHO						
432									
433		TOTAL OTHER POWER SUPPLY EXPENSES							
434									
435		TOTAL PRODUCTION EXPENSES							
436									
437									
438	TRANSMISSION EXPENSES								
439									
440	OPERATION								
441	560-OP	SUPERVISION & ENGINEERING	L-560						
442	561-OP	LOAD DISPATCHING	T-PLT						
443	562-OP	STATION EXPENSES	T-353						
444	563-OP	OVERHEAD LINE EXPENSES	T-354-356						
445	565-OP	TRANSMISSION OF ELECTRICITY BY OT	KWH-T						
446	566-OP	MISCELLANEOUS EXPENSES	T-PLT						
447	567-OP	RENTS	T-354-359						
448									
449		TOTAL TRANSMISSION OPERATION							

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
450	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****											
451	MAINTENANCE											
452	568-MT	SUPERVISION & ENGINEERING	L-568	212,937						212,919		18
453	569-MT	STRUCTURES	T-352	2,060,282						2,060,282		
454	570-MT	STATION EQUIPMENT	T-353	2,927,971						2,927,482		489
455	571-MT	OVERHEAD LINES	T-354-356	3,119,250						3,119,245		5
456	573-MT	MISCELLANEOUS PLANT	T-PLT	5,545						5,544		0
457												
458		TOTAL TRANSMISSION MAINTENANCE		8,325,986								
459												
460		TOTAL TRANSMISSION EXPENSES		36,160,321								
461												
462	REGIONAL MARKET EXPENSES											
463	OPERATION											
464	575 / OPER TRANS MKT ADMIN - EIM		T-100	658,814						658,814		
465												
466		TOTAL REGIONAL MARKET EXPENSES		658,814								
467												
468	DISTRIBUTION EXPENSES				Base-load	Peak						
469												
470	OPERATION											
471	580-OP	SUPERVISION & ENGINEERING	L-580	6,125,235								
472	581-OP	LOAD DISPATCHING	D3601	5,719,617								
473	582-OP	STATION EXPENSES	D362	1,941,646								
474	583-OP	OVERHEAD LINE EXPENSES	D-364-365	5,775,361								
475	584-OP	UNDERGROUND LINE EXPENSES	D-366-367	4,896,899								
476	585-OP	STREET LIGHTING & SIGNAL SYSTEMS	CUSTINST	46,840								
477	586-OP	METER EXPENSES	METER	6,300,993								
478	587-OP	CUSTOMER INSTALLATIONS EXPENSE	CUSTINST	1,145,133								
479	588-OP	MISCELLANEOUS EXPENSES	D3601	4,946,817								
480	589-OP	RENTS	D3601	706,360								
481		TOTAL DISTRIBUTION OPERATION		37,604,900								
482												
483	MAINTENANCE											
484	590-MT	SUPERVISION & ENGINEERING	L-590	12,909								
485	591-MT	STRUCTURES	D361									
486	592-MT	STATION EQUIPMENT	D362	4,398,336								
487	593-MT	OVERHEAD LINES	D-364-365	33,104,169								
488	594-MT	UNDERGROUND LINES	D-366-367	824,825								
489	595-MT	LINE TRANSFORMERS	D368	92,933								
490	596-MT	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT	222,570								
491	597-MT	METERS	METER	949,631								
492	598-MT	MISCELLANEOUS PLANT	CUSTINST	132,362								
493		TOTAL DISTRIBUTION MAINTENANCE		39,737,736								
494												
495		TOTAL DISTRIBUTION EXPENSES		77,342,636								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *				DISTRIBUTION FUNCTION *						
8			ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
450	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****												
451	MAINTENANCE												
452	568-MT	SUPERVISION & ENGINEERING	L-568										
453	569-MT	STRUCTURES	T-352										
454	570-MT	STATION EQUIPMENT	T-353										
455	571-MT	OVERHEAD LINES	T-354-356										
456	573-MT	MISCELLANEOUS PLANT	T-PLT										
457													
458		TOTAL TRANSMISSION MAINTENANCE											
459													
460		TOTAL TRANSMISSION EXPENSES											
461													
462	REGIONAL MARKET EXPENSES												
463	OPERATION												
464	575 / OPER TRANS MKT ADMIN - EIM		T-100										
465													
466		TOTAL REGIONAL MARKET EXPENSES											
467													
468	DISTRIBUTION EXPENSES												
469													
470	OPERATION												
471	580-OP	SUPERVISION & ENGINEERING	L-580	785,039	36,050		1,592,180	789,107	80,250	127,685	63,282	35,386	369,281
472	581-OP	LOAD DISPATCHING	D3601	1,101,147	51,354		1,344,902	666,552	84,044	302,526	149,936	83,842	874,942
473	582-OP	STATION EXPENSES	D362	1,858,243	83,403								
474	583-OP	OVERHEAD LINE EXPENSES	D-364-365				3,567,212	1,767,960	44,608				
475	584-OP	UNDERGROUND LINE EXPENSES	D-366-367				2,884,677	1,429,686	360,208				
476	585-OP	STREET LIGHTING & SIGNAL SYSTEMS	CUSTINST										
477	586-OP	METER EXPENSES	METER										
478	587-OP	CUSTOMER INSTALLATIONS EXPENSE	CUSTINST										
479	588-OP	MISCELLANEOUS EXPENSES	D3601	952,366	44,415		1,163,187	576,492	72,688	261,651	129,678	72,514	756,725
480	589-OP	RENTS	D3601	135,989	6,342		166,092	82,318	10,379	37,361	18,517	10,354	108,053
481		TOTAL DISTRIBUTION OPERATION											
482													
483	MAINTENANCE												
484	590-MT	SUPERVISION & ENGINEERING	L-590	3,743	168		4,774	2,366	91	12	6	3	35
485	591-MT	STRUCTURES	D361										
486	592-MT	STATION EQUIPMENT	D362	4,209,407	188,929								
487	593-MT	OVERHEAD LINES	D-364-365				20,447,135	10,133,887	255,692				
488	594-MT	UNDERGROUND LINES	D-366-367				485,890	240,814	60,673				
489	595-MT	LINE TRANSFORMERS	D368							15,239	7,553	4,223	44,074
490	596-MT	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT										
491	597-MT	METERS	METER										
492	598-MT	MISCELLANEOUS PLANT	CUSTINST										
493		TOTAL DISTRIBUTION MAINTENANCE											
494													
495		TOTAL DISTRIBUTION EXPENSES											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Account	Description	(A) ALLOCATOR	(S) LINE TRANS SEC CUST	(T) SEC LINES DEMAND	(U) SEC LINES CUSTOMER	(V) SERVICES	(W) METERS	(X) STREET LIGHTS	(Y) INSTALLATION CUST PREM
6			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
8			ALLOCATOR	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
450	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****									
451	MAINTENANCE									
452	568-MT	SUPERVISION & ENGINEERING	L-568							
453	569-MT	STRUCTURES	T-352							
454	570-MT	STATION EQUIPMENT	T-353							
455	571-MT	OVERHEAD LINES	T-354-356							
456	573-MT	MISCELLANEOUS PLANT	T-PLT							
457										
458		TOTAL TRANSMISSION MAINTENANCE								
459										
460		TOTAL TRANSMISSION EXPENSES								
461										
462	REGIONAL MARKET EXPENSES									
463	OPERATION									
464	575 / OPER TRANS MKT ADMIN - EIM		T-100							
465										
466		TOTAL REGIONAL MARKET EXPENSES								
467										
468	DISTRIBUTION EXPENSES									
469										
470	OPERATION									
471	580-OP	SUPERVISION & ENGINEERING	L-580	183,021	105,910	52,490	74,030	1,568,096	13,683	249,747
472	581-OP	LOAD DISPATCHING	D3601	433,634	86,189	42,717	175,399	295,232	15,873	11,329
473	582-OP	STATION EXPENSES	D362							
474	583-OP	OVERHEAD LINE EXPENSES	D-364-365		264,494	131,087				
475	584-OP	UNDERGROUND LINE EXPENSES	D-366-367		148,653	73,674				
476	585-OP	STREET LIGHTING & SIGNAL SYSTEMS	CUSTINST							46,840
477	586-OP	METER EXPENSES	METER					6,300,993		
478	587-OP	CUSTOMER INSTALLATIONS EXPENSE	CUSTINST							1,145,133
479	588-OP	MISCELLANEOUS EXPENSES	D3601	375,044	74,544	36,945	151,700	255,342	13,729	9,798
480	589-OP	RENTS	D3601	53,553	10,644	5,275	21,661	36,460	1,960	1,399
481		TOTAL DISTRIBUTION OPERATION								
482										
483	MAINTENANCE									
484	590-MT	SUPERVISION & ENGINEERING	L-590	17	348	172	4	991	179	0
485	591-MT	STRUCTURES	D361							
486	592-MT	STATION EQUIPMENT	D362							
487	593-MT	OVERHEAD LINES	D-364-365		1,516,069	751,385				
488	594-MT	UNDERGROUND LINES	D-366-367		25,039	12,410				
489	595-MT	LINE TRANSFORMERS	D368	21,844						
490	596-MT	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT						222,570	
491	597-MT	METERS	METER					949,631		
492	598-MT	MISCELLANEOUS PLANT	CUSTINST							132,362
493		TOTAL DISTRIBUTION MAINTENANCE								
494										
495		TOTAL DISTRIBUTION EXPENSES								

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
				- - - CUSTOMER ACCOUNTING FUNCTION - - -				***** CUSTOMER INFORMATION FUNCTION *****			
			ALLOCATOR	METER READING	CUSTOMER RECORDS	UNCOLLECT ACCOUNTS	OTHER	CUSTOMER ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
450	****** TABLE 5 - OPERATION & MAINTENANCE EXPENSES ******										
451	MAINTENANCE										
452	568-MT	SUPERVISION & ENGINEERING	L-568								
453	569-MT	STRUCTURES	T-352								
454	570-MT	STATION EQUIPMENT	T-353								
455	571-MT	OVERHEAD LINES	T-354-356								
456	573-MT	MISCELLANEOUS PLANT	T-PLT								
457											
458		TOTAL TRANSMISSION MAINTENANCE									
459											
460		TOTAL TRANSMISSION EXPENSES									
461											
462	REGIONAL MARKET EXPENSES										
463	OPERATION										
464	575 / OPER TRANS MKT ADMIN - EIM		T-100								
465											
466		TOTAL REGIONAL MARKET EXPENSES									
467											
468	DISTRIBUTION EXPENSES										
469											
470	OPERATION										
471	580-OP	SUPERVISION & ENGINEERING	L-580								
472	581-OP	LOAD DISPATCHING	D3601								
473	582-OP	STATION EXPENSES	D362								
474	583-OP	OVERHEAD LINE EXPENSES	D-364-365								
475	584-OP	UNDERGROUND LINE EXPENSES	D-366-367								
476	585-OP	STREET LIGHTING & SIGNAL SYSTEMS	CUSTINST								
477	586-OP	METER EXPENSES	METER								
478	587-OP	CUSTOMER INSTALLATIONS EXPENSE	CUSTINST								
479	588-OP	MISCELLANEOUS EXPENSES	D3601								
480	589-OP	RENTS	D3601								
481		TOTAL DISTRIBUTION OPERATION									
482											
483	MAINTENANCE										
484	590-MT	SUPERVISION & ENGINEERING	L-590								
485	591-MT	STRUCTURES	D361								
486	592-MT	STATION EQUIPMENT	D362								
487	593-MT	OVERHEAD LINES	D-364-365								
488	594-MT	UNDERGROUND LINES	D-366-367								
489	595-MT	LINE TRANSFORMERS	D368								
490	596-MT	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT								
491	597-MT	METERS	METER								
492	598-MT	MISCELLANEOUS PLANT	CUSTINST								
493		TOTAL DISTRIBUTION MAINTENANCE									
494											
495		TOTAL DISTRIBUTION EXPENSES									

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
450	**** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ****								
451	MAINTENANCE								
452	568-MT	SUPERVISION & ENGINEERING	L-568						
453	569-MT	STRUCTURES	T-352						
454	570-MT	STATION EQUIPMENT	T-353						
455	571-MT	OVERHEAD LINES	T-354-356						
456	573-MT	MISCELLANEOUS PLANT	T-PLT						
457									
458		TOTAL TRANSMISSION MAINTENANCE							
459									
460		TOTAL TRANSMISSION EXPENSES							
461									
462	REGIONAL MARKET EXPENSES								
463	OPERATION								
464	575 / OPER TRANS MKT ADMIN - EIM		T-100						
465									
466		TOTAL REGIONAL MARKET EXPENSES							
467									
468	DISTRIBUTION EXPENSES								
469									
470	OPERATION								
471	580-OP	SUPERVISION & ENGINEERING	L-580						
472	581-OP	LOAD DISPATCHING	D3601						
473	582-OP	STATION EXPENSES	D362						
474	583-OP	OVERHEAD LINE EXPENSES	D-364-365						
475	584-OP	UNDERGROUND LINE EXPENSES	D-366-367						
476	585-OP	STREET LIGHTING & SIGNAL SYSTEMS	CUSTINST						
477	586-OP	METER EXPENSES	METER						
478	587-OP	CUSTOMER INSTALLATIONS EXPENSE	CUSTINST						
479	588-OP	MISCELLANEOUS EXPENSES	D3601						
480	589-OP	RENTS	D3601						
481		TOTAL DISTRIBUTION OPERATION							
482									
483	MAINTENANCE								
484	590-MT	SUPERVISION & ENGINEERING	L-590						
485	591-MT	STRUCTURES	D361						
486	592-MT	STATION EQUIPMENT	D362						
487	593-MT	OVERHEAD LINES	D-364-365						
488	594-MT	UNDERGROUND LINES	D-366-367						
489	595-MT	LINE TRANSFORMERS	D368						
490	596-MT	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT						
491	597-MT	METERS	METER						
492	598-MT	MISCELLANEOUS PLANT	CUSTINST						
493		TOTAL DISTRIBUTION MAINTENANCE							
494									
495		TOTAL DISTRIBUTION EXPENSES							

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
496	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***											
497												
498	CUSTOMER ACCOUNTING EXPENSES											
499	901-OP	SUPERVISION	L-901	917,533								
500	902-OP	METER READING	M-READ	1,768,247								
501	903-OP	CUSTOMER RECORDS & COLLECTIONS	C-RECORI	16,063,116								
502	904-OP	UNCOLLECTIBLE ACCOUNTS	UAR	5,389,398								
503	905-OP	MISC CUSTOMER ACCOUNTS EXPENSE	D-902-904	(2,881)								
504		TOTAL CUSTOMER ACCOUNTING EXPENSES		24,135,413								
505	CUSTOMER SERVICES & INFORMATION EXPENSES											
506	907-OP	SUPERVISION	L-907	1,103,115	162,234							
507	908-OP	CUSTOMER ASSISTANCE										
508		ENERGY EFFICIENCY PROGRAMS	PI-H	1,673,332	1,673,332							
509		OTHER	C-ASSIST	9,704,522								
510		TOTAL ACCOUNT 908		11,377,854								
511	909-OP	INFORMATION & INSTRUCTIONAL	C-ASSIST	285,588								
512	910-OP	MISCELLANEOUS EXPENSES	D-908-909	775,684	111,286							
513	912	DEMO AND SELLING EXPENSES	NONE									
514		TOTAL CUST SERV & INFO EXPENSES		13,542,241								
515												
516	ADMINISTRATIVE & GENERAL EXPENSES											
517												
518	920-OP	ADMINISTRATIVE & GENERAL SALARIES	LABOR	85,713,649	36,897,029	1,488,199				10,018,677		893
519	921-OP	OFFICE SUPPLIES	LABOR	14,512,913	6,247,352	251,980				1,696,348		151
520	922-OP	ADMIN & GENERAL EXP TRANSFERRED	LABOR	(38,641,443)	(16,633,925)	(670,910)				(4,516,622)		(403)
521	923-OP	OUTSIDE SERVICES	LABOR	8,352,051	3,595,295	145,012				976,233		87
522												
523	924-OP	PROPERTY INSURANCE										
524		PRODUCTION - STEAM	PI-S	395,764	395,764							
525		ALL RISK & MISCELLANEOUS	P110P-L20	4,725,542	1,483,795	159,944				1,149,860		67
526		TOTAL ACCOUNT 924		5,121,307								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Account	Description	(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *			DISTRIBUTION FUNCTION *						
8			ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
496	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***												
497													
498	CUSTOMER ACCOUNTING EXPENSES												
499	901-OP	SUPERVISION	L-901										
500	902-OP	METER READING	M-READ										
501	903-OP	CUSTOMER RECORDS & COLLECTIONS	C-RECORI										
502	904-OP	UNCOLLECTIBLE ACCOUNTS	UAR										
503	905-OP	MISC CUSTOMER ACCOUNTS EXPENSE	D-902-904										
504		TOTAL CUSTOMER ACCOUNTING EXPENSES											
505	CUSTOMER SERVICES & INFORMATION EXPENSES												
506	907-OP	SUPERVISION	L-907										
507	908-OP	CUSTOMER ASSISTANCE											
508		ENERGY EFFICIENCY PROGRAMS	PI-H										
509		OTHER	C-ASSIST										
510		TOTAL ACCOUNT 908											
511	909-OP	INFORMATION & INSTRUCTIONAL	C-ASSIST										
512	910-OP	MISCELLANEOUS EXPENSES	D-908-909										
513	912	DEMO AND SELLING EXPENSES	NONE										
514		TOTAL CUST SERV & INFO EXPENSES											
515													
516	ADMINISTRATIVE & GENERAL EXPENSES												
517													
518	920-OP	ADMINISTRATIVE & GENERAL SALARIES	LABOR	4,235,199	192,338		7,017,805	3,478,122	270,162	355,876	176,377	98,627	1,029,238
519	921-OP	OFFICE SUPPLIES	LABOR	717,098	32,566		1,188,245	588,911	45,743	60,256	29,864	16,699	174,269
520	922-OP	ADMIN & GENERAL EXP TRANSFERRED	LABOR	(1,909,313)	(86,710)		(3,163,768)	(1,568,008)	(121,794)	(160,436)	(79,514)	(44,463)	(464,001)
521	923-OP	OUTSIDE SERVICES	LABOR	412,683	18,742		683,824	338,913	26,325	34,677	17,186	9,610	100,290
522													
523	924-OP	PROPERTY INSURANCE											
524		PRODUCTION - STEAM	PI-S										
525		ALL RISK & MISCELLANEOUS	P110P-L2(	371,927	17,345		454,258	225,137	28,387	102,182	50,643	28,319	295,523
526		TOTAL ACCOUNT 924											

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Account	Description	(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
496	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***									
497										
498	CUSTOMER ACCOUNTING EXPENSES									
499	901-OP	SUPERVISION	L-901							
500	902-OP	METER READING	M-READ							
501	903-OP	CUSTOMER RECORDS & COLLECTIONS	C-RECORI							
502	904-OP	UNCOLLECTIBLE ACCOUNTS	UAR							
503	905-OP	MISC CUSTOMER ACCOUNTS EXPENSE	D-902-904							
504		TOTAL CUSTOMER ACCOUNTING EXPENSES								
505	CUSTOMER SERVICES & INFORMATION EXPENSES									
506	907-OP	SUPERVISION	L-907							
507	908-OP	CUSTOMER ASSISTANCE								
508		ENERGY EFFICIENCY PROGRAMS	PI-H							
509		OTHER	C-ASSIST							
510		TOTAL ACCOUNT 908								
511	909-OP	INFORMATION & INSTRUCTIONAL	C-ASSIST							
512	910-OP	MISCELLANEOUS EXPENSES	D-908-909							
513	912	DEMO AND SELLING EXPENSES	NONE							
514		TOTAL CUST SERV & INFO EXPENSES								
515										
516	ADMINISTRATIVE & GENERAL EXPENSES									
517										
518	920-OP	ADMINISTRATIVE & GENERAL SALARIES	LABOR	510,105	483,631	239,694	204,389	4,841,196	137,209	683,047
519	921-OP	OFFICE SUPPLIES	LABOR	86,370	81,888	40,585	34,607	819,704	23,232	115,653
520	922-OP	ADMIN & GENERAL EXP TRANSFERRED	LABOR	(229,965)	(218,031)	(108,059)	(92,143)	(2,182,509)	(61,857)	(307,932)
521	923-OP	OUTSIDE SERVICES	LABOR	49,705	47,126	23,356	19,916	471,733	13,370	66,557
522										
523	924-OP	PROPERTY INSURANCE								
524		PRODUCTION - STEAM	PI-S							
525		ALL RISK & MISCELLANEOUS	P110P-L2(	146,465	29,112	14,428	59,243	99,718	5,361	3,827
526		TOTAL ACCOUNT 924								

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Account	Description	(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				***** CUSTOMER INFORMATION FUNCTION *****			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
496	***** TABLE 5 - OPERATION & MAINTENANCE EXPENSES *****										
497											
498	CUSTOMER ACCOUNTING EXPENSES										
499	901-OP	SUPERVISION	L-901	95,868	821,665						
500	902-OP	METER READING	M-READ	1,768,247							
501	903-OP	CUSTOMER RECORDS & COLLECTIONS	C-RECORI		16,063,116						
502	904-OP	UNCOLLECTIBLE ACCOUNTS	UAR			5,389,398					
503	905-OP	MISC CUSTOMER ACCOUNTS EXPENSE	D-902-904	(219)	(1,993)	(669)					
504		TOTAL CUSTOMER ACCOUNTING EXPENSES									
505	CUSTOMER SERVICES & INFORMATION EXPENSES										
506	907-OP	SUPERVISION	L-907					940,881			
507	908-OP	CUSTOMER ASSISTANCE									
508		ENERGY EFFICIENCY PROGRAMS	PI-H								
509		OTHER	C-ASSIST					9,704,522			
510		TOTAL ACCOUNT 908									
511	909-OP	INFORMATION & INSTRUCTIONAL	C-ASSIST					285,588			
512	910-OP	MISCELLANEOUS EXPENSES	D-908-909					664,398			
513	912	DEMO AND SELLING EXPENSES	NONE								
514		TOTAL CUST SERV & INFO EXPENSES									
515											
516	ADMINISTRATIVE & GENERAL EXPENSES										
517											
518	920-OP	ADMINISTRATIVE & GENERAL SALARIES	LABOR	972,917	8,338,669			4,044,248			
519	921-OP	OFFICE SUPPLIES	LABOR	164,733	1,411,892			684,766			
520	922-OP	ADMIN & GENERAL EXP TRANSFERRED	LABOR	(438,610)	(3,759,240)			(1,823,229)			
521	923-OP	OUTSIDE SERVICES	LABOR	94,802	812,531			394,077			
522											
523	924-OP	PROPERTY INSURANCE									
524		PRODUCTION - STEAM	PI-S								
525		ALL RISK & MISCELLANEOUS	P110P-L20								
526		TOTAL ACCOUNT 924									

Line	Acct	Description	(A) ALLOCATOF	(AH) DEMAND	(AI) ENERGY	(AJ) CUSTOMER	(AK) REVENUE	(AL) OTHER	(AM) INC TAXES & REVENUES TRANSFER
1						IDAHO POWER COMPANY			
2						BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION			
3						CLASS COST OF SERVICE STUDY			
4						FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023			
5						FUNCTIONALIZATION AND CLASSIFICATION OF COSTS			
6			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
496	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***								
497									
498	CUSTOMER ACCOUNTING EXPENSES								
499	901-OP	SUPERVISION	L-901						
500	902-OP	METER READING	M-READ						
501	903-OP	CUSTOMER RECORDS & COLLECTIONS	C-RECORI						
502	904-OP	UNCOLLECTIBLE ACCOUNTS	UAR						
503	905-OP	MISC CUSTOMER ACCOUNTS EXPENSE	D-902-904						
504		TOTAL CUSTOMER ACCOUNTING EXPENSES							
505	CUSTOMER SERVICES & INFORMATION EXPENSES								
506	907-OP	SUPERVISION	L-907						
507	908-OP	CUSTOMER ASSISTANCE							
508		ENERGY EFFICIENCY PROGRAMS	PI-H						
509		OTHER	C-ASSIST						
510		TOTAL ACCOUNT 908							
511	909-OP	INFORMATION & INSTRUCTIONAL	C-ASSIST						
512	910-OP	MISCELLANEOUS EXPENSES	D-908-909						
513	912	DEMO AND SELLING EXPENSES	NONE						
514		TOTAL CUST SERV & INFO EXPENSES							
515									
516	ADMINISTRATIVE & GENERAL EXPENSES								
517									
518	920-OP	ADMINISTRATIVE & GENERAL SALARIES	LABOR						
519	921-OP	OFFICE SUPPLIES	LABOR						
520	922-OP	ADMIN & GENERAL EXP TRANSFERRED	LABOR						
521	923-OP	OUTSIDE SERVICES	LABOR						
522									
523	924-OP	PROPERTY INSURANCE							
524		PRODUCTION - STEAM	PI-S						
525		ALL RISK & MISCELLANEOUS	P110P-L2(						
526		TOTAL ACCOUNT 924							

Line	Acct	Description	Allocator	Totals	Demand Base-load	Demand Peak		Energy	Demand Power Sup	Demand Trans	Demand Subtrans	Demand Direct
1							IDAHO POWER COMPANY					
2							BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION					
3							CLASS COST OF SERVICE STUDY					
4							FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023					
5							FUNCTIONALIZATION AND CLASSIFICATION OF COSTS					
6			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS		* * PRODUCTION FUNCTION * *			- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
527	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***											
528												
529	925-OP	INJURIES & DAMAGES	LABOR	11,358,326	4,889,402	197,208				1,327,623		118
530	926-OP	EMPLOYEE PENSIONS & BENEFITS	LABOR	74,961,492	32,268,564	1,301,515				8,761,907		781
531	927-OP	FRANCHISE REQUIREMENTS	P101P									
532												
533	928-OP	REGULATORY COMMISSION EXPENSES										
534		FERC ADMIN ASSESS & SECURITIES										
535		CAPACITY RELATED	PI-SHO	2,711,513	2,477,997	233,516						
536		ENERGY RELATED	KWH-T	921,198				921,198				
537		FERC RATE CASE	T-PLT									
538		FERC ORDER 472	KWH-O	924,547				924,547				
539		FERC OTHER	T-100	104,606						104,606		
540		FERC - OREGON HYDRO FEE	PI-HO	260,632	232,325	28,307						
541		SEC EXPENSES	NONE									
542		IDAHO PUC -RATE CASE	OTH-EXP									
543		-OTHER	OTH-EXP	332,773								
544		OREGON PUC -RATE CASE	OTH-EXP									
545		-OTHER	OTH-EXP									
546		TOTAL ACCOUNT 928		5,255,269								
547												
548	929-OP	DUPLICATE CHARGES-CR	LABOR									
549	9301-OP	GENERAL ADVERTISING	LABOR									
550	9302-OP	MISCELLANEOUS EXPENSES	LABOR	3,870,432	1,666,099	67,200				452,397		40
551	931-OP	RENTS	L GEN-PLT									
552		TOTAL ADM & GEN OPERATION		170,503,996								
553												
554	935-MT	GENERAL PLANT MAINTENANCE	L GEN-PLT	7,723,111	2,654,017	250,103				1,798,027		106
555												
556		TOTAL ADMIN & GENERAL EXPENSES		178,227,107								
557												
558	416	MERCHANDISING EXPENSE	M-EXP	4,523,796				10,097				
559												
560		TOTAL OPER & MAINT EXPENSES		888,823,963	138,136,693	16,516,367		492,817,416		48,778,156		3,521
561												

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *	DISTRIBUTION FUNCTION	* *							
8			ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
527	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***												
528													
529	925-OP	INJURIES & DAMAGES	LABOR	561,227	25,488		929,963	460,903	35,800	47,159	23,373	13,070	136,389
530	926-OP	EMPLOYEE PENSIONS & BENEFITS	LABOR	3,703,924	168,210		6,137,472	3,041,817	236,272	311,234	154,252	86,255	900,127
531	927-OP	FRANCHISE REQUIREMENTS	P101P										
532													
533	928-OP	REGULATORY COMMISSION EXPENSES											
534		FERC ADMIN ASSESS & SECURITIES											
535		CAPACITY RELATED	PI-SHO										
536		ENERGY RELATED	KWH-T										
537		FERC RATE CASE	T-PLT										
538		FERC ORDER 472	KWH-O										
539		FERC OTHER	T-100										
540		FERC - OREGON HYDRO FEE	PI-HO										
541		SEC EXPENSES	NONE										
542		IDAHO PUC -RATE CASE	OTH-EXP										
543		-OTHER	OTH-EXP										
544		OREGON PUC -RATE CASE	OTH-EXP										
545		-OTHER	OTH-EXP										
546		TOTAL ACCOUNT 928											
547													
548	929-OP	DUPLICATE CHARGES-CR	LABOR										
549	9301-OP	GENERAL ADVERTISING	LABOR										
550	9302-OP	MISCELLANEOUS EXPENSES	LABOR	191,242	8,685		316,892	157,056	12,199	16,070	7,964	4,454	46,476
551	931-OP	RENTS	L GEN-PLT										
552		TOTAL ADM & GEN OPERATION											
553													
554	935-MT	GENERAL PLANT MAINTENANCE	L GEN-PLT	581,579	27,123		710,320	352,045	44,388	159,781	79,190	44,282	462,107
555													
556		TOTAL ADMIN & GENERAL EXPENSES											
557													
558	416	MERCHANDISING EXPENSE	M-EXP				1,421,031	704,283	88,801	319,651	158,423	88,588	924,469
559													
560		TOTAL OPER & MAINT EXPENSES		17,911,499	814,448		47,352,090	23,468,360	1,634,918	1,990,925	986,730	551,763	5,757,998
561													

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *	DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *				
8			ALLOCATOR	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
527	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***									
528										
529	925-OP	INJURIES & DAMAGES	LABOR	67,596	64,088	31,763	27,085	641,530	18,182	90,514
530	926-OP	EMPLOYEE PENSIONS & BENEFITS	LABOR	446,116	422,963	209,626	178,750	4,233,903	119,997	597,364
531	927-OP	FRANCHISE REQUIREMENTS	P101P							
532										
533	928-OP	REGULATORY COMMISSION EXPENSES								
534		FERC ADMIN ASSESS & SECURITIES								
535		CAPACITY RELATED	PI-SHO							
536		ENERGY RELATED	KWH-T							
537		FERC RATE CASE	T-PLT							
538		FERC ORDER 472	KWH-O							
539		FERC OTHER	T-100							
540		FERC - OREGON HYDRO FEE	PI-HO							
541		SEC EXPENSES	NONE							
542		IDAHO PUC -RATE CASE	OTH-EXP							
543		-OTHER	OTH-EXP							
544		OREGON PUC -RATE CASE	OTH-EXP							
545		-OTHER	OTH-EXP							
546		TOTAL ACCOUNT 928								
547										
548	929-OP	DUPLICATE CHARGES-CR	LABOR							
549	9301-OP	GENERAL ADVERTISING	LABOR							
550	9302-OP	MISCELLANEOUS EXPENSES	LABOR	23,034	21,839	10,823	9,229	218,606	6,196	30,843
551	931-OP	RENTS	L GEN-PLT							
552		TOTAL ADM & GEN OPERATION								
553										
554	935-MT	GENERAL PLANT MAINTENANCE	L GEN-PLT	229,027	45,522	22,561	92,639	155,929	8,384	5,984
555										
556		TOTAL ADMIN & GENERAL EXPENSES								
557										
558	416	MERCHANDISING EXPENSE	M-EXP	458,180	91,068	45,135	185,328		16,772	11,970
559										
560		TOTAL OPER & MAINT EXPENSES		2,853,745	3,301,093	1,636,068	1,141,837	18,706,555	554,840	2,894,436
561										

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Account	Description	(A) ALLOCATOF	(Z) METER READING	(AA) CUSTOMER RECORDS	(AB) UNCOLLECT ACCOUNTS	(AC) OTHER	(AD) CUSTOMER ASSISTANCE	(AE) DEMONSTR	(AF) ADVERTISING	(AG) OTHER
				- - - CUSTOMER ACCOUNTING FUNCTION			- - -	***** CUSTOMER INFORMATION FUNCTION *****			
527	*** TABLE 5 - OPERATION & MAINTENANCE EXPENSES ***										
528											
529	925-OP	INJURIES & DAMAGES	LABOR	128,926	1,104,997			535,923			
530	926-OP	EMPLOYEE PENSIONS & BENEFITS	LABOR	850,871	7,292,644			3,536,926			
531	927-OP	FRANCHISE REQUIREMENTS	P101P								
532											
533	928-OP	REGULATORY COMMISSION EXPENSES									
534		FERC ADMIN ASSESS & SECURITIES									
535		CAPACITY RELATED	PI-SHO								
536		ENERGY RELATED	KWH-T								
537		FERC RATE CASE	T-PLT								
538		FERC ORDER 472	KWH-O								
539		FERC OTHER	T-100								
540		FERC - OREGON HYDRO FEE	PI-HO								
541		SEC EXPENSES	NONE								
542		IDAHO PUC -RATE CASE	OTH-EXP								
543		-OTHER	OTH-EXP								
544		OREGON PUC -RATE CASE	OTH-EXP								
545		-OTHER	OTH-EXP								
546		TOTAL ACCOUNT 928									
547											
548	929-OP	DUPLICATE CHARGES-CR	LABOR								
549	9301-OP	GENERAL ADVERTISING	LABOR								
550	9302-OP	MISCELLANEOUS EXPENSES	LABOR	43,932	376,536			182,620			
551	931-OP	RENTS	L GEN-PLT								
552		TOTAL ADM & GEN OPERATION									
553											
554	935-MT	GENERAL PLANT MAINTENANCE	L GEN-PLT								
555											
556		TOTAL ADMIN & GENERAL EXPENSES									
557											
558	416	MERCHANDISING EXPENSE	M-EXP								
559											
560		TOTAL OPER & MAINT EXPENSES		3,681,466	32,460,816	5,388,730		19,150,720			
561											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Account	Description		(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7					- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8				ALLOCATOF						& REVENUES
9					DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
527	*** * * TABLE 5 - OPERATION & MAINTENANCE EXPENSES * * ***									
528										
529	925-OP	INJURIES & DAMAGES		LABOR						
530	926-OP	EMPLOYEE PENSIONS & BENEFITS		LABOR						
531	927-OP	FRANCHISE REQUIREMENTS		P101P						
532										
533	928-OP	REGULATORY COMMISSION EXPENSES								
534		FERC ADMIN ASSESS & SECURITIES								
535		CAPACITY RELATED		PI-SHO						
536		ENERGY RELATED		KWH-T						
537		FERC RATE CASE		T-PLT						
538		FERC ORDER 472		KWH-O						
539		FERC OTHER		T-100						
540		FERC - OREGON HYDRO FEE		PI-HO						
541		SEC EXPENSES		NONE						
542		IDAHO PUC -RATE CASE		OTH-EXP						
543		-OTHER		OTH-EXP					332,773	
544		OREGON PUC -RATE CASE		OTH-EXP						
545		-OTHER		OTH-EXP						
546		TOTAL ACCOUNT 928								
547										
548	929-OP	DUPLICATE CHARGES-CR		LABOR						
549	9301-OP	GENERAL ADVERTISING		LABOR						
550	9302-OP	MISCELLANEOUS EXPENSES		LABOR						
551	931-OP	RENTS	L	GEN-PLT						
552		TOTAL ADM & GEN OPERATION								
553										
554	935-MT	GENERAL PLANT MAINTENANCE	L	GEN-PLT						
555										
556		TOTAL ADMIN & GENERAL EXPENSES								
557										
558	416	MERCHANDISING EXPENSE		M-EXP						
559										
560		TOTAL OPER & MAINT EXPENSES							332,773	
561										

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS		* * PRODUCTION FUNCTION * *			- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
562	**** * * TABLE 6 - DEPRECIATION & AMORTIZATION EXPENSE * * ****											
563												
564	DEPRECIATION EXPENSE											
565	310-316	STEAM PRODUCTION	PI-S	9,212,961	9,212,961							
566	330-336	HYDRAULIC PRODUCTION	PI-H	24,324,647	24,324,647							
567	340-346	OTHER PRODUCTION (BASELOAD)	PI-S	13,251,245	13,251,245							
568	340-346	OTHER PRODUCTION (PEAKERS)	PI-O	5,921,482		5,921,482						
569		TOTAL PRODUCTION PLANT		52,710,336								
570												
571	TRANSMISSION PLANT											
572	350	LAND & LAND RIGHTS	T-350	399,371						399,371		
573	352	STRUCTURES & IMPROVEMENTS	T-352	1,842,519						1,842,519		
574	353	STATION EQUIPMENT	T-353	9,871,275						9,869,626		1,650
575	354	TOWERS & FIXTURES	T-354	2,772,265						2,772,265		
576	355	POLES & FIXTURES	T-355	5,903,489						5,903,489		
577	356	OVERHEAD CONDUCTORS & DEVICES	T-356	3,930,824						3,930,806		18
578	359	ROADS & TRAILS	T-359	2,583						2,583		
579		TOTAL TRANSMISSION PLANT		24,722,326								
580												
581	DISTRIBUTION PLANT											
582	360	LAND & LAND RIGHTS	D360N	29,909								
583	361	STRUCTURES & IMPROVEMENTS	D361N	1,323,816								
584	362	STATION EQUIPMENT	D362N	6,442,540								
585	363	STORAGE BATTERY EQUIPMENT	PI-S	8,383,489	8,383,489							
586	364	POLES, TOWERS & FIXTURES	D364	6,133,059								
587	365	OVERHEAD CONDUCTORS & DEVICES	D365	3,477,165								
588	366	UNDERGROUND CONDUIT	D366	1,307,020								
589	367	UNDERGROUND CONDUCTORS & DEVI(	D367	7,813,424								
590	368	LINE TRANSFORMERS	D368	13,756,994								
591	369	SERVICES	SERVICE	1,118,272								
592	370	METERS	METER	5,718,060								
593	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST	180,039								
594	373	STREET LIGHTING SYSTEMS	STLIGHT	208,773								
595		TOTAL DISTRIBUTION PLANT		55,892,559								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *			DISTRIBUTION FUNCTION	* *					
8			ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
562	**** * * TABLE 6 - DEPRECIATION & AMORTIZATION EXPENSE ****												
563													
564	DEPRECIATION EXPENSE												
565	310-316	STEAM PRODUCTION	PI-S										
566	330-336	HYDRAULIC PRODUCTION	PI-H										
567	340-346	OTHER PRODUCTION (BASELOAD)	PI-S										
568	340-346	OTHER PRODUCTION (PEAKERS)	PI-O										
569		TOTAL PRODUCTION PLANT											
570													
571	TRANSMISSION PLANT												
572	350	LAND & LAND RIGHTS	T-350										
573	352	STRUCTURES & IMPROVEMENTS	T-352										
574	353	STATION EQUIPMENT	T-353										
575	354	TOWERS & FIXTURES	T-354										
576	355	POLES & FIXTURES	T-355										
577	356	OVERHEAD CONDUCTORS & DEVICES	T-356										
578	359	ROADS & TRAILS	T-359										
579		TOTAL TRANSMISSION PLANT											
580													
581	DISTRIBUTION PLANT												
582	360	LAND & LAND RIGHTS	D360N	29,909	0								
583	361	STRUCTURES & IMPROVEMENTS	D361N	1,311,337	12,478								
584	362	STATION EQUIPMENT	D362N	6,371,385	71,155								
585	363	STORAGE BATTERY EQUIPMENT	PI-S										
586	364	POLES, TOWERS & FIXTURES	D364				3,840,542	1,903,427	42,753				
587	365	OVERHEAD CONDUCTORS & DEVICES	D365				2,088,062	1,034,873	32,114				
588	366	UNDERGROUND CONDUIT	D366				621,627	308,087	158,384				
589	367	UNDERGROUND CONDUCTORS & DEVIC	D367				4,746,136	2,352,252	514,570				
590	368	LINE TRANSFORMERS	D368							2,255,892	1,118,052	625,195	6,524,314
591	369	SERVICES	SERVICE										
592	370	METERS	METER										
593	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST										
594	373	STREET LIGHTING SYSTEMS	STLIGHT										
595		TOTAL DISTRIBUTION PLANT											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *	DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *				
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
562	**** * * TABLE 6 - DEPRECIATION & AMORTIZATION EXPENSE ****									
563										
564	DEPRECIATION EXPENSE									
565	310-316	STEAM PRODUCTION	PI-S							
566	330-336	HYDRAULIC PRODUCTION	PI-H							
567	340-346	OTHER PRODUCTION (BASELOAD)	PI-S							
568	340-346	OTHER PRODUCTION (PEAKERS)	PI-O							
569		TOTAL PRODUCTION PLANT								
570										
571	TRANSMISSION PLANT									
572	350	LAND & LAND RIGHTS	T-350							
573	352	STRUCTURES & IMPROVEMENTS	T-352							
574	353	STATION EQUIPMENT	T-353							
575	354	TOWERS & FIXTURES	T-354							
576	355	POLES & FIXTURES	T-355							
577	356	OVERHEAD CONDUCTORS & DEVICES	T-356							
578	359	ROADS & TRAILS	T-359							
579		TOTAL TRANSMISSION PLANT								
580										
581	DISTRIBUTION PLANT									
582	360	LAND & LAND RIGHTS	D360N							
583	361	STRUCTURES & IMPROVEMENTS	D361N							
584	362	STATION EQUIPMENT	D362N							
585	363	STORAGE BATTERY EQUIPMENT	PI-S							
586	364	POLES, TOWERS & FIXTURES	D364		231,568	114,769				
587	365	OVERHEAD CONDUCTORS & DEVICES	D365		215,374	106,742				
588	366	UNDERGROUND CONDUIT	D366		146,375	72,546				
589	367	UNDERGROUND CONDUCTORS & DEVIC	D367		134,036	66,430				
590	368	LINE TRANSFORMERS	D368	3,233,542						
591	369	SERVICES	SERVICE				1,118,272			
592	370	METERS	METER					5,718,060		
593	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST							180,039
594	373	STREET LIGHTING SYSTEMS	STLIGHT						208,773	
595		TOTAL DISTRIBUTION PLANT								

1 **IDAHO POWER COMPANY**
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5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line												
6			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * *			
8			ALLOCATOF	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
562	**** * * TABLE 6 - DEPRECIATION & AMORTIZATION EXPENSE ****										
563											
564	DEPRECIATION EXPENSE										
565	310-316	STEAM PRODUCTION	PI-S								
566	330-336	HYDRAULIC PRODUCTION	PI-H								
567	340-346	OTHER PRODUCTION (BASELOAD)	PI-S								
568	340-346	OTHER PRODUCTION (PEAKERS)	PI-O								
569		TOTAL PRODUCTION PLANT									
570											
571	TRANSMISSION PLANT										
572	350	LAND & LAND RIGHTS	T-350								
573	352	STRUCTURES & IMPROVEMENTS	T-352								
574	353	STATION EQUIPMENT	T-353								
575	354	TOWERS & FIXTURES	T-354								
576	355	POLES & FIXTURES	T-355								
577	356	OVERHEAD CONDUCTORS & DEVICES	T-356								
578	359	ROADS & TRAILS	T-359								
579		TOTAL TRANSMISSION PLANT									
580											
581	DISTRIBUTION PLANT										
582	360	LAND & LAND RIGHTS	D360N								
583	361	STRUCTURES & IMPROVEMENTS	D361N								
584	362	STATION EQUIPMENT	D362N								
585	363	STORAGE BATTERY EQUIPMENT	PI-S								
586	364	POLES, TOWERS & FIXTURES	D364								
587	365	OVERHEAD CONDUCTORS & DEVICES	D365								
588	366	UNDERGROUND CONDUIT	D366								
589	367	UNDERGROUND CONDUCTORS & DEVIC	D367								
590	368	LINE TRANSFORMERS	D368								
591	369	SERVICES	SERVICE								
592	370	METERS	METER								
593	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST								
594	373	STREET LIGHTING SYSTEMS	STLIGHT								
595		TOTAL DISTRIBUTION PLANT									

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Acct	Description	(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
562	**** * * TABLE 6 - DEPRECIATION & AMORTIZATION EXPENSE ****								
563									
564	DEPRECIATION EXPENSE								
565	310-316	STEAM PRODUCTION	PI-S						
566	330-336	HYDRAULIC PRODUCTION	PI-H						
567	340-346	OTHER PRODUCTION (BASELOAD)	PI-S						
568	340-346	OTHER PRODUCTION (PEAKERS)	PI-O						
569		TOTAL PRODUCTION PLANT							
570									
571	TRANSMISSION PLANT								
572	350	LAND & LAND RIGHTS	T-350						
573	352	STRUCTURES & IMPROVEMENTS	T-352						
574	353	STATION EQUIPMENT	T-353						
575	354	TOWERS & FIXTURES	T-354						
576	355	POLES & FIXTURES	T-355						
577	356	OVERHEAD CONDUCTORS & DEVICES	T-356						
578	359	ROADS & TRAILS	T-359						
579		TOTAL TRANSMISSION PLANT							
580									
581	DISTRIBUTION PLANT								
582	360	LAND & LAND RIGHTS	D360N						
583	361	STRUCTURES & IMPROVEMENTS	D361N						
584	362	STATION EQUIPMENT	D362N						
585	363	STORAGE BATTERY EQUIPMENT	PI-S						
586	364	POLES, TOWERS & FIXTURES	D364						
587	365	OVERHEAD CONDUCTORS & DEVICES	D365						
588	366	UNDERGROUND CONDUIT	D366						
589	367	UNDERGROUND CONDUCTORS & DEVIC	D367						
590	368	LINE TRANSFORMERS	D368						
591	369	SERVICES	SERVICE						
592	370	METERS	METER						
593	371	INSTALLATIONS ON CUSTOMER PREMIS	CUSTINST						
594	373	STREET LIGHTING SYSTEMS	STLIGHT						
595		TOTAL DISTRIBUTION PLANT							

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
596	**** * * TABLE 6 - DEPRECIATION & AMORTIZATION EXPENSE * * ****											
597												
598	GENERAL PLANT											
599	389	LAND & LAND RIGHTS	P-PTD									
600	390	STRUCTURES & IMPROVEMENTS	P-PTD	3,220,402	1,106,678	104,289				749,746		44
601	391	OFFICE FURNITURE & EQUIPMENT	P-PTD	6,688,226	2,298,383	216,590				1,557,094		91
602	392	TRANSPORTATION EQUIPMENT	P-PTD	69,294	23,813	2,244				16,132		1
603	393	STORES EQUIPMENT	P-PTD	217,528	74,753	7,044				50,643		3
604	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD	773,482	265,804	25,048				180,075		11
605	395	LABORATORY EQUIPMENT	P-PTD	747,582	256,904	24,210				174,045		10
606	396	POWER OPERATED EQUIPMENT	P-PTD									
607	397	COMMUNICATIONS EQUIPMENT	P-PTD	5,370,906	1,845,691	173,930				1,250,407		73
608	398	MISCELLANEOUS EQUIPMENT	P-PTD	823,363	282,946	26,664				191,688		11
609		TOTAL GENERAL PLANT		17,910,784								
610												
611	DEPRECIATION ON DISALLOWED COSTS		P101P	(283,814)	(97,532)	(9,191)				(66,075)		(4)
612		TOTAL DEPRECIATION EXPENSE		150,952,190	61,229,781	6,492,310				28,824,414		1,909
613												
614	AMORTIZATION EXPENSE											
615		302/FRANCHISES AND CONSENTS	P101P	1,480,576	508,794	47,947				344,695		20
616		303/MISCELLANEOUS INTANGIBLE PLAN	PI-H	4,230,438	4,230,438							
617		ADJUSTMENTS, GAINS & LOSSES	P101P	14,385	4,943	466				3,349		0
618		TOTAL AM0RTIZATION EXPENSE		5,725,400	4,744,176	48,412				348,044		20
619												
620		TOTAL DEPRECIATION & AM0RTIZATION EXP		156,677,590	65,973,958	6,540,722				29,172,458		1,929
621												

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Acct	Description	(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *				DISTRIBUTION FUNCTION *					
8			ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
596	**** * * TABLE 6 - DEPRECIATION & AMORTIZATION EXPENSE ****												
597													
598	GENERAL PLANT												
599	389	LAND & LAND RIGHTS	P-PTD										
600	390	STRUCTURES & IMPROVEMENTS	P-PTD	242,508	11,310		296,191	146,796	18,509	66,626	33,021	18,465	192,691
601	391	OFFICE FURNITURE & EQUIPMENT	P-PTD	503,648	23,488		615,138	304,871	38,440	138,371	68,579	38,348	400,186
602	392	TRANSPORTATION EQUIPMENT	P-PTD	5,218	243		6,373	3,159	398	1,434	711	397	4,146
603	393	STORES EQUIPMENT	P-PTD	16,381	764		20,007	9,916	1,250	4,500	2,230	1,247	13,016
604	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD	58,246	2,716		71,140	35,258	4,446	16,002	7,931	4,435	46,281
605	395	LABORATORY EQUIPMENT	P-PTD	56,296	2,625		68,758	34,077	4,297	15,467	7,665	4,286	44,731
606	396	POWER OPERATED EQUIPMENT	P-PTD										
607	397	COMMUNICATIONS EQUIPMENT	P-PTD	404,449	18,862		493,980	244,823	30,869	111,117	55,071	30,795	321,365
608	398	MISCELLANEOUS EQUIPMENT	P-PTD	62,002	2,892		75,727	37,532	4,732	17,034	8,442	4,721	49,265
609		TOTAL GENERAL PLANT											
610													
611	DEPRECIATION ON DISALLOWED COSTS		P101P	(21,372)	(997)		(26,103)	(12,937)	(1,631)	(5,872)	(2,910)	(1,627)	(16,982)
612		TOTAL DEPRECIATION EXPENSE		9,040,007	145,538		12,917,578	6,402,133	849,132	2,620,571	1,298,792	726,262	7,579,012
613													
614	AMORTIZATION EXPENSE												
615		302/FRANCHISES AND CONSENTS	P101P	111,493	5,200		136,173	67,489	8,510	30,631	15,181	8,489	88,589
616		303/MISCELLANEOUS INTANGIBLE PLAN	PI-H										
617		ADJUSTMENTS, GAINS & LOSSES	P101P	1,083	51		1,323	656	83	298	148	82	861
618		TOTAL AM0RTIZATION EXPENSE		112,576	5,250		137,497	68,145	8,592	30,929	15,329	8,572	89,450
619													
620		TOTAL DEPRECIATION & AM0RTIZATION EXP		9,152,583	150,788		13,055,074	6,470,278	857,725	2,651,500	1,314,121	734,834	7,668,462
621													

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
8			ALLOCATOR	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
596	**** * * TABLE 6 - DEPRECIATION & AMORTIZATION EXPENSE ****									
597										
598	GENERAL PLANT									
599	389	LAND & LAND RIGHTS	P-PTD							
600	390	STRUCTURES & IMPROVEMENTS	P-PTD	95,500	18,982	9,408	38,629	65,020	3,496	2,495
601	391	OFFICE FURNITURE & EQUIPMENT	P-PTD	198,338	39,422	19,538	80,225	135,035	7,260	5,182
602	392	TRANSPORTATION EQUIPMENT	P-PTD	2,055	408	202	831	1,399	75	54
603	393	STORES EQUIPMENT	P-PTD	6,451	1,282	635	2,609	4,392	236	169
604	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD	22,937	4,559	2,260	9,278	15,617	840	599
605	395	LABORATORY EQUIPMENT	P-PTD	22,169	4,406	2,184	8,967	15,094	812	579
606	396	POWER OPERATED EQUIPMENT	P-PTD							
607	397	COMMUNICATIONS EQUIPMENT	P-PTD	159,273	31,657	15,690	64,424	108,438	5,830	4,161
608	398	MISCELLANEOUS EQUIPMENT	P-PTD	24,417	4,853	2,405	9,876	16,624	894	638
609		TOTAL GENERAL PLANT								
610										
611	DEPRECIATION ON DISALLOWED COSTS		P101P	(8,416)	(1,673)	(829)	(3,404)	(5,730)	(308)	(220)
612		TOTAL DEPRECIATION EXPENSE		3,756,265	831,250	411,979	1,329,707	6,073,947	227,907	193,695
613										
614	AMORTIZATION EXPENSE									
615		302/FRANCHISES AND CONSENTS	P101P	43,906	8,727	4,325	17,759	29,893	1,607	1,147
616		303/MISCELLANEOUS INTANGIBLE PLAN	PI-H							
617		ADJUSTMENTS, GAINS & LOSSES	P101P	427	85	42	173	290	16	11
618		TOTAL AM0RTIZATION EXPENSE		44,333	8,812	4,367	17,932	30,183	1,623	1,158
619										
620		TOTAL DEPRECIATION & AM0RTIZATION EXP		3,800,597	840,062	416,347	1,347,639	6,104,130	229,530	194,854
621										

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION			- - -	* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
596	**** * * TABLE 6 - DEPRECIATION & AMORTIZATION EXPENSE ****										
597											
598	GENERAL PLANT										
599	389	LAND & LAND RIGHTS	P-PTD								
600	390	STRUCTURES & IMPROVEMENTS	P-PTD								
601	391	OFFICE FURNITURE & EQUIPMENT	P-PTD								
602	392	TRANSPORTATION EQUIPMENT	P-PTD								
603	393	STORES EQUIPMENT	P-PTD								
604	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD								
605	395	LABORATORY EQUIPMENT	P-PTD								
606	396	POWER OPERATED EQUIPMENT	P-PTD								
607	397	COMMUNICATIONS EQUIPMENT	P-PTD								
608	398	MISCELLANEOUS EQUIPMENT	P-PTD								
609		TOTAL GENERAL PLANT									
610											
611	DEPRECIATION ON DISALLOWED COSTS		P101P								
612		TOTAL DEPRECIATION EXPENSE									
613											
614	AMORTIZATION EXPENSE										
615		302/FRANCHISES AND CONSENTS	P101P								
616		303/MISCELLANEOUS INTANGIBLE PLAN	PI-H								
617		ADJUSTMENTS, GAINS & LOSSES	$\boxed{\text{P101P}}$								
618		TOTAL AM0RTIZATION EXPENSE									
619											
620		TOTAL DEPRECIATION & AM0RTIZATION EXP									
621											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
596	**** * * TABLE 6 - DEPRECIATION & AMORTIZATION EXPENSE ****								
597									
598	GENERAL PLANT								
599	389	LAND & LAND RIGHTS	P-PTD						
600	390	STRUCTURES & IMPROVEMENTS	P-PTD						
601	391	OFFICE FURNITURE & EQUIPMENT	P-PTD						
602	392	TRANSPORTATION EQUIPMENT	P-PTD						
603	393	STORES EQUIPMENT	P-PTD						
604	394	TOOLS, SHOP & GARAGE EQUIPMENT	P-PTD						
605	395	LABORATORY EQUIPMENT	P-PTD						
606	396	POWER OPERATED EQUIPMENT	P-PTD						
607	397	COMMUNICATIONS EQUIPMENT	P-PTD						
608	398	MISCELLANEOUS EQUIPMENT	P-PTD						
609		TOTAL GENERAL PLANT							
610									
611	DEPRECIATION ON DISALLOWED COSTS		P101P						
612		TOTAL DEPRECIATION EXPENSE							
613									
614	AMORTIZATION EXPENSE								
615		302/FRANCHISES AND CONSENTS	P101P						
616		303/MISCELLANEOUS INTANGIBLE PLAN	PI-H						
617		ADJUSTMENTS, GAINS & LOSSES	P101P						
618		TOTAL AM0RTIZATION EXPENSE							
619									
620		TOTAL DEPRECIATION & AM0RTIZATION EXP							
621									

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7			TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8		ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9				Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
622	**** * * TABLE 7 - TAXES OTHER THAN INCOME TAXES * * ****										
623											
624	TAXES OTHER THAN INCOME										
625	FEDERAL TAXES	NONE									
626	FICA	LABOR									
627	FUTA	LABOR									
628	LESS PAYROLL DEDUCTION	LABOR									
629											
630	STATE TAXES										
631	AD VALOREM TAXES										
632	JIM BRIDGER STATION	PI-S									
633	VALMY	PI-S									
634	OTHER-PRODUCTION PLANT	PI-HO	7,828,388	6,978,158	850,229						
635	OTHER-TRANSMISSION PLANT	T-PLT	6,547,695						6,547,311		384
636	OTHER-DISTRIBUTION PLANT	D3602N	8,749,620								
637	OTHER-GENERAL PLANT	GEN-PLT	1,735,401	596,364	56,199				404,021		24
638											
639	LICENSES - HYDRO PROJECTS	PI-H	4,067	4,067							
640											
641	REGULATORY COMMISSION FEES										
642	STATE OF IDAHO	P101P	2,616,251	899,064	84,724				609,093		36
643	STATE OF OREGON	NONE									
644											
645	FRANCHISE TAXES										
646	STATE OF OREGON	NONE									
647											
648	OTHER STATE TAXES										
649	UNEMPLOYMENT TAXES	NONE									
650	HYDRO GENERATION TAX	KWH-TAX	1,806,165								
651	IRRIGATION-PIC	KWH-TAX	313,744								
652											
653	TOTAL TAXES OTHER THAN INCOME		29,601,331	8,477,654	991,152				7,560,424		444

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line												
6		(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7			* DISTRIBUTION FUNCTION *									
8		ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9			GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
622	**** * * TABLE 7 - TAXES OTHER THAN INCOME TAXES * * ****											
623												
624	TAXES OTHER THAN INCOME											
625	FEDERAL TAXES	NONE										
626	FICA	LABOR										
627	FUTA	LABOR										
628	LESS PAYROLL DEDUCTION	LABOR										
629												
630	STATE TAXES											
631	AD VALOREM TAXES											
632	JIM BRIDGER STATION	PI-S										
633	VALMY	PI-S										
634	OTHER-PRODUCTION PLANT	PI-HO										
635	OTHER-TRANSMISSION PLANT	T-PLT										
636	OTHER-DISTRIBUTION PLANT	D3602N	1,548,179	16,510		2,115,783	1,048,612	132,217	475,930	235,878	131,899	1,376,448
637	OTHER-GENERAL PLANT	GEN-PLT	130,682	6,095		159,611	79,105	9,974	35,903	17,794	9,950	103,837
638												
639	LICENSES - HYDRO PROJECTS	PI-H										
640												
641	REGULATORY COMMISSION FEES											
642	STATE OF IDAHO	P101P	197,013	9,188		240,625	119,257	15,037	54,127	26,826	15,001	156,542
643	STATE OF OREGON	NONE										
644												
645	FRANCHISE TAXES											
646	STATE OF OREGON	NONE										
647												
648	OTHER STATE TAXES											
649	UNEMPLOYMENT TAXES	NONE										
650	HYDRO GENERATION TAX	KWH-TAX										
651	IRRIGATION-PIC	KWH-TAX										
652												
653	TOTAL TAXES OTHER THAN INCOME		1,875,874	31,792		2,516,018	1,246,974	157,228	565,960	280,498	156,850	1,636,826

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line		(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
			* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
		ALLOCATOR	LINE TRANS SEC CUST	SEC LINES DEMAND	SEC LINES CUSTOMER	SERVICES	METERS	STREET LIGHTS	INSTALLATION CUST PREM
622	**** * * TABLE 7 - TAXES OTHER THAN INCOME TAXES * * ****								
623									
624	TAXES OTHER THAN INCOME								
625	FEDERAL TAXES	NONE							
626	FICA	LABOR							
627	FUTA	LABOR							
628	LESS PAYROLL DEDUCTION	LABOR							
629									
630	STATE TAXES								
631	AD VALOREM TAXES								
632	JIM BRIDGER STATION	PI-S							
633	VALMY	PI-S							
634	OTHER-PRODUCTION PLANT	PI-HO							
635	OTHER-TRANSMISSION PLANT	T-PLT							
636	OTHER-DISTRIBUTION PLANT	D3602N	682,187	135,592	67,201	275,936	464,455	24,972	17,823
637	OTHER-GENERAL PLANT	GEN-PLT	51,463	10,229	5,070	20,816	35,038	1,884	1,345
638									
639	LICENSES - HYDRO PROJECTS	PI-H							
640									
641	REGULATORY COMMISSION FEES								
642	STATE OF IDAHO	P101P	77,584	15,421	7,643	31,382	52,822	2,840	2,027
643	STATE OF OREGON	NONE							
644									
645	FRANCHISE TAXES								
646	STATE OF OREGON	NONE							
647									
648	OTHER STATE TAXES								
649	UNEMPLOYMENT TAXES	NONE							
650	HYDRO GENERATION TAX	KWH-TAX							
651	IRRIGATION-PIC	KWH-TAX							
652									
653	TOTAL TAXES OTHER THAN INCOME		811,234	161,241	79,913	328,134	552,314	29,696	21,194

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Description	(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
			- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
		ALLOCATOR	METER READING	CUSTOMER RECORDS	UNCOLLECT ACCOUNTS	OTHER	CUSTOMER ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
622	**** * * TABLE 7 - TAXES OTHER THAN INCOME TAXES * * ****									
623										
624	TAXES OTHER THAN INCOME									
625	FEDERAL TAXES	NONE								
626	FICA	LABOR								
627	FUTA	LABOR								
628	LESS PAYROLL DEDUCTION	LABOR								
629										
630	STATE TAXES									
631	AD VALOREM TAXES									
632	JIM BRIDGER STATION	PI-S								
633	VALMY	PI-S								
634	OTHER-PRODUCTION PLANT	PI-HO								
635	OTHER-TRANSMISSION PLANT	T-PLT								
636	OTHER-DISTRIBUTION PLANT	D3602N								
637	OTHER-GENERAL PLANT	GEN-PLT								
638										
639	LICENSES - HYDRO PROJECTS	PI-H								
640										
641	REGULATORY COMMISSION FEES									
642	STATE OF IDAHO	P101P								
643	STATE OF OREGON	NONE								
644										
645	FRANCHISE TAXES									
646	STATE OF OREGON	NONE								
647										
648	OTHER STATE TAXES									
649	UNEMPLOYMENT TAXES	NONE								
650	HYDRO GENERATION TAX	KWH-TAX								
651	IRRIGATION-PIC	KWH-TAX								
652										
653	TOTAL TAXES OTHER THAN INCOME									

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line		(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
			- - - - - - - - - -	- - - - - - - - - -	MISCELLANEOUS	- - - - - - - - - -	- - - -	INC TAXES
		ALLOCATOF						& REVENUES
			DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
622	**** * * TABLE 7 - TAXES OTHER THAN INCOME TAXES * * ****							
623								
624	TAXES OTHER THAN INCOME							
625	FEDERAL TAXES	NONE						
626	FICA	LABOR						
627	FUTA	LABOR						
628	LESS PAYROLL DEDUCTION	LABOR						
629								
630	STATE TAXES							
631	AD VALOREM TAXES							
632	JIM BRIDGER STATION	PI-S						
633	VALMY	PI-S						
634	OTHER-PRODUCTION PLANT	PI-HO						
635	OTHER-TRANSMISSION PLANT	T-PLT						
636	OTHER-DISTRIBUTION PLANT	D3602N						
637	OTHER-GENERAL PLANT	GEN-PLT						
638								
639	LICENSES - HYDRO PROJECTS	PI-H						
640								
641	REGULATORY COMMISSION FEES							
642	STATE OF IDAHO	P101P						
643	STATE OF OREGON	NONE						
644								
645	FRANCHISE TAXES							
646	STATE OF OREGON	NONE						
647								
648	OTHER STATE TAXES							
649	UNEMPLOYMENT TAXES	NONE						
650	HYDRO GENERATION TAX	KWH-TAX		1,806,165				
651	IRRIGATION-PIC	KWH-TAX		313,744				
652								
653	TOTAL TAXES OTHER THAN INCOME			2,119,909				

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
654	**** * * TABLE 8 - REGULATORY DEBITS/CREDITS * * ****											
655												
656	REGULAT	STATE OF IDAHO - Siemens LTP Amort	PI-OS	1,075,354	754,483	320,871						
657	REGULAT	STATE OF IDAHO - Cloud Computing	P101P	201,265	69,164	6,518				46,857		3
658	REGULAT	STATE OF IDAHO - Wildfire Mitigation	P-PTD	1,865,167	640,957	60,401				434,232		25
659												
660	**** * * TABLE 9 - INCOME TAXES * * ****											
661												
662	410/411 NET PROVISION FOR DEFER INC TAXES											
663		ACCOUNT #282 - RELATED	P111P	(15,882,182)	(5,512,531)	(519,478)				(3,734,595)		(219)
664		ACCOUNTS #190 & #283 - RELATED	ADIT	(1,242,756)	(372,378)	(35,091)				(252,277)		(15)
665		TOTAL NET PROVISION FOR DEFER IT		(17,124,938)	(5,884,910)	(554,569)				(3,986,872)		(234)
666												
667	411.4	INVESTMENT TAX CREDIT ADJUSTMENT	P111P	23,926,476	8,304,618	782,592				5,626,160		330
668												
669	SUMMARY OF INCOME TAXES											
670												
671	TOTAL FEDERAL INCOME TAX		TAX-REV	39,040,245								
672												
673	STATE INCOME TAXES											
674		STATE OF IDAHO	TAX-REV	(3,747,326)								
675		STATE OF OREGON	TAX-REV	685,175								
676		OTHER STATES	TAX-REV	233,716								
677		TOTAL STATE INCOME TAXES		(2,828,435)								
678												
679	TOTAL OPERATING EXPENSES			1,119,191,586								
680												
681	NET OPERATING INCOME			287,458,444								
682												
683					Base-load	Peak						

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Description	(A) ALLOCATOR	(I) SUBSTATION GENERAL	(J) SUBSTATION DIRECT	(K) SUBSTATION CIAC	(L) PRI LINES DEMAND	(M) PRI LINES CUSTOMER	(N) SEC LINES DIRECT	(O) LINE TRANS PRI DMD	(P) LINE TRANS PRI CUST	(Q) LINE TRANS PRI DIRECT	(R) LINE TRANS SEC DMD
			* * * * * * *	* * * * *	* * * * *	* * * * DISTRIBUTION FUNCTION	* * * * *	* * * * *	* * * * *	* * * * *	* * * * *	* * * * *
654	**** * * TABLE 8 - REGULATORY DEBITS/CREDITS * * ****											
655												
656	REGULAT STATE OF IDAHO - Siemens LTP Amort	PI-OS										
657	REGULAT STATE OF IDAHO - Cloud Computing	P101P	15,156	707		18,511	9,174	1,157	4,164	2,064	1,154	12,043
658	REGULAT STATE OF IDAHO - Wildfire Mitigation	P-PTD	140,454	6,550		171,546	85,020	10,720	38,588	19,125	10,694	111,601
659												
660	**** * * TABLE 9 - INCOME TAXES * * ****											
661												
662	410/411 NET PROVISION FOR DEFER INC TAXES											
663	ACCOUNT #282 - RELATED	P111P	(1,090,022)	(15,161)		(1,475,372)	(731,215)	(92,197)	(331,874)	(164,482)	(91,975)	(959,821)
664	ACCOUNTS #190 & #283 - RELATED	ADIT	(73,632)	(1,024)		(172,824)	(85,654)	(6,228)	(25,372)	(12,575)	(6,213)	(73,926)
665	TOTAL NET PROVISION FOR DEFER IT		(1,163,654)	(16,185)		(1,648,196)	(816,869)	(98,425)	(357,246)	(177,056)	(98,188)	(1,033,747)
666												
667	411.4 INVESTMENT TAX CREDIT ADJUSTMENT	P111P	1,642,116	22,840		2,222,644	1,101,574	138,894	499,968	247,791	138,561	1,445,968
668												
669	SUMMARY OF INCOME TAXES											
670												
671	TOTAL FEDERAL INCOME TAX	TAX-REV										
672												
673	STATE INCOME TAXES											
674	STATE OF IDAHO	TAX-REV										
675	STATE OF OREGON	TAX-REV										
676	OTHER STATES	TAX-REV										
677	TOTAL STATE INCOME TAXES											
678												
679	TOTAL OPERATING EXPENSES											
680												
681	NET OPERATING INCOME											
682												
683												

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

	(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
		* * * * * * * * * * * * * *	DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *				
	ALLOCATOF	LINE TRANS SEC CUST	SEC LINES DEMAND	SEC LINES CUSTOMER	SERVICES	METERS	STREET LIGHTS	INSTALLATION CUST PREM
**** * * TABLE 8 - REGULATORY DEBITS/CREDITS * * ****								
REGULAT STATE OF IDAHO - Siemens LTP Amort	PI-OS							
REGULAT STATE OF IDAHO - Cloud Computing	P101P	5,968	1,186	588	2,414	4,064	218	156
REGULAT STATE OF IDAHO - Wildfire Mitigation	P-PTD	55,311	10,994	5,449	22,373	37,658	2,025	1,445
**** * * TABLE 9 - INCOME TAXES * * ****								
410/411 NET PROVISION FOR DEFER INC TAXES								
ACCOUNT #282 - RELATED	P111P	(475,701)	(94,551)	(46,861)	(192,415)	(323,872)	(17,413)	(12,428)
ACCOUNTS #190 & #283 - RELATED	ADIT	(36,639)	(18,721)	(9,279)	(36,739)	(21,894)	(1,411)	(864)
TOTAL NET PROVISION FOR DEFER IT		(512,340)	(113,272)	(56,139)	(229,154)	(345,766)	(18,824)	(13,292)
411.4 INVESTMENT TAX CREDIT ADJUSTMENT	P111P	716,642	142,440	70,595	289,873	487,913	26,233	18,723
SUMMARY OF INCOME TAXES								
TOTAL FEDERAL INCOME TAX	TAX-REV							
STATE INCOME TAXES								
STATE OF IDAHO	TAX-REV							
STATE OF OREGON	TAX-REV							
OTHER STATES	TAX-REV							
TOTAL STATE INCOME TAXES								
TOTAL OPERATING EXPENSES								
NET OPERATING INCOME								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line										
6		(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7			- - - CUSTOMER ACCOUNTING FUNCTION - - -				***** CUSTOMER INFORMATION FUNCTION *****			
8		ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9			READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
654	****** TABLE 8 - REGULATORY DEBITS/CREDITS ******									
655										
656	REGULAT STATE OF IDAHO - Siemens LTP Amort	PI-OS								
657	REGULAT STATE OF IDAHO - Cloud Computing	P101P								
658	REGULAT STATE OF IDAHO - Wildfire Mitigation	P-PTD								
659										
660	****** TABLE 9 - INCOME TAXES ******									
661										
662	410/411 NET PROVISION FOR DEFER INC TAXES									
663	ACCOUNT #282 - RELATED	P111P								
664	ACCOUNTS #190 & #283 - RELATED	ADIT								
665	TOTAL NET PROVISION FOR DEFER IT									
666										
667	411.4 INVESTMENT TAX CREDIT ADJUSTMENT	P111P								
668										
669	SUMMARY OF INCOME TAXES									
670										
671	TOTAL FEDERAL INCOME TAX	TAX-REV								
672										
673	STATE INCOME TAXES									
674	STATE OF IDAHO	TAX-REV								
675	STATE OF OREGON	TAX-REV								
676	OTHER STATES	TAX-REV								
677	TOTAL STATE INCOME TAXES									
678										
679	TOTAL OPERATING EXPENSES									
680										
681	NET OPERATING INCOME									
682										
683										

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Description	(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7			- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8		ALLOCATOF						& REVENUES
9			DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
654	**** * * TABLE 8 - REGULATORY DEBITS/CREDITS * * ****							
655								
656	REGULAT STATE OF IDAHO - Siemens LTP Amort	PI-OS						
657	REGULAT STATE OF IDAHO - Cloud Computing	P101P						
658	REGULAT STATE OF IDAHO - Wildfire Mitigation	P-PTD						
659								
660	**** * * TABLE 9 - INCOME TAXES * * ****							
661								
662	410/411 NET PROVISION FOR DEFER INC TAXES							
663	ACCOUNT #282 - RELATED	P111P						
664	ACCOUNTS #190 & #283 - RELATED	ADIT						
665	TOTAL NET PROVISION FOR DEFER IT							
666								
667	411.4 INVESTMENT TAX CREDIT ADJUSTMENT	P111P						
668								
669	SUMMARY OF INCOME TAXES							
670								
671	TOTAL FEDERAL INCOME TAX	TAX-REV						39,040,245
672								
673	STATE INCOME TAXES							
674	STATE OF IDAHO	TAX-REV						(3,747,326)
675	STATE OF OREGON	TAX-REV						685,175
676	OTHER STATES	TAX-REV						233,716
677	TOTAL STATE INCOME TAXES							
678								
679	TOTAL OPERATING EXPENSES							
680								
681	NET OPERATING INCOME							
682								
683								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Description	(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7			TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8		ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9				Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
684	**** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOCATOR * * ****										
685	STEAM POWER GENERATION										
686	OPERATION										
687	500 / SUPERVISION & ENGINEERING	L-500	255,277	255,277							
688	501 / FUEL	PI-S	2,455,198	2,455,198							
689	502 / STEAM EXPENSES										
690	LABOR	PI-S	1,542,164	1,542,164							
691	OTHER	PI-S									
692	TOTAL ACCOUNT 502										
693	505 / ELECTRIC EXPENSES										
694	LABOR	PI-S	600,571	600,571							
695	OTHER	PI-S	3,215,661	3,215,661							
696	TOTAL ACCOUNT 505										
697	506 / MISCELLANEOUS EXPENSES	PI-S									
698	507 / RENTS	PI-S									
699	STEAM OPERATION EXPENSES		8,068,870								
700											
701	MAINTENANCE										
702	510 / SUPERVISION & ENGINEERING	L-510									
703	511 / STRUCTURES	PI-S	631	631							
704	512 / BOILER PLANT										
705	LABOR	PI-S	3,821,200	3,821,200							
706	OTHER	PI-S									
707	TOTAL ACCOUNT 512		3,821,200								
708	513 / ELECTRIC PLANT										
709	LABOR	PI-S	1,460,523	1,460,523							
710	OTHER	PI-S									
711	TOTAL ACCOUNT 513		1,460,523								
712	514 / MISCELLANEOUS STEAM PLANT	PI-S	2,342,261	2,342,261							
713	STEAM MAINTENANCE EXPENSES		7,624,615								
714	TOTAL STEAM GENERATION EXPENSES		15,693,485								
715											
716	HYDRAULIC POWER GENERATION										
717	535-OP SUPERVISION & ENGINEERING	L-535	4,061,414	4,061,414							
718	536-OP WATER FOR POWER	PI-H	828,021	828,021							
719	537-OP HYDRAULIC EXPENSES	PI-H	6,006,734	6,006,734							
720	538-OP ELECTRIC EXPENSES	PI-H	1,448,837	1,448,837							
721	539-OP MISCELLANEOUS EXPENSES	PI-H	3,262,471	3,262,471							
722	540-OP RENTS										
723	TOTAL HYDRAULIC OPERATION EXPENSES		15,607,477								
724	541-MT SUPERVISION & ENGINEERING	L-541	86,513	86,513							
725	542-MT STRUCTURES	PI-H	554,103	554,103							
726	543-MT RESERVOIRS, DAMS & WATERWAYS	PI-H	244,475	244,475							
727	544-MT ELECTRIC PLANT	PI-H	1,725,993	1,725,993							
728	545-MT MISCELLANEOUS HYDRAULIC PLANT	PI-H	2,075,350	2,075,350							
729	TOTAL HYDRAULIC MAINTENANCE EXPENSES		4,686,434								
730	TOTAL HYDRAULIC GENERATION EXPENSES		20,293,911								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Description	(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7			* *	DISTRIBUTION FUNCTION	* *							
8		ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9			GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
684	**** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.***											
685	STEAM POWER GENERATION											
686	OPERATION											
687	500 / SUPERVISION & ENGINEERING	L-500										
688	501 / FUEL	PI-S										
689	502 / STEAM EXPENSES											
690	LABOR	PI-S										
691	OTHER	PI-S										
692	TOTAL ACCOUNT 502											
693	505 / ELECTRIC EXPENSES											
694	LABOR	PI-S										
695	OTHER	PI-S										
696	TOTAL ACCOUNT 505											
697	506 / MISCELLANEOUS EXPENSES	PI-S										
698	507 / RENTS	PI-S										
699	STEAM OPERATION EXPENSES											
700												
701	MAINTENANCE											
702	510 / SUPERVISION & ENGINEERING	L-510										
703	511 / STRUCTURES	PI-S										
704	512 / BOILER PLANT											
705	LABOR	PI-S										
706	OTHER	PI-S										
707	TOTAL ACCOUNT 512											
708	513 / ELECTRIC PLANT											
709	LABOR	PI-S										
710	OTHER	PI-S										
711	TOTAL ACCOUNT 513											
712	514 / MISCELLANEOUS STEAM PLANT	PI-S										
713	STEAM MAINTENANCE EXPENSES											
714	TOTAL STEAM GENERATION EXPENSES											
715												
716	HYDRAULIC POWER GENERATION											
717	535-OP SUPERVISION & ENGINEERING	L-535										
718	536-OP WATER FOR POWER	PI-H										
719	537-OP HYDRAULIC EXPENSES	PI-H										
720	538-OP ELECTRIC EXPENSES	PI-H										
721	539-OP MISCELLANEOUS EXPENSES	PI-H										
722	540-OP RENTS											
723	TOTAL HYDRAULIC OPERATION EXPENSES											
724	541-MT SUPERVISION & ENGINEERING	L-541										
725	542-MT STRUCTURES	PI-H										
726	543-MT RESERVOIRS, DAMS & WATERWAYS	PI-H										
727	544-MT ELECTRIC PLANT	PI-H										
728	545-MT MISCELLANEOUS HYDRAULIC PLANT	PI-H										
729	TOTAL HYDRAULIC MAINTENANCE EXPENSES											
730	TOTAL HYDRAULIC GENERATION EXPENSES											

Line									
1	**IDAHO POWER COMPANY**								
2	**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**								
3	**CLASS COST OF SERVICE STUDY**								
4	**FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**								
5	**FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**								
6		(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7			* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
8		ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9			SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
684	**** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.***								
685	STEAM POWER GENERATION								
686	OPERATION								
687	500 / SUPERVISION & ENGINEERING	L-500							
688	501 / FUEL	PI-S							
689	502 / STEAM EXPENSES								
690	LABOR	PI-S							
691	OTHER	PI-S							
692	TOTAL ACCOUNT 502								
693	505 / ELECTRIC EXPENSES								
694	LABOR	PI-S							
695	OTHER	PI-S							
696	TOTAL ACCOUNT 505								
697	506 / MISCELLANEOUS EXPENSES	PI-S							
698	507 / RENTS	PI-S							
699	STEAM OPERATION EXPENSES								
700									
701	MAINTENANCE								
702	510 / SUPERVISION & ENGINEERING	L-510							
703	511 / STRUCTURES	PI-S							
704	512 / BOILER PLANT								
705	LABOR	PI-S							
706	OTHER	PI-S							
707	TOTAL ACCOUNT 512								
708	513 / ELECTRIC PLANT								
709	LABOR	PI-S							
710	OTHER	PI-S							
711	TOTAL ACCOUNT 513								
712	514 / MISCELLANEOUS STEAM PLANT	PI-S							
713	STEAM MAINTENANCE EXPENSES								
714	TOTAL STEAM GENERATION EXPENSES								
715									
716	HYDRAULIC POWER GENERATION								
717	535-OP SUPERVISION & ENGINEERING	L-535							
718	536-OP WATER FOR POWER	PI-H							
719	537-OP HYDRAULIC EXPENSES	PI-H							
720	538-OP ELECTRIC EXPENSES	PI-H							
721	539-OP MISCELLANEOUS EXPENSES	PI-H							
722	540-OP RENTS								
723	TOTAL HYDRAULIC OPERATION EXPENSES								
724	541-MT SUPERVISION & ENGINEERING	L-541							
725	542-MT STRUCTURES	PI-H							
726	543-MT RESERVOIRS, DAMS & WATERWAYS	PI-H							
727	544-MT ELECTRIC PLANT	PI-H							
728	545-MT MISCELLANEOUS HYDRAULIC PLANT	PI-H							
729	TOTAL HYDRAULIC MAINTENANCE EXPENSES								
730	TOTAL HYDRAULIC GENERATION EXPENSES								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Description	(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7			- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8		ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9			READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
684	**** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.***									
685	STEAM POWER GENERATION									
686	OPERATION									
687	500 / SUPERVISION & ENGINEERING	L-500								
688	501 / FUEL	PI-S								
689	502 / STEAM EXPENSES									
690	LABOR	PI-S								
691	OTHER	PI-S								
692	TOTAL ACCOUNT 502									
693	505 / ELECTRIC EXPENSES									
694	LABOR	PI-S								
695	OTHER	PI-S								
696	TOTAL ACCOUNT 505									
697	506 / MISCELLANEOUS EXPENSES	PI-S								
698	507 / RENTS	PI-S								
699	STEAM OPERATION EXPENSES									
700										
701	MAINTENANCE									
702	510 / SUPERVISION & ENGINEERING	L-510								
703	511 / STRUCTURES	PI-S								
704	512 / BOILER PLANT									
705	LABOR	PI-S								
706	OTHER	PI-S								
707	TOTAL ACCOUNT 512									
708	513 / ELECTRIC PLANT									
709	LABOR	PI-S								
710	OTHER	PI-S								
711	TOTAL ACCOUNT 513									
712	514 / MISCELLANEOUS STEAM PLANT	PI-S								
713	STEAM MAINTENANCE EXPENSES									
714	TOTAL STEAM GENERATION EXPENSES									
715										
716	HYDRAULIC POWER GENERATION									
717	535-OP SUPERVISION & ENGINEERING	L-535								
718	536-OP WATER FOR POWER	PI-H								
719	537-OP HYDRAULIC EXPENSES	PI-H								
720	538-OP ELECTRIC EXPENSES	PI-H								
721	539-OP MISCELLANEOUS EXPENSES	PI-H								
722	540-OP RENTS									
723	TOTAL HYDRAULIC OPERATION EXPENSES									
724	541-MT SUPERVISION & ENGINEERING	L-541								
725	542-MT STRUCTURES	PI-H								
726	543-MT RESERVOIRS, DAMS & WATERWAYS	PI-H								
727	544-MT ELECTRIC PLANT	PI-H								
728	545-MT MISCELLANEOUS HYDRAULIC PLANT	PI-H								
729	TOTAL HYDRAULIC MAINTENANCE EXPENSES									
730	TOTAL HYDRAULIC GENERATION EXPENSES									

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7			- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8		ALLOCATOF						& REVENUES
9			DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
684	**** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.***							
685	STEAM POWER GENERATION							
686	OPERATION							
687	500 / SUPERVISION & ENGINEERING	L-500						
688	501 / FUEL	PI-S						
689	502 / STEAM EXPENSES							
690	LABOR	PI-S						
691	OTHER	PI-S						
692	TOTAL ACCOUNT 502							
693	505 / ELECTRIC EXPENSES							
694	LABOR	PI-S						
695	OTHER	PI-S						
696	TOTAL ACCOUNT 505							
697	506 / MISCELLANEOUS EXPENSES	PI-S						
698	507 / RENTS	PI-S						
699	STEAM OPERATION EXPENSES							
700								
701	MAINTENANCE							
702	510 / SUPERVISION & ENGINEERING	L-510						
703	511 / STRUCTURES	PI-S						
704	512 / BOILER PLANT							
705	LABOR	PI-S						
706	OTHER	PI-S						
707	TOTAL ACCOUNT 512							
708	513 / ELECTRIC PLANT							
709	LABOR	PI-S						
710	OTHER	PI-S						
711	TOTAL ACCOUNT 513							
712	514 / MISCELLANEOUS STEAM PLANT	PI-S						
713	STEAM MAINTENANCE EXPENSES							
714	TOTAL STEAM GENERATION EXPENSES							
715								
716	HYDRAULIC POWER GENERATION							
717	535-OP SUPERVISION & ENGINEERING	L-535						
718	536-OP WATER FOR POWER	PI-H						
719	537-OP HYDRAULIC EXPENSES	PI-H						
720	538-OP ELECTRIC EXPENSES	PI-H						
721	539-OP MISCELLANEOUS EXPENSES	PI-H						
722	540-OP RENTS							
723	TOTAL HYDRAULIC OPERATION EXPENSES							
724	541-MT SUPERVISION & ENGINEERING	L-541						
725	542-MT STRUCTURES	PI-H						
726	543-MT RESERVOIRS, DAMS & WATERWAYS	PI-H						
727	544-MT ELECTRIC PLANT	PI-H						
728	545-MT MISCELLANEOUS HYDRAULIC PLANT	PI-H						
729	TOTAL HYDRAULIC MAINTENANCE EXPENSES							
730	TOTAL HYDRAULIC GENERATION EXPENSES							

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
731	*** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOCATOR * * ***											
732												
733	OTHER POWER GENERATION											
734	546-OP	SUPERVISION & ENGINEERING	L-546	495,643	347,750	147,893						
735	548-OP	GENERATING EXPENSES	PI-OS	3,102,974	2,177,089	925,885						
736	549-OP	MISCELLANEOUS EXPENSES	PI-OS	355,488	249,415	106,073						
737	550-OP	RENTS	PI-OS									
738		TOTAL OTHER POWER OPER EXPENSES		3,954,105								
739												
740	551-MT	SUPERVISION & ENGINEERING	L-551									
741	552-MT	STRUCTURES	PI-OS	41,290	28,970	12,320						
742	553-MT	GENERATING & ELECTRIC PLANT	PI-OS	54,507	38,243	16,264						
743	554-MT	MISCELLANEOUS EXPENSES	PI-OS	662,259	464,650	197,609						
744		TOTAL OTHER POWER MAINT EXPENSES		758,056								
745		TOTAL OTHER POWER GEN EXPENSES		4,712,161								
746	555	PURCHASED POWER										
747	556	LOAD CONTROL & DISPATCHING EXPEN	PP-KW									
748	557	OTHER	PI-SHO	4,311,949	3,940,603	371,346						
749		TOTAL OTHER POWER SUPPLY EXPENSES		4,311,949								
750												
751		TOTAL PRODUCTION EXPENSES		45,011,506								
752												
753	TRANSMISSION EXPENSES											
754	560-OP	SUPERVISION & ENGINEERING	L-560	2,283,367						2,283,156		211
755	561-OP	LOAD DISPATCHING	T-PLT	2,929,396						2,929,224		172
756	562-OP	STATION EXPENSES	T-353	1,806,653						1,806,351		302
757	563-OP	OVERHEAD LINE EXPENSES	T-354-356	410,892						410,891		1
758	565-OP	TRANSMISSION OF ELECTRICITY BY OT	KWH-T									
759	566-OP	MISCELLANEOUS EXPENSES	T-PLT									
760	567-OP	RENTS	T-PLT									
761		TOTAL TRANSMISSION OPERATION		7,430,307								
762	568-MT	SUPERVISION & ENGINEERING	L-568	87,233						87,226		7
763	569-MT	STRUCTURES	T-352	1,383,185						1,383,185		
764	570-MT	STATION EQUIPMENT	T-353	2,232,077						2,231,704		373
765	571-MT	OVERHEAD LINES	T-354-356	830,425						830,424		1
766	573-MT	MISCELLANEOUS PLANT	T-PLT	3,376						3,376		0
767		TOTAL TRANSMISSION MAINTENANCE		4,536,296								
768		TOTAL TRANSMISSION EXPENSES		11,966,603								

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Line			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *	DISTRIBUTION FUNCTION	* *							
8			ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
731	*** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC/**												
732													
733	OTHER POWER GENERATION												
734	546-OP	SUPERVISION & ENGINEERING	L-546										
735	548-OP	GENERATING EXPENSES	PI-OS										
736	549-OP	MISCELLANEOUS EXPENSES	PI-OS										
737	550-OP	RENTS	PI-OS										
738		TOTAL OTHER POWER OPER EXPENSES											
739													
740	551-MT	SUPERVISION & ENGINEERING	L-551										
741	552-MT	STRUCTURES	PI-OS										
742	553-MT	GENERATING & ELECTRIC PLANT	PI-OS										
743	554-MT	MISCELLANEOUS EXPENSES	PI-OS										
744		TOTAL OTHER POWER MAINT EXPENSES											
745		TOTAL OTHER POWER GEN EXPENSES											
746	555	PURCHASED POWER											
747	556	LOAD CONTROL & DISPATCHING EXPEN	PP-KW										
748	557	OTHER	PI-SHO										
749		TOTAL OTHER POWER SUPPLY EXPENSES											
750													
751		TOTAL PRODUCTION EXPENSES											
752													
753	TRANSMISSION EXPENSES												
754	560-OP	SUPERVISION & ENGINEERING	L-560										
755	561-OP	LOAD DISPATCHING	T-PLT										
756	562-OP	STATION EXPENSES	T-353										
757	563-OP	OVERHEAD LINE EXPENSES	T-354-356										
758	565-OP	TRANSMISSION OF ELECTRICITY BY OT	KWH-T										
759	566-OP	MISCELLANEOUS EXPENSES	T-PLT										
760	567-OP	RENTS	T-PLT										
761		TOTAL TRANSMISSION OPERATION											
762	568-MT	SUPERVISION & ENGINEERING	L-568										
763	569-MT	STRUCTURES	T-352										
764	570-MT	STATION EQUIPMENT	T-353										
765	571-MT	OVERHEAD LINES	T-354-356										
766	573-MT	MISCELLANEOUS PLANT	T-PLT										
767		TOTAL TRANSMISSION MAINTENANCE											
768		TOTAL TRANSMISSION EXPENSES											

1											
2											
3											
4											
5											
6			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	
7				* * * * * * * * * * * * * *	DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *					
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION	
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM	
731	*** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC/**										
732											
733	OTHER POWER GENERATION										
734	546-OP	SUPERVISION & ENGINEERING	L-546								
735	548-OP	GENERATING EXPENSES	PI-OS								
736	549-OP	MISCELLANEOUS EXPENSES	PI-OS								
737	550-OP	RENTS	PI-OS								
738		TOTAL OTHER POWER OPER EXPENSES									
739											
740	551-MT	SUPERVISION & ENGINEERING	L-551								
741	552-MT	STRUCTURES	PI-OS								
742	553-MT	GENERATING & ELECTRIC PLANT	PI-OS								
743	554-MT	MISCELLANEOUS EXPENSES	PI-OS								
744		TOTAL OTHER POWER MAINT EXPENSES									
745		TOTAL OTHER POWER GEN EXPENSES									
746	555	PURCHASED POWER									
747	556	LOAD CONTROL & DISPATCHING EXPEN	PP-KW								
748	557	OTHER	PI-SHO								
749		TOTAL OTHER POWER SUPPLY EXPENSES									
750											
751		TOTAL PRODUCTION EXPENSES									
752											
753	TRANSMISSION EXPENSES										
754	560-OP	SUPERVISION & ENGINEERING	L-560								
755	561-OP	LOAD DISPATCHING	T-PLT								
756	562-OP	STATION EXPENSES	T-353								
757	563-OP	OVERHEAD LINE EXPENSES	T-354-356								
758	565-OP	TRANSMISSION OF ELECTRICITY BY OT	KWH-T								
759	566-OP	MISCELLANEOUS EXPENSES	T-PLT								
760	567-OP	RENTS	T-PLT								
761		TOTAL TRANSMISSION OPERATION									
762	568-MT	SUPERVISION & ENGINEERING	L-568								
763	569-MT	STRUCTURES	T-352								
764	570-MT	STATION EQUIPMENT	T-353								
765	571-MT	OVERHEAD LINES	T-354-356								
766	573-MT	MISCELLANEOUS PLANT	T-PLT								
767		TOTAL TRANSMISSION MAINTENANCE									
768		TOTAL TRANSMISSION EXPENSES									

Rows 1–5 carry the centered title lines:

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

1		IDAHO POWER COMPANY										
2		BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION										
3		CLASS COST OF SERVICE STUDY										
4		FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023										
5		FUNCTIONALIZATION AND CLASSIFICATION OF COSTS										
6			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				***** CUSTOMER INFORMATION FUNCTION *****				
8			ALLOCATOF	METER	CUSTOMER	UNCOLLECT		CUSTOMER				
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER	
731	*** TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC/											
732												
733	OTHER POWER GENERATION											
734	546-OP	SUPERVISION & ENGINEERING	L-546									
735	548-OP	GENERATING EXPENSES	PI-OS									
736	549-OP	MISCELLANEOUS EXPENSES	PI-OS									
737	550-OP	RENTS	PI-OS									
738		TOTAL OTHER POWER OPER EXPENSES										
739												
740	551-MT	SUPERVISION & ENGINEERING	L-551									
741	552-MT	STRUCTURES	PI-OS									
742	553-MT	GENERATING & ELECTRIC PLANT	PI-OS									
743	554-MT	MISCELLANEOUS EXPENSES	PI-OS									
744		TOTAL OTHER POWER MAINT EXPENSES										
745		TOTAL OTHER POWER GEN EXPENSES										
746	555	PURCHASED POWER										
747	556	LOAD CONTROL & DISPATCHING EXPEN	PP-KW									
748	557	OTHER	PI-SHO									
749		TOTAL OTHER POWER SUPPLY EXPENSES										
750												
751		TOTAL PRODUCTION EXPENSES										
752												
753	TRANSMISSION EXPENSES											
754	560-OP	SUPERVISION & ENGINEERING	L-560									
755	561-OP	LOAD DISPATCHING	T-PLT									
756	562-OP	STATION EXPENSES	T-353									
757	563-OP	OVERHEAD LINE EXPENSES	T-354-356									
758	565-OP	TRANSMISSION OF ELECTRICITY BY OT	KWH-T									
759	566-OP	MISCELLANEOUS EXPENSES	T-PLT									
760	567-OP	RENTS	T-PLT									
761		TOTAL TRANSMISSION OPERATION										
762	568-MT	SUPERVISION & ENGINEERING	L-568									
763	569-MT	STRUCTURES	T-352									
764	570-MT	STATION EQUIPMENT	T-353									
765	571-MT	OVERHEAD LINES	T-354-356									
766	573-MT	MISCELLANEOUS PLANT	T-PLT									
767		TOTAL TRANSMISSION MAINTENANCE										
768		TOTAL TRANSMISSION EXPENSES										

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Account	Description	(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
731	*** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC/**								
732									
733	OTHER POWER GENERATION								
734	546-OP	SUPERVISION & ENGINEERING	L-546						
735	548-OP	GENERATING EXPENSES	PI-OS						
736	549-OP	MISCELLANEOUS EXPENSES	PI-OS						
737	550-OP	RENTS	PI-OS						
738		TOTAL OTHER POWER OPER EXPENSES							
739									
740	551-MT	SUPERVISION & ENGINEERING	L-551						
741	552-MT	STRUCTURES	PI-OS						
742	553-MT	GENERATING & ELECTRIC PLANT	PI-OS						
743	554-MT	MISCELLANEOUS EXPENSES	PI-OS						
744		TOTAL OTHER POWER MAINT EXPENSES							
745		TOTAL OTHER POWER GEN EXPENSES							
746	555	PURCHASED POWER							
747	556	LOAD CONTROL & DISPATCHING EXPEN	PP-KW						
748	557	OTHER	PI-SHO						
749		TOTAL OTHER POWER SUPPLY EXPENSES							
750									
751		TOTAL PRODUCTION EXPENSES							
752									
753	TRANSMISSION EXPENSES								
754	560-OP	SUPERVISION & ENGINEERING	L-560						
755	561-OP	LOAD DISPATCHING	T-PLT						
756	562-OP	STATION EXPENSES	T-353						
757	563-OP	OVERHEAD LINE EXPENSES	T-354-356						
758	565-OP	TRANSMISSION OF ELECTRICITY BY OTI	KWH-T						
759	566-OP	MISCELLANEOUS EXPENSES	T-PLT						
760	567-OP	RENTS	T-PLT						
761		TOTAL TRANSMISSION OPERATION							
762	568-MT	SUPERVISION & ENGINEERING	L-568						
763	569-MT	STRUCTURES	T-352						
764	570-MT	STATION EQUIPMENT	T-353						
765	571-MT	OVERHEAD LINES	T-354-356						
766	573-MT	MISCELLANEOUS PLANT	T-PLT						
767		TOTAL TRANSMISSION MAINTENANCE							
768		TOTAL TRANSMISSION EXPENSES							

Line	Acct	Description	Allocator	Totals								
1							**IDAHO POWER COMPANY**					
2							**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**					
3							**CLASS COST OF SERVICE STUDY**					
4							**FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**					
5							**FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**					
6			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
769	*****	***TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOCATOR* * ***										
770												
771		DISTRIBUTION EXPENSES										
772	580-OP	SUPERVISION & ENGINEERING	L-580	2,854,543								
773	581-OP	LOAD DISPATCHING	D3601	4,009,091								
774	582-OP	STATION EXPENSES	D362	936,981								
775	583-OP	OVERHEAD LINE EXPENSES	D-364-365	3,354,617								
776	584-OP	UNDERGROUND LINE EXPENSES	D-366-367	1,352,112								
777	585-OP	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT	19,552								
778	586-OP	METER EXPENSES	METER	4,041,475								
779	587-OP	CUSTOMER INSTALLATIONS EXPENSE	CUSTINST	685,851								
780	588-OP	MISCELLANEOUS EXPENSES	D3601	2,749,719								
781	589-OP	RENTS	D3601									
782		TOTAL DISTRIBUTION OPERATION		20,003,940								
783												
784	590-MT	SUPERVISION & ENGINEERING	L-590	8,912								
785	591-MT	STRUCTURES	D361									
786	592-MT	STATION EQUIPMENT	D362	2,588,326								
787	593-MT	OVERHEAD LINES	D-364-365	4,830,600								
788	594-MT	UNDERGROUND LINES	D-366-367	300,238								
789	595-MT	LINE TRANSFORMERS	D368	24,370								
790	596-MT	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT	118,851								
791	597-MT	METERS	METER	656,208								
792	598-MT	MISCELLANEOUS PLANT	D3601	76,191								
793		TOTAL DISTRIBUTION MAINTENANCE		8,603,695								
794		TOTAL DISTRIBUTION EXPENSES		28,607,635								
795												
796		CUSTOMER ACCOUNTING EXPENSES										
797	901-OP	SUPERVISION	L-901	610,646								
798	902-OP	METER READING	M-READ	1,098,173								
799	903-OP	CUSTOMER RECORDS & COLLECTIONS	C-RECORI	9,412,221								
800	904-OP	UNCOLLECTIBLE ACCOUNTS	UAR									
801	905-OP	MISC CUSTOMER ACCOUNTS EXPENS	L 798-800									
802		TOTAL CUSTOMER ACCOUNTING EXPENSES		11,121,040								
803												
804		CUSTOMER SERVICES & INFORMATION EXPENSES										
805	907-OP	SUPERVISION	L-907	806,758	118,649							
806	908-OP	CUSTOMER ASSISTANCE	D-908	4,555,597	669,988							
807	908 /	ENERGY EFFICIENCY RIDER	NONE									
808	909-OP	INFORMATION & INSTRUCTIONAL	C-ASSIST									
809	912	DEMO AND SELLING EXPENSES	L 806-808	300,634	44,214							
810		TOTAL CUST SERV & INFO EXPENSES		5,662,989								
811												

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
				* * * * * * * * *	* * * * * * *	* * * * * * *	* * * * * DISTRIBUTION FUNCTION	* * * *	* * * *	* * * *	* * * *	* * * *	* * * *
			ALLOCATOF	SUBSTATION GENERAL	SUBSTATION DIRECT	SUBSTATION CIAC	PRI LINES DEMAND	PRI LINES CUSTOMER	SEC LINES DIRECT	LINE TRANS PRI DMD	LINE TRANS PRI CUST	LINE TRANS PRI DIRECT	LINE TRANS SEC DMD
769	**** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.***												
770													
771		DISTRIBUTION EXPENSES											
772	580-OP	SUPERVISION & ENGINEERING	L-580	365,851	16,800		742,003	367,747	37,399	59,505	29,492	16,491	172,096
773	581-OP	LOAD DISPATCHING	D3601	771,834	35,996		942,691	467,211	58,909	212,052	105,096	58,768	613,279
774	582-OP	STATION EXPENSES	D362	896,734	40,248								
775	583-OP	OVERHEAD LINE EXPENSES	D-364-365				2,072,014	1,026,919	25,911				
776	584-OP	UNDERGROUND LINE EXPENSES	D-366-367				796,505	394,759	99,459				
777	585-OP	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT										
778	586-OP	METER EXPENSES	METER										
779	587-OP	CUSTOMER INSTALLATIONS EXPENSE	CUSTINST										
780	588-OP	MISCELLANEOUS EXPENSES	D3601	529,379	24,688		646,565	320,446	40,404	145,440	72,082	40,307	420,630
781	589-OP	RENTS	D3601										
782		TOTAL DISTRIBUTION OPERATION											
783													
784	590-MT	SUPERVISION & ENGINEERING	L-590	2,584	116		3,296	1,633	63	8	4	2	24
785	591-MT	STRUCTURES	D361										
786	592-MT	STATION EQUIPMENT	D362	2,477,145	111,181								
787	593-MT	OVERHEAD LINES	D-364-365				2,983,670	1,478,749	37,311				
788	594-MT	UNDERGROUND LINES	D-366-367				176,865	87,657	22,085				
789	595-MT	LINE TRANSFORMERS	D368							3,996	1,981	1,108	11,557
790	596-MT	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT										
791	597-MT	METERS	METER										
792	598-MT	MISCELLANEOUS PLANT	D3601	14,668	684		17,915	8,879	1,120	4,030	1,997	1,117	11,655
793		TOTAL DISTRIBUTION MAINTENANCE											
794		TOTAL DISTRIBUTION EXPENSES											
795													
796		CUSTOMER ACCOUNTING EXPENSES											
797	901-OP	SUPERVISION	L-901										
798	902-OP	METER READING	M-READ										
799	903-OP	CUSTOMER RECORDS & COLLECTIONS	C-RECORI										
800	904-OP	UNCOLLECTIBLE ACCOUNTS	UAR										
801	905-OP	MISC CUSTOMER ACCOUNTS EXPENS	L 798-800										
802		TOTAL CUSTOMER ACCOUNTING EXPENSES											
803													
804		CUSTOMER SERVICES & INFORMATION EXPENSES											
805	907-OP	SUPERVISION	L-907										
806	908-OP	CUSTOMER ASSISTANCE	D-908										
807	908 /	ENERGY EFFICIENCY RIDER	NONE										
808	909-OP	INFORMATION & INSTRUCTIONAL	C-ASSIST										
809	912	DEMO AND SELLING EXPENSES	L 806-808										
810		TOTAL CUST SERV & INFO EXPENSES											
811													

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *	DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *				
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
769	***** TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.**									
770										
771		DISTRIBUTION EXPENSES								
772	580-OP	SUPERVISION & ENGINEERING	L-580	85,293	49,357	24,462	34,500	730,780	6,377	116,389
773	581-OP	LOAD DISPATCHING	D3601	303,950	60,413	29,942	122,944	206,939	11,126	7,941
774	582-OP	STATION EXPENSES	D362							
775	583-OP	OVERHEAD LINE EXPENSES	D-364-365		153,631	76,142				
776	584-OP	UNDERGROUND LINE EXPENSES	D-366-367		41,045	20,343				
777	585-OP	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT						19,552	
778	586-OP	METER EXPENSES	METER					4,041,475		
779	587-OP	CUSTOMER INSTALLATIONS EXPENSE	CUSTINST							685,851
780	588-OP	MISCELLANEOUS EXPENSES	D3601	208,470	41,436	20,536	84,324	141,933	7,631	5,447
781	589-OP	RENTS	D3601							
782		TOTAL DISTRIBUTION OPERATION								
783										
784	590-MT	SUPERVISION & ENGINEERING	L-590	12	240	119	2	684	123	0
785	591-MT	STRUCTURES	D361							
786	592-MT	STATION EQUIPMENT	D362							
787	593-MT	OVERHEAD LINES	D-364-365		221,227	109,643				
788	594-MT	UNDERGROUND LINES	D-366-367		9,114	4,517				
789	595-MT	LINE TRANSFORMERS	D368	5,728						
790	596-MT	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT						118,851	
791	597-MT	METERS	METER					656,208		
792	598-MT	MISCELLANEOUS PLANT	D3601	5,776	1,148	569	2,336	3,933	211	151
793		TOTAL DISTRIBUTION MAINTENANCE								
794		TOTAL DISTRIBUTION EXPENSES								
795										
796		CUSTOMER ACCOUNTING EXPENSES								
797	901-OP	SUPERVISION	L-901							
798	902-OP	METER READING	M-READ							
799	903-OP	CUSTOMER RECORDS & COLLECTIONS	C-RECORI							
800	904-OP	UNCOLLECTIBLE ACCOUNTS	UAR							
801	905-OP	MISC CUSTOMER ACCOUNTS EXPENS	L 798-800							
802		TOTAL CUSTOMER ACCOUNTING EXPENSES								
803										
804		CUSTOMER SERVICES & INFORMATION EXPENSES								
805	907-OP	SUPERVISION	L-907							
806	908-OP	CUSTOMER ASSISTANCE	D-908							
807	908 / ENERGY EFFICIENCY RIDER		NONE							
808	909-OP	INFORMATION & INSTRUCTIONAL	C-ASSIST							
809	912	DEMO AND SELLING EXPENSES	L 806-808							
810		TOTAL CUST SERV & INFO EXPENSES								
811										

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line	Acct	Description	(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION			- - -	* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
769	***** TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.***										
770											
771		DISTRIBUTION EXPENSES									
772	580-OP	SUPERVISION & ENGINEERING	L-580								
773	581-OP	LOAD DISPATCHING	D3601								
774	582-OP	STATION EXPENSES	D362								
775	583-OP	OVERHEAD LINE EXPENSES	D-364-365								
776	584-OP	UNDERGROUND LINE EXPENSES	D-366-367								
777	585-OP	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT								
778	586-OP	METER EXPENSES	METER								
779	587-OP	CUSTOMER INSTALLATIONS EXPENSE	CUSTINST								
780	588-OP	MISCELLANEOUS EXPENSES	D3601								
781	589-OP	RENTS	D3601								
782		TOTAL DISTRIBUTION OPERATION									
783											
784	590-MT	SUPERVISION & ENGINEERING	L-590								
785	591-MT	STRUCTURES	D361								
786	592-MT	STATION EQUIPMENT	D362								
787	593-MT	OVERHEAD LINES	D-364-365								
788	594-MT	UNDERGROUND LINES	D-366-367								
789	595-MT	LINE TRANSFORMERS	D368								
790	596-MT	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT								
791	597-MT	METERS	METER								
792	598-MT	MISCELLANEOUS PLANT	D3601								
793		TOTAL DISTRIBUTION MAINTENANCE									
794		TOTAL DISTRIBUTION EXPENSES									
795											
796		CUSTOMER ACCOUNTING EXPENSES									
797	901-OP	SUPERVISION	L-901	63,803	546,843						
798	902-OP	METER READING	M-READ	1,098,173							
799	903-OP	CUSTOMER RECORDS & COLLECTIONS	C-RECORI		9,412,221						
800	904-OP	UNCOLLECTIBLE ACCOUNTS	UAR								
801	905-OP	MISC CUSTOMER ACCOUNTS EXPENS	L 798-800								
802		TOTAL CUSTOMER ACCOUNTING EXPENSES									
803											
804		CUSTOMER SERVICES & INFORMATION EXPENSES									
805	907-OP	SUPERVISION	L-907					688,109			
806	908-OP	CUSTOMER ASSISTANCE	D-908					3,885,609			
807	908 / ENERGY EFFICIENCY RIDER		NONE								
808	909-OP	INFORMATION & INSTRUCTIONAL	C-ASSIST								
809	912	DEMO AND SELLING EXPENSES	L 806-808					256,420			
810		TOTAL CUST SERV & INFO EXPENSES									
811											

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
			ALLOCATOF						& REVENUES
				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
769	*** *TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.*								
770									
771		DISTRIBUTION EXPENSES							
772	580-OP	SUPERVISION & ENGINEERING	L-580						
773	581-OP	LOAD DISPATCHING	D3601						
774	582-OP	STATION EXPENSES	D362						
775	583-OP	OVERHEAD LINE EXPENSES	D-364-365						
776	584-OP	UNDERGROUND LINE EXPENSES	D-366-367						
777	585-OP	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT						
778	586-OP	METER EXPENSES	METER						
779	587-OP	CUSTOMER INSTALLATIONS EXPENSE	CUSTINST						
780	588-OP	MISCELLANEOUS EXPENSES	D3601						
781	589-OP	RENTS	D3601						
782		TOTAL DISTRIBUTION OPERATION							
783									
784	590-MT	SUPERVISION & ENGINEERING	L-590						
785	591-MT	STRUCTURES	D361						
786	592-MT	STATION EQUIPMENT	D362						
787	593-MT	OVERHEAD LINES	D-364-365						
788	594-MT	UNDERGROUND LINES	D-366-367						
789	595-MT	LINE TRANSFORMERS	D368						
790	596-MT	STREET LIGHTING & SIGNAL SYSTEMS	STLIGHT						
791	597-MT	METERS	METER						
792	598-MT	MISCELLANEOUS PLANT	D3601						
793		TOTAL DISTRIBUTION MAINTENANCE							
794		TOTAL DISTRIBUTION EXPENSES							
795									
796		CUSTOMER ACCOUNTING EXPENSES							
797	901-OP	SUPERVISION	L-901						
798	902-OP	METER READING	M-READ						
799	903-OP	CUSTOMER RECORDS & COLLECTIONS	C-RECORI						
800	904-OP	UNCOLLECTIBLE ACCOUNTS	UAR						
801	905-OP	MISC CUSTOMER ACCOUNTS EXPENS	L 798-800						
802		TOTAL CUSTOMER ACCOUNTING EXPENSES							
803									
804		CUSTOMER SERVICES & INFORMATION EXPENSES							
805	907-OP	SUPERVISION	L-907						
806	908-OP	CUSTOMER ASSISTANCE	D-908						
807	908 / ENERGY EFFICIENCY RIDER		NONE						
808	909-OP	INFORMATION & INSTRUCTIONAL	C-ASSIST						
809	912	DEMO AND SELLING EXPENSES	L 806-808						
810		TOTAL CUST SERV & INFO EXPENSES							
811									

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
812	**** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOCATOR * * ****											
813												
814	ADMINISTRATIVE & GENERAL EXPENSES											
815	920-OP	ADMINISTRATIVE & GENERAL SALARIES	LABOR	51,175,830	22,029,585	888,538				5,981,709		533
816	921-OP	OFFICE SUPPLIES	LABOR	218,898	94,229	3,801				25,586		2
817	922-OP	ADMIN & GENERAL EXP TRANSFERRED	LABOR									
818	923-OP	OUTSIDE SERVICES	O&M-M									
819	924-OP	PROPERTY INSURANCE										
820		PRODUCTION - STEAM	NONE									
821		ALL RISK & MISCELLANEOUS	P101P	363,208	124,815	11,762				84,559		5
822		TOTAL ACCOUNT 924		363,208								
823												
824	925-OP	INJURIES & DAMAGES	LABOR	126,578	54,488	2,198				14,795		1
825	926-OP	EMPLOYEE PENSIONS & BENEFITS	LABOR									
826	927-OP	FRANCHISE REQUIREMENTS	NONE									
827	928-OP	REGULATORY COMMISSION EXPENSES										
828		FERC ADMIN ASSESSMENTS	NONE									
829		FERC RATE CASE EXPENSE	NONE									
830		SEC EXPENSES	NONE									
831		IDAHO PUC - RATE CASE	NONE									
832		- OTHER	NONE									
833		OREGON PUC - RATE CASE	NONE									
834		-OTHER	NONE									
835		NEVADA PSC - RATE CASE	NONE									
836		-OTHER	NONE									
837		TOTAL ACCOUNT 928										
838												
839	929-OP	DUPLICATE CHARGES-CR	NONE									
840	9301-OP	GENERAL ADVERTISING	LABOR									
841	9302-OP	MISCELLANEOUS EXPENSES	LABOR	205,380	88,410	3,566				24,006		2
842	931-OP	RENTS	GEN-PLT									
843	935-MT	GENERAL PLANT MAINTENANCE	GEN-PLT	993,286	341,339	32,166				231,248		14
844		TOTAL ADMIN & GENERAL EXPENSES		53,083,181								
845		TOTAL OPER & MAINT EXPENSES		155,452,955	66,799,832	2,719,421				18,327,439		1,625
846												
847		TOTAL LABOR - RATIO (%)		1.0000	0.4297	0.0175				0.1179		0.0000

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line	Account	Description	Allocator	Substation General	Substation Direct	Substation CIAC	Pri Lines Demand	Pri Lines Customer	Sec Lines Direct	Line Trans Pri Dmd	Line Trans Pri Cust	Line Trans Pri Direct	Line Trans Sec Dmd
6			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *			DISTRIBUTION FUNCTION	* *					
8			ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
812	***** * * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.***												
813													
814	ADMINISTRATIVE & GENERAL EXPENSES												
815	920-OP	ADMINISTRATIVE & GENERAL SALARIES	LABOR	2,528,650	114,836		4,190,021	2,076,633	161,302	212,478	105,307	58,886	614,512
816	921-OP	OFFICE SUPPLIES	LABOR	10,816	491		17,922	8,883	690	909	450	252	2,629
817	922-OP	ADMIN & GENERAL EXP TRANSFERRED	LABOR										
818	923-OP	OUTSIDE SERVICES	O&M-M										
819	924-OP	PROPERTY INSURANCE											
820		PRODUCTION - STEAM	NONE										
821		ALL RISK & MISCELLANEOUS	P101P	27,351	1,276		33,405	16,556	2,088	7,514	3,724	2,083	21,732
822		TOTAL ACCOUNT 924											
823													
824	925-OP	INJURIES & DAMAGES	LABOR	6,254	284		10,364	5,136	399	526	260	146	1,520
825	926-OP	EMPLOYEE PENSIONS & BENEFITS	LABOR										
826	927-OP	FRANCHISE REQUIREMENTS	NONE										
827	928-OP	REGULATORY COMMISSION EXPENSES											
828		FERC ADMIN ASSESSMENTS	NONE										
829		FERC RATE CASE EXPENSE	NONE										
830		SEC EXPENSES	NONE										
831		IDAHO PUC - RATE CASE	NONE										
832		- OTHER	NONE										
833		OREGON PUC - RATE CASE	NONE										
834		-OTHER	NONE										
835		NEVADA PSC - RATE CASE	NONE										
836		-OTHER	NONE										
837		TOTAL ACCOUNT 928											
838													
839	929-OP	DUPLICATE CHARGES-CR	NONE										
840	9301-OP	GENERAL ADVERTISING	LABOR										
841	9302-OP	MISCELLANEOUS EXPENSES	LABOR	10,148	461		16,816	8,334	647	853	423	236	2,466
842	931-OP	RENTS	GEN-PLT										
843	935-MT	GENERAL PLANT MAINTENANCE	GEN-PLT	74,798	3,488		91,356	45,277	5,709	20,550	10,185	5,695	59,433
844		TOTAL ADMIN & GENERAL EXPENSES											
845		TOTAL OPER & MAINT EXPENSES		7,716,213	350,549		12,741,408	6,314,821	493,495	667,861	331,001	185,090	1,931,534
846													
847		TOTAL LABOR - RATIO (%)		0.0496	0.0023		0.0820	0.0406	0.0032	0.0043	0.0021	0.0012	0.0124

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * * DISTRIBUTION FUNCTION * * * * * * * * * * * * * *						
8			ALLOCATOR	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
812	***** * * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.***									
813										
814	ADMINISTRATIVE & GENERAL EXPENSES									
815	920-OP	ADMINISTRATIVE & GENERAL SALARIES	LABOR	304,561	288,755	143,111	122,032	2,890,464	81,921	407,817
816	921-OP	OFFICE SUPPLIES	LABOR	1,303	1,235	612	522	12,364	350	1,744
817	922-OP	ADMIN & GENERAL EXP TRANSFERRED	LABOR							
818	923-OP	OUTSIDE SERVICES	O&M-M							
819	924-OP	PROPERTY INSURANCE								
820		PRODUCTION - STEAM	NONE							
821		ALL RISK & MISCELLANEOUS	P101P	10,771	2,141	1,061	4,357	7,333	394	281
822		TOTAL ACCOUNT 924								
823										
824	925-OP	INJURIES & DAMAGES	LABOR	753	714	354	302	7,149	203	1,009
825	926-OP	EMPLOYEE PENSIONS & BENEFITS	LABOR							
826	927-OP	FRANCHISE REQUIREMENTS	NONE							
827	928-OP	REGULATORY COMMISSION EXPENSES								
828		FERC ADMIN ASSESSMENTS	NONE							
829		FERC RATE CASE EXPENSE	NONE							
830		SEC EXPENSES	NONE							
831		IDAHO PUC - RATE CASE	NONE							
832		- OTHER	NONE							
833		OREGON PUC - RATE CASE	NONE							
834		-OTHER	NONE							
835		NEVADA PSC - RATE CASE	NONE							
836		-OTHER	NONE							
837		TOTAL ACCOUNT 928								
838										
839	929-OP	DUPLICATE CHARGES-CR	NONE							
840	9301-OP	GENERAL ADVERTISING	LABOR							
841	9302-OP	MISCELLANEOUS EXPENSES	LABOR	1,222	1,159	574	490	11,600	329	1,637
842	931-OP	RENTS	GEN-PLT							
843	935-MT	GENERAL PLANT MAINTENANCE	GEN-PLT	29,456	5,855	2,902	11,914	20,054	1,078	770
844		TOTAL ADMIN & GENERAL EXPENSES								
845		TOTAL OPER & MAINT EXPENSES		957,295	877,470	434,886	383,723	8,730,916	248,148	1,229,037
846										
847		TOTAL LABOR - RATIO (%)		0.0062	0.0056	0.0028	0.0025	0.0562	0.0016	0.0079

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOF	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
812	**** * * TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.***										
813											
814	ADMINISTRATIVE & GENERAL EXPENSES										
815	920-OP	ADMINISTRATIVE & GENERAL SALARIES	LABOR	580,885	4,978,651			2,414,642			
816	921-OP	OFFICE SUPPLIES	LABOR	2,485	21,296			10,328			
817	922-OP	ADMIN & GENERAL EXP TRANSFERRED	LABOR								
818	923-OP	OUTSIDE SERVICES	O&M-M								
819	924-OP	PROPERTY INSURANCE									
820		PRODUCTION - STEAM	NONE								
821		ALL RISK & MISCELLANEOUS	P101P								
822		TOTAL ACCOUNT 924									
823											
824	925-OP	INJURIES & DAMAGES	LABOR	1,437	12,314			5,972			
825	926-OP	EMPLOYEE PENSIONS & BENEFITS	LABOR								
826	927-OP	FRANCHISE REQUIREMENTS	NONE								
827	928-OP	REGULATORY COMMISSION EXPENSES									
828		FERC ADMIN ASSESSMENTS	NONE								
829		FERC RATE CASE EXPENSE	NONE								
830		SEC EXPENSES	NONE								
831		IDAHO PUC - RATE CASE	NONE								
832		- OTHER	NONE								
833		OREGON PUC - RATE CASE	NONE								
834		-OTHER	NONE								
835		NEVADA PSC - RATE CASE	NONE								
836		-OTHER	NONE								
837		TOTAL ACCOUNT 928									
838											
839	929-OP	DUPLICATE CHARGES-CR	NONE								
840	9301-OP	GENERAL ADVERTISING	LABOR								
841	9302-OP	MISCELLANEOUS EXPENSES	LABOR	2,331	19,980			9,691			
842	931-OP	RENTS	GEN-PLT								
843	935-MT	GENERAL PLANT MAINTENANCE	GEN-PLT								
844		TOTAL ADMIN & GENERAL EXPENSES									
845		TOTAL OPER & MAINT EXPENSES		1,749,115	14,991,305			7,270,771			
846											
847		TOTAL LABOR - RATIO (%)		0.0113	0.0964			0.0468			

Line			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
812	***** TABLE 10 - DEVELOPMENT OF LABOR RELATED ALLOC.**								
813									
814	ADMINISTRATIVE & GENERAL EXPENSES								
815	920-OP	ADMINISTRATIVE & GENERAL SALARIES	LABOR						
816	921-OP	OFFICE SUPPLIES	LABOR						
817	922-OP	ADMIN & GENERAL EXP TRANSFERRED	LABOR						
818	923-OP	OUTSIDE SERVICES	O&M-M						
819	924-OP	PROPERTY INSURANCE							
820		PRODUCTION - STEAM	NONE						
821		ALL RISK & MISCELLANEOUS	P101P						
822		TOTAL ACCOUNT 924							
823									
824	925-OP	INJURIES & DAMAGES	LABOR						
825	926-OP	EMPLOYEE PENSIONS & BENEFITS	LABOR						
826	927-OP	FRANCHISE REQUIREMENTS	NONE						
827	928-OP	REGULATORY COMMISSION EXPENSES							
828		FERC ADMIN ASSESSMENTS	NONE						
829		FERC RATE CASE EXPENSE	NONE						
830		SEC EXPENSES	NONE						
831		IDAHO PUC - RATE CASE	NONE						
832		- OTHER	NONE						
833		OREGON PUC - RATE CASE	NONE						
834		-OTHER	NONE						
835		NEVADA PSC - RATE CASE	NONE						
836		-OTHER	NONE						
837		TOTAL ACCOUNT 928							
838									
839	929-OP	DUPLICATE CHARGES-CR	NONE						
840	9301-OP	GENERAL ADVERTISING	LABOR						
841	9302-OP	MISCELLANEOUS EXPENSES	LABOR						
842	931-OP	RENTS	GEN-PLT						
843	935-MT	GENERAL PLANT MAINTENANCE	GEN-PLT						
844		TOTAL ADMIN & GENERAL EXPENSES							
845		TOTAL OPER & MAINT EXPENSES							
846									
847		TOTAL LABOR - RATIO (%)							

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line		(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7			TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8		ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9				Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
848	*** *TABLE 11 - FUNCTIONALIZATION ALLOCATORS* ***										
849											
850	**DIRECT ASSIGNMENT ALLOCATORS**										
851	PRODUCTION DIRECT ASSIGNMENT ALLOCATORS										
852	KWH GENERATION - BY STEAM UNITS	KWH-S	100%				100%				
853	KWH GENERATION - BY HYDRAULIC UNITS	KWH-H	100%				100%				
854	KWH GENERATION - BY OTHER UNITS	KWH-O	100%				100%				
855	KWH GENERATION - BY OTHER	KWH-O	100%				100%				
856	KWH GENERATION - ANNUAL	KWH-T	100%				100%				
857	555 PURCHASED POWER - CAPACITY	PP-KW	100%	91%	9%						
858	555 PURCHASED POWER - ENERGY	PP-KWH	100%				100%				
859	555 PURCHASED POWER - OTHER	PP-OT	100%				100%				
860	555 PURCHASED POWER - TOTAL	PP-T	100%	30%	3%		67%				
861	TOTAL COGEN & SMALL POWER PROD	COGEN-E:	100%				100%				
862	PRODUCTION - STEAM INVESTMENT	PI-S	100%	100%							
863	PRODUCTION - HYDRAULIC INVESTMENT	PI-H	100%	100%							
864	PRODUCTION - OTHER INVESTMENT	PI-O	100%		100%						
865	PRODUCTION - OTHER INVESTMENT - Baseload ;	PI-OS	100%	70%	30%						
866	TRANSMISSION DIRECT ASSIGNMENT ALLOCATORS										
867	TRANSMISSION PLANT	T-100	100%						100%		
868	TRANSMISSION DIRECT ASSIGNMENT	T-Direct	100%								100%
869	DISTRIBUTION DIRECT ASSIGNMENT ALLOCATORS										
870	SUBSTATION CIAC	CIAC	100%								
871	SERVICES	SERVICE	100%								
872	METERS	METER	100%								
873	METER READING	M-READ	100%								
874	CUSTOMER RECORDS	C-RECORI	100%								
875	CUSTOMER ASSISTANCE	C-ASSIST	100%								
876	UNCOLLECTIBLE ACCOUNTS	UAR	100%								
877	INSTALLATIONS ON CUSTOMER PREMISES	CUSTINST	100%								
878	STREET LIGHTING SYSTEMS	STLIGHT	100%								
879	OTHER DIRECT ASSIGNMENT ALLOCATORS										
880	MISC. REVENUE	MISC-REV	100%								
881	OTHER REVENUE	OTH-REV	100%								
882	OTHER EXPENSE	OTH-EXP	100%								
883	INCOME TAX AND REVENUE ALLOCATOR	TAX-REV	100%								
884	KWH-TAX	KWH-TAX	100%								
885	NULL REV. REQ. VALUE	NONE									
886	**DERIVED ALLOCATORS**										
887	PRODUCTION ALLOCATORS										
888	PRODUCTION - HYDRAULIC & OTHER INVESTMENT		1,664,974,337	1,484,143,992	180,830,345						
889	L 21-23	PI-HO	100%	89%	11%						
890	TOTAL PRODUCTION PLANT INVESTMENT		2,099,744,010	1,918,913,664	180,830,345						
891	L 25	PI-SHO	100%	91%	9%						
892	TRANSMISSION ALLOCATORS										
893	350 LAND & LAND RIGHTS		39,364,923						39,364,923		
894	L 31	T-350	100%						100%		
895	352 STRUCTURES & IMPROVEMENTS		96,459,348						96,459,348		

1 **IDAHO POWER COMPANY**
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4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7			* *				DISTRIBUTION FUNCTION *					
8		ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9			GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
848	****** TABLE 11 - FUNCTIONALIZATION ALLOCATORS ******											
849												
850	**DIRECT ASSIGNMENT ALLOCATORS**											
851	PRODUCTION DIRECT ASSIGNMENT ALLOCATORS											
852	KWH GENERATION - BY STEAM UNITS	KWH-S										
853	KWH GENERATION - BY HYDRAULIC UNITS	KWH-H										
854	KWH GENERATION - BY OTHER UNITS	KWH-O										
855	KWH GENERATION - BY OTHER	KWH-O										
856	KWH GENERATION - ANNUAL	KWH-T										
857	555 PURCHASED POWER - CAPACITY	PP-KW										
858	555 PURCHASED POWER - ENERGY	PP-KWH										
859	555 PURCHASED POWER - OTHER	PP-OT										
860	555 PURCHASED POWER - TOTAL	PP-T										
861	TOTAL COGEN & SMALL POWER PROD	COGEN-E										
862	PRODUCTION - STEAM INVESTMENT	PI-S										
863	PRODUCTION - HYDRAULIC INVESTMENT	PI-H										
864	PRODUCTION - OTHER INVESTMENT	PI-O										
865	PRODUCTION - OTHER INVESTMENT - Baseload &	PI-OS										
866	TRANSMISSION DIRECT ASSIGNMENT ALLOCATORS											
867	TRANSMISSION PLANT	T-100										
868	TRANSMISSION DIRECT ASSIGNMENT	T-Direct										
869	DISTRIBUTION DIRECT ASSIGNMENT ALLOCATORS											
870	SUBSTATION CIAC	CIAC			100%							
871	SERVICES	SERVICE										
872	METERS	METER										
873	METER READING	M-READ										
874	CUSTOMER RECORDS	C-RECORI										
875	CUSTOMER ASSISTANCE	C-ASSIST										
876	UNCOLLECTIBLE ACCOUNTS	UAR										
877	INSTALLATIONS ON CUSTOMER PREMISES	CUSTINST										
878	STREET LIGHTING SYSTEMS	STLIGHT										
879	OTHER DIRECT ASSIGNMENT ALLOCATORS											
880	MISC. REVENUE	MISC-REV										
881	OTHER REVENUE	OTH-REV										
882	OTHER EXPENSE	OTH-EXP										
883	INCOME TAX AND REVENUE ALLOCATOR	TAX-REV										
884	KWH-TAX	KWH-TAX										
885	NULL REV. REQ. VALUE	NONE										
886	**DERIVED ALLOCATORS**											
887	PRODUCTION ALLOCATORS											
888	PRODUCTION - HYDRAULIC & OTHER INVESTMENT											
889	L 21-23	PI-HO										
890	TOTAL PRODUCTION PLANT INVESTMENT											
891	L 25	PI-SHO										
892	TRANSMISSION ALLOCATORS											
893	350 LAND & LAND RIGHTS											
894	L 31	T-350										
895	352 STRUCTURES & IMPROVEMENTS											

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7			* * * * * * * * * * * * * *	DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *				
8		ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9			SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
848	*** *TABLE 11 - FUNCTIONALIZATION ALLOCATORS* ***								
849									
850	**DIRECT ASSIGNMENT ALLOCATORS**								
851	PRODUCTION DIRECT ASSIGNMENT ALLOCATORS								
852	KWH GENERATION - BY STEAM UNITS	KWH-S							
853	KWH GENERATION - BY HYDRAULIC UNITS	KWH-H							
854	KWH GENERATION - BY OTHER UNITS	KWH-O							
855	KWH GENERATION - BY OTHER	KWH-O							
856	KWH GENERATION - ANNUAL	KWH-T							
857	555 PURCHASED POWER - CAPACITY	PP-KW							
858	555 PURCHASED POWER - ENERGY	PP-KWH							
859	555 PURCHASED POWER - OTHER	PP-OT							
860	555 PURCHASED POWER - TOTAL	PP-T							
861	TOTAL COGEN & SMALL POWER PROD	COGEN-E:							
862	PRODUCTION - STEAM INVESTMENT	PI-S							
863	PRODUCTION - HYDRAULIC INVESTMENT	PI-H							
864	PRODUCTION - OTHER INVESTMENT	PI-O							
865	PRODUCTION - OTHER INVESTMENT - Baseload ε	PI-OS							
866	TRANSMISSION DIRECT ASSIGNMENT ALLOCATORS								
867	TRANSMISSION PLANT	T-100							
868	TRANSMISSION DIRECT ASSIGNMENT	T-Direct							
869	DISTRIBUTION DIRECT ASSIGNMENT ALLOCATORS								
870	SUBSTATION CIAC	CIAC							
871	SERVICES	SERVICE				100%			
872	METERS	METER					100%		
873	METER READING	M-READ							
874	CUSTOMER RECORDS	C-RECORI							
875	CUSTOMER ASSISTANCE	C-ASSIST							
876	UNCOLLECTIBLE ACCOUNTS	UAR							
877	INSTALLATIONS ON CUSTOMER PREMISES	CUSTINST							100%
878	STREET LIGHTING SYSTEMS	STLIGHT						100%	
879	OTHER DIRECT ASSIGNMENT ALLOCATORS								
880	MISC. REVENUE	MISC-REV							
881	OTHER REVENUE	OTH-REV							
882	OTHER EXPENSE	OTH-EXP							
883	INCOME TAX AND REVENUE ALLOCATOR	TAX-REV							
884	KWH-TAX	KWH-TAX							
885	NULL REV. REQ. VALUE	NONE							
886	**DERIVED ALLOCATORS**								
887	PRODUCTION ALLOCATORS								
888	PRODUCTION - HYDRAULIC & OTHER INVESTMENT								
889	L 21-23	PI-HO							
890	TOTAL PRODUCTION PLANT INVESTMENT								
891	L 25	PI-SHO							
892	TRANSMISSION ALLOCATORS								
893	350 LAND & LAND RIGHTS								
894	L 31	T-350							
895	352 STRUCTURES & IMPROVEMENTS								

1	IDAHO POWER COMPANY									
2	BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION									
3	CLASS COST OF SERVICE STUDY									
4	FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023									
5	FUNCTIONALIZATION AND CLASSIFICATION OF COSTS									
6		(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7			- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8		ALLOCATOF	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9			READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
848	*** *TABLE 11 - FUNCTIONALIZATION ALLOCATORS* ***									
849										
850	**DIRECT ASSIGNMENT ALLOCATORS**									
851	PRODUCTION DIRECT ASSIGNMENT ALLOCATORS									
852	KWH GENERATION - BY STEAM UNITS	KWH-S								
853	KWH GENERATION - BY HYDRAULIC UNITS	KWH-H								
854	KWH GENERATION - BY OTHER UNITS	KWH-O								
855	KWH GENERATION - BY OTHER	KWH-O								
856	KWH GENERATION - ANNUAL	KWH-T								
857	555 PURCHASED POWER - CAPACITY	PP-KW								
858	555 PURCHASED POWER - ENERGY	PP-KWH								
859	555 PURCHASED POWER - OTHER	PP-OT								
860	555 PURCHASED POWER - TOTAL	PP-T								
861	TOTAL COGEN & SMALL POWER PROD	COGEN-E)								
862	PRODUCTION - STEAM INVESTMENT	PI-S								
863	PRODUCTION - HYDRAULIC INVESTMENT	PI-H								
864	PRODUCTION - OTHER INVESTMENT	PI-O								
865	PRODUCTION - OTHER INVESTMENT - Baseload &	PI-OS								
866	TRANSMISSION DIRECT ASSIGNMENT ALLOCATORS									
867	TRANSMISSION PLANT	T-100								
868	TRANSMISSION DIRECT ASSIGNMENT	T-Direct								
869	DISTRIBUTION DIRECT ASSIGNMENT ALLOCATORS									
870	SUBSTATION CIAC	CIAC								
871	SERVICES	SERVICE								
872	METERS	METER								
873	METER READING	M-READ	100%							
874	CUSTOMER RECORDS	C-RECORI		100%						
875	CUSTOMER ASSISTANCE	C-ASSIST					100%			
876	UNCOLLECTIBLE ACCOUNTS	UAR			100%					
877	INSTALLATIONS ON CUSTOMER PREMISES	CUSTINST								
878	STREET LIGHTING SYSTEMS	STLIGHT								
879	OTHER DIRECT ASSIGNMENT ALLOCATORS									
880	MISC. REVENUE	MISC-REV								
881	OTHER REVENUE	OTH-REV								
882	OTHER EXPENSE	OTH-EXP								
883	INCOME TAX AND REVENUE ALLOCATOR	TAX-REV								
884	KWH-TAX	KWH-TAX								
885	NULL REV. REQ. VALUE	NONE								
886	**DERIVED ALLOCATORS**									
887	PRODUCTION ALLOCATORS									
888	PRODUCTION - HYDRAULIC & OTHER INVESTMENT									
889	L 21-23	PI-HO								
890	TOTAL PRODUCTION PLANT INVESTMENT									
891	L 25	PI-SHO								
892	TRANSMISSION ALLOCATORS									
893	350 LAND & LAND RIGHTS									
894	L 31	T-350								
895	352 STRUCTURES & IMPROVEMENTS									

IDAHO POWER COMPANY
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Line		(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7			- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8		ALLOCATOF						& REVENUES
9			DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
848	*** ***TABLE 11 - FUNCTIONALIZATION ALLOCATORS*** ***							
849								
850	**DIRECT ASSIGNMENT ALLOCATORS**							
851	PRODUCTION DIRECT ASSIGNMENT ALLOCATORS							
852	KWH GENERATION - BY STEAM UNITS	KWH-S						
853	KWH GENERATION - BY HYDRAULIC UNITS	KWH-H						
854	KWH GENERATION - BY OTHER UNITS	KWH-O						
855	KWH GENERATION - BY OTHER	KWH-O						
856	KWH GENERATION - ANNUAL	KWH-T						
857	555 PURCHASED POWER - CAPACITY	PP-KW						
858	555 PURCHASED POWER - ENERGY	PP-KWH						
859	555 PURCHASED POWER - OTHER	PP-OT						
860	555 PURCHASED POWER - TOTAL	PP-T						
861	TOTAL COGEN & SMALL POWER PROD	COGEN-E)						
862	PRODUCTION - STEAM INVESTMENT	PI-S						
863	PRODUCTION - HYDRAULIC INVESTMENT	PI-H						
864	PRODUCTION - OTHER INVESTMENT	PI-O						
865	PRODUCTION - OTHER INVESTMENT - Baseload &	PI-OS						
866	TRANSMISSION DIRECT ASSIGNMENT ALLOCATORS							
867	TRANSMISSION PLANT	T-100						
868	TRANSMISSION DIRECT ASSIGNMENT	T-Direct						
869	DISTRIBUTION DIRECT ASSIGNMENT ALLOCATORS							
870	SUBSTATION CIAC	CIAC						
871	SERVICES	SERVICE						
872	METERS	METER						
873	METER READING	M-READ						
874	CUSTOMER RECORDS	C-RECORI						
875	CUSTOMER ASSISTANCE	C-ASSIST						
876	UNCOLLECTIBLE ACCOUNTS	UAR						
877	INSTALLATIONS ON CUSTOMER PREMISES	CUSTINST						
878	STREET LIGHTING SYSTEMS	STLIGHT						
879	OTHER DIRECT ASSIGNMENT ALLOCATORS							
880	MISC. REVENUE	MISC-REV				100%		
881	OTHER REVENUE	OTH-REV					100%	
882	OTHER EXPENSE	OTH-EXP					100%	
883	INCOME TAX AND REVENUE ALLOCATOR	TAX-REV						100%
884	KWH-TAX	KWH-TAX		100%				
885	NULL REV. REQ. VALUE	NONE						
886	**DERIVED ALLOCATORS**							
887	PRODUCTION ALLOCATORS							
888	PRODUCTION - HYDRAULIC & OTHER INVESTMENT							
889	L 21-23	PI-HO						
890	TOTAL PRODUCTION PLANT INVESTMENT							
891	L 25	PI-SHO						
892	TRANSMISSION ALLOCATORS							
893	350 LAND & LAND RIGHTS							
894	L 31	T-350						
895	352 STRUCTURES & IMPROVEMENTS							

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7				TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8			ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9					Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
896		L 36	T-352	100%						100%		
897	353	STATION EQUIPMENT		449,356,402						449,281,302		75,100
898		L 41	T-353	100%						100%		0%
899	354	TOWERS & FIXTURES		227,483,716						227,483,716		
900		L 47	T-354	100%						100%		
901	355	POLES & FIXTURES		226,404,073						226,404,073		
902		L 52	T-355	100%						100%		
903	356	OVERHEAD CONDUCTORS & DEVICES		260,647,076						260,645,887		1,189
904		L 57	T-356	100%						100%		0%
905	359	ROADS & TRAILS		374,346						374,346		
906		L 63	T-359	100%						100%		
907	354-359	COMBINED TRANSMISSION ALLOCATOR		714,909,210						714,908,021		1,189
####		L 45-62	T-354-359	100%						100%		0%
909	354 - 35	COMBINED TRANSMISSION ALLOCATOR		714,534,864						714,533,675		1,189
910		L 45-56	T-354-356	100%						100%		0%
911	TOTAL TRANSMISSION PLANT			1,300,089,883						1,300,013,594		76,289
912		L 64	T-PLT	100%						100%		0%
913	DISTRIBUTION ALLOCATORS											
914	#360 LAND			9,056,163								
915	(DERIVED FROM ACTUALS)		D360	100%								
916	#361 STRUCTURES & IMPROVEMENTS			64,320,867								
917	(DERIVED FROM ACTUALS)		D361	100%								
918	#362 STATION EQUIPMENT			349,200,558								
919	(DERIVED FROM ACTUALS)		D362	100%								
920	#360 NET PLANT			8,625,808								
921	(DERIVED FROM ACTUALS)		D360N	100%								
922	#361 NET PLANT			56,873,252								
923	(DERIVED FROM ACTUALS)		D361N	100%								
924	#362 NET PLANT			314,307,682								
925	(DERIVED FROM ACTUALS)		D362N	100%								
926	#364 POLES, TOWERS, & FIXTURES			288,748,305								
927	(DERIVED FROM ACTUALS)		D364	100%								
928	#365 OVERHEAD CONDUCTORS & DEVICES			146,384,826								
929	(DERIVED FROM ACTUALS)		D365	100%								
930	#366 UNDERGROUND CONDUIT			51,958,505								
931	(DERIVED FROM ACTUALS)		D366	100%								
932	#367 UNDERGROUND CONDUCTORS & DEVICES			313,429,461								
933	(DERIVED FROM ACTUALS)		D367	100%								
934	#368 LINE TRANSFORMERS			666,063,582								
935	(DERIVED FROM ACTUALS)		D368	100%								
936	TOTAL DISTRIBUTION PLANT			2,184,148,463								
937			D3601	100%								
938	TOTAL NET DISTRIBUTION PLANT			2,123,850,274								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line			(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7				* *			DISTRIBUTION FUNCTION		* *				
8			ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9				GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
896		L 36	T-352										
897	353	STATION EQUIPMENT											
898		L 41	T-353										
899	354	TOWERS & FIXTURES											
900		L 47	T-354										
901	355	POLES & FIXTURES											
902		L 52	T-355										
903	356	OVERHEAD CONDUCTORS & DEVICES											
904		L 57	T-356										
905	359	ROADS & TRAILS											
906		L 63	T-359										
907	354-359	COMBINED TRANSMISSION ALLOCATOR											
####		L 45-62	T-354-359										
909	354 - 35	COMBINED TRANSMISSION ALLOCATOR											
910		L 45-56	T-354-356										
911	TOTAL TRANSMISSION PLANT												
912		L 64	T-PLT										
913	DISTRIBUTION ALLOCATORS												
914	#360 LAND			9,056,112	51								
915	(DERIVED FROM ACTUALS)		D360	100%	0%								
916	#361 STRUCTURES & IMPROVEMENTS			60,478,466	3,842,401								
917	(DERIVED FROM ACTUALS)		D361	94%	6%								
918	#362 STATION EQUIPMENT			334,200,746	14,999,812								
919	(DERIVED FROM ACTUALS)		D362	96%	4%								
920	#360 NET PLANT			8,625,757	51								
921	(DERIVED FROM ACTUALS)		D360N	100%	0%								
922	#361 NET PLANT			56,337,171	536,081								
923	(DERIVED FROM ACTUALS)		D361N	99%	1%								
924	#362 NET PLANT			310,836,279	3,471,403								
925	(DERIVED FROM ACTUALS)		D362N	99%	1%								
926	#364 POLES, TOWERS, & FIXTURES						180,815,162	89,614,532	2,012,844				
927	(DERIVED FROM ACTUALS)		D364				63%	31%	1%				
928	#365 OVERHEAD CONDUCTORS & DEVICES						87,905,108	43,567,005	1,351,968				
929	(DERIVED FROM ACTUALS)		D365				60%	30%	1%				
930	#366 UNDERGROUND CONDUIT						24,711,812	12,247,521	6,296,318				
931	(DERIVED FROM ACTUALS)		D366				48%	24%	12%				
932	#367 UNDERGROUND CONDUCTORS & DEVICES						190,387,577	94,358,755	20,641,588				
933	(DERIVED FROM ACTUALS)		D367				61%	30%	7%				
934	#368 LINE TRANSFORMERS									109,222,060	54,131,986	30,269,678	315,883,541
935	(DERIVED FROM ACTUALS)		D368							16%	8%	5%	47%
936	TOTAL DISTRIBUTION PLANT			420,494,493	19,610,440		513,577,215	254,536,076	32,093,767	115,525,520	57,256,069	32,016,611	334,113,916
937			D3601	19%	1%		24%	12%	1%	5%	3%	1%	15%
938	TOTAL NET DISTRIBUTION PLANT			375,799,208	4,007,536		513,577,215	254,536,076	32,093,767	115,525,520	57,256,069	32,016,611	334,113,916

1					IDAHO POWER COMPANY					
2					BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION					
3					CLASS COST OF SERVICE STUDY					
4					FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023					
5					FUNCTIONALIZATION AND CLASSIFICATION OF COSTS					
6			(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7				* * * * * * * * * * * * * *		DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *			
8			ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9				SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
896		L 36	T-352							
897	353	STATION EQUIPMENT								
898		L 41	T-353							
899	354	TOWERS & FIXTURES								
900		L 47	T-354							
901	355	POLES & FIXTURES								
902		L 52	T-355							
903	356	OVERHEAD CONDUCTORS & DEVICES								
904		L 57	T-356							
905	359	ROADS & TRAILS								
906		L 63	T-359							
907	354-359	COMBINED TRANSMISSION ALLOCATOR								
####		L 45-62	T-354-359							
909	354 - 35	COMBINED TRANSMISSION ALLOCATOR								
910		L 45-56	T-354-356							
911	TOTAL TRANSMISSION PLANT									
912		L 64	T-PLT							
913	DISTRIBUTION ALLOCATORS									
914	#360 LAND									
915	(DERIVED FROM ACTUALS)		D360							
916	#361 STRUCTURES & IMPROVEMENTS									
917	(DERIVED FROM ACTUALS)		D361							
918	#362 STATION EQUIPMENT									
919	(DERIVED FROM ACTUALS)		D362							
920	#360 NET PLANT									
921	(DERIVED FROM ACTUALS)		D360N							
922	#361 NET PLANT									
923	(DERIVED FROM ACTUALS)		D361N							
924	#362 NET PLANT									
925	(DERIVED FROM ACTUALS)		D362N							
926	#364 POLES, TOWERS, & FIXTURES				10,902,390	5,403,377				
927	(DERIVED FROM ACTUALS)		D364		4%	2%				
928	#365 OVERHEAD CONDUCTORS & DEVICES				9,067,008	4,493,736				
929	(DERIVED FROM ACTUALS)		D365		6%	3%				
930	#366 UNDERGROUND CONDUIT				5,818,917	2,883,937				
931	(DERIVED FROM ACTUALS)		D366		11%	6%				
932	#367 UNDERGROUND CONDUCTORS & DEVICES				5,376,749	2,664,792				
933	(DERIVED FROM ACTUALS)		D367		2%	1%				
934	#368 LINE TRANSFORMERS			156,556,316						
935	(DERIVED FROM ACTUALS)		D368	24%						
936	TOTAL DISTRIBUTION PLANT			165,591,546	32,913,074	16,312,181	66,979,720	112,739,963	6,061,607	4,326,265
937			D3601	8%	2%	1%	3%	5%	0%	0%
938	TOTAL NET DISTRIBUTION PLANT			165,591,546	32,913,074	16,312,181	66,979,720	112,739,963	6,061,607	4,326,265

1 **IDAHO POWER COMPANY**
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4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6			(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7				- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8			ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9				READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
896		L 36	T-352								
897	353	STATION EQUIPMENT									
898		L 41	T-353								
899	354	TOWERS & FIXTURES									
900		L 47	T-354								
901	355	POLES & FIXTURES									
902		L 52	T-355								
903	356	OVERHEAD CONDUCTORS & DEVICES									
904		L 57	T-356								
905	359	ROADS & TRAILS									
906		L 63	T-359								
907	354-359	COMBINED TRANSMISSION ALLOCATOR									
####		L 45-62	T-354-359								
909	354 - 35	COMBINED TRANSMISSION ALLOCATOR									
910		L 45-56	T-354-356								
911	TOTAL TRANSMISSION PLANT										
912		L 64	T-PLT								
913	DISTRIBUTION ALLOCATORS										
914	#360 LAND										
915	(DERIVED FROM ACTUALS)		D360								
916	#361 STRUCTURES & IMPROVEMENTS										
917	(DERIVED FROM ACTUALS)		D361								
918	#362 STATION EQUIPMENT										
919	(DERIVED FROM ACTUALS)		D362								
920	#360 NET PLANT										
921	(DERIVED FROM ACTUALS)		D360N								
922	#361 NET PLANT										
923	(DERIVED FROM ACTUALS)		D361N								
924	#362 NET PLANT										
925	(DERIVED FROM ACTUALS)		D362N								
926	#364 POLES, TOWERS, & FIXTURES										
927	(DERIVED FROM ACTUALS)		D364								
928	#365 OVERHEAD CONDUCTORS & DEVICES										
929	(DERIVED FROM ACTUALS)		D365								
930	#366 UNDERGROUND CONDUIT										
931	(DERIVED FROM ACTUALS)		D366								
932	#367 UNDERGROUND CONDUCTORS & DEVICES										
933	(DERIVED FROM ACTUALS)		D367								
934	#368 LINE TRANSFORMERS										
935	(DERIVED FROM ACTUALS)		D368								
936	TOTAL DISTRIBUTION PLANT										
937			D3601								
938	TOTAL NET DISTRIBUTION PLANT										

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Line									
6			(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7				- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8			ALLOCATOF						& REVENUES
9				DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
896		L 36	T-352						
897	353	STATION EQUIPMENT							
898		L 41	T-353						
899	354	TOWERS & FIXTURES							
900		L 47	T-354						
901	355	POLES & FIXTURES							
902		L 52	T-355						
903	356	OVERHEAD CONDUCTORS & DEVICES							
904		L 57	T-356						
905	359	ROADS & TRAILS							
906		L 63	T-359						
907	354-359	COMBINED TRANSMISSION ALLOCATOR							
####		L 45-62	T-354-359						
909	354 - 35	COMBINED TRANSMISSION ALLOCATOR							
910		L 45-56	T-354-356						
911	TOTAL TRANSMISSION PLANT								
912		L 64	T-PLT						
913	DISTRIBUTION ALLOCATORS								
914	#360 LAND								
915	(DERIVED FROM ACTUALS)		D360						
916	#361 STRUCTURES & IMPROVEMENTS								
917	(DERIVED FROM ACTUALS)		D361						
918	#362 STATION EQUIPMENT								
919	(DERIVED FROM ACTUALS)		D362						
920	#360 NET PLANT								
921	(DERIVED FROM ACTUALS)		D360N						
922	#361 NET PLANT								
923	(DERIVED FROM ACTUALS)		D361N						
924	#362 NET PLANT								
925	(DERIVED FROM ACTUALS)		D362N						
926	#364 POLES, TOWERS, & FIXTURES								
927	(DERIVED FROM ACTUALS)		D364						
928	#365 OVERHEAD CONDUCTORS & DEVICES								
929	(DERIVED FROM ACTUALS)		D365						
930	#366 UNDERGROUND CONDUIT								
931	(DERIVED FROM ACTUALS)		D366						
932	#367 UNDERGROUND CONDUCTORS & DEVICES								
933	(DERIVED FROM ACTUALS)		D367						
934	#368 LINE TRANSFORMERS								
935	(DERIVED FROM ACTUALS)		D368						
936	TOTAL DISTRIBUTION PLANT								
937			D3601						
938	TOTAL NET DISTRIBUTION PLANT								

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6		(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7			TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8		ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9				Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
939		D3602N	100%								
940	DARK FIBER PROJECT REVENUE (ACCT 454)		2,184,148,463								
941	(DERIVED FROM ACTUALS)	D-FIBER	100%								
942	MERCHANDISING REVENUE		1,631,303,567				641				
943	(DERIVED FROM ACTUALS)	M-REV	100%								
944	MERCHANDISING EXPENSE		1,631,303,567				10,097				
945	(DERIVED FROM ACTUALS)	M-EXP	100%								
946	CUSTOMER ADVANCES FOR CONSTRUCTION		63,977,523								
947		CUSTADV	100%								
948	364-365 COMBINED DISTRIBUTION ALLOCATOR		461,598,814								
949	L 87-88	D-364-365	100%								
950	366-367 COMBINED DISTRIBUTION ALLOCATOR		387,833,499								
951	L 89-90	D-366-367	100%								
952	902-904 COMBINED DISTRIBUTION ALLOCATOR		23,220,761								
953	L 500-502	D-902-904	100%								
954	908 COMBINED DISTRIBUTION ALLOCATOR		11,377,854	1,673,332							
955	507-509	D-908	100%	15%							
956	908-909 COMBINED DISTRIBUTION ALLOCATOR		11,663,442	1,673,332							
957	L 507-511	D-908-909	100%	14%							
958	<u>PLANT-RELATED ALLOCATORS</u>										
959	"P112P' NET TOTAL PLANT PLUS INTANGIBLE		6,119,224,374	2,123,568,725	200,116,177				1,438,662,020		84,425
960		P112P	100%	35%	3%				24%		0%
961	"P111P" NET TOTAL PLANT LESS INTANGIBLE		6,018,437,105	2,088,933,575	196,852,306				1,415,197,616		83,048
962		P111P	100%	35%	3%				24%		0%
963	"P101P" TOTAL PLANT LESS INTANGIBLE		6,078,735,296	2,088,933,575	196,852,306				1,415,197,616		83,048
964		P101P	100%	34%	3%				23%		0%
965	"P110P" TOTAL PLANT INCLUDING INTANGIBLE		6,179,522,565	2,123,568,725	200,116,177				1,438,662,020		84,425
966		P110P	100%	34%	3%				23%		0%
967	"PTD" PLANT		5,583,982,355	1,918,913,664	180,830,345				1,300,013,594		76,289
968		P-PTD	100%	34%	3%				23%		0%
969	P110P - LESS STEAM PRODUCTION		5,912,422,670	1,856,468,830	200,116,177				1,438,662,020		84,425
970		P110P-L2(	100%	31%	3%				24%		0%
971	TOTAL GENERAL PLANT		494,752,941	170,019,910	16,021,961				115,184,022		6,759
972		GEN-PLT	100%	34%	3%				23%		0%
973	<u>O&M /LABOR ALLOCATORS</u>										
974	O&M PROD,TRANS,DIST,CA & CI (LABOR ONLY)		102,369,774	44,066,967	1,777,391				11,965,536		1,067
975		LABOR	100%	43%	2%				12%		0%
976	O&M PROD,TRANS,DIST,CA & CI (TOTAL O&M)		706,073,060	61,962,979	13,064,291		490,961,573		27,009,100		1,679
977		O&M-M	100%	9%	2%		70%		4%		0%
978	O&M PROD,ADMIN & GENERAL ONLY (TOTAL O&M)		182,750,903	76,173,715	3,452,075		1,855,842		21,769,057		1,842
979		O&M-AG	100%	42%	2%		1%		12%		0%
980	TOTAL OPERATING EXPENSES		888,823,963	138,136,693	16,516,367		492,817,416		48,778,156		3,521
981	L 560	O&M-T	100%	16%	2%		55%		5%		0%
982	SUPERVISION 500 - 501-507		7,813,593	7,813,593							
983	L 688-698	L-500	100%	100%							

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line		(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7			* *				DISTRIBUTION FUNCTION	* *				
8		ALLOCATOF	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9			GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
939		D3602N	18%	0%		24%	12%	2%	5%	3%	2%	16%
940	DARK FIBER PROJECT REVENUE (ACCT 454)		420,494,493	19,610,440		513,577,215	254,536,076	32,093,767	115,525,520	57,256,069	32,016,611	334,113,916
941	(DERIVED FROM ACTUALS)	D-FIBER	19%	1%		24%	12%	1%	5%	3%	1%	15%
942	MERCHANDISING REVENUE					513,577,215	254,536,076	32,093,767	115,525,520	57,256,069	32,016,611	334,113,916
943	(DERIVED FROM ACTUALS)	M-REV				31%	16%	2%	7%	4%	2%	20%
944	MERCHANDISING EXPENSE					513,577,215	254,536,076	32,093,767	115,525,520	57,256,069	32,016,611	334,113,916
945	(DERIVED FROM ACTUALS)	M-EXP				31%	16%	2%	7%	4%	2%	20%
946	CUSTOMER ADVANCES FOR CONSTRUCTION					27,550,407	13,654,368		1,112,215	551,229		3,422,755
947		CUSTADV				43%	21%		2%	1%		5%
948	364-365 COMBINED DISTRIBUTION ALLOCATOR					285,111,328	141,305,176	3,565,330				
949	L 87-88	D-364-365				62%	31%	1%				
950	366-367 COMBINED DISTRIBUTION ALLOCATOR					228,465,887	113,230,900	28,528,437				
951	L 89-90	D-366-367				59%	29%	7%				
952	902-904 COMBINED DISTRIBUTION ALLOCATOR											
953	L 500-502	D-902-904										
954	908 COMBINED DISTRIBUTION ALLOCATOR											
955	507-509	D-908										
956	908-909 COMBINED DISTRIBUTION ALLOCATOR											
957	L 507-511	D-908-909										
958	<u>PLANT-RELATED ALLOCATORS</u>											
959	"P112P' NET TOTAL PLANT PLUS INTANGIBLE		420,645,584	6,099,019		568,351,006	281,682,735	35,516,616	127,846,492	63,362,516	35,431,232	369,747,673
960		P112P	7%	0%		9%	5%	1%	2%	1%	1%	6%
961	"P111P" NET TOTAL PLANT LESS INTANGIBLE		413,055,930	5,745,063		559,081,269	277,088,524	34,937,344	125,761,331	62,329,081	34,853,352	363,717,133
962		P111P	7%	0%		9%	5%	1%	2%	1%	1%	6%
963	"P101P" TOTAL PLANT LESS INTANGIBLE		457,751,217	21,347,968		559,081,269	277,088,524	34,937,344	125,761,331	62,329,081	34,853,352	363,717,133
964		P101P	8%	0%		9%	5%	1%	2%	1%	1%	6%
965	"P110P" TOTAL PLANT INCLUDING INTANGIBLE		465,340,871	21,701,923		568,351,006	281,682,735	35,516,616	127,846,492	63,362,516	35,431,232	369,747,673
966		P110P	8%	0%		9%	5%	1%	2%	1%	1%	6%
967	"PTD" PLANT		420,494,493	19,610,440		513,577,215	254,536,076	32,093,767	115,525,520	57,256,069	32,016,611	334,113,916
968		P-PTD	8%	0%		9%	5%	1%	2%	1%	1%	6%
969	P110P - LESS STEAM PRODUCTION		465,340,871	21,701,923		568,351,006	281,682,735	35,516,616	127,846,492	63,362,516	35,431,232	369,747,673
970		P110P-L2(	8%	0%		10%	5%	1%	2%	1%	1%	6%
971	TOTAL GENERAL PLANT		37,256,724	1,737,527		45,504,054	22,552,448	2,843,577	10,235,811	5,073,012	2,836,741	29,603,217
972		GEN-PLT	8%	0%		9%	5%	1%	2%	1%	1%	6%
973	<u>O&M /LABOR ALLOCATORS</u>											
974	O&M PROD,TRANS,DIST,CA & CI (LABOR ONLY)		5,058,195	229,713		8,381,525	4,154,001	322,661	425,031	210,651	117,793	1,229,242
975		LABOR	5%	0%		8%	4%	0%	0%	0%	0%	1%
976	O&M PROD,TRANS,DIST,CA & CI (TOTAL O&M)		9,045,933	410,661		31,656,049	15,689,182	968,634	744,474	368,972	206,323	2,153,110
977		O&M-M	1%	0%		4%	2%	0%	0%	0%	0%	0%
978	O&M PROD,ADMIN & GENERAL ONLY (TOTAL O&M)		8,865,565	403,787		15,696,041	7,779,178	666,284	1,246,451	617,758	345,440	3,604,888
979		O&M-AG	5%	0%		9%	4%	0%	1%	0%	0%	2%
980	TOTAL OPERATING EXPENSES		17,911,499	814,448		47,352,090	23,468,360	1,634,918	1,990,925	986,730	551,763	5,757,998
981	L 560	O&M-T	2%	0%		5%	3%	0%	0%	0%	0%	1%
982	SUPERVISION 500 - 501-507											
983	L 688-698	L-500										

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3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7			* * * * * * * * * * * * * * *		DISTRIBUTION FUNCTION	* * * * * * * * * * * * * * * *			
8		ALLOCATOF	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9			SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
939		D3602N	8%	2%	1%	3%	5%	0%	0%
940	DARK FIBER PROJECT REVENUE (ACCT 454)		165,591,546	32,913,074	16,312,181	66,979,720	112,739,963	6,061,607	4,326,265
941	(DERIVED FROM ACTUALS)	D-FIBER	8%	2%	1%	3%	5%	0%	0%
942	MERCHANDISING REVENUE		165,591,546	32,913,074	16,312,181	66,979,720		6,061,607	4,326,265
943	(DERIVED FROM ACTUALS)	M-REV	10%	2%	1%	4%		0%	0%
944	MERCHANDISING EXPENSE		165,591,546	32,913,074	16,312,181	66,979,720		6,061,607	4,326,265
945	(DERIVED FROM ACTUALS)	M-EXP	10%	2%	1%	4%		0%	0%
946	CUSTOMER ADVANCES FOR CONSTRUCTION		1,696,365	4,644,708	2,301,982	8,940,078	6,113	88,201	9,103
947		CUSTADV	3%	7%	4%	14%	0%	0%	0%
948	364-365 COMBINED DISTRIBUTION ALLOCATOR			21,139,799	10,477,181				
949	L 87-88	D-364-365		5%	2%				
950	366-367 COMBINED DISTRIBUTION ALLOCATOR			11,773,274	5,835,000				
951	L 89-90	D-366-367		3%	2%				
952	902-904 COMBINED DISTRIBUTION ALLOCATOR								
953	L 500-502	D-902-904							
954	908 COMBINED DISTRIBUTION ALLOCATOR								
955	507-509	D-908							
956	908-909 COMBINED DISTRIBUTION ALLOCATOR								
957	L 507-511	D-908-909							
958	PLANT-RELATED ALLOCATORS								
959	"P112P' NET TOTAL PLANT PLUS INTANGIBLE		183,252,136	36,423,303	18,051,900	74,123,210	124,763,852	6,708,087	4,787,668
960		P112P	3%	1%	0%	1%	2%	0%	0%
961	"P111P" NET TOTAL PLANT LESS INTANGIBLE		180,263,316	35,829,243	17,757,476	72,914,269	122,728,968	6,598,679	4,709,581
962		P111P	3%	1%	0%	1%	2%	0%	0%
963	"P101P" TOTAL PLANT LESS INTANGIBLE		180,263,316	35,829,243	17,757,476	72,914,269	122,728,968	6,598,679	4,709,581
964		P101P	3%	1%	0%	1%	2%	0%	0%
965	"P110P" TOTAL PLANT INCLUDING INTANGIBLE		183,252,136	36,423,303	18,051,900	74,123,210	124,763,852	6,708,087	4,787,668
966		P110P	3%	1%	0%	1%	2%	0%	0%
967	"PTD" PLANT		165,591,546	32,913,074	16,312,181	66,979,720	112,739,963	6,061,607	4,326,265
968		P-PTD	3%	1%	0%	1%	2%	0%	0%
969	P110P - LESS STEAM PRODUCTION		183,252,136	36,423,303	18,051,900	74,123,210	124,763,852	6,708,087	4,787,668
970		P110P-L2(	3%	1%	0%	1%	2%	0%	0%
971	TOTAL GENERAL PLANT		14,671,770	2,916,170	1,445,295	5,934,548	9,989,005	537,072	383,316
972		GEN-PLT	3%	1%	0%	1%	2%	0%	0%
973	O&M /LABOR ALLOCATORS								
974	O&M PROD,TRANS,DIST,CA & CI (LABOR ONLY)		609,230	577,611	286,272	244,107	5,781,951	163,872	815,779
975		LABOR	1%	1%	0%	0%	6%	0%	1%
976	O&M PROD,TRANS,DIST,CA & CI (TOTAL O&M)		1,067,112	2,231,889	1,106,155	422,794	9,406,745	267,994	1,596,609
977		O&M-M	0%	0%	0%	0%	1%	0%	0%
978	O&M PROD,ADMIN & GENERAL ONLY (TOTAL O&M)		1,786,633	1,069,204	529,913	719,043	9,299,810	286,846	1,297,827
979		O&M-AG	1%	1%	0%	0%	5%	0%	1%
980	TOTAL OPERATING EXPENSES		2,853,745	3,301,093	1,636,068	1,141,837	18,706,555	554,840	2,894,436
981	L 560	O&M-T	0%	0%	0%	0%	2%	0%	0%
982	SUPERVISION 500 - 501-507								
983	L 688-698	L-500							

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4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
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Line	Description	(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7			- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8		ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9			READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
939		D3602N								
940	DARK FIBER PROJECT REVENUE (ACCT 454)									
941	(DERIVED FROM ACTUALS)	D-FIBER								
942	MERCHANDISING REVENUE									
943	(DERIVED FROM ACTUALS)	M-REV								
944	MERCHANDISING EXPENSE									
945	(DERIVED FROM ACTUALS)	M-EXP								
946	CUSTOMER ADVANCES FOR CONSTRUCTION									
947		CUSTADV								
948	364-365 COMBINED DISTRIBUTION ALLOCATOR									
949	L 87-88	D-364-365								
950	366-367 COMBINED DISTRIBUTION ALLOCATOR									
951	L 89-90	D-366-367								
952	902-904 COMBINED DISTRIBUTION ALLOCATOR		1,768,247	16,063,116	5,389,398					
953	L 500-502	D-902-904	8%	69%	23%					
954	908 COMBINED DISTRIBUTION ALLOCATOR						9,704,522			
955	507-509	D-908					85%			
956	908-909 COMBINED DISTRIBUTION ALLOCATOR						9,990,110			
957	L 507-511	D-908-909					86%			
958	PLANT-RELATED ALLOCATORS									
959	"P112P' NET TOTAL PLANT PLUS INTANGIBLE									
960		P112P								
961	"P111P" NET TOTAL PLANT LESS INTANGIBLE									
962		P111P								
963	"P101P" TOTAL PLANT LESS INTANGIBLE									
964		P101P								
965	"P110P" TOTAL PLANT INCLUDING INTANGIBLE									
966		P110P								
967	"PTD" PLANT									
968		P-PTD								
969	P110P - LESS STEAM PRODUCTION									
970		P110P-L2(								
971	TOTAL GENERAL PLANT									
972		GEN-PLT								
973	O&M /LABOR ALLOCATORS									
974	O&M PROD,TRANS,DIST,CA & CI (LABOR ONLY)		1,161,976	9,959,064			4,830,138			
975		LABOR	1%	10%			5%			
976	O&M PROD,TRANS,DIST,CA & CI (TOTAL O&M)		1,863,895	16,882,788	5,388,730		11,595,389			
977		O&M-M	0%	2%	1%		2%			
978	O&M PROD,ADMIN & GENERAL ONLY (TOTAL O&M)		1,817,571	15,578,028			7,555,331			
979		O&M-AG	1%	9%			4%			
980	TOTAL OPERATING EXPENSES		3,681,466	32,460,816	5,388,730		19,150,720			
981	L 560	O&M-T	0%	4%	1%		2%			
982	SUPERVISION 500 - 501-507									
983	L 688-698	L-500								

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4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

Line		(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7			- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8		ALLOCATOF						& REVENUES
9			DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
939		D3602N						
940	DARK FIBER PROJECT REVENUE (ACCT 454)							
941	(DERIVED FROM ACTUALS)	D-FIBER						
942	MERCHANDISING REVENUE							
943	(DERIVED FROM ACTUALS)	M-REV						
944	MERCHANDISING EXPENSE							
945	(DERIVED FROM ACTUALS)	M-EXP						
946	CUSTOMER ADVANCES FOR CONSTRUCTION							
947		CUSTADV						
948	364-365 COMBINED DISTRIBUTION ALLOCATOR							
949	L 87-88	D-364-365						
950	366-367 COMBINED DISTRIBUTION ALLOCATOR							
951	L 89-90	D-366-367						
952	902-904 COMBINED DISTRIBUTION ALLOCATOR							
953	L 500-502	D-902-904						
954	908 COMBINED DISTRIBUTION ALLOCATOR							
955	507-509	D-908						
956	908-909 COMBINED DISTRIBUTION ALLOCATOR							
957	L 507-511	D-908-909						
958	<u>PLANT-RELATED ALLOCATORS</u>							
959	"P112P' NET TOTAL PLANT PLUS INTANGIBLE							
960		P112P						
961	"P111P" NET TOTAL PLANT LESS INTANGIBLE							
962		P111P						
963	"P101P" TOTAL PLANT LESS INTANGIBLE							
964		P101P						
965	"P110P" TOTAL PLANT INCLUDING INTANGIBLE							
966		P110P						
967	"PTD" PLANT							
968		P-PTD						
969	P110P - LESS STEAM PRODUCTION							
970		P110P-L2(						
971	TOTAL GENERAL PLANT							
972		GEN-PLT						
973	<u>O&M /LABOR ALLOCATORS</u>							
974	O&M PROD,TRANS,DIST,CA & CI (LABOR ONLY)							
975		LABOR						
976	O&M PROD,TRANS,DIST,CA & CI (TOTAL O&M)							
977		O&M-M						
978	O&M PROD,ADMIN & GENERAL ONLY (TOTAL O&M)						332,773	
979		O&M-AG					0%	
980	TOTAL OPERATING EXPENSES						332,773	
981	L 560	O&M-T					0%	
982	SUPERVISION 500 - 501-507							
983	L 688-698	L-500						

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5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(B)	(C)	(CC)	(CCC)	(D)	(E)	(F)	(G)	(H)
7			TOTALS	* * PRODUCTION FUNCTION * *				- - - - - - - - TRANSMISSION FUNCTION - - - - - - - -			
8		ALLOCATOF		DEMAND			ENERGY	DEMAND	DEMAND	DEMAND	DEMAND
9				Base-load	Peak			POWER SUP	TRANS	SUBTRANS	DIRECT
984	SUPERVISION 510 - 511-514			7,624,615							
985	L 703-712	L-510	100%	100%							
986	SUPERVISION 535 - 536-540		11,546,063	11,546,063							
987	L 718-722	L-535	100%	100%							
988	SUPERVISION 541 - 542-545		4,599,921	4,599,921							
989	L 725-728	L-541	100%	100%							
990	SUPERVISION 546 - 548-550		3,458,462	2,426,504	1,031,958						
991	L 735-737	L-546	100%	70%	30%						
992	SUPERVISION 551 - 552-554		758,056	531,862	226,194						
993	L 741-743	L-551	100%	70%	30%						
994	SUPERVISION 560 - 561-567		5,146,941						5,146,466		475
995	L 755-760	L-560	100%						100%		0%
996	SUPERVISION 568 - 569-573		4,449,063						4,448,688		375
997	L 763-766	L-568	100%						100%		0%
998	SUPERVISION 580 - 581-589		17,149,398								
999	L 773-781	L-580	100%								
1000	SUPERVISION 590 - 591-598		8,594,783								
1001	L 785-792	L-590	100%								
1002	SUPERVISION 901- 902-905		10,510,395								
1003	L 798-801	L-901	100%								
1004	SUPERVISION 907 - 908-912		4,856,231	714,202							
1005	L 806-809	L-907	100%	15%							
1006	DEFERRED TAX ALLOCATOR										
1007	ADIT 190 & 283		(13,118,782)	(3,930,900)	(370,431)				(2,663,082)		(156)
1008	L 189,190,193	ADIT	100%	30%	3%				20%		0%

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6		(A)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
7			* *				DISTRIBUTION FUNCTION	* *				
8		ALLOCATOR	SUBSTATION	SUBSTATION	SUBSTATION	PRI LINES	PRI LINES	SEC LINES	LINE TRANS	LINE TRANS	LINE TRANS	LINE TRANS
9			GENERAL	DIRECT	CIAC	DEMAND	CUSTOMER	DIRECT	PRI DMD	PRI CUST	PRI DIRECT	SEC DMD
984	SUPERVISION 510 - 511-514											
985	L 703-712	L-510										
986	SUPERVISION 535 - 536-540											
987	L 718-722	L-535										
988	SUPERVISION 541 - 542-545											
989	L 725-728	L-541										
990	SUPERVISION 546 - 548-550											
991	L 735-737	L-546										
992	SUPERVISION 551 - 552-554											
993	L 741-743	L-551										
994	SUPERVISION 560 - 561-567											
995	L 755-760	L-560										
996	SUPERVISION 568 - 569-573											
997	L 763-766	L-568										
998	SUPERVISION 580 - 581-589		2,197,947	100,932		4,457,775	2,209,336	224,684	357,492	177,178	99,075	1,033,910
999	L 773-781	L-580	13%	1%		26%	13%	1%	2%	1%	1%	6%
1000	SUPERVISION 590 - 591-598		2,491,814	111,865		3,178,451	1,575,285	60,516	8,026	3,978	2,224	23,213
1001	L 785-792	L-590	29%	1%		37%	18%	1%	0%	0%	0%	0%
1002	SUPERVISION 901- 902-905											
1003	L 798-801	L-901										
1004	SUPERVISION 907 - 908-912											
1005	L 806-809	L-907										
1006	DEFERRED TAX ALLOCATOR											
1007	ADIT 190 & 283		(777,278)	(10,811)		(1,824,369)	(904,183)	(65,744)	(267,832)	(132,742)	(65,586)	(780,381)
1008	L 189,190,193	ADIT	6%	0%		14%	7%	1%	2%	1%	0%	6%

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4					**FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**				
5					**FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**				
6		(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
7			* * * * * * * * * * * * * *		DISTRIBUTION FUNCTION	* * * * * * * * * * * * * *			
8		ALLOCATOR	LINE TRANS	SEC LINES	SEC LINES	SERVICES	METERS	STREET	INSTALLATION
9			SEC CUST	DEMAND	CUSTOMER			LIGHTS	CUST PREM
984	SUPERVISION 510 - 511-514								
985	L 703-712	L-510							
986	SUPERVISION 535 - 536-540								
987	L 718-722	L-535							
988	SUPERVISION 541 - 542-545								
989	L 725-728	L-541							
990	SUPERVISION 546 - 548-550								
991	L 735-737	L-546							
992	SUPERVISION 551 - 552-554								
993	L 741-743	L-551							
994	SUPERVISION 560 - 561-567								
995	L 755-760	L-560							
996	SUPERVISION 568 - 569-573								
997	L 763-766	L-568							
998	SUPERVISION 580 - 581-589		512,420	296,525	146,962	207,268	4,390,347	38,309	699,239
999	L 773-781	L-580	3%	2%	1%	1%	26%	0%	4%
1000	SUPERVISION 590 - 591-598		11,504	231,489	114,729	2,336	660,141	119,062	151
1001	L 785-792	L-590	0%	3%	1%	0%	8%	1%	0%
1002	SUPERVISION 901- 902-905								
1003	L 798-801	L-901							
1004	SUPERVISION 907 - 908-912								
1005	L 806-809	L-907							
1006	DEFERRED TAX ALLOCATOR								
1007	ADIT 190 & 283		(386,768)	(197,625)	(97,946)	(387,820)	(231,119)	(14,890)	(9,118)
1008	L 189,190,193	ADIT	3%	2%	1%	3%	2%	0%	0%

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
7			- - - CUSTOMER ACCOUNTING FUNCTION - - -				* * * * * CUSTOMER INFORMATION FUNCTION * * * * *			
8		ALLOCATOR	METER	CUSTOMER	UNCOLLECT		CUSTOMER			
9			READING	RECORDS	ACCOUNTS	OTHER	ASSISTANCE	DEMONSTR	ADVERTISING	OTHER
984	SUPERVISION 510 - 511-514									
985	L 703-712	L-510								
986	SUPERVISION 535 - 536-540									
987	L 718-722	L-535								
988	SUPERVISION 541 - 542-545									
989	L 725-728	L-541								
990	SUPERVISION 546 - 548-550									
991	L 735-737	L-546								
992	SUPERVISION 551 - 552-554									
993	L 741-743	L-551								
994	SUPERVISION 560 - 561-567									
995	L 755-760	L-560								
996	SUPERVISION 568 - 569-573									
997	L 763-766	L-568								
998	SUPERVISION 580 - 581-589									
999	L 773-781	L-580								
1000	SUPERVISION 590 - 591-598									
1001	L 785-792	L-590								
1002	SUPERVISION 901- 902-905		1,098,173	9,412,221						
1003	L 798-801	L-901	10%	90%						
1004	SUPERVISION 907 - 908-912						4,142,029			
1005	L 806-809	L-907					85%			
1006	DEFERRED TAX ALLOCATOR									
1007	ADIT 190 & 283									
1008	L 189,190,193	ADIT								

1 **IDAHO POWER COMPANY**
2 **BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**
3 **CLASS COST OF SERVICE STUDY**
4 **FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2023**
5 **FUNCTIONALIZATION AND CLASSIFICATION OF COSTS**

6		(A)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)
7			- - - - - - - - - -		MISCELLANEOUS	- - - - - - - - - -		INC TAXES
8		ALLOCATOF						& REVENUES
9			DEMAND	ENERGY	CUSTOMER	REVENUE	OTHER	TRANSFER
984	SUPERVISION 510 - 511-514							
985	L 703-712	L-510						
986	SUPERVISION 535 - 536-540							
987	L 718-722	L-535						
988	SUPERVISION 541 - 542-545							
989	L 725-728	L-541						
990	SUPERVISION 546 - 548-550							
991	L 735-737	L-546						
992	SUPERVISION 551 - 552-554							
993	L 741-743	L-551						
994	SUPERVISION 560 - 561-567							
995	L 755-760	L-560						
996	SUPERVISION 568 - 569-573							
997	L 763-766	L-568						
998	SUPERVISION 580 - 581-589							
999	L 773-781	L-580						
1000	SUPERVISION 590 - 591-598							
1001	L 785-792	L-590						
1002	SUPERVISION 901- 902-905							
1003	L 798-801	L-901						
1004	SUPERVISION 907 - 908-912							
1005	L 806-809	L-907						
1006	DEFERRED TAX ALLOCATOR							
1007	ADIT 190 & 283							
1008	L 189,190,193	ADIT						

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI
TESTIMONY

EXHIBIT NO. 38

1 **IDAHO POWER COMPANY**

2 **3CP/12CP CLASS COST OF SERVICE STUDY**

3 ****** RATE BASE ****** **TWELVE MONTHS ENDING DECEMBER 31, 2023**

4 **SUMMARY OF FUNCTIONALIZED COSTS**

5		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
6	FUNCTION	PLANT	DEPRECIATION	AMORTIZATION	SUBSTATION	NET	CUSTOMER	ACCUM DEF	ACQUISITION	WORKING	DEFERRED	SUBSIDIARY	PLNT HLD FOR	TOTAL
7		IN SERVICE	RESERVE	RESERVE	CIAC	PLANT	ADV CONST	INC TAXES	ADJUSTMENT	CAPITAL	PROGRAMS	RATE BASE	FUTURE USE	RATE BASE
8	PRODUCTION													
9	DEMAND - Base-load	2,123,568,725	775,552,890	28,321,108	0	1,319,694,727	0	127,470,124	0	15,553,944	19,207,519	0	0	1,226,986,067
10	DEMAND - Peak	200,116,177	69,317,877	583,298	0	130,215,002	0	12,012,248	0	1,465,738	6,539,110	0	0	126,207,603
11	DEMAND - Not in Use	0	0	0	0	0	0	0	0	0	0	0	0	0
12	ENERGY - POWER SUPPLY	0	0	0	0	0	0	0	0	23,609,967	0	29,980,646	0	53,590,613
13	ENERGY - Summer	0	0	0	0	0	0	0	0	0	0	0	0	0
14	ENERGY - Non-Summer	0	0	0	0	0	0	0	0	0	0	0	0	0
15		0	0	0	0	0	0	0	0	0	0	0	0	0
16	TRANSMISSION	0	0	0	0	0	0	0	0	0	0	0	0	0
17	DEMAND - POWER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0
18	DEMAND - TRANSMISSION	1,438,662,020	433,115,447	4,193,406	0	1,001,353,167	0	86,357,660	628,247	15,047,187	3,273,907	0	2,640,221	936,585,068
19	DEMAND - SUBTRANSMISSION	0	0	0	0	0	0	0	0	0	0	0	0	0
20	DEMAND - DIRECT	84,425	21,968	246	0	62,211	0	5,068	0	883	192	0	0	58,219
21		0	0	0	0	0	0	0	0	0	0	0	0	0
22	DISTRIBUTION	0	0	0	0	0	0	0	0	0	0	0	0	0
23	SUBSTATIONS - GENERAL	465,340,871	94,499,470	1,356,374	0	369,485,027	0	25,205,345	0	10,475,525	1,058,958	0	5,316,573	361,130,739
24	SUBSTATIONS - DIRECT	21,701,923	1,380,982	63,257	0	20,257,685	0	350,573	0	488,543	49,386	0	30	20,445,071
25	LINES - PRIMARY DEMAND	568,351,006	199,786,215	1,656,627	0	366,908,163	3,181,235	33,343,743	0	12,794,439	1,293,374	0	0	344,470,998
26	LINES - PRIMARY CUSTOMER	281,682,735	99,016,852	821,048	0	181,844,835	1,576,665	16,525,627	0	6,341,104	641,014	0	0	170,724,661
27	LINES - SECONDARY DIRECT	35,516,616	11,284,088	103,524	0	24,129,005	0	2,131,934	0	799,533	80,824	0	0	22,877,428
28	LINE TRANS - PRIMARY DEMAND	127,846,492	33,700,274	372,646	0	93,773,572	128,427	7,642,983	0	2,878,018	290,935	0	0	89,171,115
29	LINE TRANS - PRIMARY CUST	63,362,516	16,702,329	184,689	0	46,475,498	63,650	3,787,970	0	1,426,386	144,192	0	0	44,194,456
30	LINE TRANS - SECOND DIRECT	35,431,232	9,339,656	103,275	0	25,988,301	0	2,126,808	0	797,611	80,629	0	0	24,739,733
31	LINE TRANS - SECOND DEMAND	369,747,673	97,465,309	1,077,739	0	271,204,625	395,224	22,098,663	0	8,323,578	841,420	0	0	257,875,737
32	LINE TRANS - SECOND CUSTOME	183,252,136	48,305,175	534,143	0	134,412,819	195,879	10,952,407	0	4,125,282	417,020	0	0	127,806,834
33	LINES - SECONDARY DEMAND	36,423,303	12,989,768	106,166	0	23,327,369	536,323	2,056,156	0	819,944	82,887	0	0	21,637,720
34	LINES - SECONDARY CUSTOMER	18,051,900	6,437,911	52,618	0	11,561,371	265,809	1,019,060	0	406,376	41,080	0	0	10,723,958
35	SERVICES	74,123,210	45,312,003	216,054	0	28,595,152	1,032,307	4,198,735	0	1,668,625	168,679	0	0	25,201,414
36	METERS	124,763,852	38,756,001	363,661	0	85,644,190	706	7,488,950	0	2,808,623	283,920	0	0	81,247,077
37	STREET LIGHTS	6,708,087	175,721	19,553	0	6,512,814	10,184	400,190	0	151,009	15,265	0	0	6,268,714
38	INSTALL ON CUST PREMISES	4,787,668	1,206,758	13,955	0	3,566,955	1,051	287,131	0	107,778	10,895	0	0	3,397,445
39		0	0	0	0	0	0	0	0	0	0	0	0	0
40	CUSTOMER ACCOUNTING	0	0	0	0	0	0	0	0	0	0	0	0	0
41	METER READING	0	0	0	0	0	0	0	0	0	0	0	0	0
42	CUSTOMER ACCOUNTS	0	0	0	0	0	0	0	0	0	0	0	0	0
43	UNCOLLECTIBLES	0	0	0	0	0	0	0	0	0	0	0	0	0
44	MISC	0	0	0	0	0	0	0	0	0	0	0	0	0
45		0	0	0	0	0	0	0	0	0	0	0	0	0
46	CONSUMER INFORMATION	0	0	0	0	0	0	0	0	0	0	0	0	0
47	CUSTOMER ASSIST	0	0	0	0	0	0	0	0	0	0	0	0	0
48	SALES EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0	0
49	ADVERTISING	0	0	0	0	0	0	0	0	0	0	0	0	0
50	MISC	0	0	0	0	0	0	0	0	0	0	0	0	0
51		0	0	0	0	0	0	0	0	0	0	0	0	0
52	MISCELLANEOUS	0	0	0	0	0	0	0	0	0	0	0	0	0
53	DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0
54	ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
55	CUSTOMER	0	0	0	0	0	0	0	0	0	0	0	0	0
56	REVENUE	0	0	0	0	0	0	0	0	0	0	0	0	0
57	OTHER	0	0	0	0	0	0	0	0	0	0	0	0	0
58	SUBSTATION CIAC	0	0	0	(42,770,847)	(42,770,847)	0	0	0	0	0	0	0	(42,770,847)
59														
60	TOTALS	6,179,522,565	1,994,366,693	40,143,386	(42,770,847)	4,102,241,639	7,387,459	365,461,375	628,247	110,090,091	34,521,209	29,980,646	7,956,825	3,912,569,823

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
SUMMARY OF FUNCTIONALIZED COSTS

****** OPERATING EXPENSES ******

FUNCTION	(A) OPERATION & MAINTENANCE	(B) DEPRECIATION EXPENSE	(C) AMORTIZATION EXPENSE	(D) OTHER TAXES	(E) REGULATORY DEB/CRED	(F) PROV FOR DEF FIT	(G) DEFERRED ITC	(H) CONST WORK IN PROGRESS	(I)	(J)	(K)	(L)	(M) TOTAL EXPENSES
PRODUCTION													
DEMAND - Base-load	138,136,693	61,229,781	4,744,176	8,477,654	1,464,604	(5,884,910)	8,304,618	6,537,444					223,010,061
DEMAND - Peak	16,516,367	6,492,310	48,412	991,152	387,790	(554,569)	782,592						24,664,054
DEMAND - Not in Use	0	0	0	0	0	0	0						0
ENERGY - POWER SUPPLY	492,817,416	0	0	0	0	0	0	0					492,817,416
ENERGY - Summer	0	0	0	0	0	0	0						0
ENERGY - Non-Summer	0	0	0	0	0	0	0						0
	0	0	0	0	0	0	0						0
TRANSMISSION	0	0	0	0	0	0	0						0
DEMAND - POWER SUPPLY	0	0	0	0	0	0	0						0
DEMAND - TRANSMISSION	48,778,156	28,824,414	348,044	7,560,424	481,088	(3,986,872)	5,626,160						87,631,416
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0	0						0
DEMAND - DIRECT	3,521	1,909	20	444	28	(234)	330						6,018
	0	0	0	0	0	0	0						0
DISTRIBUTION	0	0	0	0	0	0	0						0
SUBSTATIONS - GENERAL	17,911,499	9,040,007	112,576	1,875,874	155,610	(1,163,654)	1,642,116						29,574,028
SUBSTATIONS - DIRECT	814,448	145,538	5,250	31,792	7,257	(16,185)	22,840						1,010,940
LINES - PRIMARY DEMAND	47,352,090	12,917,578	137,497	2,516,018	190,057	(1,648,196)	2,222,644						63,687,687
LINES - PRIMARY CUSTOMER	23,468,360	6,402,133	68,145	1,246,974	94,195	(816,869)	1,101,574						31,564,512
LINES - SECONDARY DIRECT	1,634,918	849,132	8,592	157,228	11,877	(98,425)	138,894						2,702,216
LINE TRANS - PRIMARY DEMAND	1,990,925	2,620,571	30,929	565,960	42,752	(357,246)	499,968						5,393,859
LINE TRANS - PRIMARY CUST	986,730	1,298,792	15,329	280,498	21,188	(177,056)	247,791						2,673,272
LINE TRANS - SECOND DIRECT	551,763	726,262	8,572	156,850	11,848	(98,188)	138,561						1,495,666
LINE TRANS - SECOND DEMAND	5,757,998	7,579,012	89,450	1,636,826	123,644	(1,033,747)	1,445,968						15,599,151
LINE TRANS - SECOND CUSTOME	2,853,745	3,756,265	44,333	811,234	61,280	(512,340)	716,642						7,731,158
LINES - SECONDARY DEMAND	3,301,093	831,250	8,812	161,241	12,180	(113,272)	142,440						4,343,745
LINES - SECONDARY CUSTOMER	1,636,068	411,979	4,367	79,913	6,037	(56,139)	70,595						2,152,821
SERVICES	1,141,837	1,329,707	17,932	328,134	24,787	(229,154)	289,873						2,903,116
METERS	18,706,555	6,073,947	30,183	552,314	41,721	(345,766)	487,913						25,546,867
STREET LIGHTS	554,840	227,907	1,623	29,696	2,243	(18,824)	26,233						823,719
INSTALL ON CUST PREMISES	2,894,436	193,695	1,158	21,194	1,601	(13,292)	18,723						3,117,516
	0	0	0	0	0	0	0						0
CUSTOMER ACCOUNTING	0	0	0	0	0	0	0						0
METER READING	3,681,466	0	0	0	0	0	0						3,681,466
CUSTOMER ACCOUNTS	32,460,816	0	0	0	0	0	0						32,460,816
UNCOLLECTIBLES	5,388,730	0	0	0	0	0	0						5,388,730
MISC	0	0	0	0	0	0	0						0
	0	0	0	0	0	0	0						0
CONSUMER INFORMATION	0	0	0	0	0	0	0						0
CUSTOMER ASSIST	19,150,720	0	0	0	0	0	0						19,150,720
SALES EXPENSE	0	0	0	0	0	0	0						0
ADVERTISING	0	0	0	0	0	0	0						0
MISC	0	0	0	0	0	0	0						0
	0	0	0	0	0	0	0						0
MISCELLANEOUS	0	0	0	0	0	0	0						0
DEMAND	0	0	0	0	0	0	0						0
ENERGY	0	0	0	2,119,909	0	0	0						2,119,909
CUSTOMER	0	0	0	0	0	0	0						0
REVENUE	0	0	0	0	0	0	0						0
OTHER	332,773	0	0	0	0	0	0						332,773
RETAIL SALES REVENUE	0	0	0	0	0	0	0						0
TOTALS	888,823,963	150,952,190	5,725,400	29,601,331	3,141,786	(17,124,938)	23,926,476	6,537,444	0	0	0	0	1,091,583,652

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
SUMMARY OF FUNCTIONALIZED COSTS

****** OTHER REVENUES ******

FUNCTION	(A) REVENUES	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M) TOTAL REVENUES
PRODUCTION													
DEMAND - Base-load	1,105,981												1,105,981
DEMAND - Peak	2,661												2,661
DEMAND - Not in Use	0												0
ENERGY - POWER SUPPLY	29,557,875												29,557,875
ENERGY - Summer	0												0
ENERGY - Non-Summer	0												0
	0												
TRANSMISSION	0												
DEMAND - POWER SUPPLY	0												0
DEMAND - TRANSMISSION	60,109,852												60,109,852
DEMAND - SUBTRANSMISSION	0												0
DEMAND - DIRECT	518												518
	0												
DISTRIBUTION	0												
SUBSTATIONS - GENERAL	299,274												299,274
SUBSTATIONS - DIRECT	13,957												13,957
LINES - PRIMARY DEMAND	2,502,919												2,502,919
LINES - PRIMARY CUSTOMER	1,240,482												1,240,482
LINES - SECONDARY DIRECT	107,956												107,956
LINE TRANS - PRIMARY DEMAND	350,797												350,797
LINE TRANS - PRIMARY CUST	173,860												173,860
LINE TRANS - SECOND DIRECT	97,220												97,220
LINE TRANS - SECOND DEMAND	1,014,549												1,014,549
LINE TRANS - SECOND CUSTOME	502,825												502,825
LINES - SECONDARY DEMAND	156,826												156,826
LINES - SECONDARY CUSTOMER	77,725												77,725
SERVICES	203,386												203,386
METERS	80,239												80,239
STREET LIGHTS	18,406												18,406
INSTALL ON CUST PREMISES	13,137												13,137
	0												
CUSTOMER ACCOUNTING	0												
METER READING	0												0
CUSTOMER ACCOUNTS	0												0
UNCOLLECTIBLES	0												0
MISC	0												0
	0												
CONSUMER INFORMATION	0												
CUSTOMER ASSIST	0												0
SALES EXPENSE	0												0
ADVERTISING	0												0
MISC	0												0
	0												
MISCELLANEOUS	0												
DEMAND	0												0
ENERGY	0												0
CUSTOMER	0												0
MISC. REVENUE	6,150,427												6,150,427
FACILITIES CHARGE REVENUE	9,859,316												9,859,316
RETAIL SALES REVENUE													0
TOTALS	113,640,190	0	0	0	0	0	0	0	0	0		0	113,640,190

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI
TESTIMONY

EXHIBIT NO. 39

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	SOURCES	TOTALS		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
****** SUMMARY OF RESULTS ******	& NOTES		RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	SEC/PRIM/TRAI	SECONDARY
			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
RATE BASE											
ELECTRIC PLANT IN SERVICE	PAGE 2C	6,179,522,565	2,817,968,008	87,956,334	85,902,468	456,112	193,263,380	1,134,709,132	5,857,139	650,933,342	951,366,556
LESS: ACCUM PROVISION FOR DEPRECIATION	PAGE 2D	1,994,366,693	921,361,756	28,133,301	28,458,084	143,379	62,367,609	368,351,197	1,523,155	211,347,951	296,136,020
: AMORT OF OTHER UTILITY PLANT	PAGE 2E	40,143,386	17,679,176	506,489	449,874	2,228	1,348,962	7,989,663	17,072	4,710,910	5,478,003
SUBSTATION CIAC	PAGE 2F	(42,770,847)	(4,292,179)	(205,156)	(472,238)	(6,923)	(1,519,756)	(2,598,489)	(4,296)	(15,762,857)	(3,041,944)
NET ELECTRIC PLANT IN SERVICE		4,102,241,639	1,874,634,897	59,111,388	56,522,272	303,581	128,027,053	755,769,783	4,312,615	419,111,624	646,710,588
CUSTOMER ADVANCES FOR CONSTRUCTION	PAGE 2H	7,387,459	4,347,671	154,394	200,296	1,030	102,620	1,027,059	2,848	399,869	1,108,864
ACCUMULATED DEFERRED INCOME TAXES	PAGE 2I	365,461,375	167,060,145	5,192,663	5,085,278	26,799	11,494,617	67,389,032	349,846	38,650,665	56,109,225
ELECTRIC PLANT ACQUISITION ADJUSTMENT	PAGE 2J	628,247	267,673	7,023	5,597	25	21,946	130,853	0	78,393	82,507
WORKING CAPITAL	PAGE 2K	110,090,091	49,797,567	1,639,182	1,688,736	9,167	3,441,483	19,895,022	140,180	11,782,152	17,303,885
DEFERRED PROGRAMS	PAGE 2L	34,521,209	15,072,007	424,089	371,436	1,784	1,129,045	6,680,942	13,329	3,920,677	5,268,086
SUBSIDIARY RATE BASE	PAGE 2M	29,980,646	11,169,860	315,122	283,541	1,236	1,183,254	6,747,739	10,573	4,695,810	3,528,365
PLANT HELD FOR FUTURE USE	PAGE 2N	7,956,825	3,145,909	126,112	67,402	747	250,847	1,474,094	2,038	963,340	1,767,139
TOTAL RATE BASE		3,912,569,823	1,782,680,096	56,275,860	53,653,411	288,712	122,456,391	722,282,341	4,126,040	401,501,460	617,442,481
RETURN UNDER PRESENT RATES											
SALES REVENUES	PAGE 1	1,293,009,840	566,136,133	13,032,773	17,760,920	48,160	43,557,610	269,827,909	1,327,038	153,898,825	162,447,833
OTHER OPERATING REVENUES	PAGE 4C	113,640,190	46,200,098	1,158,525	1,173,490	4,682	6,781,861	20,560,253	112,468	18,324,115	12,860,615
TOTAL OPERATING REVENUES		1,406,650,030	612,336,231	14,191,298	18,934,410	52,842	50,339,471	290,388,162	1,439,506	172,222,939	175,308,448
OPERATING EXPENSES											
OPERATION & MAINTENANCE EXPENSES	PAGE 3C	888,823,963	388,738,091	11,127,348	12,888,267	53,211	29,936,675	176,244,175	616,357	112,246,184	109,548,662
DEPRECIATION EXPENSE	PAGE 3D	150,952,190	69,023,727	2,106,824	2,171,839	10,768	4,779,265	28,116,787	50,132	15,972,606	22,676,682
AMORTIZATION OF LIMITED TERM PLANT	PAGE 3E	5,725,400	2,491,872	69,110	58,965	282	196,930	1,169,587	417	695,293	747,246
TAXES OTHER THAN INCOME	PAGE 3F	29,601,331	13,347,740	407,862	402,452	2,065	947,637	5,535,886	8,310	3,240,936	4,495,074
REGULATORY DEBITS/CREDITS	PAGE 3G	3,141,786	1,398,600	41,212	38,043	192	100,848	594,931	576	345,861	481,396
PROVISION FOR DEFERRED INCOME TAXES	PAGE 3H	(17,124,938)	(7,870,826)	(245,266)	(242,206)	(1,274)	(534,177)	(3,147,003)	(4,774)	(1,798,057)	(2,628,690)
INVESTMENT TAX CREDIT ADJUSTMENT	PAGE 3I	23,926,476	10,965,963	341,101	335,293	1,765	750,485	4,407,628	6,673	2,524,389	3,673,546
CONSTRUCTION WORK IN PROGRESS	PAGE 3J	6,537,444	2,796,006	73,882	58,927	265	232,072	1,383,095	0	831,110	799,028
FEDERAL INCOME TAXES	PAGE 1	39,040,245	13,370,532	262,324	322,579	494	1,659,227	9,065,970	7,507	6,781,260	4,554,856
STATE INCOME TAXES	PAGE 1	(2,828,435)	(968,684)	(19,005)	(23,371)	(36)	(120,210)	(656,822)	(544)	(491,297)	(329,996)
TOTAL OPERATING EXPENSES		1,127,795,462	493,293,021	14,165,393	16,010,788	67,732	37,948,754	222,714,233	684,655	140,348,285	144,017,803
OPERATING INCOME		278,854,568	119,043,210	25,905	2,923,623	(14,890)	12,390,717	67,673,928	754,851	31,874,654	31,290,645
ADD: IERCO OPERATING INCOME	PAGE 1	1,759,534	655,548	18,494	16,641	73	69,444	396,018	621	275,592	207,076
CONSOLIDATED OPERATING INCOME		280,614,102	119,698,758	44,400	2,940,263	(14,817)	12,460,161	68,069,946	755,471	32,150,247	31,497,721
RATE OF RETURN UNDER PRESENT RATES		7.172%	6.715%	0.079%	5.480%	-5.132%	10.175%	9.424%	18.310%	8.008%	5.101%
RATE OF RETURN INDEX		1.000	0.936	0.011	0.764	(0.716)	1.419	1.314	2.553	1.116	0.711

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

	SOURCES	TOTALS	(K) UNMETERED	(L) MUNICIPAL	(M) TRAFFIC	(N) SC	(O) SC	(P) SC
****** SUMMARY OF RESULTS ******	& NOTES		GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
			(40)	(41)	(42)			
RATE BASE								
ELECTRIC PLANT IN SERVICE	PAGE 2C	6,179,522,565	5,566,052	12,793,366	1,496,706	45,213,165	37,652,894	148,387,912
LESS: ACCUM PROVISION FOR DEPRECIATION	PAGE 2D	1,994,366,693	1,760,030	1,979,162	476,366	15,377,730	12,079,222	44,871,729
: AMORT OF OTHER UTILITY PLANT	PAGE 2E	40,143,386	31,489	37,290	7,485	408,021	282,490	1,194,233
SUBSTATION CIAC	PAGE 2F	(42,770,847)	(10,144)	(21,076)	(1,060)	0	(70,288)	(14,764,442)
NET ELECTRIC PLANT IN SERVICE		4,102,241,639	3,764,389	10,755,838	1,011,795	29,427,413	25,220,894	87,557,509
CUSTOMER ADVANCES FOR CONSTRUCTION	PAGE 2H	7,387,459	10,108	29,490	3,144	0	62	2
ACCUMULATED DEFERRED INCOME TAXES	PAGE 2I	365,461,375	329,188	755,652	88,821	2,713,982	2,188,449	8,027,016
ELECTRIC PLANT ACQUISITION ADJUSTMENT	PAGE 2J	628,247	425	0	87	7,526	4,844	21,349
WORKING CAPITAL	PAGE 2K	110,090,091	111,796	325,745	30,946	748,168	708,114	2,467,948
DEFERRED PROGRAMS	PAGE 2L	34,521,209	25,867	29,113	6,090	326,077	239,943	1,012,723
SUBSIDIARY RATE BASE	PAGE 2M	29,980,646	28,061	47,932	5,743	460,286	338,953	1,164,174
PLANT HELD FOR FUTURE USE	PAGE 2N	7,956,825	6,596	9,997	867	31,630	20,361	89,747
TOTAL RATE BASE		3,912,569,823	3,597,837	10,383,484	963,563	28,287,118	24,344,597	84,286,431
RETURN UNDER PRESENT RATES								
SALES REVENUES	PAGE 1	1,293,009,840	1,309,792	3,750,417	199,244	13,302,981	9,818,665	36,591,539
OTHER OPERATING REVENUES	PAGE 4C	113,640,190	93,861	176,934	19,105	1,187,749	1,744,729	3,241,706
TOTAL OPERATING REVENUES		1,406,650,030	1,403,653	3,927,351	218,349	14,490,730	11,563,394	39,833,245
OPERATING EXPENSES								
OPERATION & MAINTENANCE EXPENSES	PAGE 3C	888,823,963	901,046	1,947,396	254,097	9,999,258	7,468,743	26,854,451
DEPRECIATION EXPENSE	PAGE 3D	150,952,190	130,341	365,665	37,901	1,157,872	917,560	3,434,221
AMORTIZATION OF LIMITED TERM PLANT	PAGE 3E	5,725,400	4,267	3,100	960	63,741	42,128	181,501
TAXES OTHER THAN INCOME	PAGE 3F	29,601,331	26,730	59,758	7,082	236,953	189,440	693,404
REGULATORY DEBITS/CREDITS	PAGE 3G	3,141,786	2,559	4,285	643	26,845	20,698	85,097
PROVISION FOR DEFERRED INCOME TAXES	PAGE 3H	(17,124,938)	(15,575)	(35,952)	(4,223)	(125,296)	(101,036)	(370,583)
INVESTMENT TAX CREDIT ADJUSTMENT	PAGE 3I	23,926,476	21,651	49,777	5,857	176,815	142,577	522,956
CONSTRUCTION WORK IN PROGRESS	PAGE 3J	6,537,444	4,509	0	922	81,598	51,026	225,005
FEDERAL INCOME TAXES	PAGE 3J	39,040,245	36,701	53,040	6,863	692,053	509,028	1,717,811
STATE INCOME TAXES	PAGE 1	(2,828,435)	(2,659)	(3,843)	(497)	(50,139)	(36,879)	(124,454)
TOTAL OPERATING EXPENSES		1,127,795,462	1,109,570	2,443,226	309,606	12,259,699	9,203,286	33,219,409
OPERATING INCOME		278,854,568	294,083	1,484,125	(91,256)	2,231,030	2,360,107	6,613,835
ADD: IERCO OPERATING INCOME	PAGE 1	1,759,534	1,647	2,813	337	27,014	19,893	68,324
CONSOLIDATED OPERATING INCOME		280,614,102	295,730	1,486,938	(90,919)	2,258,044	2,380,000	6,682,159
RATE OF RETURN UNDER PRESENT RATES		7.172%	8.220%	14.320%	-9.436%	7.983%	9.776%	7.928%
RATE OF RETURN INDEX		1.000	1.146	1.997	(1.316)	1.113	1.363	1.105

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

****** TABLE 1 - PLANT IN SERVICE ******

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAN (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
PRODUCTION											
DEMAND - BASE-LOAD TOTAL		2,123,568,725									
DEMAND - Base-load Summer	D10BS	912,537,126	376,673,290	9,220,865	6,956,707	24,362	26,841,350	158,618,772	0	91,778,497	201,916,584
DEMAND - Peak	D10P	200,116,177	82,603,126	2,022,103	1,525,581	5,343	5,886,214	34,784,538	0	20,126,701	44,279,595
DEMAND - Base-load Non-Summer	D10BNS	1,211,031,599	531,557,965	14,778,334	12,184,575	61,839	48,543,094	290,654,133	0	178,192,266	57,632,856
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	1,438,662,020	612,960,171	16,081,551	12,817,335	56,695	50,256,351	299,648,375	0	179,516,094	188,938,204
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	84,425	0	0	0	0	84,425	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	465,340,871	176,891,787	8,454,990	3,840,624	56,305	13,883,137	80,890,364	178,369	55,482,426	124,322,651
SUBSTATIONS - DIRECT	DA3602	21,701,923	0	0	0	0	0	0	0	5,490	0
LINES - PRIMARY DEMAND	D20	568,351,006	216,049,420	10,326,629	4,690,803	68,770	16,956,377	98,796,651	217,854	67,764,287	151,843,322
LINES - PRIMARY CUSTOMER	C20	281,682,735	231,590,653	6,248,594	14,296,103	41,147	131,671	17,758,414	0	53,609	9,018,943
LINES - SECONDARY DIRECT	DA3647	35,516,616	0	0	0	0	9,491,902	0	439,858	20,759,445	0
LINE TRANS - PRIMARY DEMAND	D50	127,846,492	48,598,771	2,322,901	1,055,163	15,469	3,814,216	22,223,600	49,005	15,243,092	34,156,069
LINE TRANS - PRIMARY CUST	C50	63,362,516	52,094,660	1,405,576	3,215,806	9,256	29,618	3,994,628	0	12,059	2,028,747
LINE TRANS - SECOND DIRECT	DA368	35,431,232	0	0	0	0	14,022,768	0	0	19,352,982	0
LINE TRANS - SECOND DEMAND	D60	369,747,673	165,102,692	7,891,501	3,584,662	52,553	0	75,499,361	166,481	162,458	116,037,068
LINE TRANS - SECOND CUSTOMER	C60	183,252,136	150,763,036	4,067,768	9,306,610	26,786	0	11,560,538	0	306	5,871,235
LINES - SECONDARY DEMAND	D30	36,423,303	23,702,539	1,132,923	514,623	7,545	0	10,838,869	23,900	23,323	0
LINES - SECONDARY CUSTOMER	C30	18,051,900	15,343,023	413,973	947,126	2,726	0	1,176,506	0	31	0
SERVICES	CW369	74,123,210	59,450,076	1,601,186	3,905,191	11,065	220,591	5,616,328	0	317,126	2,997,199
METERS	CW370	124,763,852	74,586,799	1,987,439	7,061,560	16,250	3,083,729	22,648,055	560	2,140,242	12,324,084
STREET LIGHTS	DA373	6,708,087	0	0	0	0	14,118	0	0	173	0
INSTALL ON CUST PREMISES	DA371	4,787,668	0	0	0	0	3,819	0	4,781,112	2,737	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 2C	6,179,522,565	2,817,968,008	87,956,334	85,902,468	456,112	193,263,380	1,134,709,132	5,857,139	650,933,342	951,366,556

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 1 - PLANT IN SERVICE ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
PRODUCTION								
DEMAND - BASE-LOAD TOTAL		2,123,568,725						
DEMAND - Base-load Summer	D10BS	912,537,126	492,751	0	98,491	6,564,608	6,308,535	27,042,312
DEMAND - Peak	D10P	200,116,177	108,059	0	21,599	1,439,595	1,383,440	5,930,284
DEMAND - Base-load Non-Summer	D10BNS	1,211,031,599	971,964	0	201,068	19,940,877	10,266,336	46,046,292
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	1,438,662,020	972,112	0	198,507	17,235,001	11,093,508	48,888,117
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	84,425	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	465,340,871	421,174	875,026	44,017	0	0	0
SUBSTATIONS - DIRECT	DA3602	21,701,923	0	0	0	0	1,634,335	20,062,099
LINES - PRIMARY DEMAND	D20	568,351,006	514,407	1,068,726	53,761	0	0	0
LINES - PRIMARY CUSTOMER	C20	281,682,735	782,031	1,401,355	360,214	0	0	0
LINES - SECONDARY DIRECT	DA3647	35,516,616	0	0	0	0	4,825,412	0
LINE TRANS - PRIMARY DEMAND	D50	127,846,492	115,712	240,402	12,093	0	0	0
LINE TRANS - PRIMARY CUST	C50	63,362,516	175,912	315,225	81,028	0	0	0
LINE TRANS - SECOND DIRECT	DA368	35,431,232	0	0	0	0	2,055,481	0
LINE TRANS - SECOND DEMAND	D60	369,747,673	393,104	816,709	41,084	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	183,252,136	509,094	912,267	234,496	0	0	0
LINES - SECONDARY DEMAND	D30	36,423,303	56,435	117,249	5,898	0	0	0
LINES - SECONDARY CUSTOMER	C30	18,051,900	51,810	92,841	23,864	0	0	0
SERVICES	CW369	74,123,210	0	0	0	0	4,448	0
METERS	CW370	124,763,852	1,486	259,770	120,587	33,083	81,400	418,809
STREET LIGHTS	DA373	6,708,087	0	6,693,796	0	0	0	0
INSTALL ON CUST PREMISES	DA371	4,787,668	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS		6,179,522,565	5,566,052	12,793,366	1,496,706	45,213,165	37,652,894	148,387,912

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 2 - ACCUMULATED RESERVE FOR DEPRECIATION ****** **ALLOCATION TO CIATION TO CLASSES**

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION	TOTALS		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
	FACTOR		RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	SEC/PRIM/TRAN	SECONDARY
PRODUCTION			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - BASE-LOAD TOTAL		775,552,890									
DEMAND - Base-load Summer	D10BS	333,269,555	137,565,625	3,367,571	2,540,673	8,897	9,802,785	57,929,487	0	33,518,613	73,742,370
DEMAND - Peak	D10P	69,317,877	28,612,746	700,433	528,443	1,851	2,038,915	12,048,953	0	6,971,651	15,337,928
DEMAND - Base-load Non-Summer	D10BNS	442,283,334	194,131,375	5,397,226	4,449,954	22,584	17,728,523	106,150,392	0	65,077,963	21,048,213
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	433,115,447	184,534,321	4,841,421	3,858,714	17,068	15,129,893	90,210,444	0	54,044,099	56,880,667
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	21,968	0	0	0	0	21,968	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	94,499,470	35,922,441	1,717,004	779,938	11,434	2,819,329	16,426,875	36,222	11,267,138	25,246,922
SUBSTATIONS - DIRECT	DA3602	1,380,982	0	0	0	0	0	0	0	349	0
LINES - PRIMARY DEMAND	D20	199,786,215	75,945,490	3,630,007	1,648,907	24,174	5,960,490	34,728,907	76,580	23,820,439	53,375,823
LINES - PRIMARY CUSTOMER	C20	99,016,852	81,408,530	2,196,500	5,025,353	14,464	46,285	6,242,421	0	18,845	3,170,330
LINES - SECONDARY DIRECT	DA3647	11,284,088	0	0	0	0	3,015,700	0	139,749	6,595,544	0
LINE TRANS - PRIMARY DEMAND	D50	33,700,274	12,810,613	612,316	278,140	4,078	1,005,425	5,858,130	12,918	4,018,072	9,003,523
LINE TRANS - PRIMARY CUST	C50	16,702,329	13,732,127	370,509	847,685	2,440	7,807	1,052,982	0	3,179	534,777
LINE TRANS - SECOND DIRECT	DA368	9,339,656	0	0	0	0	3,696,395	0	0	5,101,437	0
LINE TRANS - SECOND DEMAND	D60	97,465,309	43,520,990	2,080,196	944,915	13,853	0	19,901,595	43,884	42,824	30,587,315
LINE TRANS - SECOND CUSTOMER	C60	48,305,175	39,741,064	1,072,262	2,453,218	7,061	0	3,047,352	0	81	1,547,655
LINES - SECONDARY DEMAND	D30	12,989,768	8,453,118	404,038	183,532	2,691	0	3,865,503	8,524	8,318	0
LINES - SECONDARY CUSTOMER	C30	6,437,911	5,471,835	147,637	337,777	972	0	419,581	0	11	0
SERVICES	CW369	45,312,003	36,342,221	978,815	2,387,269	6,764	134,848	3,433,298	0	193,861	1,832,207
METERS	CW370	38,756,001	23,169,259	617,368	2,193,567	5,048	957,914	7,035,275	174	664,834	3,828,290
STREET LIGHTS	DA373	175,721	0	0	0	0	370	0	0	5	0
INSTALL ON CUST PREMISES	DA371	1,206,758	0	0	0	0	963	0	1,205,105	690	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 2D	1,994,366,693	921,361,756	28,133,301	28,458,084	143,379	62,367,609	368,351,197	1,523,155	211,347,951	296,136,020

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

***** TABLE 2 - ACCUMULATED RESERVE FOR DEPRECIATION *****

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
PRODUCTION								
DEMAND - BASE-LOAD TOTAL		775,552,890						
DEMAND - Base-load Summer	D10BS	333,269,555	179,959	0	35,970	2,397,474	2,303,953	9,876,178
DEMAND - Peak	D10P	69,317,877	37,430	0	7,482	498,659	479,207	2,054,180
DEMAND - Base-load Non-Summer	D10BNS	442,283,334	354,973	0	73,432	7,282,649	3,749,390	16,816,661
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	433,115,447	292,659	0	59,761	5,188,672	3,339,749	14,717,980
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	21,968	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	94,499,470	85,530	177,697	8,939	0	0	0
SUBSTATIONS - DIRECT	DA3602	1,380,982	0	0	0	0	103,999	1,276,633
LINES - PRIMARY DEMAND	D20	199,786,215	180,824	375,678	18,898	0	0	0
LINES - PRIMARY CUSTOMER	C20	99,016,852	274,899	492,603	126,622	0	0	0
LINES - SECONDARY DIRECT	DA3647	11,284,088	0	0	0	0	1,533,096	0
LINE TRANS - PRIMARY DEMAND	D50	33,700,274	30,502	63,370	3,188	0	0	0
LINE TRANS - PRIMARY CUST	C50	16,702,329	46,370	83,093	21,359	0	0	0
LINE TRANS - SECOND DIRECT	DA368	9,339,656	0	0	0	0	541,824	0
LINE TRANS - SECOND DEMAND	D60	97,465,309	103,622	215,284	10,830	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	48,305,175	134,197	240,473	61,813	0	0	0
LINES - SECONDARY DEMAND	D30	12,989,768	20,127	41,815	2,103	0	0	0
LINES - SECONDARY CUSTOMER	C30	6,437,911	18,477	33,110	8,511	0	0	0
SERVICES	CW369	45,312,003	0	0	0	0	2,719	0
METERS	CW370	38,756,001	462	80,694	37,458	10,277	25,286	130,097
STREET LIGHTS	DA373	175,721	0	175,346	0	0	0	0
INSTALL ON CUST PREMISES	DA371	1,206,758	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2D	1,994,366,693	1,760,030	1,979,162	476,366	15,377,730	12,079,222	44,871,729

IDAHO POWER COMPANY PAGE 2E

3CP/12CP CLASS COST OF SERVICE STUDY

TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 3 - AMORTIZATION RESERVE****** **ALLOCATION TO CIATION TO CLASSES**

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION	TOTALS		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
	FACTOR		RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	SEC/PRIM/TRAI	SECONDARY
PRODUCTION			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - BASE-LOAD TOTAL		28,321,108									
DEMAND - Base-load Summer	D10BS	12,170,109	5,023,527	122,975	92,779	325	357,971	2,115,429	0	1,224,010	2,692,873
DEMAND - Peak	D10P	583,298	240,771	5,894	4,447	16	17,157	101,390	0	58,665	129,066
DEMAND - Base-load Non-Summer	D10BNS	16,150,999	7,089,156	197,092	162,500	825	647,398	3,876,327	0	2,376,472	768,624
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	4,193,406	1,786,654	46,874	37,360	165	146,487	873,414	0	523,253	550,716
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	246	0	0	0	0	246	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	1,356,374	515,603	24,645	11,195	164	40,467	235,779	520	161,720	362,375
SUBSTATIONS - DIRECT	DA3602	63,257	0	0	0	0	0	0	0	16	0
LINES - PRIMARY DEMAND	D20	1,656,627	629,740	30,100	13,673	200	49,424	287,972	635	197,519	442,592
LINES - PRIMARY CUSTOMER	C20	821,048	675,040	18,213	41,670	120	384	51,762	0	156	26,288
LINES - SECONDARY DIRECT	DA3647	103,524	0	0	0	0	27,667	0	1,282	60,510	0
LINE TRANS - PRIMARY DEMAND	D50	372,646	141,656	6,771	3,076	45	11,118	64,777	143	44,431	99,558
LINE TRANS - PRIMARY CUST	C50	184,689	151,845	4,097	9,373	27	86	11,644	0	35	5,913
LINE TRANS - SECOND DIRECT	DA368	103,275	0	0	0	0	40,874	0	0	56,410	0
LINE TRANS - SECOND DEMAND	D60	1,077,739	481,241	23,002	10,449	153	0	220,065	485	474	338,224
LINE TRANS - SECOND CUSTOMER	C60	534,143	439,443	11,857	27,127	78	0	33,697	0	1	17,113
LINES - SECONDARY DEMAND	D30	106,166	69,088	3,302	1,500	22	0	31,593	70	68	0
LINES - SECONDARY CUSTOMER	C30	52,618	44,722	1,207	2,761	8	0	3,429	0	0	0
SERVICES	CW369	216,054	173,285	4,667	11,383	32	643	16,370	0	924	8,736
METERS	CW370	363,661	217,405	5,793	20,583	47	8,988	66,014	2	6,238	35,922
STREET LIGHTS	DA373	19,553	0	0	0	0	41	0	0	1	0
INSTALL ON CUST PREMISES	DA371	13,955	0	0	0	0	11	0	13,936	8	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 2E	40,143,386	17,679,176	506,489	449,874	2,228	1,348,962	7,989,663	17,072	4,710,910	5,478,003

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 3 - AMORTIZATION RESERVE******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
PRODUCTION								
DEMAND - BASE-LOAD TOTAL		28,321,108						
DEMAND - Base-load Summer	D10BS	12,170,109	6,572	0	1,314	87,549	84,134	360,651
DEMAND - Peak	D10P	583,298	315	0	63	4,196	4,032	17,286
DEMAND - Base-load Non-Summer	D10BNS	16,150,999	12,963	0	2,682	265,943	136,918	614,099
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	4,193,406	2,834	0	579	50,237	32,335	142,499
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	246	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	1,356,374	1,228	2,551	128	0	0	0
SUBSTATIONS - DIRECT	DA3602	63,257	0	0	0	0	4,764	58,477
LINES - PRIMARY DEMAND	D20	1,656,627	1,499	3,115	157	0	0	0
LINES - PRIMARY CUSTOMER	C20	821,048	2,279	4,085	1,050	0	0	0
LINES - SECONDARY DIRECT	DA3647	103,524	0	0	0	0	14,065	0
LINE TRANS - PRIMARY DEMAND	D50	372,646	337	701	35	0	0	0
LINE TRANS - PRIMARY CUST	C50	184,689	513	919	236	0	0	0
LINE TRANS - SECOND DIRECT	DA368	103,275	0	0	0	0	5,991	0
LINE TRANS - SECOND DEMAND	D60	1,077,739	1,146	2,381	120	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	534,143	1,484	2,659	684	0	0	0
LINES - SECONDARY DEMAND	D30	106,166	164	342	17	0	0	0
LINES - SECONDARY CUSTOMER	C30	52,618	151	271	70	0	0	0
SERVICES	CW369	216,054	0	0	0	0	13	0
METERS	CW370	363,661	4	757	351	96	237	1,221
STREET LIGHTS	DA373	19,553	0	19,511	0	0	0	0
INSTALL ON CUST PREMISES	DA371	13,955	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2E	40,143,386	31,489	37,290	7,485	408,021	282,490	1,194,233

IDAHO POWER COMPANY PAGE 2F
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
****** TABLE 4 - SUBSTATION CIAC ****** **ALLOCATION TO CIATION TO CLASSES**

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAI (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
PRODUCTION											
DEMAND - BASE-LOAD TOTAL		0									
DEMAND - Base-load Summer	D10BS	0	0	0	0	0	0	0	0	0	0
DEMAND - Peak	D10P	0	0	0	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	0	0	0	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0	0	0	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	(42,770,847)	(4,292,179)	(205,156)	(472,238)	(6,923)	(1,519,756)	(2,598,489)	(4,296)	(15,762,857)	(3,041,944)
TOTALS	PAGE 2F	(42,770,847)	(4,292,179)	(205,156)	(472,238)	(6,923)	(1,519,756)	(2,598,489)	(4,296)	(15,762,857)	(3,041,944)

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 4 - SUBSTATION CIAC ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
PRODUCTION								
DEMAND - Base-load Summer		0						
DEMAND - Base-load Summer	D10BS	0	0	0	0	0	0	0
DEMAND - Peak	D10P	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0	0	0	0	0	0	0
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	(42,770,847)	(10,144)	(21,076)	(1,060)	0	(70,288)	(14,764,442)
TOTALS		(42,770,847)	(10,144)	(21,076)	(1,060)	0	(70,288)	(14,764,442)

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 5 - CUSTOMER ADVANCES FOR CONSTRUCTION ******
ALLOCATION TO CIATION TO CLASSES

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAI (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
DEMAND - BASE-LOAD TOTAL		0									
DEMAND - Base-load Summer	D10BS	0	0	0	0	0	0	0	0	0	0
DEMAND - Peak	D10P	0	0	0	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	0	0	0	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	3,181,235	1,209,295	57,801	26,256	385	94,910	552,995	1,219	379,297	849,914
LINES - PRIMARY CUSTOMER	C20	1,576,665	1,296,284	34,975	80,020	230	737	99,399	0	300	50,482
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	128,427	48,819	2,333	1,060	16	3,832	22,325	49	15,312	34,311
LINE TRANS - PRIMARY CUST	C50	63,650	52,331	1,412	3,230	9	30	4,013	0	12	2,038
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	395,224	176,479	8,435	3,832	56	0	80,701	178	174	124,032
LINE TRANS - SECOND CUSTOMER	C60	195,879	161,151	4,348	9,948	29	0	12,357	0	0	6,276
LINES - SECONDARY DEMAND	D30	536,323	349,013	16,682	7,578	111	0	159,599	352	343	0
LINES - SECONDARY CUSTOMER	C30	265,809	225,922	6,096	13,946	40	0	17,324	0	0	0
SERVICES	CW369	1,032,307	827,956	22,300	54,387	154	3,072	78,218	0	4,417	41,742
METERS	CW370	706	422	11	40	0	17	128	0	12	70
STREET LIGHTS	DA373	10,184	0	0	0	0	21	0	0	0	0
INSTALL ON CUST PREMISES	DA371	1,051	0	0	0	0	1	0	1,050	1	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 2H	7,387,459	4,347,671	154,394	200,296	1,030	102,620	1,027,059	2,848	399,869	1,108,864

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 5 - CUSTOMER ADVANCES FOR CONSTRUCTION ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		0						
DEMAND - Base-load Summer	D10BS	0	0	0	0	0	0	0
DEMAND - Peak	D10P	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	3,181,235	2,879	5,982	301	0	0	0
LINES - PRIMARY CUSTOMER	C20	1,576,665	4,377	7,844	2,016	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	128,427	116	241	12	0	0	0
LINE TRANS - PRIMARY CUST	C50	63,650	177	317	81	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	395,224	420	873	44	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	195,879	544	975	251	0	0	0
LINES - SECONDARY DEMAND	D30	536,323	831	1,726	87	0	0	0
LINES - SECONDARY CUSTOMER	C30	265,809	763	1,367	351	0	0	0
SERVICES	CW369	1,032,307	0	0	0	0	62	0
METERS	CW370	706	0	1	1	0	0	2
STREET LIGHTS	DA373	10,184	0	10,163	0	0	0	0
INSTALL ON CUST PREMISES	DA371	1,051	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2H	7,387,459	10,108	29,490	3,144	0	62	2

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

***** TABLE 6 - ACCUMULATED DEFERRED INCOME TAXES *****

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER EC/PRIM/TRAI (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
DEMAND - BASE-LOAD TOTAL		127,470,124									
DEMAND - Base-load Summer	D10BS	54,776,292	22,610,331	553,495	417,586	1,462	1,611,189	9,521,309	0	5,509,130	12,120,320
DEMAND - Peak	D10P	12,012,248	4,958,366	121,380	91,575	321	353,328	2,087,990	0	1,208,133	2,657,943
DEMAND - Base-load Non-Summer	D10BNS	72,693,832	31,907,496	887,090	731,396	3,712	2,913,866	17,446,913	0	10,696,235	3,459,491
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	86,357,660	36,793,775	965,317	769,378	3,403	3,016,706	17,986,805	0	10,775,700	11,341,275
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	5,068	0	0	0	0	5,068	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	25,205,345	9,581,403	457,967	208,029	3,050	751,985	4,381,454	9,661	3,005,224	6,733,978
SUBSTATIONS - DIRECT	DA3602	350,573	0	0	0	0	0	0	0	89	0
LINES - PRIMARY DEMAND	D20	33,343,743	12,675,083	605,838	275,198	4,035	994,789	5,796,154	12,781	3,975,563	8,908,271
LINES - PRIMARY CUSTOMER	C20	16,525,627	13,586,849	366,590	838,717	2,414	7,725	1,041,842	0	3,145	529,119
LINES - SECONDARY DIRECT	DA3647	2,131,934	0	0	0	0	569,764	0	26,403	1,246,114	0
LINE TRANS - PRIMARY DEMAND	D50	7,642,983	2,905,356	138,869	63,080	925	228,023	1,328,582	2,930	911,270	2,041,935
LINE TRANS - PRIMARY CUST	C50	3,787,970	3,114,349	84,029	192,249	553	1,771	238,809	0	721	121,284
LINE TRANS - SECOND DIRECT	DA368	2,126,808	0	0	0	0	841,736	0	0	1,161,689	0
LINE TRANS - SECOND DEMAND	D60	22,098,663	9,867,672	471,650	214,244	3,141	0	4,512,361	9,950	9,710	6,935,173
LINE TRANS - SECOND CUSTOMER	C60	10,952,407	9,010,635	243,118	556,227	1,601	0	690,937	0	18	350,905
LINES - SECONDARY DEMAND	D30	2,056,156	1,338,048	63,955	29,051	426	0	611,872	1,349	1,317	0
LINES - SECONDARY CUSTOMER	C30	1,019,060	866,139	23,369	53,467	154	0	66,416	0	2	0
SERVICES	CW369	4,198,735	3,367,570	90,700	221,211	627	12,495	318,139	0	17,964	169,777
METERS	CW370	7,488,950	4,477,072	119,296	423,870	975	185,101	1,359,449	34	128,468	739,753
STREET LIGHTS	DA373	400,190	0	0	0	0	842	0	0	10	0
INSTALL ON CUST PREMISES	DA371	287,131	0	0	0	0	229	0	286,738	164	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 2I	365,461,375	167,060,145	5,192,663	5,085,278	26,799	11,494,617	67,389,032	349,846	38,650,665	56,109,225

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 6 - ACCUMULATED DEFERRED INCOME TAXES ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - Base-load Summer	D10BS	127,470,124	29,578	0	5,912	394,050	378,678	1,623,252
DEMAND - Peak	D10P	12,012,248	6,486	0	1,296	86,414	83,043	355,973
DEMAND - Base-load Non-Summer	D10BNS	72,693,832	58,343	0	12,069	1,196,979	616,251	2,763,992
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	86,357,660	58,352	0	11,916	1,034,555	665,903	2,934,576
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	5,068	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	25,205,345	22,813	47,396	2,384	0	0	0
SUBSTATIONS - DIRECT	DA3602	350,573	0	0	0	0	26,401	324,083
LINES - PRIMARY DEMAND	D20	33,343,743	30,179	62,700	3,154	0	0	0
LINES - PRIMARY CUSTOMER	C20	16,525,627	45,880	82,214	21,133	0	0	0
LINES - SECONDARY DIRECT	DA3647	2,131,934	0	0	0	0	289,652	0
LINE TRANS - PRIMARY DEMAND	D50	7,642,983	6,918	14,372	723	0	0	0
LINE TRANS - PRIMARY CUST	C50	3,787,970	10,516	18,845	4,844	0	0	0
LINE TRANS - SECOND DIRECT	DA368	2,126,808	0	0	0	0	123,383	0
LINE TRANS - SECOND DEMAND	D60	22,098,663	23,495	48,812	2,455	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	10,952,407	30,427	54,523	14,015	0	0	0
LINES - SECONDARY DEMAND	D30	2,056,156	3,186	6,619	333	0	0	0
LINES - SECONDARY CUSTOMER	C30	1,019,060	2,925	5,241	1,347	0	0	0
SERVICES	CW369	4,198,735	0	0	0	0	252	0
METERS	CW370	7,488,950	89	15,593	7,238	1,986	4,886	25,139
STREET LIGHTS	DA373	400,190	0	399,337	0	0	0	0
INSTALL ON CUST PREMISES	DA371	287,131	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2I	365,461,375	329,188	755,652	88,821	2,713,982	2,188,449	8,027,016

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

****** TABLE 7 - ACQUISITION ADJUSTMENT ******

Line	FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAI (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
427	DEMAND - BASE-LOAD TOTAL		0									
428	DEMAND - Base-load Summer	D10BS	0	0	0	0	0	0	0	0	0	0
429	DEMAND - Peak	D10P	0	0	0	0	0	0	0	0	0	0
430	DEMAND - Base-load Non-Summer	D10BNS	0	0	0	0	0	0	0	0	0	0
431	ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
432	ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
433	ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
434			0									
435	TRANSMISSION		0									
436	DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
437	DEMAND - TRANSMISSION	D13	628,247	267,673	7,023	5,597	25	21,946	130,853	0	78,393	82,507
438	DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
439	DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0	0	0
440			0									
441	DISTRIBUTION		0									
442	SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0	0	0	0
443	SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0	0	0	0
444	LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0	0	0	0
445	LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0	0	0	0
446	LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0	0	0
447	LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0	0	0	0
448	LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0	0	0	0
449	LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0	0	0
450	LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0	0	0	0
451	LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0	0	0	0
452	LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0	0	0	0
453	LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0	0	0	0
454	SERVICES	CW369	0	0	0	0	0	0	0	0	0	0
455	METERS	CW370	0	0	0	0	0	0	0	0	0	0
456	STREET LIGHTS	DA373	0	0	0	0	0	0	0	0	0	0
457	INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0	0	0	0
458			0									
459	CUSTOMER ACCOUNTING		0									
460	METER READING	CW902	0	0	0	0	0	0	0	0	0	0
461	CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
462	UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
463	MISC	C10	0	0	0	0	0	0	0	0	0	0
464			0									
465	CONSUMER INFORMATION		0									
466	CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
467	SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
468	ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
469	MISC	C10	0	0	0	0	0	0	0	0	0	0
470			0									
471	MISCELLANEOUS		0									
472	DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
473	ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
474	CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
475	REVENUE	R02	0	0	0	0	0	0	0	0	0	0
476	OTHER	R01	0	0	0	0	0	0	0	0	0	0
477	SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
478												
479	TOTALS	PAGE 2J	628,247	267,673	7,023	5,597	25	21,946	130,853	0	78,393	82,507

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 7 - ACQUISITION ADJUSTMENT ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL								
DEMAND - Base-load Summer	D10BS	0	0	0	0	0	0	0
DEMAND - Peak	D10P	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	628,247	425	0	87	7,526	4,844	21,349
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2J	628,247	425	0	87	7,526	4,844	21,349

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

****** TABLE 8 - WORKING CAPITAL ******

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAI (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
DEMAND - BASE-LOAD TOTAL		15,553,944									
DEMAND - Base-load Summer	D10BS	6,683,820	2,758,920	67,538	50,954	178	196,598	1,161,793	0	672,226	1,478,925
DEMAND - Peak	D10P	1,465,738	605,021	14,811	11,174	39	43,113	254,777	0	147,417	324,323
DEMAND - Base-load Non-Summer	D10BNS	8,870,124	3,893,363	108,243	89,245	453	355,551	2,128,878	0	1,305,158	422,128
ENERGY - POWER SUPPLY	E10	23,609,967	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	2,703,345	68,296	69,967	256	318,420	1,744,491	2,625	1,197,327	2,264,967
ENERGY - Non-Summer	E10NS	0	6,092,997	179,865	153,323	717	613,400	3,569,400	5,701	2,500,656	513,645
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	15,047,187	6,411,044	168,199	134,058	593	525,639	3,134,068	0	1,877,586	1,976,134
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	883	0	0	0	0	883	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	10,475,525	3,982,101	190,335	86,458	1,268	312,530	1,820,964	4,015	1,248,993	2,798,691
SUBSTATIONS - DIRECT	DA3602	488,543	0	0	0	0	0	0	0	124	0
LINES - PRIMARY DEMAND	D20	12,794,439	4,863,599	232,468	105,597	1,548	381,714	2,224,062	4,904	1,525,476	3,418,222
LINES - PRIMARY CUSTOMER	C20	6,341,104	5,213,455	140,665	321,827	926	2,964	399,769	0	1,207	203,030
LINES - SECONDARY DIRECT	DA3647	799,533	0	0	0	0	213,677	0	9,902	467,326	0
LINE TRANS - PRIMARY DEMAND	D50	2,878,018	1,094,032	52,292	23,753	348	85,864	500,287	1,103	343,145	768,905
LINE TRANS - PRIMARY CUST	C50	1,426,386	1,172,729	31,642	72,393	208	667	89,925	0	271	45,670
LINE TRANS - SECOND DIRECT	DA368	797,611	0	0	0	0	315,674	0	0	435,665	0
LINE TRANS - SECOND DEMAND	D60	8,323,578	3,716,711	177,650	80,696	1,183	0	1,699,605	3,748	3,657	2,612,170
LINE TRANS - SECOND CUSTOMER	C60	4,125,282	3,393,904	91,572	209,506	603	0	260,245	0	7	132,170
LINES - SECONDARY DEMAND	D30	819,944	533,580	25,504	11,585	170	0	243,999	538	525	0
LINES - SECONDARY CUSTOMER	C30	406,376	345,395	9,319	21,321	61	0	26,485	0	1	0
SERVICES	CW369	1,668,625	1,338,311	36,045	87,912	249	4,966	126,432	0	7,139	67,471
METERS	CW370	2,808,623	1,679,061	44,740	158,966	366	69,419	509,842	13	48,180	277,434
STREET LIGHTS	DA373	151,009	0	0	0	0	318	0	0	4	0
INSTALL ON CUST PREMISES	DA371	107,778	0	0	0	0	86	0	107,630	62	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	(0)	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 2K	110,090,091	49,797,567	1,639,182	1,688,736	9,167	3,441,483	19,895,022	140,180	11,782,152	17,303,885

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 8 - WORKING CAPITAL ******

ALLOCATION TO CLASSES

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		15,553,944						
DEMAND - Base-load Summer	D10BS	6,683,820	3,609	0	721	48,082	46,206	198,070
DEMAND - Peak	D10P	1,465,738	791	0	158	10,544	10,133	43,436
DEMAND - Base-load Non-Summer	D10BNS	8,870,124	7,119	0	1,473	146,056	75,195	337,263
ENERGY - POWER SUPPLY	E10	23,609,967	0	0	0	0	0	0
ENERGY - Summer	E10S	0	7,079	11,360	1,416	86,241	81,952	299,069
ENERGY - Non-Summer	E10NS	0	15,019	26,387	3,107	276,237	184,975	617,726
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	15,047,187	10,167	0	2,076	180,264	116,029	511,328
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	883	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	10,475,525	9,481	19,698	991	0	0	0
SUBSTATIONS - DIRECT	DA3602	488,543	0	0	0	0	36,791	451,628
LINES - PRIMARY DEMAND	D20	12,794,439	11,580	24,059	1,210	0	0	0
LINES - PRIMARY CUSTOMER	C20	6,341,104	17,605	31,547	8,109	0	0	0
LINES - SECONDARY DIRECT	DA3647	799,533	0	0	0	0	108,627	0
LINE TRANS - PRIMARY DEMAND	D50	2,878,018	2,605	5,412	272	0	0	0
LINE TRANS - PRIMARY CUST	C50	1,426,386	3,960	7,096	1,824	0	0	0
LINE TRANS - SECOND DIRECT	DA368	797,611	0	0	0	0	46,272	0
LINE TRANS - SECOND DEMAND	D60	8,323,578	8,849	18,385	925	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	4,125,282	11,460	20,537	5,279	0	0	0
LINES - SECONDARY DEMAND	D30	819,944	1,270	2,639	133	0	0	0
LINES - SECONDARY CUSTOMER	C30	406,376	1,166	2,090	537	0	0	0
SERVICES	CW369	1,668,625	0	0	0	0	100	0
METERS	CW370	2,808,623	33	5,848	2,715	745	1,832	9,428
STREET LIGHTS	DA373	151,009	0	150,687	0	0	0	0
INSTALL ON CUST PREMISES	DA371	107,778	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2K	110,090,091	111,796	325,745	30,946	748,168	708,114	2,467,948

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

****** TABLE 9 - DEFERRED PROGRAMS ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION	TOTALS		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
	FACTOR		RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	EC/PRIM/TRAI	SECONDARY
			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - BASE-LOAD TOTAL		19,207,519									
DEMAND - Base-load Summer	D10BS	8,253,830	3,406,982	83,402	62,923	220	242,778	1,434,695	0	830,130	1,826,320
DEMAND - Peak	D10P	6,539,110	2,699,187	66,075	49,851	175	192,341	1,136,639	0	657,672	1,446,905
DEMAND - Base-load Non-Summer	D10BNS	10,953,690	4,807,902	133,669	110,209	559	439,069	2,628,945	0	1,611,736	521,285
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	3,273,907	1,394,889	36,596	29,168	129	114,366	681,898	0	408,518	429,959
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	192	0	0	0	0	192	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	1,058,958	402,546	19,241	8,740	128	31,593	184,079	406	126,259	282,916
SUBSTATIONS - DIRECT	DA3602	49,386	0	0	0	0	0	0	0	12	0
LINES - PRIMARY DEMAND	D20	1,293,374	491,655	23,500	10,675	156	38,587	224,828	496	154,209	345,544
LINES - PRIMARY CUSTOMER	C20	641,014	527,022	14,220	32,533	94	300	40,412	0	122	20,524
LINES - SECONDARY DIRECT	DA3647	80,824	0	0	0	0	21,600	0	1,001	47,241	0
LINE TRANS - PRIMARY DEMAND	D50	290,935	110,594	5,286	2,401	35	8,680	50,573	112	34,688	77,728
LINE TRANS - PRIMARY CUST	C50	144,192	118,550	3,199	7,318	21	67	9,090	0	27	4,617
LINE TRANS - SECOND DIRECT	DA368	80,629	0	0	0	0	31,911	0	0	44,041	0
LINE TRANS - SECOND DEMAND	D60	841,420	375,718	17,958	8,157	120	0	171,811	379	370	264,061
LINE TRANS - SECOND CUSTOMER	C60	417,020	343,086	9,257	21,179	61	0	26,308	0	1	13,361
LINES - SECONDARY DEMAND	D30	82,887	53,939	2,578	1,171	17	0	24,666	54	53	0
LINES - SECONDARY CUSTOMER	C30	41,080	34,916	942	2,155	6	0	2,677	0	0	0
SERVICES	CW369	168,679	135,288	3,644	8,887	25	502	12,781	0	722	6,821
METERS	CW370	283,920	169,734	4,523	16,070	37	7,018	51,539	1	4,870	28,045
STREET LIGHTS	DA373	15,265	0	0	0	0	32	0	0	0	0
INSTALL ON CUST PREMISES	DA371	10,895	0	0	0	0	9	0	10,880	6	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 2L	34,521,209	15,072,007	424,089	371,436	1,784	1,129,045	6,680,942	13,329	3,920,677	5,268,086

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 9 - DEFERRED PROGRAMS ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		19,207,519						
DEMAND - Base-load Summer	D10BS	8,253,830	4,457	0	891	59,376	57,060	244,596
DEMAND - Peak	D10P	6,539,110	3,531	0	706	47,041	45,206	193,781
DEMAND - Base-load Non-Summer	D10BNS	10,953,690	8,791	0	1,819	180,364	92,858	416,485
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	3,273,907	2,212	0	452	39,221	25,245	111,253
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	192	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	1,058,958	958	1,991	100	0	0	0
SUBSTATIONS - DIRECT	DA3602	49,386	0	0	0	0	3,719	45,655
LINES - PRIMARY DEMAND	D20	1,293,374	1,171	2,432	122	0	0	0
LINES - PRIMARY CUSTOMER	C20	641,014	1,780	3,189	820	0	0	0
LINES - SECONDARY DIRECT	DA3647	80,824	0	0	0	0	10,981	0
LINE TRANS - PRIMARY DEMAND	D50	290,935	263	547	28	0	0	0
LINE TRANS - PRIMARY CUST	C50	144,192	400	717	184	0	0	0
LINE TRANS - SECOND DIRECT	DA368	80,629	0	0	0	0	4,678	0
LINE TRANS - SECOND DEMAND	D60	841,420	895	1,859	93	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	417,020	1,159	2,076	534	0	0	0
LINES - SECONDARY DEMAND	D30	82,887	128	267	13	0	0	0
LINES - SECONDARY CUSTOMER	C30	41,080	118	211	54	0	0	0
SERVICES	CW369	168,679	0	0	0	0	10	0
METERS	CW370	283,920	3	591	274	75	185	953
STREET LIGHTS	DA373	15,265	0	15,233	0	0	0	0
INSTALL ON CUST PREMISES	DA371	10,895	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2L	34,521,209	25,867	29,113	6,090	326,077	239,943	1,012,723

IDAHO POWER COMPANY PAGE 2M

3CP/12CP CLASS COST OF SERVICE STUDY

TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 10 - SUBSIDIARY RATE BASE ****** **ALLOCATION TO CIATION TO CLASSES**

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION	TOTALS		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
	FACTOR		RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	SEC/PRIM/TRAI	SECONDARY
			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - BASE-LOAD TOTAL		0									
DEMAND - Base-load Summer	D10BS	0	0	0	0	0	0	0	0	0	0
DEMAND - Peak	D10P	0	0	0	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	0	0	0	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	29,980,646	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	3,432,789	86,724	88,846	325	404,340	2,215,207	3,334	1,520,402	2,876,123
ENERGY - Non-Summer	E10NS	0	7,737,071	228,397	194,694	910	778,914	4,532,532	7,240	3,175,408	652,242
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0	0	0	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 2M	29,980,646	11,169,860	315,122	283,541	1,236	1,183,254	6,747,739	10,573	4,695,810	3,528,365

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 10 - SUBSIDIARY RATE BASE ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		0						
DEMAND - Base-load Summer	D10BS	0	0	0	0	0	0	0
DEMAND - Peak	D10P	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	29,980,646	0	0	0	0	0	0
ENERGY - Summer	E10S	0	8,989	14,426	1,798	109,511	104,065	379,766
ENERGY - Non-Summer	E10NS	0	19,072	33,507	3,945	350,774	234,887	784,408
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2M	29,980,646	28,061	47,932	5,743	460,286	338,953	1,164,174

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

***** TABLE 11 - PLANT HELD FOR FUTURE USE *****

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	RESIDENTIAL On Site Gen (6)	GEN SRV (7)	GEN SRV On Site Gen (8)	GEN SRV PRIM & TRAN (9-P/T)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER SEC/PRIM/TRAI (19-S/P/T)	IRRIGATION SECONDARY (24-S)
DEMAND - BASE-LOAD TOTAL		0									
DEMAND - Base-load Summer	D10BS	0	0	0	0	0	0	0	0	0	0
DEMAND - Peak	D10P	0	0	0	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	0	0	0	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	2,640,221	1,124,900	29,513	23,522	104	92,230	549,912	0	329,447	346,738
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	5,316,573	2,021,009	96,599	43,880	643	158,616	924,182	2,038	633,893	1,420,401
SUBSTATIONS - DIRECT	DA3602	30	0	0	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0	0	0	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 2N	7,956,825	3,145,909	126,112	67,402	747	250,847	1,474,094	2,038	963,340	1,767,139

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

***** TABLE 11 - PLANT HELD FOR FUTURE USE *****

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		0						
DEMAND - Base-load Summer	D10BS	0	0	0	0	0	0	0
DEMAND - Peak	D10P	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	2,640,221	1,784	0	364	31,630	20,359	89,719
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	5,316,573	4,812	9,997	503	0	0	0
SUBSTATIONS - DIRECT	DA3602	30	0	0	0	0	2	28
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2N	7,956,825	6,596	9,997	867	31,630	20,361	89,747

IDAHO POWER COMPANY

3CP/12CP CLASS COST OF SERVICE STUDY

TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 12 - OTHER REVENUES ******

ALLOCATION TO CIATION TO CLASSES

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION	TOTALS		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
	FACTOR		RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	SEC/PRIM/TRAI	SECONDARY
			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - BASE-LOAD TOTAL		1,105,981									
DEMAND - Base-load Summer	D10BS	475,261	196,176	4,802	3,623	13	13,979	82,611	0	47,799	105,161
DEMAND - Peak	D10P	2,661	1,098	27	20	0	78	463	0	268	589
DEMAND - Base-load Non-Summer	D10BNS	630,720	276,842	7,697	6,346	32	25,282	151,376	0	92,805	30,016
ENERGY - POWER SUPPLY	E10	29,557,875	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	3,384,382	85,501	87,593	321	398,638	2,183,969	3,287	1,498,962	2,835,565
ENERGY - Non-Summer	E10NS	0	7,627,967	225,177	191,949	898	767,931	4,468,617	7,138	3,130,630	643,045
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	60,109,852	25,610,564	671,916	535,531	2,369	2,099,800	12,519,841	0	7,500,501	7,894,173
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	518	0	0	0	0	518	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	299,274	113,764	5,438	2,470	36	8,929	52,023	115	35,682	79,955
SUBSTATIONS - DIRECT	DA3602	13,957	0	0	0	0	0	0	0	4	0
LINES - PRIMARY DEMAND	D20	2,502,919	951,444	45,477	20,657	303	74,673	435,083	959	298,422	668,692
LINES - PRIMARY CUSTOMER	C20	1,240,482	1,019,885	27,518	62,958	181	580	78,205	0	236	39,718
LINES - SECONDARY DIRECT	DA3647	107,956	0	0	0	0	28,852	0	1,337	63,100	0
LINE TRANS - PRIMARY DEMAND	D50	350,797	133,350	6,374	2,895	42	10,466	60,979	134	41,825	93,721
LINE TRANS - PRIMARY CUST	C50	173,860	142,942	3,857	8,824	25	81	10,961	0	33	5,567
LINE TRANS - SECOND DIRECT	DA368	97,220	0	0	0	0	38,477	0	0	53,103	0
LINE TRANS - SECOND DEMAND	D60	1,014,549	453,024	21,653	9,836	144	0	207,162	457	446	318,394
LINE TRANS - SECOND CUSTOMER	C60	502,825	413,678	11,162	25,536	73	0	31,721	0	1	16,110
LINES - SECONDARY DEMAND	D30	156,826	102,055	4,878	2,216	32	0	46,668	103	100	0
LINES - SECONDARY CUSTOMER	C30	77,725	66,062	1,782	4,078	12	0	5,066	0	0	0
SERVICES	CW369	203,386	163,125	4,393	10,715	30	605	15,411	0	870	8,224
METERS	CW370	80,239	47,969	1,278	4,541	10	1,983	14,566	0	1,376	7,926
STREET LIGHTS	DA373	18,406	0	0	0	0	39	0	0	0	0
INSTALL ON CUST PREMISES	DA371	13,137	0	0	0	0	10	0	13,119	8	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
MISC. REVENUE	R02	6,150,427	5,495,771	29,596	193,701	159	1,918	195,532	11,086	40	113,760
FACILITIES CHARGE REVENUE	DA454	9,859,316	0	0	0	0	3,309,023	0	74,734	5,557,903	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 4C	113,640,190	46,200,098	1,158,525	1,173,490	4,682	6,781,861	20,560,253	112,468	18,324,115	12,860,615

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 12 - OTHER REVENUES ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		1,105,981						
DEMAND - Base-load Summer	D10BS	475,261	257	0	51	3,419	3,286	14,084
DEMAND - Peak	D10P	2,661	1	0	0	19	18	79
DEMAND - Base-load Non-Summer	D10BNS	630,720	506	0	105	10,385	5,347	23,981
ENERGY - POWER SUPPLY	E10	29,557,875	0	0	0	0	0	0
ENERGY - Summer	E10S	0	8,862	14,222	1,773	107,967	102,598	374,411
ENERGY - Non-Summer	E10NS	0	18,803	33,034	3,889	345,828	231,575	773,346
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	60,109,852	40,617	0	8,294	720,109	463,506	2,042,632
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	518	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	299,274	271	563	28	0	0	0
SUBSTATIONS - DIRECT	DA3602	13,957	0	0	0	0	1,051	12,903
LINES - PRIMARY DEMAND	D20	2,502,919	2,265	4,706	237	0	0	0
LINES - PRIMARY CUSTOMER	C20	1,240,482	3,444	6,171	1,586	0	0	0
LINES - SECONDARY DIRECT	DA3647	107,956	0	0	0	0	14,667	0
LINE TRANS - PRIMARY DEMAND	D50	350,797	318	660	33	0	0	0
LINE TRANS - PRIMARY CUST	C50	173,860	483	865	222	0	0	0
LINE TRANS - SECOND DIRECT	DA368	97,220	0	0	0	0	5,640	0
LINE TRANS - SECOND DEMAND	D60	1,014,549	1,079	2,241	113	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	502,825	1,397	2,503	643	0	0	0
LINES - SECONDARY DEMAND	D30	156,826	243	505	25	0	0	0
LINES - SECONDARY CUSTOMER	C30	77,725	223	400	103	0	0	0
SERVICES	CW369	203,386	0	0	0	0	12	0
METERS	CW370	80,239	1	167	78	21	52	269
STREET LIGHTS	DA373	18,406	0	18,367	0	0	0	0
INSTALL ON CUST PREMISES	DA371	13,137	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
MISC. REVENUE	R02	6,150,427	15,092	91,849	1,924	0	0	0
FACILITIES CHARGE REVENUE	DA454	9,859,316	0	681	0	0	916,976	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 4C	113,640,190	93,861	176,934	19,105	1,187,749	1,744,729	3,241,706

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

****** TABLE 13 - OPERATION & MAINTENANCE EXPENSES ******

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAN (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
DEMAND - BASE-LOAD TOTAL		138,136,693									
DEMAND - Base-load Summer	D10BS	59,359,916	24,502,340	599,811	452,529	1,585	1,746,011	10,318,043	0	5,970,128	13,134,536
DEMAND - Peak	D10P	16,516,367	6,817,557	166,892	125,912	441	485,812	2,870,903	0	1,661,135	3,654,567
DEMAND - Base-load Non-Summer	D10BNS	78,776,777	34,577,482	961,321	792,598	4,023	3,157,695	18,906,853	0	11,591,285	3,748,978
ENERGY - POWER SUPPLY	E10	492,817,416	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	56,427,674	1,425,561	1,460,441	5,347	6,646,475	36,413,240	54,800	24,992,144	47,277,280
ENERGY - Non-Summer	E10NS	0	127,180,821	3,754,364	3,200,359	14,966	12,803,679	74,505,086	119,005	52,196,879	10,721,459
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	48,778,156	20,782,551	545,249	434,575	1,922	1,703,953	10,159,645	0	6,086,533	6,405,992
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	3,521	0	0	0	0	3,521	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	17,911,499	6,808,766	325,442	147,830	2,167	534,378	3,113,562	6,866	2,135,582	4,785,320
SUBSTATIONS - DIRECT	DA3602	814,448	0	0	0	0	0	0	0	206	0
LINES - PRIMARY DEMAND	D20	47,352,090	18,000,129	860,362	390,814	5,730	1,412,718	8,231,230	18,150	5,645,773	12,650,806
LINES - PRIMARY CUSTOMER	C20	23,468,360	19,294,945	520,601	1,191,078	3,428	10,970	1,479,540	0	4,466	751,412
LINES - SECONDARY DIRECT	DA3647	1,634,918	0	0	0	0	436,936	0	20,248	955,609	0
LINE TRANS - PRIMARY DEMAND	D50	1,990,925	756,818	36,174	16,432	241	59,398	346,083	763	237,377	531,905
LINE TRANS - PRIMARY CUST	C50	986,730	811,259	21,889	50,079	144	461	62,207	0	188	31,593
LINE TRANS - SECOND DIRECT	DA368	551,763	0	0	0	0	218,373	0	0	301,380	0
LINE TRANS - SECOND DEMAND	D60	5,757,998	2,571,107	122,893	55,823	818	0	1,175,735	2,593	2,530	1,807,019
LINE TRANS - SECOND CUSTOMER	C60	2,853,745	2,347,799	63,346	144,930	417	0	180,030	0	5	91,431
LINES - SECONDARY DEMAND	D30	3,301,093	2,148,193	102,678	46,641	684	0	982,341	2,166	2,114	0
LINES - SECONDARY CUSTOMER	C30	1,636,068	1,390,559	37,519	85,839	247	0	106,628	0	3	0
SERVICES	CW369	1,141,837	915,804	24,666	60,158	170	3,398	86,517	0	4,885	46,171
METERS	CW370	18,706,555	11,183,224	297,988	1,058,780	2,436	462,361	3,395,752	84	320,899	1,847,820
STREET LIGHTS	DA373	554,840	0	0	0	0	1,168	0	0	14	0
INSTALL ON CUST PREMISES	CWINSTAL	2,894,436	2,057,683	55,519	127,021	366	1,187	157,784	391,659	485	80,133
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	3,681,466	2,818,451	55,951	220,902	536	104,762	238,482	0	42,766	194,122
CUSTOMER ACCOUNTS	CW903	32,460,816	26,554,621	716,476	1,639,218	4,718	129,538	2,036,213	0	52,881	1,034,129
UNCOLLECTIBLES	CW904	5,388,730	4,833,086	2,063	205,622	0	1,916	254,688	(3)	25,816	65,542
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	19,150,720	15,744,877	424,816	971,932	2,797	9,085	1,207,320	0	3,709	613,160
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	INTFUND	332,773	212,346	5,770	8,754	26	2,878	16,293	26	11,394	75,286
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 3C	888,823,963	388,738,091	11,127,348	12,888,267	53,211	29,936,675	176,244,175	616,357	112,246,184	109,548,662

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 13 - OPERATION & MAINTENANCE EXPENSES ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		138,136,693						
DEMAND - Base-load Summer	D10BS	59,359,916	32,053	0	6,407	427,023	410,366	1,759,084
DEMAND - Peak	D10P	16,516,367	8,919	0	1,783	118,815	114,181	489,449
DEMAND - Base-load Non-Summer	D10BNS	78,776,777	63,226	0	13,079	1,297,140	667,818	2,995,280
ENERGY - POWER SUPPLY	E10	492,817,416	0	0	0	0	0	0
ENERGY - Summer	E10S	0	147,761	237,125	29,555	1,800,130	1,710,612	6,242,542
ENERGY - Non-Summer	E10NS	0	313,495	550,779	64,846	5,765,976	3,861,040	12,893,976
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	48,778,156	32,960	0	6,730	584,357	376,128	1,657,563
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	3,521	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	17,911,499	16,211	33,681	1,694	0	0	0
SUBSTATIONS - DIRECT	DA3602	814,448	0	0	0	0	61,335	752,907
LINES - PRIMARY DEMAND	D20	47,352,090	42,858	89,041	4,479	0	0	0
LINES - PRIMARY CUSTOMER	C20	23,468,360	65,155	116,754	30,011	0	0	0
LINES - SECONDARY DIRECT	DA3647	1,634,918	0	0	0	0	222,126	0
LINE TRANS - PRIMARY DEMAND	D50	1,990,925	1,802	3,744	188	0	0	0
LINE TRANS - PRIMARY CUST	C50	986,730	2,739	4,909	1,262	0	0	0
LINE TRANS - SECOND DIRECT	DA368	551,763	0	0	0	0	32,010	0
LINE TRANS - SECOND DEMAND	D60	5,757,998	6,122	12,718	640	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	2,853,745	7,928	14,207	3,652	0	0	0
LINES - SECONDARY DEMAND	D30	3,301,093	5,115	10,626	535	0	0	0
LINES - SECONDARY CUSTOMER	C30	1,636,068	4,696	8,414	2,163	0	0	0
SERVICES	CW369	1,141,837	0	0	0	0	69	0
METERS	CW370	18,706,555	223	38,949	18,080	4,960	12,205	62,794
STREET LIGHTS	DA373	554,840	0	553,658	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	2,894,436	6,948	12,451	3,201	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	3,681,466	0	4,387	0	369	369	369
CUSTOMER ACCOUNTS	CW903	32,460,816	89,669	160,682	41,303	456	456	456
UNCOLLECTIBLES	CW904	5,388,730	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	19,150,720	53,167	95,272	24,489	32	32	32
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	INTFUND	332,773	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3C	888,823,963	901,046	1,947,396	254,097	9,999,258	7,468,743	26,854,451

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

****** TABLE 14 - DEPRECIATION EXPENSE ******

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAI (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
DEMAND - BASE-LOAD TOTAL		61,229,781									
DEMAND - Base-load Summer	D10BS	26,311,580	10,860,785	265,869	200,586	702	773,928	4,573,524	0	2,646,289	5,821,949
DEMAND - Peak	D10P	6,492,310	2,679,869	65,602	49,494	173	190,965	1,128,504	0	652,965	1,436,550
DEMAND - Base-load Non-Summer	D10BNS	34,918,201	15,326,642	426,110	351,323	1,783	1,399,664	8,380,557	0	5,137,895	1,661,753
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	28,824,414	12,281,007	322,203	256,803	1,136	1,006,915	6,003,626	0	3,596,707	3,785,485
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	1,909	0	0	0	0	1,909	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	9,040,007	3,436,412	164,252	74,610	1,094	269,703	1,571,428	3,465	1,077,837	2,415,171
SUBSTATIONS - DIRECT	DA3602	145,538	0	0	0	0	0	0	0	37	0
LINES - PRIMARY DEMAND	D20	12,917,578	4,910,408	234,705	106,613	1,563	385,387	2,245,467	4,951	1,540,158	3,451,121
LINES - PRIMARY CUSTOMER	C20	6,402,133	5,263,632	142,019	324,924	935	2,993	403,616	0	1,218	204,984
LINES - SECONDARY DIRECT	DA3647	849,132	0	0	0	0	226,933	0	10,516	496,317	0
LINE TRANS - PRIMARY DEMAND	D50	2,620,571	996,168	47,614	21,629	317	78,183	455,535	1,004	312,450	700,124
LINE TRANS - PRIMARY CUST	C50	1,298,792	1,067,826	28,811	65,917	190	607	81,881	0	247	41,585
LINE TRANS - SECOND DIRECT	DA368	726,262	0	0	0	0	287,436	0	0	396,693	0
LINE TRANS - SECOND DEMAND	D60	7,579,012	3,384,241	161,758	73,478	1,077	0	1,547,570	3,413	3,330	2,378,504
LINE TRANS - SECOND CUSTOMER	C60	3,756,265	3,090,310	83,380	190,765	549	0	236,966	0	6	120,347
LINES - SECONDARY DEMAND	D30	831,250	540,938	25,855	11,745	172	0	247,364	545	532	0
LINES - SECONDARY CUSTOMER	C30	411,979	350,158	9,448	21,615	62	0	26,850	0	1	0
SERVICES	CW369	1,329,707	1,066,483	28,724	70,056	199	3,957	100,752	0	5,689	53,767
METERS	CW370	6,073,947	3,631,150	96,756	343,782	791	150,127	1,102,588	27	104,195	599,980
STREET LIGHTS	DA373	227,907	0	0	0	0	480	0	0	6	0
INSTALL ON CUST PREMISES	CWINSTAL	193,695	137,700	3,715	8,500	24	79	10,559	26,210	32	5,363
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 3D	150,952,190	69,023,727	2,106,824	2,171,839	10,768	4,779,265	28,116,787	50,132	15,972,606	22,676,682

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 14 - DEPRECIATION EXPENSE ******

ALLOCATION TO CLASSES

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		61,229,781						
DEMAND - Base-load Summer	D10BS	26,311,580	14,208	0	2,840	189,280	181,897	779,723
DEMAND - Peak	D10P	6,492,310	3,506	0	701	46,704	44,883	192,394
DEMAND - Base-load Non-Summer	D10BNS	34,918,201	28,025	0	5,797	574,964	296,014	1,327,673
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	28,824,414	19,477	0	3,977	345,313	222,265	979,501
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	1,909	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	9,040,007	8,182	16,999	855	0	0	0
SUBSTATIONS - DIRECT	DA3602	145,538	0	0	0	0	10,960	134,541
LINES - PRIMARY DEMAND	D20	12,917,578	11,692	24,290	1,222	0	0	0
LINES - PRIMARY CUSTOMER	C20	6,402,133	17,774	31,850	8,187	0	0	0
LINES - SECONDARY DIRECT	DA3647	849,132	0	0	0	0	115,366	0
LINE TRANS - PRIMARY DEMAND	D50	2,620,571	2,372	4,928	248	0	0	0
LINE TRANS - PRIMARY CUST	C50	1,298,792	3,606	6,461	1,661	0	0	0
LINE TRANS - SECOND DIRECT	DA368	726,262	0	0	0	0	42,133	0
LINE TRANS - SECOND DEMAND	D60	7,579,012	8,058	16,741	842	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	3,756,265	10,435	18,699	4,807	0	0	0
LINES - SECONDARY DEMAND	D30	831,250	1,288	2,676	135	0	0	0
LINES - SECONDARY CUSTOMER	C30	411,979	1,182	2,119	545	0	0	0
SERVICES	CW369	1,329,707	0	0	0	0	80	0
METERS	CW370	6,073,947	72	12,647	5,871	1,611	3,963	20,389
STREET LIGHTS	DA373	227,907	0	227,422	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	193,695	465	833	214	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3D	150,952,190	130,341	365,665	37,901	1,157,872	917,560	3,434,221

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
****** TABLE 15 - AMORTIZATION OF LIMITED TERM PLANT ****** **ALLOCATION TO CIATION TO CLASSES**

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION	TOTALS		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
	FACTOR		RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	SEC/PRIM/TRAI	SECONDARY
			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - BASE-LOAD TOTAL		4,744,176									
DEMAND - Base-load Summer	D10BS	2,038,661	841,510	20,600	15,542	54	59,965	354,364	0	205,039	451,093
DEMAND - Peak	D10P	48,412	19,984	489	369	1	1,424	8,415	0	4,869	10,712
DEMAND - Base-load Non-Summer	D10BNS	2,705,515	1,187,531	33,016	27,221	138	108,448	649,338	0	398,092	128,755
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	348,044	148,288	3,890	3,101	14	12,158	72,491	0	43,429	45,708
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	20	0	0	0	0	20	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	112,576	42,794	2,045	929	14	3,359	19,569	43	13,422	30,076
SUBSTATIONS - DIRECT	DA3602	5,250	0	0	0	0	0	0	0	1	0
LINES - PRIMARY DEMAND	D20	137,497	52,267	2,498	1,135	17	4,102	23,901	53	16,394	36,734
LINES - PRIMARY CUSTOMER	C20	68,145	56,027	1,512	3,459	10	32	4,296	0	13	2,182
LINES - SECONDARY DIRECT	DA3647	8,592	0	0	0	0	2,296	0	106	5,022	0
LINE TRANS - PRIMARY DEMAND	D50	30,929	11,757	562	255	4	923	5,376	12	3,688	8,263
LINE TRANS - PRIMARY CUST	C50	15,329	12,603	340	778	2	7	966	0	3	491
LINE TRANS - SECOND DIRECT	DA368	8,572	0	0	0	0	3,392	0	0	4,682	0
LINE TRANS - SECOND DEMAND	D60	89,450	39,942	1,909	867	13	0	18,265	40	39	28,072
LINE TRANS - SECOND CUSTOMER	C60	44,333	36,473	984	2,251	6	0	2,797	0	0	1,420
LINES - SECONDARY DEMAND	D30	8,812	5,734	274	124	2	0	2,622	6	6	0
LINES - SECONDARY CUSTOMER	C30	4,367	3,712	100	229	1	0	285	0	0	0
SERVICES	CW369	17,932	14,382	387	945	3	53	1,359	0	77	725
METERS	CW370	30,183	18,044	481	1,708	4	746	5,479	0	518	2,981
STREET LIGHTS	DA373	1,623	0	0	0	0	3	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	1,158	823	22	51	0	0	63	157	0	32
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 3E	5,725,400	2,491,872	69,110	58,965	282	196,930	1,169,587	417	695,293	747,246

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 15 - AMORTIZATION OF LIMITED TERM PLANT ******

ALLOCATION TO CLASSES

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		4,744,176						
DEMAND - Base-load Summer	D10BS	2,038,661	1,101	0	220	14,666	14,094	60,414
DEMAND - Peak	D10P	48,412	26	0	5	348	335	1,435
DEMAND - Base-load Non-Summer	D10BNS	2,705,515	2,171	0	449	44,549	22,936	102,870
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	348,044	235	0	48	4,170	2,684	11,827
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	20	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	112,576	102	212	11	0	0	0
SUBSTATIONS - DIRECT	DA3602	5,250	0	0	0	0	395	4,853
LINES - PRIMARY DEMAND	D20	137,497	124	259	13	0	0	0
LINES - PRIMARY CUSTOMER	C20	68,145	189	339	87	0	0	0
LINES - SECONDARY DIRECT	DA3647	8,592	0	0	0	0	1,167	0
LINE TRANS - PRIMARY DEMAND	D50	30,929	28	58	3	0	0	0
LINE TRANS - PRIMARY CUST	C50	15,329	43	76	20	0	0	0
LINE TRANS - SECOND DIRECT	DA368	8,572	0	0	0	0	497	0
LINE TRANS - SECOND DEMAND	D60	89,450	95	198	10	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	44,333	123	221	57	0	0	0
LINES - SECONDARY DEMAND	D30	8,812	14	28	1	0	0	0
LINES - SECONDARY CUSTOMER	C30	4,367	13	22	6	0	0	0
SERVICES	CW369	17,932	0	0	0	0	1	0
METERS	CW370	30,183	0	63	29	8	20	101
STREET LIGHTS	DA373	1,623	0	1,619	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	1,158	3	5	1	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3E	5,725,400	4,267	3,100	960	63,741	42,128	181,501

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 16 - TAXES OTHER THAN INCOME ****** **ALLOCATION TO CIATION TO CLASSES**

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAI (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
DEMAND - BASE-LOAD TOTAL		8,477,654									
DEMAND - Base-load Summer	D10BS	3,643,006	1,503,745	36,811	27,772	97	107,155	633,234	0	366,396	806,086
DEMAND - Peak	D10P	991,152	409,124	10,015	7,556	26	29,154	172,284	0	99,685	219,312
DEMAND - Base-load Non-Summer	D10BNS	4,834,648	2,122,071	58,998	48,643	247	193,792	1,160,342	0	711,374	230,080
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	7,560,424	3,221,214	84,511	67,357	298	264,106	1,574,705	0	943,389	992,904
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	444	0	0	0	0	444	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	1,875,874	713,083	34,084	15,482	227	55,965	326,084	719	223,660	501,167
SUBSTATIONS - DIRECT	DA3602	31,792	0	0	0	0	0	0	0	8	0
LINES - PRIMARY DEMAND	D20	2,516,018	956,424	45,715	20,766	304	75,064	437,360	964	299,984	672,191
LINES - PRIMARY CUSTOMER	C20	1,246,974	1,025,223	27,662	63,287	182	583	78,614	0	237	39,926
LINES - SECONDARY DIRECT	DA3647	157,228	0	0	0	0	42,019	0	1,947	91,899	0
LINE TRANS - PRIMARY DEMAND	D50	565,960	215,141	10,283	4,671	68	16,885	98,381	217	67,479	151,205
LINE TRANS - PRIMARY CUST	C50	280,498	230,617	6,222	14,236	41	131	17,684	0	53	8,981
LINE TRANS - SECOND DIRECT	DA368	156,850	0	0	0	0	62,077	0	0	85,673	0
LINE TRANS - SECOND DEMAND	D60	1,636,826	730,889	34,935	15,869	233	0	334,226	737	719	513,681
LINE TRANS - SECOND CUSTOMER	C60	811,234	667,409	18,007	41,199	119	0	51,177	0	1	25,991
LINES - SECONDARY DEMAND	D30	161,241	104,928	5,015	2,278	33	0	47,982	106	103	0
LINES - SECONDARY CUSTOMER	C30	79,913	67,922	1,833	4,193	12	0	5,208	0	0	0
SERVICES	CW369	328,134	263,178	7,088	17,288	49	977	24,863	0	1,404	13,268
METERS	CW370	552,314	330,186	8,798	31,261	72	13,651	100,260	2	9,475	54,557
STREET LIGHTS	DA373	29,696	0	0	0	0	62	0	0	1	0
INSTALL ON CUST PREMISES	CWINSTAL	21,194	15,067	407	930	3	9	1,155	2,868	4	587
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	2,119,909	771,520	17,478	19,664	53	85,562	472,327	749	339,390	265,137
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 3F	29,601,331	13,347,740	407,862	402,452	2,065	947,637	5,535,886	8,310	3,240,936	4,495,074

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

***** TABLE 16 - TAXES OTHER THAN INCOME *****

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		8,477,654						
DEMAND - Base-load Summer	D10BS	3,643,006	1,967	0	393	26,207	25,185	107,958
DEMAND - Peak	D10P	991,152	535	0	107	7,130	6,852	29,372
DEMAND - Base-load Non-Summer	D10BNS	4,834,648	3,880	0	803	79,607	40,985	183,825
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	7,560,424	5,109	0	1,043	90,573	58,298	256,916
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	444	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	1,875,874	1,698	3,527	177	0	0	0
SUBSTATIONS - DIRECT	DA3602	31,792	0	0	0	0	2,394	29,390
LINES - PRIMARY DEMAND	D20	2,516,018	2,277	4,731	238	0	0	0
LINES - PRIMARY CUSTOMER	C20	1,246,974	3,462	6,204	1,595	0	0	0
LINES - SECONDARY DIRECT	DA3647	157,228	0	0	0	0	21,361	0
LINE TRANS - PRIMARY DEMAND	D50	565,960	512	1,064	54	0	0	0
LINE TRANS - PRIMARY CUST	C50	280,498	779	1,395	359	0	0	0
LINE TRANS - SECOND DIRECT	DA368	156,850	0	0	0	0	9,099	0
LINE TRANS - SECOND DEMAND	D60	1,636,826	1,740	3,615	182	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	811,234	2,254	4,038	1,038	0	0	0
LINES - SECONDARY DEMAND	D30	161,241	250	519	26	0	0	0
LINES - SECONDARY CUSTOMER	C30	79,913	229	411	106	0	0	0
SERVICES	CW369	328,134	0	0	0	0	20	0
METERS	CW370	552,314	7	1,150	534	146	360	1,854
STREET LIGHTS	DA373	29,696	0	29,633	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	21,194	51	91	23	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	2,119,909	1,980	3,379	405	33,289	24,885	84,090
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3F	29,601,331	26,730	59,758	7,082	236,953	189,440	693,404

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

****** TABLE 17 - REGULATORY DEBITS/CREDITS ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	RESIDENTIAL On Site Gen (6)	GEN SRV (7)	GEN SRV On Site Gen (8)	GEN SRV PRIM & TRAN (9-P/T)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER SEC/PRIM/TRAI (19-S/P/T)	IRRIGATION SECONDARY (24-S)
DEMAND - BASE-LOAD TOTAL		0									
DEMAND - Base-load Summer	D10BS	1,464,604	259,788	6,360	4,798	17	18,512	109,398	0	63,299	139,260
DEMAND - Peak	D10P	387,790	160,070	3,918	2,956	10	11,406	67,406	0	39,002	85,806
DEMAND - Base-load Non-Summer	D10BNS	0	366,610	10,192	8,404	43	33,480	200,461	0	122,897	39,749
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	481,088	204,974	5,378	4,286	19	16,806	100,202	0	60,030	63,181
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	28	0	0	0	0	28	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	155,610	59,153	2,827	1,284	19	4,643	27,050	60	18,553	41,573
SUBSTATIONS - DIRECT	DA3602	7,257	0	0	0	0	0	0	0	2	0
LINES - PRIMARY DEMAND	D20	190,057	72,247	3,453	1,569	23	5,670	33,038	73	22,660	50,776
LINES - PRIMARY CUSTOMER	C20	94,195	77,444	2,090	4,781	14	44	5,938	0	18	3,016
LINES - SECONDARY DIRECT	DA3647	11,877	0	0	0	0	3,174	0	147	6,942	0
LINE TRANS - PRIMARY DEMAND	D50	42,752	16,251	777	353	5	1,275	7,432	16	5,097	11,422
LINE TRANS - PRIMARY CUST	C50	21,188	17,420	470	1,075	3	10	1,336	0	4	678
LINE TRANS - SECOND DIRECT	DA368	11,848	0	0	0	0	4,689	0	0	6,472	0
LINE TRANS - SECOND DEMAND	D60	123,644	55,210	2,639	1,199	18	0	25,247	56	54	38,803
LINE TRANS - SECOND CUSTOMER	C60	61,280	50,415	1,360	3,112	9	0	3,866	0	0	1,963
LINES - SECONDARY DEMAND	D30	12,180	7,926	379	172	3	0	3,625	8	8	0
LINES - SECONDARY CUSTOMER	C30	6,037	5,131	138	317	1	0	393	0	0	0
SERVICES	CW369	24,787	19,880	535	1,306	4	74	1,878	0	106	1,002
METERS	CW370	41,721	24,942	665	2,361	5	1,031	7,574	0	716	4,121
STREET LIGHTS	DA373	2,243	0	0	0	0	5	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	1,601	1,138	31	70	0	1	87	217	0	44
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 3G	3,141,786	1,398,600	41,212	38,043	192	100,848	594,931	576	345,861	481,396

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 17 - REGULATORY DEBITS/CREDITS ******

ALLOCATION TO CLASSES

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		0						
DEMAND - Base-load Summer	D10BS	1,464,604	340	0	68	4,528	4,351	18,651
DEMAND - Peak	D10P	387,790	209	0	42	2,790	2,681	11,492
DEMAND - Base-load Non-Summer	D10BNS	0	670	0	139	13,753	7,081	31,758
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	481,088	325	0	66	5,763	3,710	16,348
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	28	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	155,610	141	293	15	0	0	0
SUBSTATIONS - DIRECT	DA3602	7,257	0	0	0	0	547	6,709
LINES - PRIMARY DEMAND	D20	190,057	172	357	18	0	0	0
LINES - PRIMARY CUSTOMER	C20	94,195	262	469	120	0	0	0
LINES - SECONDARY DIRECT	DA3647	11,877	0	0	0	0	1,614	0
LINE TRANS - PRIMARY DEMAND	D50	42,752	39	80	4	0	0	0
LINE TRANS - PRIMARY CUST	C50	21,188	59	105	27	0	0	0
LINE TRANS - SECOND DIRECT	DA368	11,848	0	0	0	0	687	0
LINE TRANS - SECOND DEMAND	D60	123,644	131	273	14	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	61,280	170	305	78	0	0	0
LINES - SECONDARY DEMAND	D30	12,180	19	39	2	0	0	0
LINES - SECONDARY CUSTOMER	C30	6,037	17	31	8	0	0	0
SERVICES	CW369	24,787	0	0	0	0	1	0
METERS	CW370	41,721	0	87	40	11	27	140
STREET LIGHTS	DA373	2,243	0	2,238	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	1,601	4	7	2	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3G	3,141,786	2,559	4,285	643	26,845	20,698	85,097

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

****** TABLE 18 - PROVISIONS FOR DEFERRED INCOME TAXES ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL	RESIDENTIAL On Site Gen	GEN SRV	GEN SRV On Site Gen	GEN SRV PRIM & TRAN	GEN SRV SECONDARY	AREA LIGHTING	LG POWER SEC/PRIM/TRAI	IRRIGATION SECONDARY
			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - BASE-LOAD TOTAL		(5,884,910)									
DEMAND - Base-load Summer	D10BS	(2,528,856)	(1,043,851)	(25,553)	(19,279)	(68)	(74,384)	(439,570)	0	(254,340)	(559,558)
DEMAND - Peak	D10P	(554,569)	(228,913)	(5,604)	(4,228)	(15)	(16,312)	(96,396)	0	(55,776)	(122,709)
DEMAND - Base-load Non-Summer	D10BNS	(3,356,054)	(1,473,072)	(40,954)	(33,766)	(171)	(134,524)	(805,471)	0	(493,813)	(159,714)
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	(3,986,872)	(1,698,657)	(44,566)	(35,520)	(157)	(139,272)	(830,396)	0	(497,481)	(523,592)
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	(234)	0	0	0	0	(234)	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	(1,163,654)	(442,344)	(21,143)	(9,604)	(141)	(34,717)	(202,278)	(446)	(138,742)	(310,887)
SUBSTATIONS - DIRECT	DA3602	(16,185)	0	0	0	0	0	0	0	(4)	0
LINES - PRIMARY DEMAND	D20	(1,648,196)	(626,535)	(29,947)	(13,603)	(199)	(49,173)	(286,506)	(632)	(196,514)	(440,340)
LINES - PRIMARY CUSTOMER	C20	(816,869)	(671,604)	(18,121)	(41,458)	(119)	(382)	(51,499)	0	(155)	(26,155)
LINES - SECONDARY DIRECT	DA3647	(98,425)	0	0	0	0	(26,304)	0	(1,219)	(57,529)	0
LINE TRANS - PRIMARY DEMAND	D50	(357,246)	(135,801)	(6,491)	(2,948)	(43)	(10,658)	(62,100)	(137)	(42,594)	(95,444)
LINE TRANS - PRIMARY CUST	C50	(177,056)	(145,570)	(3,928)	(8,986)	(26)	(83)	(11,162)	0	(34)	(5,669)
LINE TRANS - SECOND DIRECT	DA368	(98,188)	0	0	0	0	(38,860)	0	0	(53,632)	0
LINE TRANS - SECOND DEMAND	D60	(1,033,747)	(461,597)	(22,063)	(10,022)	(147)	0	(211,082)	(465)	(454)	(324,419)
LINE TRANS - SECOND CUSTOMER	C60	(512,340)	(421,506)	(11,373)	(26,020)	(75)	0	(32,321)	0	(1)	(16,415)
LINES - SECONDARY DEMAND	D30	(113,272)	(73,712)	(3,523)	(1,600)	(23)	0	(33,707)	(74)	(73)	0
LINES - SECONDARY CUSTOMER	C30	(56,139)	(47,715)	(1,287)	(2,945)	(8)	0	(3,659)	0	(0)	0
SERVICES	CW369	(229,154)	(183,791)	(4,950)	(12,073)	(34)	(682)	(17,363)	0	(980)	(9,266)
METERS	CW370	(345,766)	(206,707)	(5,508)	(19,570)	(45)	(8,546)	(62,766)	(2)	(5,931)	(34,155)
STREET LIGHTS	DA373	(18,824)	0	0	0	0	(40)	0	0	(0)	0
INSTALL ON CUST PREMISES	CWINSTAL	(13,292)	(9,449)	(255)	(583)	(2)	(5)	(725)	(1,799)	(2)	(368)
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 3H	(17,124,938)	(7,870,826)	(245,266)	(242,206)	(1,274)	(534,177)	(3,147,003)	(4,774)	(1,798,057)	(2,628,690)

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 18 - PROVISIONS FOR DEFERRED INCOME TAXES ******

ALLOCATION TO CLASSES

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		(5,884,910)						
DEMAND - Base-load Summer	D10BS	(2,528,856)	(1,366)	0	(273)	(18,192)	(17,482)	(74,941)
DEMAND - Peak	D10P	(554,569)	(299)	0	(60)	(3,989)	(3,834)	(16,434)
DEMAND - Base-load Non-Summer	D10BNS	(3,356,054)	(2,694)	0	(557)	(55,261)	(28,450)	(127,605)
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	(3,986,872)	(2,694)	0	(550)	(47,762)	(30,743)	(135,481)
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	(234)	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	(1,163,654)	(1,053)	(2,188)	(110)	0	0	0
SUBSTATIONS - DIRECT	DA3602	(16,185)	0	0	0	0	(1,219)	(14,962)
LINES - PRIMARY DEMAND	D20	(1,648,196)	(1,492)	(3,099)	(156)	0	0	0
LINES - PRIMARY CUSTOMER	C20	(816,869)	(2,268)	(4,064)	(1,045)	0	0	0
LINES - SECONDARY DIRECT	DA3647	(98,425)	0	0	0	0	(13,372)	0
LINE TRANS - PRIMARY DEMAND	D50	(357,246)	(323)	(672)	(34)	0	0	0
LINE TRANS - PRIMARY CUST	C50	(177,056)	(492)	(881)	(226)	0	0	0
LINE TRANS - SECOND DIRECT	DA368	(98,188)	0	0	0	0	(5,696)	0
LINE TRANS - SECOND DEMAND	D60	(1,033,747)	(1,099)	(2,283)	(115)	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	(512,340)	(1,423)	(2,551)	(656)	0	0	0
LINES - SECONDARY DEMAND	D30	(113,272)	(176)	(365)	(18)	0	0	0
LINES - SECONDARY CUSTOMER	C30	(56,139)	(161)	(289)	(74)	0	0	0
SERVICES	CW369	(229,154)	0	0	0	0	(14)	0
METERS	CW370	(345,766)	(4)	(720)	(334)	(92)	(226)	(1,161)
STREET LIGHTS	DA373	(18,824)	0	(18,784)	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	(13,292)	(32)	(57)	(15)	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3H	(17,124,938)	(15,575)	(35,952)	(4,223)	(125,296)	(101,036)	(370,583)

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 19 - INVESTMENT TAX CREDIT ADJUSTMENT ******

ALLOCATION TO CIATION TO CLASSES

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAN (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
DEMAND - BASE-LOAD TOTAL		8,304,618									
DEMAND - Base-load Summer	D10BS	3,568,649	1,473,052	36,060	27,206	95	104,968	620,309	0	358,917	789,633
DEMAND - Peak	D10P	782,592	323,035	7,908	5,966	21	23,019	136,032	0	78,709	173,164
DEMAND - Base-load Non-Summer	D10BNS	4,735,968	2,078,758	57,793	47,650	242	189,837	1,136,658	0	696,855	225,384
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	5,626,160	2,397,097	62,890	50,125	222	196,537	1,171,832	0	702,032	738,879
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	330	0	0	0	0	330	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	1,642,116	624,224	29,836	13,553	199	48,991	285,450	629	195,789	438,715
SUBSTATIONS - DIRECT	DA3602	22,840	0	0	0	0	0	0	0	6	0
LINES - PRIMARY DEMAND	D20	2,222,644	844,902	40,384	18,344	269	66,311	386,363	852	265,005	593,812
LINES - PRIMARY CUSTOMER	C20	1,101,574	905,679	24,436	55,908	161	515	69,448	0	210	35,270
LINES - SECONDARY DIRECT	DA3647	138,894	0	0	0	0	37,120	0	1,720	81,184	0
LINE TRANS - PRIMARY DEMAND	D50	499,968	190,055	9,084	4,126	60	14,916	86,910	192	59,611	133,574
LINE TRANS - PRIMARY CUST	C50	247,791	203,726	5,497	12,576	36	116	15,622	0	47	7,934
LINE TRANS - SECOND DIRECT	DA368	138,561	0	0	0	0	54,839	0	0	75,684	0
LINE TRANS - SECOND DEMAND	D60	1,445,968	645,665	30,861	14,019	206	0	295,255	651	635	453,785
LINE TRANS - SECOND CUSTOMER	C60	716,642	589,587	15,908	36,395	105	0	45,210	0	1	22,961
LINES - SECONDARY DEMAND	D30	142,440	92,693	4,431	2,013	30	0	42,387	93	91	0
LINES - SECONDARY CUSTOMER	C30	70,595	60,002	1,619	3,704	11	0	4,601	0	0	0
SERVICES	CW369	289,873	232,491	6,262	15,272	43	863	21,964	0	1,240	11,721
METERS	CW370	487,913	291,686	7,772	27,616	64	12,060	88,570	2	8,370	48,196
STREET LIGHTS	DA373	26,233	0	0	0	0	55	0	0	1	0
INSTALL ON CUST PREMISES	CWINSTAL	18,723	13,310	359	822	2	8	1,021	2,534	3	518
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 3I	23,926,476	10,965,963	341,101	335,293	1,765	750,485	4,407,628	6,673	2,524,389	3,673,546

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 19 - INVESTMENT TAX CREDIT ADJUSTMENT ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		8,304,618						
DEMAND - Base-load Summer	D10BS	3,568,649	1,927	0	385	25,672	24,671	105,754
DEMAND - Peak	D10P	782,592	423	0	84	5,630	5,410	23,191
DEMAND - Base-load Non-Summer	D10BNS	4,735,968	3,801	0	786	77,983	40,148	180,073
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	5,626,160	3,802	0	776	67,401	43,383	191,186
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	330	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	1,642,116	1,486	3,088	155	0	0	0
SUBSTATIONS - DIRECT	DA3602	22,840	0	0	0	0	1,720	21,114
LINES - PRIMARY DEMAND	D20	2,222,644	2,012	4,179	210	0	0	0
LINES - PRIMARY CUSTOMER	C20	1,101,574	3,058	5,480	1,409	0	0	0
LINES - SECONDARY DIRECT	DA3647	138,894	0	0	0	0	18,871	0
LINE TRANS - PRIMARY DEMAND	D50	499,968	453	940	47	0	0	0
LINE TRANS - PRIMARY CUST	C50	247,791	688	1,233	317	0	0	0
LINE TRANS - SECOND DIRECT	DA368	138,561	0	0	0	0	8,038	0
LINE TRANS - SECOND DEMAND	D60	1,445,968	1,537	3,194	161	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	716,642	1,991	3,568	917	0	0	0
LINES - SECONDARY DEMAND	D30	142,440	221	459	23	0	0	0
LINES - SECONDARY CUSTOMER	C30	70,595	203	363	93	0	0	0
SERVICES	CW369	289,873	0	0	0	0	17	0
METERS	CW370	487,913	6	1,016	472	129	318	1,638
STREET LIGHTS	DA373	26,233	0	26,177	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	18,723	45	81	21	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3I	23,926,476	21,651	49,777	5,857	176,815	142,577	522,956

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

****** TABLE 20 - CONSTRUCTION WORK IN PROGRESS ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION	TOTALS		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
	FACTOR		RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	3EC/PRIM/TRAI	SECONDARY
			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - BASE-LOAD TOTAL		6,537,444									
DEMAND - Base-load Summer	D10BS	2,809,262	1,159,595	28,387	21,416	75	82,632	488,311	0	282,542	621,604
DEMAND - Peak	D10P	0	0	0	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	3,728,182	1,636,411	45,495	37,510	190	149,441	894,784	0	548,568	177,424
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0	0	0
TRANSMISSION											
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0	0	0
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0	0	0
TOTALS	PAGE 3J	6,537,444	2,796,006	73,882	58,927	265	232,072	1,383,095	0	831,110	799,028

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 20 - CONSTRUCTION WORK IN PROGRESS ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
DEMAND - BASE-LOAD TOTAL		6,537,444						
DEMAND - Base-load Summer	D10BS	2,809,262	1,517	0	303	20,209	19,421	83,250
DEMAND - Peak	D10P	0	0	0	0	0	0	0
DEMAND - Base-load Non-Summer	D10BNS	3,728,182	2,992	0	619	61,388	31,605	141,754
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3J	6,537,444	4,509	0	922	81,598	51,026	225,005

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CIATION TO CLASSES

****** TABLE 21 - STATE INCOME TAXES ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION	TOTALS		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
	FACTOR		RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	EC/PRIM/TRAI	SECONDARY
PRODUCTION			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - Base-load Summer	D10BS	(383,179)	(118,263)	(1,799)	(1,751)	(2)	(15,224)	(83,343)	0	(64,889)	(62,353)
DEMAND - Peak	D10P	(91,720)	(28,308)	(431)	(419)	(0)	(3,644)	(19,949)	0	(15,532)	(14,925)
DEMAND - Base-load Non-Summer	D10BNS	(566,047)	(166,891)	(2,884)	(3,067)	(4)	(27,533)	(152,718)	0	(125,985)	(17,797)
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	(15,494)	(3,334)	(52)	(69)	(0)	(709)	(3,601)	(1)	(3,326)	(2,748)
ENERGY - Non-Summer	E10NS	(27,978)	(7,515)	(138)	(152)	(0)	(1,367)	(7,368)	(2)	(6,946)	(623)
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	(720,621)	(216,835)	(3,536)	(3,635)	(5)	(32,117)	(177,395)	0	(143,004)	(65,739)
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	(57)	0	0	0	0	(57)	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	(250,558)	(74,595)	(2,216)	(1,298)	(5)	(10,576)	(57,086)	(18)	(52,687)	(51,565)
SUBSTATIONS - DIRECT	DA3602	(30,246)	0	0	0	0	0	0	0	(6)	0
LINES - PRIMARY DEMAND	D20	(238,999)	(71,154)	(2,114)	(1,238)	(5)	(10,089)	(54,453)	(17)	(50,257)	(49,186)
LINES - PRIMARY CUSTOMER	C20	(94,933)	(76,272)	(1,279)	(3,774)	(3)	(78)	(9,788)	0	(40)	(2,921)
LINES - SECONDARY DIRECT	DA3647	(27,110)	0	0	0	0	(6,002)	0	(37)	(16,362)	0
LINE TRANS - PRIMARY DEMAND	D50	(61,868)	(18,419)	(547)	(321)	(1)	(2,612)	(14,096)	(5)	(13,010)	(12,733)
LINE TRANS - PRIMARY CUST	C50	(24,575)	(19,744)	(331)	(977)	(1)	(20)	(2,534)	0	(10)	(756)
LINE TRANS - SECOND DIRECT	DA368	(28,321)	0	0	0	0	(9,612)	0	0	(16,535)	0
LINE TRANS - SECOND DEMAND	D60	(157,241)	(62,570)	(1,859)	(1,089)	(5)	0	(47,884)	(15)	(139)	(43,253)
LINE TRANS - SECOND CUSTOMER	C60	(71,027)	(57,136)	(958)	(2,827)	(2)	0	(7,332)	0	(0)	(2,188)
LINES - SECONDARY DEMAND	D30	(13,939)	(7,651)	(227)	(133)	(1)	0	(5,855)	(2)	(17)	0
LINES - SECONDARY CUSTOMER	C30	(5,967)	(4,953)	(83)	(245)	(0)	0	(636)	0	(0)	0
SERVICES	CW369	(14,235)	(10,983)	(184)	(578)	(0)	(74)	(1,736)	0	(132)	(545)
METERS	CW370	(50,838)	(26,393)	(437)	(2,003)	(1)	(1,971)	(13,412)	(0)	(1,705)	(4,289)
STREET LIGHTS	DA373	(2,328)	0	0	0	0	(13)	0	0	(0)	0
INSTALL ON CUST PREMISES	DA371	(452)	0	0	0	0	(3)	0	(447)	(2)	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	(0)	(0)
CUSTOMER ACCOUNTS	CW903	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	(0)	(0)
UNCOLLECTIBLES	CW904	(0)	(0)	(0)	(0)	0	(0)	(0)	0	(0)	(0)
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	(0)	(0)
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	INTFUND	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
SUBSTATION CIAC	CIAC	49,300	2,332	69	206	1	1,492	2,363	1	19,288	1,626
TOTALS		(2,828,435)	(968,684)	(19,005)	(23,371)	(36)	(120,210)	(656,822)	(544)	(491,297)	(329,996)

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

***** TABLE 21 - STATE INCOME TAXES *****

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(K) UNMETERED GEN SERVICE	(L) MUNICIPAL ST LIGHT	(M) TRAFFIC CONTROL	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
PRODUCTION			(40)	(41)	(42)			
DEMAND - Base-load Summer	D10BS	(383,179)	(210)	0	(29)	(6,723)	(5,522)	(23,071)
DEMAND - Peak	D10P	(91,720)	(50)	0	(7)	(1,609)	(1,322)	(5,522)
DEMAND - Base-load Non-Summer	D10BNS	(566,047)	(415)	0	(60)	(20,422)	(8,986)	(39,284)
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	(15,494)	(12)	(10)	(2)	(347)	(282)	(1,002)
ENERGY - Non-Summer	E10NS	(27,978)	(25)	(22)	(4)	(1,111)	(636)	(2,070)
TRANSMISSION								
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	(720,621)	(468)	0	(67)	(19,888)	(10,940)	(46,994)
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	(57)	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	(250,558)	(242)	(251)	(18)	0	0	0
SUBSTATIONS - DIRECT	DA3602	(30,246)	0	0	0	0	(2,332)	(27,907)
LINES - PRIMARY DEMAND	D20	(238,999)	(230)	(240)	(17)	0	0	0
LINES - PRIMARY CUSTOMER	C20	(94,933)	(350)	(314)	(113)	0	0	0
LINES - SECONDARY DIRECT	DA3647	(27,110)	0	0	0	0	(4,708)	0
LINE TRANS - PRIMARY DEMAND	D50	(61,868)	(60)	(62)	(4)	0	0	0
LINE TRANS - PRIMARY CUST	C50	(24,575)	(91)	(81)	(29)	0	0	0
LINE TRANS - SECOND DIRECT	DA368	(28,321)	0	0	0	0	(2,174)	0
LINE TRANS - SECOND DEMAND	D60	(157,241)	(203)	(211)	(15)	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	(71,027)	(262)	(235)	(84)	0	0	0
LINES - SECONDARY DEMAND	D30	(13,939)	(25)	(26)	(2)	0	0	0
LINES - SECONDARY CUSTOMER	C30	(5,967)	(23)	(20)	(7)	0	0	0
SERVICES	CW369	(14,235)	0	0	0	0	(2)	0
METERS	CW370	(50,838)	(1)	(63)	(41)	(38)	(80)	(403)
STREET LIGHTS	DA373	(2,328)	0	(2,315)	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	(452)	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	(0)	0	(0)	0	(0)	(0)	(0)
CUSTOMER ACCOUNTS	CW903	(0)	(0)	(0)	(0)	(0)	(0)	(0)
UNCOLLECTIBLES	CW904	(0)	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	(0)	(0)	(0)	(0)	(0)	(0)	(0)
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	INTFUND	(0)	(0)	(0)	(0)	(0)	(0)	(0)
SUBSTATION CIAC	0	49,300	7	8	1	0	106	21,801
TOTALS		(2,828,435)	(2,659)	(3,843)	(497)	(50,139)	(36,879)	(124,454)

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TABLE 22 - FEDERAL INCOME TAXES ******
ALLOCATION TO CLASSES

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION	TOTALS		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
	FACTOR		RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	SEC/PRIM/TRAI	SECONDARY
PRODUCTION			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - Base-load Summer	D10BS	5,288,935	1,632,350	24,835	24,167	24	210,137	1,150,364	0	895,648	860,644
DEMAND - Peak	D10P	1,265,989	390,728	5,945	5,785	6	50,300	275,357	0	214,387	206,008
DEMAND - Base-load Non-Summer	D10BNS	7,813,019	2,303,558	39,803	42,327	61	380,036	2,107,934	0	1,738,943	245,653
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	213,866	46,022	723	955	1	9,793	49,701	11	45,902	37,926
ENERGY - Non-Summer	E10NS	386,177	103,729	1,903	2,092	3	18,865	101,694	24	95,867	8,601
		0									
TRANSMISSION		0									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	9,946,572	2,992,926	48,801	50,168	63	443,306	2,448,543	0	1,973,854	907,374
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	789	0	0	0	0	789	0	0	0	0
		0									
DISTRIBUTION		0									
SUBSTATIONS - GENERAL	D20	3,458,399	1,029,618	30,586	17,920	75	145,984	787,948	252	727,230	711,741
SUBSTATIONS - DIRECT	DA3602	417,480	0	0	0	0	0	0	0	87	0
LINES - PRIMARY DEMAND	D20	3,298,856	982,120	29,175	17,093	71	139,249	751,598	240	693,682	678,906
LINES - PRIMARY CUSTOMER	C20	1,310,339	1,052,767	17,654	52,095	43	1,081	135,098	0	549	40,325
LINES - SECONDARY DIRECT	DA3647	374,195	0	0	0	0	82,843	0	515	225,847	0
LINE TRANS - PRIMARY DEMAND	D50	853,955	254,235	7,552	4,425	18	36,047	194,562	62	179,569	175,744
LINE TRANS - PRIMARY CUST	C50	339,199	272,523	4,570	13,485	11	280	34,972	0	142	10,439
LINE TRANS - SECOND DIRECT	DA368	390,912	0	0	0	0	132,668	0	0	228,234	0
LINE TRANS - SECOND DEMAND	D60	2,170,366	863,643	25,656	15,031	63	0	660,930	211	1,914	597,008
LINE TRANS - SECOND CUSTOMER	C60	980,364	788,633	13,224	39,024	32	0	101,202	0	4	30,207
LINES - SECONDARY DEMAND	D30	192,396	105,609	3,137	1,838	8	0	80,821	26	234	0
LINES - SECONDARY CUSTOMER	C30	82,364	68,363	1,146	3,383	3	0	8,773	0	0	0
SERVICES	CW369	196,481	151,600	2,538	7,983	6	1,016	23,968	0	1,821	7,517
METERS	CW370	701,699	364,298	6,033	27,648	18	27,209	185,122	1	23,540	59,204
STREET LIGHTS	DA373	32,134	0	0	0	0	179	0	0	3	0
INSTALL ON CUST PREMISES		6,242	0	0	0	0	37	0	6,173	33	0
		0									
CUSTOMER ACCOUNTING		0									
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	(0)	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
CONSUMER INFORMATION		0									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
		0									
MISCELLANEOUS		0									
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	DA454	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	(680,484)	(32,192)	(956)	(2,839)	(12)	(20,592)	(32,616)	(8)	(266,231)	(22,440)
TOTALS		39,040,245	13,370,532	262,324	322,579	494	1,659,227	9,065,970	7,507	6,781,260	4,554,856

1333 **IDAHO POWER COMPANY**
1334 **3CP/12CP CLASS COST OF SERVICE STUDY**
1335 **TWELVE MONTHS ENDING DECEMBER 31, 2023**
1336 ****** TABLE 22 - FEDERAL INCOME TAXES ****** **ALLOCATION TO CLASSES**

Line			(A)	(K)	(L)	(M)	(N)	(O)	(P)
1337			(A)	(K)	(L)	(M)	(N)	(O)	(P)
1338	FUNCTION	ALLOCATION	TOTALS	UNMETERED	MUNICIPAL	TRAFFIC	SC	SC	SC
1339		FACTOR		GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
1340	PRODUCTION			(40)	(41)	(42)			
1341	DEMAND - Base-load Summer	D10BS	5,288,935	2,904	0	405	92,797	76,215	318,445
1342	DEMAND - Peak	D10P	1,265,989	695	0	97	22,212	18,243	76,225
1343	DEMAND - Base-load Non-Summer	D10BNS	7,813,019	5,729	0	827	281,883	124,030	542,233
1344	ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
1345	ENERGY - Summer	E10S	213,866	164	132	23	4,789	3,889	13,835
1346	ENERGY - Non-Summer	E10NS	386,177	348	306	50	15,340	8,779	28,576
1347									
1348	TRANSMISSION								
1349	DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
1350	DEMAND - TRANSMISSION	D13	9,946,572	6,456	0	920	274,505	151,007	648,649
1351	DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
1352	DEMAND - DIRECT	DA3509	789	0	0	0	0	0	0
1353									
1354	DISTRIBUTION								
1355	SUBSTATIONS - GENERAL	D20	3,458,399	3,334	3,469	243	0	0	0
1356	SUBSTATIONS - DIRECT	DA3602	417,480	0	0	0	0	32,194	385,198
1357	LINES - PRIMARY DEMAND	D20	3,298,856	3,180	3,309	232	0	0	0
1358	LINES - PRIMARY CUSTOMER	C20	1,310,339	4,835	4,339	1,555	0	0	0
1359	LINES - SECONDARY DIRECT	DA3647	374,195	0	0	0	0	64,990	0
1360	LINE TRANS - PRIMARY DEMAND	D50	853,955	823	857	60	0	0	0
1361	LINE TRANS - PRIMARY CUST	C50	339,199	1,252	1,123	403	0	0	0
1362	LINE TRANS - SECOND DIRECT	DA368	390,912	0	0	0	0	30,010	0
1363	LINE TRANS - SECOND DEMAND	D60	2,170,366	2,797	2,910	204	0	0	0
1364	LINE TRANS - SECOND CUSTOMER	C60	980,364	3,622	3,250	1,165	0	0	0
1365	LINES - SECONDARY DEMAND	D30	192,396	342	356	25	0	0	0
1366	LINES - SECONDARY CUSTOMER	C30	82,364	314	282	101	0	0	0
1367	SERVICES	CW369	196,481	0	0	0	0	32	0
1368	METERS	CW370	701,699	10	864	559	527	1,108	5,558
1369	STREET LIGHTS	DA373	32,134	0	31,953	0	0	0	0
1370	INSTALL ON CUST PREMISES	CWINSTAL	6,242	0	0	0	0	0	0
1371									
1372	CUSTOMER ACCOUNTING								
1373	METER READING	CW902	0	0	0	0	0	0	0
1374	CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
1375	UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
1376	MISC	C10	0	0	0	0	0	0	0
1377									
1378	CONSUMER INFORMATION								
1379	CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
1380	SALES EXPENSE	C10	0	0	0	0	0	0	0
1381	ADVERTISING	C10	0	0	0	0	0	0	0
1382	MISC	C10	0	0	0	0	0	0	0
1383			0						
1384	MISCELLANEOUS		0						
1385	DEMAND	D99U	0	0	0	0	0	0	0
1386	ENERGY	E99U	0	0	0	0	0	0	0
1387	CUSTOMER	C10	0	0	0	0	0	0	0
1388	REVENUE	R02	0	0	0	0	0	0	0
1389	OTHER	INTFUND	0	0	0	0	0	0	0
1390	SUBSTATION CIAC	0	(680,484)	(103)	(108)	(8)	0	(1,470)	(300,909)
1391									
1392	TOTALS		39,040,245	36,701	53,040	6,863	692,053	509,028	1,717,811

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 23 - ALLOCATION FACTOR SUMMARY ******

FUNCTION	FACTOR NAME	(A) TOTAL FACTOR	(B) RESIDENTIAL	(C) RESIDENTIAL On Site Gen	(D) GEN SRV	(E) GEN SRV On Site Gen	(F) GEN SRV PRIM & TRAN	(G) GEN SRV SECONDARY	(H) AREA LIGHTING	(I) LG POWER SEC/PRIM/TRAN	(J) IRRIGATION SECONDARY
PRODUCTION			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - Base-load Summer	D10BS	0.4297	0.1774	0.0043	0.0033	0.0000	0.0126	0.0747	0.0000	0.0432	0.0951
DEMAND - Peak	D10P	1.0000	0.4128	0.0101	0.0076	0.0000	0.0294	0.1738	0.0000	0.1006	0.2213
DEMAND - Base-load Non-Summer	D10BNS	0.5703	0.2503	0.0070	0.0057	0.0000	0.0229	0.1369	0.0000	0.0839	0.0271
DEMAND - BASE-LOAD TOTAL	D10B	1.0000	0.4277	0.0113	0.0090	0.0000	0.0355	0.2116	0.0000	0.1271	0.1222
ENERGY - POWER SUPPLY	E10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
ENERGY - Summer	E10S	0.3751	0.1145	0.0029	0.0030	0.0000	0.0135	0.0739	0.0001	0.0507	0.0959
ENERGY - Non-Summer	E10NS	0.6249	0.2581	0.0076	0.0065	0.0000	0.0260	0.1512	0.0002	0.1059	0.0218
ENERGY - ANNUAL	E10	1.0000	0.3726	0.0105	0.0095	0.0000	0.0395	0.2251	0.0004	0.1566	0.1177
TRANSMISSION											
DEMAND - POWER SUPPLY	D11	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
DEMAND - TRANSMISSION	D13	1.0000	0.4261	0.0112	0.0089	0.0000	0.0349	0.2083	0.0000	0.1248	0.1313
DEMAND - SUBTRANSMISSION	D15	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
DEMAND - DIRECT	DA3509	1,189	0	0	0	0	1,189	0	0	0	0
DISTRIBUTION											
SUBSTATIONS - GENERAL	D20	3,880,868	1,475,249	70,513	32,030	470	115,783	674,613	1,488	462,715	1,036,831
SUBSTATIONS - DIRECT	DA3602	18,842,265	0	0	0	0	0	0	0	4,766	0
LINES - PRIMARY DEMAND	D20	3,880,868	1,475,249	70,513	32,030	470	115,783	674,613	1,488	462,715	1,036,831
LINES - PRIMARY CUSTOMER	C20	599,002	492,481	13,288	30,401	88	280	37,764	0	114	19,179
LINES - SECONDARY DIRECT	DA3647	30,302,718	0	0	0	0	8,098,475	0	375,286	17,711,924	0
LINE TRANS - PRIMARY DEMAND	D50	3,880,868	1,475,249	70,513	32,030	470	115,783	674,613	1,488	462,715	1,036,831
LINE TRANS - PRIMARY CUST	C50	599,002	492,481	13,288	30,401	88	280	37,764	0	114	19,179
LINE TRANS - SECOND DIRECT	DA368	30,269,678	0	0	0	0	11,979,958	0	0	16,533,677	0
LINE TRANS - SECOND DEMAND	D60	3,303,822	1,475,249	70,513	32,030	470	0	674,613	1,488	1,452	1,036,831
LINE TRANS - SECOND CUSTOMER	C60	598,609	492,481	13,288	30,401	88	0	37,764	0	1	19,179
LINES - SECONDARY DEMAND	D30	2,266,991	1,475,249	70,513	32,030	470	0	674,613	1,488	1,452	0
LINES - SECONDARY CUSTOMER	C30	579,430	492,481	13,288	30,401	88	0	37,764	0	1	0
SERVICES	CW369	66,979,720	53,720,684	1,446,874	3,528,835	9,999	199,332	5,075,064	0	286,563	2,708,349
METERS	CW370	97,044,854	58,015,722	1,545,886	5,492,681	12,640	2,398,611	17,616,298	435	1,664,741	9,586,021
STREET LIGHTS	DA373	5,478,881	0	0	0	0	11,531	0	0	141	0
INSTALL ON CUST PREMISES	DA371	4,591,211	0	0	0	0	3,662	0	4,584,924	2,625	0
INSTALL ON CUST PREM	CWINSTAL	1,324,335	941,483	25,402	58,118	167	543	72,193	179,202	222	36,665
CUSTOMER ACCOUNTING											
METER READING	CW902	1,772,999	1,357,370	26,946	106,387	258	50,454	114,853	0	20,596	93,489
CUSTOMER ACCOUNTS	CW903	16,082,040	13,155,938	354,963	812,117	2,337	64,177	1,008,800	0	26,199	512,338
UNCOLLECTIBLES	CW904	5,389,398	4,833,685	2,063	205,647	0	1,917	254,719	(3)	25,819	65,550
MISC	C10	599,011	492,481	13,288	30,401	88	284	37,764	0	116	19,179
CONSUMER INFORMATION											
CUSTOMER ASSIST	C10	599,011	492,481	13,288	30,401	88	284	37,764	0	116	19,179
SALES EXPENSE	C10	599,011	492,481	13,288	30,401	88	284	37,764	0	116	19,179
ADVERTISING	C10	599,011	492,481	13,288	30,401	88	284	37,764	0	116	19,179
MISC	C10	599,011	492,481	13,288	30,401	88	284	37,764	0	116	19,179
MISCELLANEOUS											
DEMAND	D99U	23,186,898	0	0	0	0	1,565,362	11,142,321	0	4,706,101	4,065,427
ENERGY	E99U	14,907,835,244	5,425,559,433	122,912,496	138,285,160	370,708	601,699,182	3,321,544,618	5,267,423	2,386,695,635	1,864,522,772
CUSTOMER	C10	599,011	492,481	13,288	30,401	88	284	37,764	0	116	19,179
MISC. REVENUE	R02	4,327,695	3,867,051	20,825	136,296	112	1,349	137,585	7,800	28	80,047
RETAIL SALES REVENUE	R01	1,116,166,332	501,479,142	11,567,368	16,102,622	43,713	36,446,763	230,482,910	1,261,853	125,751,566	140,327,749
REVENUE - OPEN	0	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	(42,770,847)	(4,292,179)	(205,156)	(472,238)	(6,923)	(1,519,756)	(2,598,489)	(4,296)	(15,762,856)	(3,041,944)
FACILITIES CHARGE REVENUE	DA454	9,862,380	0	0	0	0	3,310,051	0	74,757	5,559,630	0
INTERVENOR FUNDING	INTFUND	291,838	186,225	5,060	7,677	23	2,524	14,289	23	9,992	66,025

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** TABLE 23 - ALLOCATION FACTOR SUMMARY ******

				(K)	(L)	(M)	(N)	(O)	(P)
6	FUNCTION	FACTOR	TOTAL	UNMETERED	MUNICIPAL	TRAFFIC			SC
7		NAME	FACTOR	GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
8	PRODUCTION			(40)	(41)	(42)			
9	DEMAND - Base-load Summer	D10BS	0.4297	0.0002	0.0000	0.0000	0.0031	0.0030	0.0127
10	DEMAND - Peak	D10P	1.0000	0.0005	0.0000	0.0001	0.0072	0.0069	0.0296
11	DEMAND - Base-load Non-Summer	D10BNS	0.5703	0.0005	0.0000	0.0001	0.0094	0.0048	0.0217
12	DEMAND - BASE-LOAD TOTAL	D10B	1.0000	0.0007	0.0000	0.0001	0.0125	0.0078	0.0344
13	ENERGY - POWER SUPPLY	E10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
14	ENERGY - Summer	E10S	0.3751	0.0003	0.0005	0.0001	0.0037	0.0035	0.0127
15	ENERGY - Non-Summer	E10NS	0.6249	0.0006	0.0011	0.0001	0.0117	0.0078	0.0262
16	ENERGY - ANNUAL	E10	1.0000	0.0009	0.0016	0.0002	0.0154	0.0113	0.0388
17	TRANSMISSION		0.0000						
18	DEMAND - POWER SUPPLY	D11	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
19	DEMAND - TRANSMISSION	D13	1.0000	0.0007	0.0000	0.0001	0.0120	0.0077	0.0340
20	DEMAND - SUBTRANSMISSION	D15	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
21	DEMAND - DIRECT	DA3509	1,189	0	0	0	0	0	0
22									
23	DISTRIBUTION								
24	SUBSTATIONS - GENERAL	D20	3,880,868	3,513	7,298	367	0	0	0
25	SUBSTATIONS - DIRECT	DA3602	18,842,265	0	0	0	0	1,418,979	17,418,519
26	LINES - PRIMARY DEMAND	D20	3,880,868	3,513	7,298	367	0	0	0
27	LINES - PRIMARY CUSTOMER	C20	599,002	1,663	2,980	766	0	0	0
28	LINES - SECONDARY DIRECT	DA3647	30,302,718	0	0	0	0	4,117,033	0
29	LINE TRANS - PRIMARY DEMAND	D50	3,880,868	3,513	7,298	367	0	0	0
30	LINE TRANS - PRIMARY CUST	C50	599,002	1,663	2,980	766	0	0	0
31	LINE TRANS - SECOND DIRECT	DA368	30,269,678	0	0	0	0	1,756,043	0
32	LINE TRANS - SECOND DEMAND	D60	3,303,822	3,513	7,298	367	0	0	0
33	LINE TRANS - SECOND CUSTOMER	C60	598,609	1,663	2,980	766	0	0	0
34	LINES - SECONDARY DEMAND	D30	2,266,991	3,513	7,298	367	0	0	0
35	LINES - SECONDARY CUSTOMER	C30	579,430	1,663	2,980	766	0	0	0
36	SERVICES	CW369	66,979,720	0	0	0	0	4,020	0
37	METERS	CW370	97,044,854	1,156	202,057	93,796	25,733	63,315	325,761
38	STREET LIGHTS	DA373	5,478,881	0	5,467,209	0	0	0	0
39	INSTALL ON CUST PREMISES	DA371	4,591,211	0	0	0	0	0	0
40	INSTALL ON CUST PREM	CWINSTAL	1,324,335	3,179	5,697	1,464	0	0	0
41	CUSTOMER ACCOUNTING								
42	METER READING	CW902	1,772,999	0	2,113	0	178	178	178
43	CUSTOMER ACCOUNTS	CW903	16,082,040	44,425	79,607	20,463	226	226	226
44	UNCOLLECTIBLES	CW904	5,389,398	0	0	0	0	0	0
45	MISC	C10	599,011	1,663	2,980	766	1	1	1
46									
47	CONSUMER INFORMATION								
48	CUSTOMER ASSIST	C10	599,011	1,663	2,980	766	1	1	1
49	SALES EXPENSE	C10	599,011	1,663	2,980	766	1	1	1
50	ADVERTISING	C10	599,011	1,663	2,980	766	1	1	1
51	MISC	C10	599,011	1,663	2,980	766	1	1	1
52									
53	MISCELLANEOUS								
54	DEMAND	D99U	23,186,898	0	0	0	422,686	267,258	1,017,744
55	ENERGY	E99U	14,907,835,244	13,925,301	23,760,014	2,847,961	234,100,000	175,000,001	591,344,540
56	CUSTOMER	C10	599,011	1,663	2,980	766	1	1	1
57	MISC. REVENUE	R02	4,327,695	10,620	64,629	1,354	0	0	0
58	RETAIL SALES REVENUE	R01	1,116,166,332	1,144,288	3,463,322	165,609	10,547,708	7,759,368	29,622,353
59	REVENUE - OPEN	0	0	0	0	0	0	0	0
60	SUBSTATION CIAC	CIAC	(42,770,847)	(10,144)	(21,076)	(1,060)	0	(70,288)	(14,764,441)
61	FACILITIES CHARGE REVENUE	DA454	9,862,380	0	681	0	0	917,261	0
62	INTERVENOR FUNDING	INTFUND							

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 40

1 **IDAHO POWER COMPANY**
2 **3CP/12CP CLASS COST OF SERVICE STUDY**
3 **TWELVE MONTHS ENDING DECEMBER 31, 2023**
4 ******* SUMMARY OF RATE BASE ****** **ALLOCATION TO CLASSES**

5			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
6	FUNCTION	ALLOCATION	TOTAL		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
7		FACTOR	RATE BASE	RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	SEC/PRIM/TRAN	SECONDARY
8	PRODUCTION			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
9	DEMAND - Base-load Summer	D10BS	527,258,819	217,639,709	5,327,764	4,019,546	14,076	15,508,781	91,649,034	0	53,029,099	116,666,267
10	DEMAND - Peak	D10P	126,207,603	52,095,451	1,275,283	962,141	3,369	3,712,268	21,937,622	0	12,693,340	27,925,886
11	DEMAND - Base-load Non-Summer	D10BNS	699,727,248	307,131,203	8,538,838	7,040,179	35,730	28,047,927	167,938,323	0	102,958,489	33,299,940
12	ENERGY - POWER SUPPLY	E10	53,590,613	0	0	0	0	0	0	0	0	0
13	ENERGY - Summer	E10S	20,103,456	6,136,134	155,020	158,813	581	722,760	3,959,697	5,959	2,717,729	5,141,089
14	ENERGY - Non-Summer	E10NS	33,487,157	13,830,068	408,262	348,018	1,627	1,392,315	8,101,932	12,941	5,676,063	1,165,887
15				0	0	0	0	0	0	0	0	0
16	TRANSMISSION											
17	DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
18	DEMAND - TRANSMISSION	D13	936,585,068	399,043,928	10,469,269	8,344,228	36,909	32,717,447	195,074,444	0	116,866,985	123,000,884
19	DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
20	DEMAND - DIRECT	DA3509	58,219	0	0	0	0	58,219	0	0	0	0
21												
22	DISTRIBUTION											
23	SUBSTATIONS - GENERAL	D20	361,130,739	137,277,995	6,561,549	2,980,540	43,696	10,774,097	62,775,481	138,424	43,057,489	96,481,383
24	SUBSTATIONS - DIRECT	DA3602	20,445,071	0	0	0	0	0	0	0	5,172	0
25	LINES - PRIMARY DEMAND	D20	344,470,998	130,945,065	6,258,851	2,843,042	41,680	10,277,065	59,879,512	132,039	41,071,154	92,030,489
26	LINES - PRIMARY CUSTOMER	C20	170,724,661	140,364,428	3,787,201	8,664,703	24,939	79,804	10,763,170	0	32,492	5,466,277
27	LINES - SECONDARY DIRECT	DA3647	22,877,428	0	0	0	0	6,114,048	0	283,327	13,371,845	0
28	LINE TRANS - PRIMARY DEMAND	D50	89,171,115	33,896,953	1,620,191	735,961	10,790	2,660,361	15,500,646	34,180	10,631,840	23,823,373
29	LINE TRANS - PRIMARY CUST	C50	44,194,456	36,335,287	980,370	2,242,979	6,456	20,658	2,786,197	0	8,411	1,415,022
30	LINE TRANS - SECOND DIRECT	DA368	24,739,733	0	0	0	0	9,791,349	0	0	13,513,152	0
31	LINE TRANS - SECOND DEMAND	D60	257,875,737	115,148,739	5,503,825	2,500,076	36,652	0	52,656,053	116,110	113,304	80,928,554
32	LINE TRANS - SECOND CUSTOMER	C60	127,806,834	105,147,731	2,837,012	6,490,775	18,682	0	8,062,748	0	214	4,094,817
33	LINES - SECONDARY DEMAND	D30	21,637,720	14,080,790	673,027	305,718	4,482	0	6,438,966	14,198	13,855	0
34	LINES - SECONDARY CUSTOMER	C30	10,723,958	9,114,716	245,926	562,652	1,619	0	698,918	0	19	0
35	SERVICES	CW369	25,201,414	20,212,644	544,393	1,327,740	3,762	74,999	1,909,515	0	107,821	1,019,028
36	METERS	CW370	81,247,077	48,571,435	1,294,234	4,598,536	10,582	2,008,145	14,748,569	365	1,393,740	8,025,528
37	STREET LIGHTS	DA373	6,268,714	0	0	0	0	13,193	0	0	162	0
38	INSTALL ON CUST PREMISES	DA371	3,397,445	0	0	0	0	2,710	0	3,392,793	1,942	0
39		CWINSTAL		0	0	0	0	0	0	0	0	0
40	CUSTOMER ACCOUNTING											
41	METER READING	CW902	0	0	0	0	0	0	0	0	0	0
42	CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
43	UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	(0)	0	0
44	MISC	C10	0	0	0	0	0	0	0	0	0	0
45												
46	CONSUMER INFORMATION											
47	CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
48	SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
49	ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
50	MISC	C10	0	0	0	0	0	0	0	0	0	0
51												
52	MISCELLANEOUS											
53	DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
54	ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
55	CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
56	REVENUE	R02	0	0	0	0	0	0	0	0	0	0
57	OTHER	R01	0	0	0	0	0	0	0	0	0	0
58	SUBSTATION CIAC	CIAC	(42,770,847)	(4,292,179)	(205,156)	(472,238)	(6,923)	(1,519,756)	(2,598,489)	(4,296)	(15,762,857)	(3,041,944)
59												
60	TOTALS		3,912,569,823	1,782,680,096	56,275,860	53,653,411	288,712	122,456,391	722,282,341	4,126,040	401,501,460	617,442,481

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

******* SUMMARY OF RATE BASE ******

ALLOCATION TO CLASSES

FUNCTION	ALLOCATION FACTOR	TOTAL RATE BASE	(K) UNMETERED GEN SERVICE	(L) MUNICIPAL ST LIGHT	(M) TRAFFIC CONTROL	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
PRODUCTION			(40)	(41)	(42)			
DEMAND - Base-load	D10BS	527,258,819	284,709	0	56,908	3,792,994	3,645,036	15,624,896
DEMAND - Peak	D10P	126,207,603	68,150	0	13,622	907,912	872,496	3,740,062
DEMAND - Not in Use	D10BNS	699,727,248	561,596	0	116,176	11,521,727	5,931,831	26,605,289
ENERGY - POWER SUPPLY	E10	53,590,613	0	0	0	0	0	0
ENERGY - Summer	E10S	20,103,456	16,068	25,786	3,214	195,752	186,018	678,835
ENERGY - Non-Summer	E10NS	33,487,157	34,090	59,894	7,052	627,011	419,862	1,402,134
	0	0	0	0	0	0	0	0
TRANSMISSION								
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	936,585,068	632,856	0	129,230	11,220,178	7,221,998	31,826,711
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	58,219	0	0	0	0	0	0
		0						
DISTRIBUTION		0						
SUBSTATIONS - GENERAL	D20	361,130,739	326,855	679,070	34,160	0	0	0
SUBSTATIONS - DIRECT	DA3602	20,445,071	0	0	0	0	1,539,683	18,900,216
LINES - PRIMARY DEMAND	D20	344,470,998	311,776	647,743	32,584	0	0	0
LINES - PRIMARY CUSTOMER	C20	170,724,661	473,980	849,345	218,322	0	0	0
LINES - SECONDARY DIRECT	DA3647	22,877,428	0	0	0	0	3,108,207	0
LINE TRANS - PRIMARY DEMAND	D50	89,171,115	80,708	167,677	8,435	0	0	0
LINE TRANS - PRIMARY CUST	C50	44,194,456	122,696	219,865	56,516	0	0	0
LINE TRANS - SECOND DIRECT	DA368	24,739,733	0	0	0	0	1,435,233	0
LINE TRANS - SECOND DEMAND	D60	257,875,737	274,165	569,603	28,653	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	127,806,834	355,061	636,249	163,546	0	0	0
LINES - SECONDARY DEMAND	D30	21,637,720	33,526	69,653	3,504	0	0	0
LINES - SECONDARY CUSTOMER	C30	10,723,958	30,778	55,153	14,177	0	0	0
SERVICES	CW369	25,201,414	0	0	0	0	1,512	0
METERS	CW370	81,247,077	968	169,164	78,527	21,544	53,008	272,731
STREET LIGHTS	DA373	6,268,714	0	6,255,359	0	0	0	0
INSTALL ON CUST PREMISES	DA371	3,397,445	0	0	0	0	0	0
	CWINSTAL	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING		0						
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
		0						
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	(42,770,847)	(10,144)	(21,076)	(1,060)	0	(70,288)	(14,764,442)
		0						
TOTALS		3,912,569,823	3,597,837	10,383,484	963,563	28,287,118	24,344,597	84,286,431

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** SUMMARY OF EXPENSES EXCLUDING INCOME TAXES ******

FUNCTION	ALLOCATION FACTOR	(A) TOTAL EXPENSES	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAN (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
PRODUCTION											
DEMAND - Base-load Summer	D10BS	95,831,586	39,556,965	968,344	730,570	2,558	2,818,789	16,657,611	0	9,638,270	21,204,602
DEMAND - Peak	D10P	24,664,054	10,180,726	249,222	188,026	658	725,468	4,287,148	0	2,480,589	5,457,402
DEMAND - Base-load Non-Summer	D10BNS	127,178,474	55,822,434	1,551,971	1,279,583	6,494	5,097,833	30,523,522	0	18,713,154	6,052,409
ENERGY - POWER SUPPLY	E10	492,817,416	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	184,870,685	56,427,674	1,425,561	1,460,441	5,347	6,646,475	36,413,240	54,800	24,992,144	47,277,280
ENERGY - Non-Summer	E10NS	307,946,730	127,180,821	3,754,364	3,200,359	14,966	12,803,679	74,505,086	119,005	52,196,879	10,721,459
TRANSMISSION											
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	87,631,416	37,336,474	979,555	780,726	3,453	3,061,202	18,252,106	0	10,934,639	11,508,556
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	6,018	0	0	0	0	6,018	0	0	0	0
DISTRIBUTION											
SUBSTATIONS - GENERAL	D20	29,574,028	11,242,087	537,344	244,085	3,578	882,322	5,140,863	11,336	3,526,101	7,901,136
SUBSTATIONS - DIRECT	DA3602	1,010,940	0	0	0	0	0	0	0	256	0
LINES - PRIMARY DEMAND	D20	63,687,687	24,209,842	1,157,171	525,637	7,706	1,900,080	11,070,853	24,412	7,593,460	17,015,101
LINES - PRIMARY CUSTOMER	C20	31,564,512	25,951,345	700,198	1,601,978	4,611	14,755	1,989,954	0	6,007	1,010,635
LINES - SECONDARY DIRECT	DA3647	2,702,216	0	0	0	0	722,174	0	33,466	1,579,444	0
LINE TRANS - PRIMARY DEMAND	D50	5,393,859	2,050,388	98,003	44,517	653	160,922	937,616	2,068	643,108	1,441,049
LINE TRANS - PRIMARY CUST	C50	2,673,272	2,197,880	59,301	135,675	391	1,250	168,534	0	509	85,593
LINE TRANS - SECOND DIRECT	DA368	1,495,666	0	0	0	0	591,946	0	0	816,952	0
LINE TRANS - SECOND DEMAND	D60	15,599,151	6,965,458	332,932	151,232	2,217	0	3,185,215	7,024	6,854	4,895,446
LINE TRANS - SECOND CUSTOMER	C60	7,731,158	6,360,487	171,614	392,633	1,130	0	487,723	0	13	247,699
LINES - SECONDARY DEMAND	D30	4,343,745	2,826,701	135,109	61,373	900	0	1,292,614	2,850	2,781	0
LINES - SECONDARY CUSTOMER	C30	2,152,821	1,829,768	49,369	112,952	325	0	140,307	0	4	0
SERVICES	CW369	2,903,116	2,328,427	62,712	152,951	433	8,640	219,970	0	12,421	117,389
METERS	CW370	25,546,867	15,272,525	406,952	1,445,937	3,327	631,430	4,637,456	115	438,240	2,523,501
STREET LIGHTS	DA373	823,719	0	0	0	0	1,734	0	0	21	0
INSTALL ON CUST PREMISES	CWINSTAL	3,117,516	2,216,273	59,798	136,811	394	1,279	169,944	421,845	522	86,309
CUSTOMER ACCOUNTING											
METER READING	CW902	3,681,466	2,818,451	55,951	220,902	536	104,762	238,482	0	42,766	194,122
CUSTOMER ACCOUNTS	CW903	32,460,816	26,554,621	716,476	1,639,218	4,718	129,538	2,036,213	0	52,881	1,034,129
UNCOLLECTIBLES	CW904	5,388,730	4,833,086	2,063	205,622	0	1,916	254,688	(3)	25,816	65,542
MISC	C10	0	0	0	0	0	0	0	0	0	0
CONSUMER INFORMATION											
CUSTOMER ASSIST	C10	19,150,720	15,744,877	424,816	971,932	2,797	9,085	1,207,320	0	3,709	613,160
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
MISCELLANEOUS											
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	2,119,909	771,520	17,478	19,664	53	85,562	472,327	749	339,390	265,137
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0	0	0
OTHER	INTFUND	332,773	212,346	5,770	8,754	26	2,878	16,293	26	11,394	75,286
RETAIL SALES REVENUE		0	0	0	0	0	0	0	0	0	0
TOTALS		1,091,583,652	480,891,174	13,922,074	15,711,579	67,274	36,409,736	214,305,086	677,692	134,058,322	139,792,943

Exhibit No. 40
Case No. IPC-E-23-11
P. Goralski IPC

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** SUMMARY OF EXPENSES EXCLUDING INCOME TAXES ******

FUNCTION	ALLOCATION FACTOR	TOTAL EXPENSES	(K) UNMETERED GEN SERVICE	(L) MUNICIPAL ST LIGHT	(M) TRAFFIC CONTROL	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
PRODUCTION			(40)	(41)	(42)			
DEMAND - Base-load	D10BS	95,831,586	51,747	0	10,343	689,393	662,501	2,839,893
DEMAND - Peak	D10P	24,664,054	13,318	0	2,662	177,428	170,507	730,900
DEMAND - Not in Use	D10BNS	127,178,474	102,072	0	21,115	2,094,124	1,078,136	4,835,627
ENERGY - POWER SUPPLY	E10	492,817,416	0	0	0	0	0	0
ENERGY - Summer	E10S	184,870,685	147,761	237,125	29,555	1,800,130	1,710,612	6,242,542
ENERGY - Non-Summer	E10NS	307,946,730	313,495	550,779	64,846	5,765,976	3,861,040	12,893,976
		0						
TRANSMISSION								
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	87,631,416	59,213	0	12,091	1,049,814	675,725	2,977,861
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	6,018	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	29,574,028	26,767	55,611	2,797	0	0	0
SUBSTATIONS - DIRECT	DA3602	1,010,940	0	0	0	0	76,132	934,552
LINES - PRIMARY DEMAND	D20	63,687,687	57,643	119,758	6,024	0	0	0
LINES - PRIMARY CUSTOMER	C20	31,564,512	87,632	157,032	40,364	0	0	0
LINES - SECONDARY DIRECT	DA3647	2,702,216	0	0	0	0	367,133	0
LINE TRANS - PRIMARY DEMAND	D50	5,393,859	4,882	10,143	510	0	0	0
LINE TRANS - PRIMARY CUST	C50	2,673,272	7,422	13,299	3,419	0	0	0
LINE TRANS - SECOND DIRECT	DA368	1,495,666	0	0	0	0	86,768	0
LINE TRANS - SECOND DEMAND	D60	15,599,151	16,585	34,456	1,733	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	7,731,158	21,478	38,487	9,893	0	0	0
LINES - SECONDARY DEMAND	D30	4,343,745	6,730	13,983	703	0	0	0
LINES - SECONDARY CUSTOMER	C30	2,152,821	6,179	11,072	2,846	0	0	0
SERVICES	CW369	2,903,116	0	0	0	0	174	0
METERS	CW370	25,546,867	304	53,191	24,692	6,774	16,668	85,756
STREET LIGHTS	DA373	823,719	0	821,964	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	3,117,516	7,484	13,411	3,447	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	3,681,466	0	4,387	0	369	369	369
CUSTOMER ACCOUNTS	CW903	32,460,816	89,669	160,682	41,303	456	456	456
UNCOLLECTIBLES	CW904	5,388,730	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	19,150,720	53,167	95,272	24,489	32	32	32
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	2,119,909	1,980	3,379	405	33,289	24,885	84,090
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	INTFUND	332,773	0	0	0	0	0	0
SUBSTATION CIAC	0	0	0	0	0	0	0	0
	0							
TOTALS		1,091,583,652	1,075,528	2,394,029	303,240	11,617,785	8,731,137	31,626,052

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** SUMMARY OF OTHER REVENUES ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	ALLOCATION	TOTAL OTHER		RESIDENTIAL		GEN SRV	GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION
	FACTOR	REVENUES	RESIDENTIAL	On Site Gen	GEN SRV	On Site Gen	PRIM & TRAN	SECONDARY	LIGHTING	SEC/PRIM/TRAN	SECONDARY
PRODUCTION			(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)
DEMAND - Base-load Summer	D10BS	475,261	196,176	4,802	3,623	13	13,979	82,611	0	47,799	105,161
DEMAND - Peak	D10P	2,661	1,098	27	20	0	78	463	0	268	589
DEMAND - Base-load Non-Summer	D10BNS	630,720	276,842	7,697	6,346	32	25,282	151,376	0	92,805	30,016
ENERGY - POWER SUPPLY	E10	29,557,875	0	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	11,088,051	3,384,382	85,501	87,593	321	398,638	2,183,969	3,287	1,498,962	2,835,565
ENERGY - Non-Summer	E10NS	18,469,824	7,627,967	225,177	191,949	898	767,931	4,468,617	7,138	3,130,630	643,045
TRANSMISSION											
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	60,109,852	25,610,564	671,916	535,531	2,369	2,099,800	12,519,841	0	7,500,501	7,894,173
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	518	0	0	0	0	518	0	0	0	0
DISTRIBUTION											
SUBSTATIONS - GENERAL	D20	299,274	113,764	5,438	2,470	36	8,929	52,023	115	35,682	79,955
SUBSTATIONS - DIRECT	DA3602	13,957	0	0	0	0	0	0	0	4	0
LINES - PRIMARY DEMAND	D20	2,502,919	951,444	45,477	20,657	303	74,673	435,083	959	298,422	668,692
LINES - PRIMARY CUSTOMER	C20	1,240,482	1,019,885	27,518	62,958	181	580	78,205	0	236	39,718
LINES - SECONDARY DIRECT	DA3647	107,956	0	0	0	0	28,852	0	1,337	63,100	0
LINE TRANS - PRIMARY DEMAND	D50	350,797	133,350	6,374	2,895	42	10,466	60,979	134	41,825	93,721
LINE TRANS - PRIMARY CUST	C50	173,860	142,942	3,857	8,824	25	81	10,961	0	33	5,567
LINE TRANS - SECOND DIRECT	DA368	97,220	0	0	0	0	38,477	0	0	53,103	0
LINE TRANS - SECOND DEMAND	D60	1,014,549	453,024	21,653	9,836	144	0	207,162	457	446	318,394
LINE TRANS - SECOND CUSTOMER	C60	502,825	413,678	11,162	25,536	73	0	31,721	0	1	16,110
LINES - SECONDARY DEMAND	D30	156,826	102,055	4,878	2,216	32	0	46,668	103	100	0
LINES - SECONDARY CUSTOMER	C30	77,725	66,062	1,782	4,078	12	0	5,066	0	0	0
SERVICES	CW369	203,386	163,125	4,393	10,715	30	605	15,411	0	870	8,224
METERS	CW370	80,239	47,969	1,278	4,541	10	1,983	14,566	0	1,376	7,926
STREET LIGHTS	DA373	18,406	0	0	0	0	39	0	0	0	0
INSTALL ON CUST PREMISES	DA371	13,137	0	0	0	0	10	0	13,119	8	0
CUSTOMER ACCOUNTING											
METER READING	CW902	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
CONSUMER INFORMATION											
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0	0	0
MISCELLANEOUS											
DEMAND	D99U	0	0	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0	0	0
MISC. REVENUE	R02	6,150,427	5,495,771	29,596	193,701	159	1,918	195,532	11,086	40	113,760
FACILITIES CHARGE REVENUE	DA454	9,859,316	0	0	0	0	3,309,023	0	74,734	5,557,903	0
RETAIL SALES REVENUE		0									
TOTALS		113,640,190	46,200,098	1,158,525	1,173,490	4,682	6,781,861	20,560,253	112,468	18,324,115	12,860,615

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

****** SUMMARY OF OTHER REVENUES ******

FUNCTION	ALLOCATION FACTOR	TOTAL OTHER REVENUES	(K) UNMETERED GEN SERVICE	(L) MUNICIPAL ST LIGHT	(M) TRAFFIC CONTROL	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
PRODUCTION			(40)	(41)	(42)			
DEMAND - Base-load	D10BS	475,261	257	0	51	3,419	3,286	14,084
DEMAND - Peak	D10P	2,661	1	0	0	19	18	79
DEMAND - Not in Use	D10BNS	630,720	506	0	105	10,385	5,347	23,981
ENERGY - POWER SUPPLY	E10	29,557,875	0	0	0	0	0	0
ENERGY - Summer	E10S	11,088,051	8,862	14,222	1,773	107,967	102,598	374,411
ENERGY - Non-Summer	E10NS	18,469,824	18,803	33,034	3,889	345,828	231,575	773,346
		0						
TRANSMISSION								
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	60,109,852	40,617	0	8,294	720,109	463,506	2,042,632
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	518	0	0	0	0	0	0
		0						
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	299,274	271	563	28	0	0	0
SUBSTATIONS - DIRECT	DA3602	13,957	0	0	0	0	1,051	12,903
LINES - PRIMARY DEMAND	D20	2,502,919	2,265	4,706	237	0	0	0
LINES - PRIMARY CUSTOMER	C20	1,240,482	3,444	6,171	1,586	0	0	0
LINES - SECONDARY DIRECT	DA3647	107,956	0	0	0	0	14,667	0
LINE TRANS - PRIMARY DEMAND	D50	350,797	318	660	33	0	0	0
LINE TRANS - PRIMARY CUST	C50	173,860	483	865	222	0	0	0
LINE TRANS - SECOND DIRECT	DA368	97,220	0	0	0	0	5,640	0
LINE TRANS - SECOND DEMAND	D60	1,014,549	1,079	2,241	113	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	502,825	1,397	2,503	643	0	0	0
LINES - SECONDARY DEMAND	D30	156,826	243	505	25	0	0	0
LINES - SECONDARY CUSTOMER	C30	77,725	223	400	103	0	0	0
SERVICES	CW369	203,386	0	0	0	0	12	0
METERS	CW370	80,239	1	167	78	21	52	269
STREET LIGHTS	DA373	18,406	0	18,367	0	0	0	0
INSTALL ON CUST PREMISES	DA371	13,137	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	6,150,427	15,092	91,849	1,924	0	0	0
OTHER	DA454	0	0	681	0	0	916,976	0
SUBSTATION CIAC	0	0						
TOTALS		113,640,190	93,861	176,934	19,105	1,187,749	1,744,729	3,241,706

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 41

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** TRANSFER ADJUSTMENT******

	SOURCES & NOTES	(A) TOTAL	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAN (19-P/S/T)	(J) IRRIGATION SECONDARY (24-S)
NORMALIZED SALES (KWH)		14,907,835,244	5,425,559,433	122,912,496	138,285,160	370,708	601,699,182	3,321,544,618	5,267,423	2,386,695,635	1,864,522,772
NORMALIZED REVENUE ($)		1,116,166,332	501,479,142	11,567,368	16,102,622	43,713	36,446,763	230,482,910	1,261,853	125,751,566	140,327,749
ENERGY EFFICIENCY COLLECTION AT CURRENT	3.10%	34,601,156	15,545,853	358,588	499,181	1,355	1,129,850	7,144,970	39,117	3,898,299	4,350,160
EE TRANSFER ADJUSTMENT	**$ 3,474,555**	3,474,555	1,561,073	36,008	50,126	136	113,456	717,479	3,928	391,457	436,831
PCA RATE TRANSER ADJUSTMENT PER KWH	**$ 0.011465**	170,912,271	62,201,834	1,409,142	1,585,383	4,250	6,898,237	38,080,159	60,389	27,362,495	21,375,996
PCA EIM TRANSFER ADJUSTMENT	**$ 2,456,681**	2,456,681	894,085	20,255	22,788	61	99,155	547,362	868	393,307	307,257
TOTAL BASE REVENUE TRANSFER		**176,843,508**	**64,656,991**	**1,465,405**	**1,658,298**	**4,447**	**7,110,848**	**39,344,999**	**65,185**	**28,147,259**	**22,120,084**
PROPOSED REQUIRED REVENUE		1,404,314,821	625,504,833	19,752,112	20,117,882	101,442	42,439,422	270,718,015	737,644	162,848,079	194,263,258
TARGET EE FUNDING	**$ 31,126,601**										
TARGET EE COLLECTION PERCENTAGE	2.22%										
ROUNDED EE COLLECTION PERCENTAGE	**2.25%**										
OVER/(UNDER) AT ROUNDED EE COLLECTION %	$ 470,482										

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
****** TRANSFER ADJUSTMENT****** **TWELVE MONTHS ENDING DECEMBER 31, 2023**

	SOURCES & NOTES	TOTAL	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
NORMALIZED SALES (KWH)		14,907,835,244	13,925,301	23,760,014	2,847,961	234,100,000	175,000,001	591,344,540
NORMALIZED REVENUE ($)		1,116,166,332	1,144,288	3,463,322	165,609	10,547,708	7,759,368	29,622,353
ENERGY EFFICIENCY COLLECTION AT CURRENT %		34,601,156	35,473	107,363	5,134	326,979	240,540	918,293
EE TRANSFER ADJUSTMENT		3,474,555	3,562	10,781	516	32,834	24,154	92,213
PCA RATE TRANSER ADJUSTMENT PER KWH		170,912,271	159,648	272,399	32,651	2,683,861	2,006,304	6,779,525
PCA EIM TRANSFER ADJUSTMENT		2,456,681	2,295	3,915	469	38,578	28,838	97,448
TOTAL BASE REVENUE TRANSFER		176,843,508	**165,505**	**287,095**	**33,636**	**2,755,273**	**2,059,297**	**6,969,186**
PROPOSED REQUIRED REVENUE		1,404,314,821	1,342,227	2,825,017	433,379	14,236,899	9,789,500	39,205,110
TARGET EE FUNDING								
TARGET EE COLLECTION PERCENTAGE								
ROUNDED EE COLLECTION PERCENTAGE								
OVER/(UNDER) AT ROUNDED EE COLLECTION %								

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 42

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

***** REVENUE REQUIREMENT SUMMARY *****

	SOURCES & NOTES	(A) TOTAL	(B) RESIDENTIAL (1)	(C) RESIDENTIAL On Site Gen (6)	(D) GEN SRV (7)	(E) GEN SRV On Site Gen (8)	(F) GEN SRV PRIM & TRAN (9-P/T)	(G) GEN SRV SECONDARY (9-S)	(H) AREA LIGHTING (15)	(I) LG POWER SEC/PRIM/TRAN (19-S/P/T)	(J) IRRIGATION SECONDARY (24-S)
TOTAL RATE BASE		3,912,569,823	1,782,680,096	56,275,860	53,653,411	288,712	122,456,391	722,282,341	4,126,040	401,501,460	617,442,481
REVENUES FROM RATES											
RETAIL		1,116,166,332	501,479,142	11,567,368	16,102,622	43,713	36,446,763	230,482,910	1,261,853	125,751,566	140,327,749
RETAIL - TRANSFER ADJUSTMENT		176,843,508	64,656,991	1,465,405	1,658,298	4,447	7,110,848	39,344,999	65,185	28,147,259	22,120,084
TOTAL SALES REVENUES		1,293,009,840	566,136,133	13,032,773	17,760,920	48,160	43,557,610	269,827,909	1,327,038	153,898,825	162,447,833
TOTAL OTHER OPERATING REVENUES		113,640,190	46,200,098	1,158,525	1,173,490	4,682	6,781,861	20,560,253	112,468	18,324,115	12,860,615
TOTAL REVENUES		1,406,650,030	612,336,231	14,191,298	18,934,410	52,842	50,339,471	290,388,162	1,439,506	172,222,939	175,308,448
OPERATING EXPENSES											
WITHOUT INC TAX		1,091,583,652	480,891,174	13,922,074	15,711,579	67,274	36,409,736	214,305,086	677,692	134,058,322	139,792,943
OPERATING INCOME											
BEFORE INCOME TAXES		315,066,378	131,445,058	269,225	3,222,831	(14,432)	13,929,735	76,083,076	761,814	38,164,617	35,515,505
TOTAL FEDERAL INCOME TAX		39,040,245	13,370,532	262,324	322,579	494	1,659,227	9,065,970	7,507	6,781,260	4,554,856
TOTAL STATE INCOME TAX		(2,828,435)	(968,684)	(19,005)	(23,371)	(36)	(120,210)	(656,822)	(544)	(491,297)	(329,996)
TOTAL OPERATING EXPENSES		1,127,795,462	493,293,021	14,165,393	16,010,788	67,732	37,948,754	222,714,233	684,655	140,348,285	144,017,803
TOTAL OPERATING INCOME		278,854,568	119,043,210	25,905	2,923,623	(14,890)	12,390,717	67,673,928	754,851	31,874,654	31,290,645
ADD: IERCO OPERATING INCOME	E10	1,759,534	655,548	18,494	16,641	73	69,444	396,018	621	275,592	207,076
CONSOLIDATED OPER INCOME		280,614,102	119,698,758	44,400	2,940,263	(14,817)	12,460,161	68,069,946	755,471	32,150,247	31,497,721
RATES OF RETURN		7.172	6.715	0.079	5.480	-5.132	10.175	9.424	18.310	8.008	5.101
RATES OF RETURN - INDEX		1.000	0.936	0.011	0.764	-0.716	1.419	1.314	2.553	1.116	0.711
AVERAGE MILLS/KWH		80.52	92.43	94.11	116.45	117.92	60.57	69.39	239.56	52.69	75.26
REVENUE REQUIREMENT CALCULATION											
RATE OF RETURN REQUIRED		7.702	7.702	7.702	7.702	7.702	7.702	7.702	7.702	7.702	7.702
REVENUE REQUIREMENT ADJUSTMENTS	Exhibit No. 46	83,386,821	35,663,794	942,384	751,627	3,385	2,960,144	17,641,736	0	10,601,024	10,191,807
REQUIRED REVENUE		1,404,314,821	625,504,833	19,752,112	20,117,882	101,442	42,439,422	270,718,015	737,644	162,848,079	194,263,258
REVENUE DEFICIENCY		111,304,981	59,368,700	6,719,340	2,356,962	53,282	(1,118,189)	890,106	(589,394)	8,949,254	31,815,425
PERCENT CHANGE REQUIRED		8.61%	10.49%	51.56%	13.27%	110.64%	-2.57%	0.33%	-44.41%	5.82%	19.59%
RETURN AT CLAIMED ROR		301,346,128	137,302,021	4,334,367	4,132,386	22,237	9,431,591	55,630,186	317,788	30,923,642	47,555,420
EARNINGS DEFICIENCY		20,732,026	17,603,263	4,289,967	1,192,122	37,054	(3,028,570)	(12,439,761)	(437,684)	(1,226,604)	16,057,699
REVENUE REQUIREMENT FOR RATE DESIGN											
TOTAL IDAHO SALES REVENUES		1,293,009,840	566,136,133	13,032,773	17,760,920	48,160	43,557,610	269,827,909	1,327,038	153,898,825	162,447,833
REQUESTED CHANGE IN REVENUE (%)		8.61%	10.49%	51.56%	13.27%	110.64%	-2.57%	0.33%	-44.41%	5.82%	19.59%
RETAIL SALES REVENUE REQUIRED		1,404,314,821	625,504,833	19,752,112	20,117,882	101,442	42,439,422	270,718,015	737,644	162,848,079	194,263,258
RATE OF RETURN AT REQUIRED REVENUE		7.702	7.702	7.702	7.702	7.702	7.702	7.702	7.702	7.702	7.702
REQUESTED AVERAGE MILLS/KWH		94.20	115.29	160.70	145.48	273.64	70.53	81.50	140.04	68.23	104.19
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		4.22	4.09	-2.01	3.26	-6.78	4.58	6.52	15.57	3.37	2.98
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		7.07	7.42	9.93	7.65	11.68	3.67	6.65	1.28	5.60	8.14

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023

****** REVENUE REQUIREMENT SUMMARY ******

	SOURCES & NOTES	TOTAL	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)	(N) SC DOE/INL	(O) SC JR SIMPLOT	(P) SC MICRON
TOTAL RATE BASE		3,912,569,823	3,597,837	10,383,484	963,563	28,287,118	24,344,597	84,286,431
REVENUES FROM RATES								
RETAIL		1,116,166,332	1,144,288	3,463,322	165,609	10,547,708	7,759,368	29,622,353
RETAIL - TRANSFER ADJUSTMENT		176,843,508	165,505	287,095	33,636	2,755,273	2,059,297	6,969,186
TOTAL SALES REVENUES		1,293,009,840	1,309,792	3,750,417	199,244	13,302,981	9,818,665	36,591,539
TOTAL OTHER OPERATING REVENUES		113,640,190	93,861	176,934	19,105	1,187,749	1,744,729	3,241,706
TOTAL REVENUES		1,406,650,030	1,403,653	3,927,351	218,349	14,490,730	11,563,394	39,833,245
OPERATING EXPENSES		0						
WITHOUT INC TAX		1,091,583,652	1,075,528	2,394,029	303,240	11,617,785	8,731,137	31,626,052
		0						
OPERATING INCOME		0						
BEFORE INCOME TAXES		315,066,378	328,125	1,533,322	(84,891)	2,872,945	2,832,256	8,207,193
TOTAL FEDERAL INCOME TAX		39,040,245	36,701	53,040	6,863	692,053	509,028	1,717,811
TOTAL STATE INCOME TAX		(2,828,435)	(2,659)	(3,843)	(497)	(50,139)	(36,879)	(124,454)
TOTAL OPERATING EXPENSES		1,127,795,462	1,109,570	2,443,226	309,606	12,259,699	9,203,286	33,219,409
TOTAL OPERATING INCOME		278,854,568	294,083	1,484,125	(91,256)	2,231,030	2,360,107	6,613,835
		0						
ADD: IERCO OPERATING INCOME	E10	1,759,534	1,647	2,813	337	27,014	19,893	68,324
CONSOLIDATED OPER INCOME		280,614,102	295,730	1,486,938	(90,919)	2,258,044	2,380,000	6,682,159
		0						
RATES OF RETURN		7.172	8.220	14.320	-9.436	7.983	9.776	7.928
RATES OF RETURN - INDEX		1.000	1.146	1.997	-1.316	1.113	1.363	1.105
AVERAGE MILLS/KWH		80.522	82.17	145.76	58.15	45.06	44.34	50.09
REVENUE REQUIREMENT CALCULATION								
RATE OF RETURN REQUIRED		7.702	7.702	7.702	7.702	7.702	7.702	7.702
REVENUE REQUIREMENT ADJUSTMENTS		83,386,821	57,515	0	11,763	1,040,799	650,851	2,869,993
REQUIRED REVENUE		1,404,314,821	1,342,227	2,825,017	433,379	14,236,899	9,789,500	39,205,110
REVENUE DEFICIENCY		111,304,981	32,435	(925,400)	234,134	933,918	(29,165)	2,613,571
PERCENT CHANGE REQUIRED		8.61%	2.48%	-24.67%	117.51%	7.02%	-0.30%	7.14%
RETURN AT CLAIMED ROR		301,346,128	277,105	799,736	74,214	2,178,674	1,875,021	6,491,741
EARNINGS DEFICIENCY		20,732,026	(18,625)	(687,202)	165,133	(79,370)	(504,979)	(190,418)
		0						
REVENUE REQUIREMENT FOR RATE DESIGN								
TOTAL IDAHO SALES REVENUES		1,293,009,840	1,309,792	3,750,417	199,244	13,302,981	9,818,665	36,591,539
REQUESTED CHANGE IN REVENUE (%)		8.61%	2.48%	-24.67%	117.51%	7.02%	-0.30%	7.14%
RETAIL SALES REVENUE REQUIRED		1,404,314,821	1,342,227	2,825,017	433,379	14,236,899	9,789,500	39,205,110
RATE OF RETURN AT REQUIRED REVENUE		7.702	7.702	7.702	7.702	7.702	7.702	7.702
REQUESTED AVERAGE MILLS/KWH		94.20	96.39	118.90	152.17	60.82	55.94	66.30
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		4.22	5.57	12.59	-11.45	3.69	2.53	4.00
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		7.07	6.47	3.68	12.85	6.99	2.41	7.10

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 43

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
UNIT COSTS

****** RESIDENTIAL SERVICE - SCHEDULE 1 ******

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	RETURN @ 6.715%	OPERATING EXPENSES	REVENUE DEFICIENCY	REVENUE REQUIREMENT ADJUSTMENTS	REVENUE REQUIREMENT	BILLING UNITS	UNIT COSTS ($/EACH)	SUMMER ($/KWH)	NON-SUMMER ($/KWH)	SERVICE ($/CUST/MO)
PRODUCTION										
DEMAND - Base-load Summer	14,613,504	41,071,053	2,149,106	14,790,945	73,173,355	1,762,822,293	0.04151	0.041509		
DEMAND - Peak	3,497,970	10,543,147	514,422		14,732,749	1,762,822,293	0.00836	0.00836		
DEMAND - Base-load Non-Summe	20,622,446	57,959,101	3,032,800	20,872,849	103,261,582	3,662,737,141	0.02819		0.02819	
ENERGY - POWER SUPPLY	0	0	0		0	5,425,559,433	0.00000			
ENERGY - Summer	412,013	56,470,362	60,592		53,378,121	1,762,822,293	0.03028	0.03028		
ENERGY - Non-Summer	928,625	127,277,035	136,566		120,307,516	3,662,737,141	0.03285		0.03285	
ENERGY - ANNUAL		0					0.0538			
TRANSMISSION		0								
DEMAND - POWER SUPPLY	0	0	0		0	0	0.00000			
DEMAND - TRANSMISSION	26,793,962	40,112,565	3,940,402		46,602,187	5,425,559,433	0.00859	0.00859	0.00859	
DEMAND - SUBTRANSMISSION	0	0	0		0	0	0.00000			
DEMAND - DIRECT	0	0	0		0	0	0.00000			
DISTRIBUTION		0								
SUBSTATIONS - GENERAL	9,217,585	12,197,110	1,355,566		23,126,364	5,425,559,433	0.00426	0.00426	0.00426	
SUBSTATIONS - DIRECT	0	0	0		0	0	0.00000			
LINES - PRIMARY DEMAND	8,792,358	25,120,808	1,293,031		34,702,943	5,425,559,433	0.00640	0.00640	0.00640	
LINES - PRIMARY CUSTOMER	9,424,825	26,927,840	1,386,043		37,199,254	5,909,767	6.29454			6.29454
LINES - SECONDARY DIRECT	0	0	0		0	0	0.00000			
LINE TRANS - PRIMARY DEMANE	2,276,024	2,286,204	334,719		4,879,618	5,425,559,433	0.00090	0.00090	0.00090	
LINE TRANS - PRIMARY CUST	2,439,747	2,450,659	358,797		5,230,627	5,909,767	0.88508			0.88508
LINE TRANS - SECOND DIRECT	0	0	0		0	0	0.00000			
LINE TRANS - SECOND DEMAND	7,731,707	7,766,531	1,137,048		16,576,386	5,425,559,433	0.00306	0.00306	0.00306	
LINE TRANS - SECOND CUSTOM	7,060,186	7,091,985	1,038,292		15,136,678	5,909,767	2.56130			2.56130
LINES - SECONDARY DEMAND	945,460	2,924,659	139,042		3,955,301	5,425,559,433	0.00073	0.00073	0.00073	
LINES - SECONDARY CUSTOME	612,011	1,893,177	90,004		2,560,328	5,909,767	0.43324			0.43324
SERVICES	1,357,186	2,469,043	199,592		3,931,879	5,909,767	0.66532			0.66532
METERS	3,261,348	15,610,429	479,624		19,469,679	5,909,767	3.29449			3.29449
STREET LIGHTS	0	0	0		0	0	0.00000			
INSTALL ON CUST PREMISES	0	2,216,273	0		2,216,273	5,909,767	0.37502			0.37502
CUSTOMER ACCOUNTING		0								
METER READING	0	2,818,451	0		2,818,451	5,909,767	0.47691			0.47691
CUSTOMER ACCOUNTS	0	26,554,621	0		26,554,621	5,909,767	4.49335			4.49335
UNCOLLECTIBLES	0	4,833,086	0		4,833,086	5,909,767	0.81781			0.81781
MISC	0	0	0		0	5,909,767	0.00000			
CONSUMER INFORMATION		0								
CUSTOMER ASSIST	0	15,744,877	0		15,744,877	5,909,767	2.66421			2.66421
SALES EXPENSE	0	0	0		0	5,909,767	0.00000			
ADVERTISING	0	0	0		0	5,909,767	0.00000			
MISC	0	0	0		0	5,909,767	0.00000			
MISCELLANEOUS		0								
DEMAND	0	0	0		0	0	0.00000			
ENERGY	0	771,520	0		771,520	5,425,559,433	0.00014	0.000142	0.000142	
CUSTOMER	0	0	0		0	5,909,767	0.00000			
REVENUE	0	0	0		(5,495,771)	5,909,767	(0.92995)			(0.9299)
OTHER	0	212,346	0		212,346	5,909,767	0.03593			0.0359
SUBSTATION CIAC	(288,200)	(29,860)	(42,384)		(375,135)	5,909,767	(0.06348)			(0.0635)
TOTALS	119,698,758	493,293,021	17,603,263	35,663,794	625,504,833			0.104220	0.085113	22.00378

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
UNIT COSTS

***** * * RESIDENTIAL SERVICE ON SITE GENERATION - SCHEDULE 6 * * ****

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	RETURN @ 0.079%	OPERATING EXPENSES	REVENUE DEFICIENCY	REVENUE REQUIREMENT ADJUSTMENTS	REVENUE REQUIREMENT	BILLING UNITS	UNIT COSTS ($/EACH)	SUMMER ($/KWH)	NON-SUMMER ($/KWH)	SERVICE ($/CUST/MO)
PRODUCTION										
DEMAND - Base-load Summer	4,203	991,380	406,141	362,079	1,899,777	35,810,327	0.05305	0.053051		
DEMAND - Peak	1,006	254,735	97,216		386,628	35,810,327	0.01080	0.01080		
DEMAND - Base-load Non-Summe	6,737	1,588,890	650,925	580,305	3,044,784	87,102,169	0.03496		0.03496	
ENERGY - POWER SUPPLY	0	0	0		0	122,912,496	0.00000			
ENERGY - Summer	122	1,426,231	11,817		1,351,676	35,810,327	0.03775	0.03775		
ENERGY - Non-Summer	322	3,756,129	31,122		3,559,780	87,102,169	0.04087		0.04087	
ENERGY - ANNUAL		0					0.0679			
TRANSMISSION		0								
DEMAND - POWER SUPPLY	0	0	0		0	0	0.00000			
DEMAND - TRANSMISSION	8,260	1,024,821	798,083		1,435,880	122,912,496	0.01168	0.01168	0.01168	
DEMAND - SUBTRANSMISSION	0	0	0		0	0	0.00000			
DEMAND - DIRECT	0	0	0		0	0	0.00000			
DISTRIBUTION										
SUBSTATIONS - GENERAL	5,177	565,714	500,194		1,239,024	122,912,496	0.01008	0.01008	0.01008	
SUBSTATIONS - DIRECT	0	0	0		0	0	0.00000			
LINES - PRIMARY DEMAND	4,938	1,184,232	477,119		1,786,191	122,912,496	0.01453	0.01453	0.01453	
LINES - PRIMARY CUSTOMER	2,988	716,573	288,702		1,080,816	159,453	6.77829			6.77829
LINES - SECONDARY DIRECT	0	0	0		0	0	0.00000			
LINE TRANS - PRIMARY DEMAND	1,278	105,009	123,509		266,233	122,912,496	0.00217	0.00217	0.00217	
LINE TRANS - PRIMARY CUST	773	63,540	74,735		161,096	159,453	1.01031			1.01031
LINE TRANS - SECOND DIRECT	0	0	0		0	0	0.00000			
LINE TRANS - SECOND DEMAND	4,342	356,729	419,562		904,408	122,912,496	0.00736	0.00736	0.00736	
LINE TRANS - SECOND CUSTOM	2,238	183,880	216,268		466,188	159,453	2.92368			2.92368
LINES - SECONDARY DEMAND	531	138,019	51,306		202,761	122,912,496	0.00165	0.00165	0.00165	
LINES - SECONDARY CUSTOME	194	50,433	18,747		74,090	159,453	0.46465			0.46465
SERVICES	430	65,066	41,500		116,986	159,453	0.73367			0.73367
METERS	1,021	412,547	98,661		545,149	159,453	3.41888			3.41888
STREET LIGHTS	0	0	0		0	0	0.00000			
INSTALL ON CUST PREMISES	0	59,798	0		59,798	159,453	0.37502			0.37502
CUSTOMER ACCOUNTING										
METER READING	0	55,951	0		55,951	159,453	0.35089			0.35089
CUSTOMER ACCOUNTS	0	716,476	0		716,476	159,453	4.49335			4.49335
UNCOLLECTIBLES	0	2,063	0		2,063	159,453	0.01294			0.01294
MISC	0	0	0		0	159,453	0.00000			
CONSUMER INFORMATION										
CUSTOMER ASSIST	0	424,816	0		424,816	159,453	2.66421			2.66421
SALES EXPENSE	0	0	0		0	159,453	0.00000			
ADVERTISING	0	0	0		0	159,453	0.00000			
MISC	0	0	0		0	159,453	0.00000			
MISCELLANEOUS		0								
DEMAND	0	0	0		0	0	0.00000			
ENERGY	0	17,478	0		17,478	122,912,496	0.00014	0.000142	0.000142	
CUSTOMER	0	0	0		0	159,453	0.00000			
REVENUE	0	0	0		(29,596)	159,453	(0.18561)			(0.1856)
OTHER	0	5,770	0		5,770	159,453	0.03618			0.0362
SUBSTATION CIAC	(162)	(887)	(15,639)		(22,109)	159,453	(0.13866)			(0.1387)
TOTALS	44,400	14,165,393	4,289,967	942,384	19,752,112			0.149204	0.123436	22.93780

121
122

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
UNIT COSTS

123 ****** SMALL GENERAL SERVICE - SCHEDULE 7 ******
124

125		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
126	FUNCTION	RETURN @	OPERATING	REVENUE	REVENUE	REVENUE	BILLING	UNIT COSTS	SUMMER	NON-SUMMER	SERVICE
127		5.480%	EXPENSES	DEFICIENCY	REQUIREMENT ADJUSTMENTS	REQUIREMENT	UNITS	($/EACH)	($/KWH)	($/KWH)	($/CUST/MO)
128	PRODUCTION										
129	DEMAND - Base-load Summer	220,275	752,986	89,310	273,171	1,363,076	45,603,878	0.02989	0.029889		
130	DEMAND - Peak	52,726	193,391	21,378		274,885	45,603,878	0.00603	0.006028		
131	DEMAND - Base-load Non-Summe	385,809	1,318,844	156,425	478,455	2,387,408	92,681,282	0.02576		0.025759	
132	ENERGY - POWER SUPPLY	0	0	0		0	138,285,160	0.00000			
133	ENERGY - Summer	8,703	1,461,327	3,529		1,381,974	45,603,878	0.03030	0.030304		
134	ENERGY - Non-Summer	19,072	3,202,300	7,733		3,028,409	92,681,282	0.03268		0.032676	
135	ENERGY - ANNUAL		0					0.05115			
136	TRANSMISSION		0								
137	DEMAND - POWER SUPPLY	0	0	0		0	0	0.00000			
138	DEMAND - TRANSMISSION	457,273	827,259	185,400		998,664	138,285,160	0.00722	0.007222	0.007222	
139	DEMAND - SUBTRANSMISSION	0	0	0		0	0	0.00000			
140	DEMAND - DIRECT	0	0	0		0	0	0.00000			
141											
142	DISTRIBUTION		0								
143	SUBSTATIONS - GENERAL	163,337	260,707	66,224		510,752	138,285,160	0.00369	0.00369	0.00369	
144	SUBSTATIONS - DIRECT	0	0	0		0	0	0.00000			
145	LINES - PRIMARY DEMAND	155,802	541,492	63,169		761,701	138,285,160	0.00551	0.00551	0.00551	
146	LINES - PRIMARY CUSTOMER	474,835	1,650,298	192,521		2,321,428	364,810	6.36338			6.363385
147	LINES - SECONDARY DIRECT	0	0	0		0	0	0.00000			
148	LINE TRANS - PRIMARY DEMAND	40,331	48,622	16,352		108,078	138,285,160	0.00078	0.00078	0.00078	
149	LINE TRANS - PRIMARY CUST	122,918	148,184	49,837		329,388	364,810	0.90290			0.902904
150	LINE TRANS - SECOND DIRECT	0	0	0		0	0	0.00000			
151	LINE TRANS - SECOND DEMAND	137,007	165,174	55,549		367,149	138,285,160	0.00266	0.00266	0.00266	
152	LINE TRANS - SECOND CUSTOM	355,701	428,830	144,218		953,202	364,810	2.61287			2.612872
153	LINES - SECONDARY DEMAND	16,754	63,077	6,793		86,763	138,285,160	0.00063	0.00063	0.00063	
154	LINES - SECONDARY CUSTOME	30,834	116,089	12,502		159,680	364,810	0.43771			0.437707
155	SERVICES	72,762	160,355	29,501		262,128	364,810	0.71853			0.71853
156	METERS	252,005	1,471,582	102,175		1,856,636	364,810	5.08932			5.08932
157	STREET LIGHTS	0	0	0		0	0	0.00000			
158	INSTALL ON CUST PREMISES	0	136,811	0		136,811	364,810	0.37502			0.37502
159			0								
160	CUSTOMER ACCOUNTING		0								
161	METER READING	0	220,902	0		220,902	364,810	0.60553			0.60553
162	CUSTOMER ACCOUNTS	0	1,639,218	0		1,639,218	364,810	4.49335			4.49335
163	UNCOLLECTIBLES	0	205,622	0		205,622	364,810	0.56364			0.56364
164	MISC	0	0	0		0	364,810	0.00000			
165											
166	CONSUMER INFORMATION		0								
167	CUSTOMER ASSIST	0	971,932	0		971,932	364,810	2.66421			2.66421
168	SALES EXPENSE	0	0	0		0	364,810	0.00000			
169	ADVERTISING	0	0	0		0	364,810	0.00000			
170	MISC	0	0	0		0	364,810	0.00000			
171											
172	MISCELLANEOUS		0								
173	DEMAND	0	0	0		0	0	0.00000			
174	ENERGY	0	19,664	0		19,664	138,285,160	0.00014	0.000142	0.000142	
175	CUSTOMER	0	0	0		0	364,810	0.00000			
176	REVENUE	0	0	0		(193,701)	364,810	(0.53096)			(0.5310)
177	OTHER	0	8,754	0		8,754	364,810	0.02400			0.02400
178	SUBSTATION CIAC	(25,879)	(2,634)	(10,493)		(42,642)	364,810	(0.11689)			(0.11689)
179											
180	TOTALS	2,940,263	16,010,788	1,192,122	751,627	20,117,882			0.086851	0.079064	24.202608

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
UNIT COSTS

**** * * SMALL GENERAL SERVICE ON SITE GENERATION - SCHEDULE 8 * * ****

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	RETURN @ -5.132%	OPERATING EXPENSES	REVENUE DEFICIENCY	REVENUE REQUIREMENT ADJUSTMENTS	REVENUE REQUIREMENT	BILLING UNITS	UNIT COSTS ($/EACH)	SUMMER ($/KWH)	NON-SUMMER ($/KWH)	SERVICE ($/CUST/MO)
PRODUCTION										
DEMAND - Base-load Summer	(722)	2,581	1,807	957	5,235	110,080	0.04756	0.047557		
DEMAND - Peak	(173)	664	432		1,073	110,080	0.00975	0.009749		
DEMAND - Base-load Non-Summe	(1,834)	6,551	4,586	2,428	13,288	260,628	0.05099		0.050986	
ENERGY - POWER SUPPLY	0	0	0		0	370,708	0.00000			
ENERGY - Summer	(30)	5,348	75		5,079	110,080	0.04614	0.046139		
ENERGY - Non-Summer	(84)	14,969	209		14,216	260,628	0.05454		0.054544	
ENERGY - ANNUAL		0					0.09079			
TRANSMISSION		0								
DEMAND - POWER SUPPLY	0	0	0		0	0	0.00000			
DEMAND - TRANSMISSION	(1,894)	3,512	4,737		5,628	370,708	0.01518	0.015181	0.015181	
DEMAND - SUBTRANSMISSION	0	0	0		0	0	0.00000			
DEMAND - DIRECT	0	0	0		0	0	0.00000			
0										
DISTRIBUTION		0								
SUBSTATIONS - GENERAL	(2,243)	3,648	5,608		8,921	370,708	0.02406	0.02406	0.02406	
SUBSTATIONS - DIRECT	0	0	0		0	0	0.00000			
LINES - PRIMARY DEMAND	(2,139)	7,772	5,349		12,534	370,708	0.03381	0.03381	0.03381	
LINES - PRIMARY CUSTOMER	(1,280)	4,650	3,201		7,499	1,050	7.14228			7.142275
LINES - SECONDARY DIRECT	0	0	0		0	0	0.00000			
LINE TRANS - PRIMARY DEMANE	(554)	670	1,385		1,938	370,708	0.00523	0.00523	0.00523	
LINE TRANS - PRIMARY CUST	(331)	401	829		1,160	1,050	1.10453			1.104530
LINE TRANS - SECOND DIRECT	0	0	0		0	0	0.00000			
LINE TRANS - SECOND DEMAND	(1,881)	2,275	4,704		6,585	370,708	0.01776	0.01776	0.01776	
LINE TRANS - SECOND CUSTOM	(959)	1,160	2,398		3,356	1,050	3.19634			3.196343
LINES - SECONDARY DEMAND	(230)	907	575		1,419	370,708	0.00383	0.00383	0.00383	
LINES - SECONDARY CUSTOME	(83)	328	208		513	1,050	0.48829			0.488285
SERVICES	(193)	439	483		866	1,050	0.82487			0.82487
METERS	(543)	3,344	1,358		4,620	1,050	4.39954			4.39954
STREET LIGHTS	0	0	0		0	0	0.00000			
INSTALL ON CUST PREMISES	0	394	0		394	1,050	0.37502			0.37502
CUSTOMER ACCOUNTING		0								
METER READING	(0)	536	0		536	1,050	0.51071			0.51071
CUSTOMER ACCOUNTS	(0)	4,718	0		4,718	1,050	4.49335			4.49335
UNCOLLECTIBLES	0	0	0		0	1,050	0.00000			0.00000
MISC	0	0	0		0	1,050	0.00000			
CONSUMER INFORMATION		0								
CUSTOMER ASSIST	(0)	2,797	0		2,797	1,050	2.66421			2.66421
SALES EXPENSE	0	0	0		0	1,050	0.00000			
ADVERTISING	0	0	0		0	1,050	0.00000			
MISC	0	0	0		0	1,050	0.00000			
MISCELLANEOUS		0								
DEMAND	0	0	0		0	0	0.00000			
ENERGY	0	53	0		53	370,708	0.00014	0.000142	0.000142	
CUSTOMER	0	0	0		0	1,050	0.00000			
REVENUE	0	0	0		(159)	1,050	(0.15148)			(0.1515)
OTHER	(0)	26	0		26	1,050	0.02516			0.02516
SUBSTATION CIAC	355	(11)	(889)		(852)	1,050	(0.81161)			(0.81161)
TOTALS	(14,817)	67,732	37,054	3,385	101,442.212			0.203461	0.205546	24.261194

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
UNIT COSTS

***** * * LARGE GENERAL SERVICE - SCHEDULE 9 SECONDARY * * ****

FUNCTION	(A) RETURN @ 9.42%	(B) OPERATING EXPENSES	(C) REVENUE DEFICIENCY	(D) REVENUE REQUIREMENT ADJUSTMENTS	(E) REVENUE REQUIREMENT	(F) BILLING UNITS	(G) UNIT COSTS ($/EACH)	(H) SUMMER ($/KW)	(I) NON-SUMMER ($/KW)	(J) SUMMER ($/KWH)	(K) NON-SUMMER ($/KWH)	(L) SERVICE ($/CUST/MO)	(M) BASIC ($/KW)
PRODUCTION													
DEMAND - Base-load Summer	8,637,266	17,724,632	(1,578,458)	6,228,532	30,382,237	3,897,816	7.79468	7.79468					
DEMAND - Peak	2,067,464	4,542,556	(377,828)		6,100,767	3,897,816	1.56518	1.56518					
DEMAND - Base-load Non-Summe	15,826,986	32,478,738	(2,892,377)	11,413,204	55,672,620	7,244,505	7.68481		7.68481				
ENERGY - POWER SUPPLY	0	0	0		0	3,321,544,618	0.00000						
ENERGY - Summer	373,173	36,459,341	(68,197)		34,426,701	1,143,297,617	0.03011			0.030112			
ENERGY - Non-Summer	763,549	74,599,413	(139,538)		70,440,430	2,178,247,001	0.03234				0.032338		
ENERGY - ANNUAL		0					0.03157						
TRANSMISSION		0											
DEMAND - POWER SUPPLY	0	0	0		0	0	0.00000						
DEMAND - TRANSMISSION	18,384,372	20,523,253	(3,359,738)		21,863,494	11,142,321	1.96220	1.96220	1.96220				
DEMAND - SUBTRANSMISSION	0	0	0		0	0	0.00000						
DEMAND - DIRECT	0	0	0		0	0	0.00000						
DISTRIBUTION		0											
SUBSTATIONS - GENERAL	5,916,140	5,871,725	(1,081,173)		10,279,913	15,010,667	0.68484						0.68484
SUBSTATIONS - DIRECT	0	0	0		0	0	0.00000						
LINES - PRIMARY DEMAND	5,643,216	11,767,998	(1,031,296)		15,587,367	15,010,667	1.03842						1.03842
LINES - PRIMARY CUSTOMER	1,014,352	2,115,264	(185,372)		2,801,784	453,162	6.18274					6.18274	
LINES - SECONDARY DIRECT	0	0	0		0	0	0.00000						
LINE TRANS - PRIMARY DEMANE	1,460,825	1,118,082	(266,965)		2,158,427	15,010,667	0.14379						0.14379
LINE TRANS - PRIMARY CUST	262,579	200,972	(47,986)		387,971	453,162	0.85614					0.85614	
LINE TRANS - SECOND DIRECT	0	0	0		0	0	0.00000						
LINE TRANS - SECOND DEMAND	4,962,457	3,798,262	(906,887)		7,332,323	15,010,667	0.48847						0.48847
LINE TRANS - SECOND CUSTOM	759,856	581,594	(138,863)		1,122,733	453,162	2.47755					2.47755	
LINES - SECONDARY DEMAND	606,827	1,367,580	(110,897)		1,778,401	15,010,667	0.11848						0.11848
LINES - SECONDARY CUSTOME	65,868	148,444	(12,037)		193,037	453,162	0.42598					0.42598	
SERVICES	179,958	242,201	(32,887)		362,462	453,162	0.79985					0.79985	
METERS	1,389,947	4,809,166	(254,012)		5,842,489	453,162	12.89272					12.89272	
STREET LIGHTS	0	0	0		0	0	0.00000					0.00000	
INSTALL ON CUST PREMISES	0	169,944	0		169,944	453,162	0.37502					0.37502	
CUSTOMER ACCOUNTING		0											
METER READING	0	238,482	(0)		238,482	453,162	0.52626					0.52626	
CUSTOMER ACCOUNTS	0	2,036,213	(0)		2,036,213	453,162	4.49335					4.49335	
UNCOLLECTIBLES	0	254,688	(0)		254,688	453,162	0.56202					0.56202	
MISC	0	0	0		0	453,162	0.00000						
CONSUMER INFORMATION		0											
CUSTOMER ASSIST	0	1,207,320	(0)		1,207,320	453,162	2.66421					2.66421	
SALES EXPENSE	0	0	0		0	453,162	0.00000						
ADVERTISING	0	0	0		0	453,162	0.00000						
MISC	0	0	0		0	453,162	0.00000						
MISCELLANEOUS		0											
DEMAND	0	0	0		0	0	0.00000						
ENERGY	0	472,327	0		472,327	3,321,544,618	0.00014			0.000142	0.000142		
CUSTOMER	0	0	0		0	453,162	0.00000						
REVENUE	0	0	0		(195,532)	453,162	(0.43148)					(0.43148)	
OTHER	0	16,293	(0)		16,293	15,010,667	0.00109					0.00109	
SUBSTATION CIAC	(244,889)	(30,253)	44,753		(214,876)	15,010,667	(0.01431)						(0.01431)
TOTALS	68,069,946	222,714,233	(12,439,761)	17,641,736	270,718,015			11.32206	9.64701	0.030254	0.032480	31.8254	2.45969

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
UNIT COSTS

***** * * LARGE GENERAL SERVICE - SCHEDULE 9 PRIM. & TRAN. * * ****

FUNCTION	(A) RETURN @ 10.18%	(B) OPERATING EXPENSES	(C) REVENUE DEFICIENCY	(D) REVENUE REQUIREMENT ADJUSTMENTS	(E) REVENUE REQUIREMENT	(F) BILLING UNITS	(G) UNIT COSTS ($/EACH)	(H) SUMMER ($/KW)	(I) NON-SUMMER ($/KW)	(J) SUMMER ($/KWH)	(K) NON-SUMMER ($/KWH)	(L) SERVICE ($/CUST/MO)	(M) BASIC ($/KW)
PRODUCTION													
DEMAND - Base-load Summer	1,578,047	3,013,701	(383,560)	1,053,987	5,115,246	566,997	9.02164	9.02164					
DEMAND - Peak	377,730	772,123	(91,811)		1,026,140	566,997	1.80978	1.80978					
DEMAND - Base-load Non-Summe	2,853,928	5,450,336	(693,676)	1,906,156	9,251,020	998,364	9.26618		9.26618				
ENERGY - POWER SUPPLY	0	0	0		0	601,699,182	0.00000						
ENERGY - Summer	73,542	6,655,558	(17,875)		6,282,661	216,006,603	0.02909			0.029086			
ENERGY - Non-Summer	141,671	12,821,177	(34,434)		12,102,833	385,692,579	0.03138				0.031379		
ENERGY - ANNUAL		0					0.03056						
TRANSMISSION		0											
DEMAND - POWER SUPPLY	0	0	0		0	0	0.00000						
DEMAND - TRANSMISSION	3,329,060	3,472,391	(809,162)		3,612,018	1,565,362	2.30747	2.30747	2.30747				
DEMAND - SUBTRANSMISSION	0	0	0		0	0	0.00000						
DEMAND - DIRECT	5,924	6,750	(1,440)		10,217	1,565,362	0.00653	0.00653	0.00653				
DISTRIBUTION		0											
SUBSTATIONS - GENERAL	1,096,284	1,017,729	(266,463)		1,746,260	1,952,328	0.89445						0.89445
SUBSTATIONS - DIRECT	0	0	0		0	0	0.00000						
LINES - PRIMARY DEMAND	1,045,710	2,029,241	(254,171)		2,658,007	1,952,328	1.36146						1.36146
LINES - PRIMARY CUSTOMER	8,120	15,758	(1,974)		20,640	3,410	6.05301					6.05301	
LINES - SECONDARY DIRECT	622,116	799,015	(151,212)		1,188,654	1,952,328	0.60884						0.60884
LINE TRANS - PRIMARY DEMANE	270,697	194,357	(65,796)		365,986	1,952,328	0.18746						0.18746
LINE TRANS - PRIMARY CUST	2,102	1,509	(511)		2,842	3,410	0.83345					0.83345	
LINE TRANS - SECOND DIRECT	996,288	715,003	(242,158)		1,346,719	1,952,328	0.68980						0.68980
LINE TRANS - SECOND DEMAND	0	0	0		0	1,952,328	0.00000						
LINE TRANS - SECOND CUSTOM	0	0	0		0	3,410	0.00000						
LINES - SECONDARY DEMAND	0	0	0		0	1,952,328	0.00000						
LINES - SECONDARY CUSTOME	0	0	0		0	3,410	0.00000						
SERVICES	7,631	9,582	(1,855)		14,110	3,410	4.13810					4.13810	
METERS	204,332	656,668	(49,665)		792,137	3,410	232.30506					232.30506	
STREET LIGHTS	1,342	1,899	(326)		2,764	3,410	0.81050					0.81050	
INSTALL ON CUST PREMISES	276	1,313	(67)		1,488	3,410	0.43633					0.43633	
CUSTOMER ACCOUNTING		0											
METER READING	0	104,762	(0)		104,762	3,410	30.72304					30.72304	
CUSTOMER ACCOUNTS	0	129,538	(0)		129,538	3,410	37.98894					37.98894	
UNCOLLECTIBLES	0	1,916	(0)		1,916	3,410	0.56202						
MISC	0	0	0		0	3,410	0.00000						
CONSUMER INFORMATION		0											
CUSTOMER ASSIST	0	9,085	(0)		9,085	3,410	2.66421					2.66421	
SALES EXPENSE	0	0	0		0	3,410	0.00000						
ADVERTISING	0	0	0		0	3,410	0.00000						
MISC	0	0	0		0	3,410	0.00000						
MISCELLANEOUS		0											
DEMAND	0	0	0		0	0	0.00000						
ENERGY	0	85,562	0		85,562	601,699,182	0.00014			0.000142	0.000142		
CUSTOMER	0	0	0		0	3,410	0.00000						
REVENUE	0	0	0		(1,918)	3,410	(0.56240)					(0.56240)	
OTHER	0	2,878	(0)		(3,306,145)	1,952,328	(1.69344)						(1.69344)
SUBSTATION CIAC	(154,638)	(19,100)	37,586		(123,124)	1,952,328	(0.06307)						(0.06307)
TOTALS	12,460,161	37,948,754	(3,028,570)	2,960,144	42,439,422			13.14541	11.58017	0.029228	0.031522	315.39024	1.98551

IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
UNIT COSTS

**** * * LARGE POWER - SCHEDULE 19 S/P/T * * ****

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
FUNCTION	RETURN @ 8.01%	OPERATING EXPENSES	REVENUE DEFICIENCY	REVENUE REQUIREMENT ADJUSTMENTS	REVENUE REQUIREMENT	BILLING UNITS	UNIT COSTS ($/EACH)	SUMMER ($/KW)	NON-SUMMER ($/KW)	SUMMER ($/KWH)	NON-SUMMER ($/KWH)	SERVICE ($/CUST/MO)	BASIC ($/KW)
PRODUCTION													
DEMAND - Base-load Summer	4,246,307	10,469,029	(162,006)	3,603,894	18,053,270	1,625,074	11.10920	11.10920					
DEMAND - Peak	1,016,420	2,679,444	(38,779)		3,643,376	1,625,074	2.24198	2.24198					
DEMAND - Base-load Non-Summe	8,244,405	20,326,112	(314,543)	6,997,130	35,051,273	3,081,027	11.37649		11.37649				
ENERGY - POWER SUPPLY	0	0	0		0	2,386,695,635	0.00000						
ENERGY - Summer	217,622	25,034,721	(8,303)		23,652,969	815,019,158	0.02902			0.029021			
ENERGY - Non-Summer	454,511	52,285,801	(17,341)		49,399,969	1,571,676,477	0.03143				0.031431		
ENERGY - ANNUAL		0					0.03061						
TRANSMISSION		0											
DEMAND - POWER SUPPLY	0	0	0		0	0	0.00000						
DEMAND - TRANSMISSION	9,358,129	12,765,489	(357,034)		14,142,328	4,706,101	3.00511	3.00511	3.00511				
DEMAND - SUBTRANSMISSION	0	0	0		0	0	0.00000						
DEMAND - DIRECT	0	0	0		0	0	0.00000						
DISTRIBUTION		0											
SUBSTATIONS - GENERAL	3,447,830	4,200,644	(131,542)		7,435,654	5,315,392	1.39889						1.39889
SUBSTATIONS - DIRECT	414	337	(16)		726	5,315,392	0.00014						0.00014
LINES - PRIMARY DEMAND	3,288,774	8,236,885	(125,474)		11,058,271	5,315,392	2.08042						2.08042
LINES - PRIMARY CUSTOMER	2,602	6,516	(99)		8,748	1,392	6.28469					6.28469	
LINES - SECONDARY DIRECT	1,070,751	1,788,929	(40,852)		2,741,568	5,315,392	0.51578						0.51578
LINE TRANS - PRIMARY DEMANE	851,345	809,667	(32,481)		1,575,448	5,315,392	0.29639						0.29639
LINE TRANS - PRIMARY CUST	674	641	(26)		1,246	1,392	0.89537					0.89537	
LINE TRANS - SECOND DIRECT	1,082,066	1,028,650	(41,283)		2,002,021	5,315,392	0.37665						0.37665
LINE TRANS - SECOND DEMAND	9,073	8,629	(346)		16,790	5,315,392	0.00316						0.00316
LINE TRANS - SECOND CUSTOM	17	16	(1)		32	1,392	0.02273					0.02273	
LINES - SECONDARY DEMAND	1,109	2,998	(42)		3,951	5,315,392	0.00074						0.00074
LINES - SECONDARY CUSTOME	1	4	(0)		5	1,392	0.00379					0.00379	
SERVICES	8,634	14,110	(329)		21,430	1,392	15.39492					15.39492	
METERS	111,604	460,074	(4,258)		564,568	1,392	405.58024					405.58024	
STREET LIGHTS	13	24	(0)		36	1,392	0.02557					0.02557	
INSTALL ON CUST PREMISES	156	552	(6)		692	1,392	0.49747					0.49747	
CUSTOMER ACCOUNTING		0											
METER READING	0	42,766	(0)		42,766	1,392	30.72304					30.72304	
CUSTOMER ACCOUNTS	0	52,881	(0)		52,881	1,392	37.98894					37.98894	
UNCOLLECTIBLES	0	25,816	(0)		25,816	1,392	18.54586					18.54586	
MISC	0	0	0		0	1,392	0.00000						
CONSUMER INFORMATION		0											
CUSTOMER ASSIST	0	3,709	(0)		3,709	1,392	2.66421					2.66421	
SALES EXPENSE	0	0	0		0	1,392	0.00000						
ADVERTISING	0	0	0		0	1,392	0.00000						
MISC	0	0	0		0	1,392	0.00000						
MISCELLANEOUS		0											
DEMAND	0	0	0		0	0	0.00000						
ENERGY	0	339,390	0		339,390	2,386,695,635	0.00014			0.00014	0.00014		
CUSTOMER	0	0	0		0	1,392	0.00000						
REVENUE	0	0	0		(40)	1,392	(0.02846)					(0.02846)	
OTHER	0	11,394	(0)		(5,546,509)	5,315,392	(1.04348)						(1.04348)
SUBSTATION CIAC	(1,262,211)	(246,943)	48,156		(1,444,306)	5,315,392	(0.27172)						(0.27172)
TOTALS	32,150,247	140,348,285	(1,226,604)	10,601,024	162,848,079			16.35628	14.38160	0.02916	0.03157	518.59836	3.35697

661
662 IDAHO POWER COMPANY
3CP/12CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2023
UNIT COSTS

663 ***IRRIGATION - SCHEDULE 24 SECONDARY***
664 (Production-related revenue and billing units are for June - September)

665		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
666	FUNCTION	RETURN @	OPERATING	REVENUE	REVENUE	REVENUE	BILLING	UNIT COSTS	IN-SEASON	IN-SEASON	OUT-SEASON	SERVICE
667		5.10%	EXPENSES	DEFICIENCY	REQUIREMENT ADJUSTMENTS	REQUIREMENT	UNITS	($/EACH)	($/KW)	($/KWH)	($/KWH)	($/CUST/MO)
668	PRODUCTION											
669	DEMAND - Base-load Summer	5,951,520	22,002,893	3,034,115	7,928,720	39,863,773	4,065,427	9.80556	9.80556			
670	DEMAND - Peak	1,424,589	5,648,485	726,263		8,050,485	4,065,427	1.98023	1.98023			
671	DEMAND - Base-load Non-Summe	1,698,737	6,280,264	866,025	2,263,087	11,378,278	4,065,427	2.79879	2.79879			
672	ENERGY - POWER SUPPLY	0	0	0		0	1,864,522,772	0.00000				
673	ENERGY - Summer	262,263	47,312,458	133,703		44,750,407	1,508,526,794	0.02966		0.029665		
674	ENERGY - Non-Summer	59,476	10,729,437	30,321		10,148,419	355,995,978	0.02851			0.028507	
675	ENERGY - ANNUAL		0				1,864,522,772	0.00000				
676	TRANSMISSION		0									
677	DEMAND - POWER SUPPLY	0	0	0		0	0	0.00000				
678	DEMAND - TRANSMISSION	6,274,670	12,350,192	3,198,859		15,038,335	4,065,427	3.69908	3.69908			
679	DEMAND - SUBTRANSMISSION	0	0	0		0	0	0.00000				
680	DEMAND - DIRECT	0	0	0		0	0	0.00000				
681												
682	DISTRIBUTION		0									
683	SUBSTATIONS - GENERAL	4,921,825	8,561,312	2,509,171		16,782,081	4,065,427	4.12800	4.12800			
684	SUBSTATIONS - DIRECT	0	0	0		0	0	0.00000				
685	LINES - PRIMARY DEMAND	4,694,770	17,644,822	2,393,418		24,893,925	4,065,427	6.12332	6.12332			
686	LINES - PRIMARY CUSTOMER	278,852	1,048,038	142,160		1,478,609	230,147	6.42463				6.42463
687	LINES - SECONDARY DIRECT	0	0	0		0	0	0.00000				
688	LINE TRANS - PRIMARY DEMAND	1,215,307	1,604,060	619,570		3,559,971	4,065,427	0.87567	0.87567			
689	LINE TRANS - PRIMARY CUST	72,185	95,275	36,800		211,449	230,147	0.91876				0.91876
690	LINE TRANS - SECOND DIRECT	0	0	0		0	0	0.00000				
691	LINE TRANS - SECOND DEMAND	4,128,425	5,449,201	2,104,692		12,093,453	4,065,427	2.97471	2.97471			
692	LINE TRANS - SECOND CUSTOM	208,890	275,718	106,493		611,904	230,147	2.65875				2.65875
693	LINES - SECONDARY DEMAND	0	0	0		0	4,065,427	0.00000				
694	LINES - SECONDARY CUSTOME	0	0	0		0	230,147	0.00000				
695	SERVICES	51,984	124,361	26,502		203,809	230,147	0.88556				0.88556
696	METERS	409,408	2,578,416	208,718		3,260,962	230,147	14.16905				14.16905
697	STREET LIGHTS	0	0	0		0	4,065,427	0.00000				
698	INSTALL ON CUST PREMISES	0	86,309	0		86,309	230,147	0.37502				0.37502
699			0									
700	CUSTOMER ACCOUNTING		0									
701	METER READING	0	194,122	0		194,122	230,147	0.84347				0.84347
702	CUSTOMER ACCOUNTS	0	1,034,129	0		1,034,129	230,147	4.49335				4.49335
703	UNCOLLECTIBLES	0	65,542	0		65,542	230,147	0.28478				0.28478
704	MISC	0	0	0		0	230,147	0.00000				
705												
706	CONSUMER INFORMATION		0									
707	CUSTOMER ASSIST	0	613,160	0		613,160	230,147	2.66421				2.66421
708	SALES EXPENSE	0	0	0		0	230,147	0.00000				
709	ADVERTISING	0	0	0		0	230,147	0.00000				
710	MISC	0	0	0		0	230,147	0.00000				
711												
712	MISCELLANEOUS		0									
713	DEMAND	0	0	0		0	0	0.00000				
714	ENERGY	0	265,137	0		265,137	1,864,522,772	0.00014		0.000142	0.000142	
715	CUSTOMER	0	0	0		0	230,147	0.00000				
716	REVENUE	0	0	0		(113,760)	230,147	(0.49430)				(0.49430)
717	OTHER	0	75,286	0		75,286	230,147	0.32712				0.32712
718	SUBSTATION CIAC	(155,179)	(20,815)	(79,111)		(282,527)	4,065,427	(0.06949)	(0.06949)			
719												
720	TOTALS	31,497,721	144,017,803	16,057,699	10,191,807	194,263,258			32.31586	0.029807	0.028649	33.5504

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 44

Idaho 2023 Marginal Cost Study

The concept and design of the 2023 Marginal Cost Study is from the National Economic Research Associates Inc (NERA) marginal cost model. The NERA model is constantly being refined but the basic concepts and methods have remained the same since Idaho Power began using this method. In this analysis, generation capacity, transmission capacity and energy marginal costs are quantified for use in the Company's class cost-of-service model.

The following is a list of attachments:

- Schedule 1, Marginal Cost of Energy
- Schedule 2, page 1 of 2: Annual Generation Capacity Cost
- Schedule 2, page 2 of 2: Seasonalized Generation Capacity Marginal Costs
- Schedule 3, page 1 of 2: Annual Transmission Marginal Costs
- Schedule 3, page 2 of 2: Seasonalized Transmission Marginal Costs

I. MARGINAL COST OF ENERGY

The marginal cost of energy was determined from the simulated hourly operation of the Company's power supply system over 37 streamflow conditions for the five-year period 2023 through 2027. Base case net power supply expenses were quantified, and the model was run a second time with fifty megawatts (MW) of load added across all hours. The difference in monthly power supply expenses between the base run and the base-plus-50-MW run was averaged over the five-year period and was divided by the difference in monthly megawatt hours to produce an average monthly marginal cost per megawatt hour. A 2023 test year net power supply run was used for the 2023 base marginal cost run. For the years 2024 through 2027, updated loads along with current resource considerations at the time of the study were used. The 2023 test year gas prices were used, adjusted for each of the years using the Bureau of Labor Statistics: Produce Price Index; Moody's Analytics. Coal plant operating characteristics, with the exception of coal costs, from the 2023 analysis were used for the entire period, 2023 – 2027.

II. GENERATION CAPACITY MARGINAL COSTS

The annual generation capacity marginal costs were derived from the surrogate capacity resource identified in the Company's most recently acknowledged Integrated Resource Plan (IRP), the 2021 IRP, a 170-MW simple cycle combustion turbine. Plant investment included in the Company's application was used and fixed operating and maintenance costs were obtained from the 2021 IRP Technical Appendix, p. 43. The carrying charge rate reflects the 2023 test year weighted cost of capital and a resource life of 32 years, from the Company's 2022 Depreciation Study. General plant, A&G and materials & supplies loading factors were derived from an average of historic data for the period 2018 through 2022. The reserve margin is 15.5% (2021 IRP, p. 140).

III. SEASONALIZATION OF GENERATION CAPACITY MARGINAL COSTS

The seasonalization of generation capacity marginal costs is based on information from the 2021 IRP. The Company plans new peaking generation capacity based on monthly peak hour load surplus/deficiency data, assuming 50th percentile water plus and 50th percentile plus 15.5% reserve margin load criteria used for planning purposes (2021 IRP Technical Appendix, p. 20-24). On this basis, during the five years 2023 through 2027, the IRP identifies the months of June through September as months which experience deficiencies. These are the months that are assigned generation capacity costs in the marginal cost analysis. The relative sizes of the five-year average monthly deficiencies were used to define the share of annual capacity cost assigned to each month.

IV. TRANSMISSION MARGINAL COSTS

The marginal cost of transmission reflects planned investment that has being included in the capital budget for the next ten years. The investment costs are for the years 2023 through 2032. The carrying charge rate reflects the 2023 test year weighted cost of capital and a resource life of 53 years, from the Company's 2022 Depreciation Study. General plant, administrative & general and materials & supplies loading factors were derived from an average of historic data for the period 2018 through 2022. Demand related transmission O&M was estimated using historic data for the period 2018 through 2022.

V. SEASONALIZATION OF TRANSMISSION MARGINAL COSTS

Because the resource integration portion of marginal transmission investment is driven by the need for new generation resources, as identified in the 2021 IRP, these costs are assigned to months in the same manner as marginal generation capacity costs. The investment in the remainder of the network is driven by peak load growth on the system, irrespective of the introduction of new resources onto the grid. Therefore, that portion of marginal transmission costs is assigned to the months based on relative monthly peak load growth from 2023 through 2032. The two portions are summed, by month. This method results in the assignment of marginal transmission capacity costs to each of the twelve months of the year.

Idaho Power Company
Marginal Cost Analysis 2023
Marginal Cost of Energy - Dollars/MWh

Line		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
	Marginal Generation Cost at Generation 1/	$67.78	$31.10	$35.53	$27.36	$24.55	$30.89	$41.93	$45.21	$40.71	$41.07	$64.31	$85.21	$44.79
(2)	Marginal Fuel Inventory	$32.22	$32.22	$32.22	$32.22	$32.22	$32.22	$32.22	$32.22	$32.22	$32.22	$32.22	$32.22	
(3)	Cost of Capital & Taxes for Fuel Inventory (2) x 9.54% 2/	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	
(4)	Marginal Variable O & M 3/	$4.82	$4.82	$4.82	$4.82	$4.82	$4.82	$4.82	$4.82	$4.82	$4.82	$4.82	$4.82	
(5)	Marginal energy cost at Generation Level	$75.67	$38.99	$43.42	$35.26	$32.44	$38.78	$49.82	$53.10	$48.61	$48.96	$72.20	$93.10	
	Average System Loss Factor Coefficients at: 4/													
(6)	Transmission	1.029	1.029	1.029	1.029	1.029	1.029	1.029	1.029	1.029	1.029	1.029	1.029	
(7)	Distribution Station	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	
(8)	Distribution Primary	1.051	1.051	1.051	1.051	1.051	1.051	1.051	1.051	1.051	1.051	1.051	1.051	
(9)	Distribution Secondary	1.076	1.076	1.076	1.076	1.076	1.076	1.076	1.076	1.076	1.076	1.076	1.076	
	Marginal Energy Cost at Service Level													
(10)	Power Supply (5)	$75.67	$38.99	$43.42	$35.26	$32.44	$38.78	$49.82	$53.10	$48.61	$48.96	$72.20	$93.10	$52.53
(11)	Transmission (6) x (5)	$77.87	$40.13	$44.68	$36.28	$33.38	$39.91	$51.27	$54.64	$50.02	$50.38	$74.30	$95.80	$54.06
(12)	Distribution Station (7) x (5)	$78.40	$40.40	$44.99	$36.53	$33.61	$40.18	$51.62	$55.01	$50.36	$50.73	$74.80	$96.45	$54.42
(13)	Distribution Primary (8) x (5)	$79.53	$40.98	$45.64	$37.06	$34.09	$40.76	$52.36	$55.81	$51.08	$51.46	$75.89	$97.85	$55.21
(14)	Distribution Secondary (9) x (5)	$81.42	$41.96	$46.72	$37.94	$34.90	$41.73	$53.61	$57.14	$52.30	$52.68	$77.69	$100.18	$56.52

1/ Aurora Power Supply Model 2023 to 2027
2/ Schedule 14. Based on 2023 Test Year Cost of Capital
3/ 2021 IRP Technical Appendix, pg. 43
4/ Schedule 15

IDAHO POWER COMPANY
MARGINAL COST ANALYSIS 2023
ANNUAL GENERATION CAPACITY COST: DOLLARS PER KW

(1)	Investment ($/kw) 1/	$1,032.52
(2)	General Plant Loading (1) x 1.09 2/	$1,123.24
(3)	Economic Carrying Charge Rate 3/	7.09%
(4)	A&G Loading .39% 4/	0.39%
(5)	Total Carrying Charge	7.48%
(6)	Annual Cost ($/kw) (2) x (5)	$84.06
(7)	Demand related fixed O&M 5/	$1.02
(8)	A&G loading (7) x 1.556 6/	$1.59
(9)	Marginal Demand Related Costs (6) + (8)	$85.64
	Working Capital	
(10)	Materials & Supplies (2) x 1.08%	$12.15
(11)	Revenue Requirement for Materials & Supplies (10) x 9.54%	$1.16
(12)	Total Marginal Demand Related Costs (9) + (11) rounded	$86.80
(13)	Adjusted for reserve margin (15.5%) 7/	**$100.00**

Notes

1/ Total Investment of 2021 IRP Surrogate Resource - 170 MW SCCT $175,528,850 / 170 MW
2/ Schedule 14. Average general plant loading 2018-2022
3/ Schedule 13. Based on 2023 Test Year Cost of Capital
4/ Average A & G expenses 2018 - 2022 applicable to plant related expenses, Schedule 14
5/ Estimated cost of a simple cycle combustion turbine , IPCo 2021 IRP Technical Appendix, p.43
6/ Average A & G expenses 2018 - 2022 applicable to non-plant related expenses, Schedule 14
7/ IPCO 2021 IRP p. 140

IDAHO POWER COMPANY
Marginal Cost Analysis 2023
Seasonalized Generation Capacity Marginal Costs

		(1)	(2)	(3)
		% Share of Total 1/	**$/kw/year $100.00**	**Monthly Marginal Cost**
	Month			(1) X (2)
(1)	**Jan**	0.00%		0.00
(2)	**Feb**	0.00%		0.00
(3)	**Mar**	0.00%		0.00
(4)	**Apr**	0.00%		0.00
(5)	**May**	0.00%		0.00
(6)	**Jun**	8.35%		8.35
(7)	**Jul**	52.64%		52.64
(8)	**Aug**	38.20%		38.20
(9)	**Sep**	0.81%		0.81
(10)	**Oct**	0.00%		0.00
(11)	**Nov**	0.00%		0.00
(12)	**Dec**	0.00%		0.00
(13)	**Sum**	100.00%		100.00

Notes
1/ G & T Assignment Factors Workpaper
Seasonalized based on average monthly share of peak hour deficiencies
for the five year period 2018-2022. Source: 2021 IRP Technical Appendix, p. 20-24

IDAHO POWER COMPANY
Marginal Cost Analysis 2023
Annual Transmission Marginal Costs
Dollars/kw

		Integration of New Resources	Planned System Expansion	Total
		(1)	(2)	(1) + (2)
(1)	Investment ($/kw)	$0.00	$2,028.90	
(2)	With General Plant Loading (1) x 1.09 1/	$0.00	$2,207.15	
(3)	Economic Carrying Charge Rate 2/	6.01%	6.01%	
(4)	A&G Loading .39% 3/	0.39%	0.39%	
(5)	Total Carrying Charge	6.40%	6.40%	
(6)	Annual Cost ($/kw) (2) x (5)	$0.00	$141.33	
(7)	Demand related O&M 4/	$6.63	$6.63	
(8)	With A&G loading (7) x 1.556 5/	$10.32	$10.32	
(9)	Marginal Demand Related Costs (6) + (8)	$10.32	$151.65	
	Working Capital			
(10)	Materials & Supplies (2) x 1.08%	$0.00	$23.87	
(11)	Revenue Requirement and Taxes for Materials & Supplies (10) x 9.54% 6/	$0.00	$2.28	
(12)	Total Marginal Demand Related Costs (9) + (11) Rounded	$10.32	$153.93	
(13)	Total Annual Transmission Marginal Costs (rounded)	**$10.00**	**$154.00**	**$ 164.00**

Notes:
1/ Average general plant loading 2018 - 2022, Schedule 14
2/ Schedule 13. Based on 2023 Test Year Cost of Capital
3/ Average A & G expenses 2018 - 2022 applicable to plant related expenses, Schedule 14
4/ Average O&M 2018 - 2022 w/o accts. 565 & 567
5/ Average A & G expenses 2018 - 2022 applicable to non-plant related expenses, Schedule 14
6/ Schedule 14. Based on 2023 Test Year Cost of Capital

IDAHO POWER COMPANY
Marginal Cost Analysis 2023
Seasonalized Transmission Marginal Costs
Dollars /kw

		Integration of New Resources			Planned System Expansion			TOTAL
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
		% Share of Total 1/	$/kw/year 2/ $10.00	Monthly Marginal Cost	% Share of Total 3/	$/kw/year 4/ $154.00	Monthly Marginal Cost	Monthly Marginal Cost
	Month			(1) X (2)			(1) X (2)	(3) + (6)
(1)	Jan	0.00%		$0.00	8.17%		$12.58	12.58
(2)	Feb	0.00%		$0.00	7.51%		$11.56	11.56
(3)	Mar	0.00%		$0.00	7.05%		$10.86	10.86
(4)	Apr	0.00%		$0.00	6.56%		$10.10	10.10
(5)	May	0.00%		$0.00	8.11%		$12.49	12.49
(6)	Jun	8.35%		$0.84	9.15%		$14.09	14.93
(7)	Jul	52.64%		$5.26	10.13%		$15.60	20.86
(8)	Aug	38.20%		$3.82	11.05%		$17.02	20.84
(9)	Sep	0.81%		$0.08	9.07%		$13.97	14.05
(10)	Oct	0.00%		$0.00	7.62%		$11.73	11.73
(11)	Nov	0.00%		$0.00	7.79%		$12.00	12.00
(12)	Dec	0.00%		$0.00	7.79%		$12.00	12.00
(13)	Sum	100.00%		$10.00	100.00%		$154.00	164.00

Notes:

1/ Seasonalized based on average monthly share of peak hour deficiencies for the five year period 2023-2027. Source: 2021 IRP Technical Appendix, p. 20-24 G & T Assignment Factors Workpaper

2/ Schedule 3, page 1 of 2

3/ Seasonalized based on monthly share of peak hour load growth between 2023 and 2027 Source: 2021 IRP Technical Appendix p. 7-9 G & T Assignment Factors Workpaper

4/ Schedule 3, page 1 of 2

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 45

IDAHO POWER COMPANY
DEVELOPMENT OF DEMAND AND ENERGY ALLOCATORS - RT DEL
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Month	Multiplier/ Marginal Cost	Total IPUC Jurisdiction	Residential (1)	Residential-NM (6)	General Service (7)	General Service-NM (8)	General Service (9-Primary&T)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service 19-Primary&S&T)	Irrigation Service (24-Secondary)
CAPACITY RELATED ALLOCATION FACTORS											
Twelve Monthly Coincident Demands @ Generation Level											
January		2,219,506	1,059,967	33,825	26,060	144	87,097	550,946	0	322,498	3,678
February		2,128,273	1,017,411	26,118	23,231	140	86,836	526,891	0	303,816	3,793
March		2,153,910	1,065,567	32,460	20,874	126	84,566	500,037	0	293,747	10,593
April		1,714,832	606,276	11,880	16,245	56	80,529	447,538	0	297,198	126,497
May		2,455,950	852,080	17,668	16,521	37	83,006	467,273	0	311,436	583,628
June		3,496,120	1,398,626	30,306	23,965	83	96,031	549,051	0	331,549	922,557
July		3,224,178	1,333,855	40,293	22,450	93	89,908	527,617	0	340,400	731,125
August		3,071,846	1,224,174	20,317	28,269	81	97,972	601,580	0	311,064	643,282
September		2,995,520	1,321,784	38,299	22,803	84	92,225	544,526	0	303,108	532,555
October		1,851,866	746,802	12,987	18,144	55	85,827	487,716	0	320,397	66,683
November		2,043,833	911,858	29,509	21,995	131	85,869	517,204	0	324,362	8,370
December		2,402,388	1,188,925	42,647	27,676	178	86,519	575,421	0	323,609	4,385
Total		29,758,221	12,727,324	336,308	268,233	1,208	1,056,385	6,295,799	0	3,783,183	3,637,146
Ratio		1.0000	0.4277	0.0113	0.0090	0.0000	0.0355	0.2116	0.0000	0.1271	0.1222
Actual	**D10BS**	**0.4297**	**0.1774**	**0.0043**	**0.0033**	**0.0000**	**0.0126**	**0.0747**	**0.0000**	**0.0432**	**0.0951**
Actual	**D10BNS**	**0.5703**	**0.2503**	**0.0070**	**0.0057**	**0.0000**	**0.0229**	**0.1369**	**0.0000**	**0.0839**	**0.0271**
Four Monthly Coincident Demands (June - September) @ Generation Level											
Power Supply Service - Generation											
January	0.00	0	0	0	0	0	0	0	0	0	0
February	0.00	0	0	0	0	0	0	0	0	0	0
March	0.00	0	0	0	0	0	0	0	0	0	0
April	0.00	0	0	0	0	0	0	0	0	0	0
May	0.00	0	0	0	0	0	0	0	0	0	0
June	1.00	3,496,120	1,398,626	30,306	23,965	83	96,031	549,051	0	331,549	922,557
July	1.00	3,224,178	1,333,855	40,293	22,450	93	89,908	527,617	0	340,400	731,125
August	1.00	3,071,846	1,224,174	20,317	28,269	81	97,972	601,580	0	311,064	643,282
September	1.00	2,995,520	1,321,784	38,299	22,803	84	92,225	544,526	0	303,108	532,555
October	0.00	0	0	0	0	0	0	0	0	0	0
November	0.00	0	0	0	0	0	0	0	0	0	0
December	0.00	0	0	0	0	0	0	0	0	0	0
Total		12,787,663	5,278,439	129,215	97,486	341	376,136	2,222,774	0	1,286,120	2,829,519
Ratio	**D10P**	**1.0000**	**0.4128**	**0.0101**	**0.0076**	**0.0000**	**0.0294**	**0.1738**	**0.0000**	**0.1006**	**0.2213**

IDAHO POWER COMPANY
DEVELOPMENT OF DEMAND AND ENERGY ALLOCATORS - RT DEL
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Month	Multiplier/ Marginal Cost	Total IPUC Jurisdiction	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
CAPACITY RELATED ALLOCATION FACTORS										
Twelve Monthly Coincident Demands @ Generatior										
January		2,219,506	1,639	0	365	2,086,219	41,611	15,260	76,416	133,287
February		2,128,273	1,666	0	367	1,990,268	38,260	23,348	76,398	138,005
March		2,153,910	1,674	0	319	2,009,963	43,356	22,419	78,172	143,946
April		1,714,832	1,682	0	367	1,588,268	25,426	22,150	78,988	126,564
May		2,455,950	1,700	0	341	2,333,690	18,122	16,075	88,063	122,260
June		3,496,120	1,710	0	332	3,354,210	24,712	22,336	94,861	141,910
July		3,224,178	1,717	0	348	3,087,806	19,117	23,051	94,204	136,372
August		3,071,846	1,734	0	345	2,928,817	24,020	22,223	96,786	143,029
September		2,995,520	1,744	0	355	2,857,483	24,142	20,794	93,101	138,037
October		1,851,866	1,750	0	348	1,740,708	22,980	4,157	84,021	111,158
November		2,043,833	1,754	0	357	1,901,409	40,726	20,506	81,191	142,423
December		2,402,388	1,756	0	353	2,251,468	48,957	19,950	82,012	150,920
Total		29,758,221	20,526	0	4,198	28,130,310	371,430	232,269	1,024,213	1,627,911
Ratio		1.0000	0.0007	0.0000	0.0001	0.9453	0.0125	0.0078	0.0344	0.0547
Actual	**D10BS**	**0.4297**	**0.0002**	**0.0000**	**0.0000**	**0.3149**	**0.0031**	**0.0030**	**0.0127**	**0.0188**
Actual	**D10BNS**	**0.5703**	**0.0005**	**0.0000**	**0.0001**	**0.6304**	**0.0094**	**0.0048**	**0.0217**	**0.0359**
Four Monthly Coincident Demands (June - Septeml										
Power Supply Service - Generation										
January	0.00	0	0	0	0	0	0	0	0	0
February	0.00	0	0	0	0	0	0	0	0	0
March	0.00	0	0	0	0	0	0	0	0	0
April	0.00	0	0	0	0	0	0	0	0	0
May	0.00	0	0	0	0	0	0	0	0	0
June	1.00	3,496,120	1,710	0	332	3,354,211	24,712	22,336	94,861	141,910
July	1.00	3,224,178	1,717	0	348	3,087,807	19,117	23,051	94,204	136,372
August	1.00	3,071,846	1,734	0	345	2,928,818	24,020	22,223	96,786	143,029
September	1.00	2,995,520	1,744	0	355	2,857,484	24,142	20,794	93,101	138,037
October	0.00	0	0	0	0	0	0	0	0	0
November	0.00	0	0	0	0	0	0	0	0	0
December	0.00	0	0	0	0	0	0	0	0	0
Total		12,787,663	6,905	0	1,380	12,228,320	91,992	88,403	378,952	559,348
Ratio	**D10P**	**1.0000**	**0.0005**	**0.0000**	**0.0001**	**0.9563**	**0.0072**	**0.0069**	**0.0296**	**0.0437**

IDAHO POWER COMPANY
DEVELOPMENT OF DEMAND AND ENERGY ALLOCATORS - RT DEL
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Month	Multiplier/ Marginal Cost	Total IPUC Jurisdiction	Residential (1)	Residential-NM (6)	General Service (7)	General Service-NM (8)	General Service (9-Primary&T)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service 19-Primary&S&T)	Irrigation Service (24-Secondary)
CAPACITY RELATED ALLOCATION FACTORS											
Monthly Coincident Demands @ Generation Level											
January		2,219,506	1,059,967	33,825	26,060	144	87,097	550,946	0	322,498	3,678
February		2,128,273	1,017,411	26,118	23,231	140	86,836	526,891	0	303,816	3,793
March		2,153,910	1,065,567	32,460	20,874	126	84,566	500,037	0	293,747	10,593
April		1,714,832	606,276	11,880	16,245	56	80,529	447,538	0	297,198	126,497
May		2,455,950	852,080	17,668	16,521	37	83,006	467,273	0	311,436	583,628
June		3,496,120	1,398,626	30,306	23,965	83	96,031	549,051	0	331,549	922,557
July		3,224,178	1,333,855	40,293	22,450	93	89,908	527,617	0	340,400	731,125
August		3,071,846	1,224,174	20,317	28,269	81	97,972	601,580	0	311,064	643,282
September		2,995,520	1,321,784	38,299	22,803	84	92,225	544,526	0	303,108	532,555
October		1,851,866	746,802	12,987	18,144	55	85,827	487,716	0	320,397	66,683
November		2,043,833	911,858	29,509	21,995	131	85,869	517,204	0	324,362	8,370
December		2,402,388	1,188,925	42,647	27,676	178	86,519	575,421	0	323,609	4,385
Total		29,758,221	12,727,324	336,308	268,233	1,208	1,056,385	6,295,799	0	3,783,183	3,637,146
Actual	D13	1.0000	0.4277	0.0113	0.0090	0.0000	0.0355	0.2116	0.0000	0.1271	0.1222
Monthly Coincident Demands Weighted by Marginal Transmission Costs											
Transmission Service											
January	12.58	27,921,395	13,334,385	425,516	327,837	1,816	1,095,681	6,930,903	0	4,057,027	46,263
February	11.56	24,602,849	11,761,266	301,928	268,545	1,618	1,003,823	6,090,855	0	3,512,114	43,849
March	10.86	23,391,472	11,572,055	352,516	226,696	1,365	918,389	5,430,405	0	3,190,092	115,039
April	10.10	17,319,812	6,123,386	119,984	164,075	562	813,347	4,520,134	0	3,001,703	1,277,623
May	12.49	30,674,832	10,642,476	220,669	206,351	466	1,036,742	5,836,238	0	3,889,835	7,289,519
June	14.93	52,197,081	20,881,487	452,464	357,803	1,239	1,433,747	8,197,327	0	4,950,032	13,773,771
July	20.86	67,256,368	27,824,213	840,508	468,301	1,945	1,875,483	11,006,092	0	7,100,737	15,251,270
August	20.84	64,017,298	25,511,788	423,410	589,116	1,682	2,041,737	12,536,924	0	6,482,564	13,406,005
September	14.05	42,087,065	18,571,060	538,103	320,381	1,187	1,295,757	7,650,590	0	4,258,664	7,482,397
October	11.73	21,722,403	8,759,991	152,340	212,823	646	1,006,753	5,720,906	0	3,758,256	782,188
November	12.00	24,526,002	10,942,301	354,108	263,946	1,571	1,030,422	6,206,445	0	3,892,345	100,439
December	12.00	28,828,673	14,267,096	511,761	332,109	2,131	1,038,231	6,905,055	0	3,883,302	52,621
Total		424,545,087	180,191,502	4,693,306	3,737,982	16,228	14,590,112	87,031,875	0	51,976,671	59,620,984
Weighted	D13	1.0000	0.4244	0.0111	0.0088	0.0000	0.0344	0.2050	0.0000	0.1224	0.1404
Average	**D13**	**1.0000**	**0.4261**	**0.0112**	**0.0089**	**0.0000**	**0.0349**	**0.2083**	**0.0000**	**0.1248**	**0.1313**

IDAHO POWER COMPANY
DEVELOPMENT OF DEMAND AND ENERGY ALLOCATORS - RT DEL
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Month	Multiplier/ Marginal Cost	Total IPUC Jurisdiction	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
CAPACITY RELATED ALLOCATION FACTORS										
Monthly Coincident Demands @ Generation Level										
January		2,219,506	1,639	0	365	2,086,219	41,611	15,260	76,416	133,287
February		2,128,273	1,666	0	367	1,990,268	38,260	23,348	76,398	138,005
March		2,153,910	1,674	0	319	2,009,963	43,356	22,419	78,172	143,946
April		1,714,832	1,682	0	367	1,588,268	25,426	22,150	78,988	126,564
May		2,455,950	1,700	0	341	2,333,690	18,122	16,075	88,063	122,260
June		3,496,120	1,710	0	332	3,354,210	24,712	22,336	94,861	141,910
July		3,224,178	1,717	0	348	3,087,806	19,117	23,051	94,204	136,372
August		3,071,846	1,734	0	345	2,928,817	24,020	22,223	96,786	143,029
September		2,995,520	1,744	0	355	2,857,483	24,142	20,794	93,101	138,037
October		1,851,866	1,750	0	348	1,740,708	22,980	4,157	84,021	111,158
November		2,043,833	1,754	0	357	1,901,409	40,726	20,506	81,191	142,423
December		2,402,388	1,756	0	353	2,251,468	48,957	19,950	82,012	150,920
Total		29,758,221	20,526	0	4,198	28,130,310	371,430	232,269	1,024,213	1,627,911
Actual	D13	1.0000	0.0007	0.0000	0.0001	0.9453	0.0125	0.0078	0.0344	0.0547
Monthly Coincident Demands Weighted by Margina										
Transmission Service										
January	12.58	27,921,395	20,613	0	4,592	26,244,644	523,466	191,968	961,317	1,676,751
February	11.56	24,602,849	19,254	0	4,244	23,007,508	442,280	269,902	883,158	1,595,341
March	10.86	23,391,472	18,179	0	3,467	21,828,214	470,844	243,467	848,947	1,563,258
April	10.10	17,319,812	16,988	0	3,708	16,041,519	256,800	223,716	797,778	1,278,293
May	12.49	30,674,832	21,236	0	4,255	29,147,800	226,344	200,778	1,099,911	1,527,033
June	14.93	52,197,081	25,525	0	4,957	50,078,367	368,956	333,476	1,416,282	2,118,714
July	20.86	67,256,368	35,825	0	7,256	64,411,650	398,785	480,838	1,965,095	2,844,718
August	20.84	64,017,298	36,133	0	7,193	61,036,572	500,572	463,129	2,017,025	2,980,726
September	14.05	42,087,065	24,506	0	4,991	40,147,649	339,202	292,151	1,308,063	1,939,416
October	11.73	21,722,403	20,529	0	4,079	20,418,522	269,559	48,761	985,561	1,303,881
November	12.00	24,526,002	21,045	0	4,288	22,816,923	488,712	246,077	974,290	1,709,079
December	12.00	28,828,673	21,075	0	4,241	27,017,633	587,488	239,404	984,148	1,811,040
Total		424,545,087	280,908	0	57,269	402,197,002	4,873,008	3,233,668	14,241,574	22,348,249
Weighted	D13	1.0000	0.0007	0.0000	0.0001	0.9474	0.0115	0.0076	0.0335	0.0526
Average	**D13**	**1.0000**	**0.0007**	**0.0000**	**0.0001**	**0.9463**	**0.0120**	**0.0077**	**0.0340**	**0.0537**

IDAHO POWER COMPANY
DEVELOPMENT OF DEMAND AND ENERGY ALLOCATORS - RT DEL
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Month	Multiplier/ Marginal Cost	Total IPUC Jurisdiction	Residential (1)	Residential-NM (6)	General Service (7)	General Service-NM (8)	General Service (9-Primary&T)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service 19-Primary&S&T)	Irrigation Service (24-Secondary)
ENERGY RELATED ALLOCATION FACTORS											
Monthly Energy Requirements @ Generation Level (Mwh)											
January		1,339,623	613,557	18,646	15,518	69	51,586	322,133	502	216,762	2,731
February		1,151,180	517,912	13,901	12,560	57	47,876	277,873	494	188,849	2,544
March		1,126,738	467,115	11,175	11,857	44	49,767	281,844	488	204,917	7,866
April		1,085,807	383,562	9,819	10,317	40	47,597	262,403	481	196,073	90,909
May		1,265,221	377,025	8,834	10,563	33	52,044	278,339	478	205,140	246,792
June		1,508,697	417,114	9,376	11,507	31	55,727	288,432	473	207,113	433,104
July		1,822,178	584,744	13,970	14,033	46	59,674	332,590	467	216,864	511,136
August		1,661,681	517,117	14,052	13,171	51	57,105	326,117	466	219,632	424,401
September		1,290,902	393,931	10,782	10,890	53	53,727	290,009	461	206,713	242,301
October		1,134,186	414,280	10,654	10,889	37	51,925	290,936	455	213,986	49,520
November		1,168,943	492,048	16,499	11,934	68	50,708	291,311	449	206,082	6,015
December		1,382,693	644,092	22,800	15,398	97	52,892	328,184	441	214,399	3,256
Total		15,937,848	5,822,497	160,508	148,636	626	630,627	3,570,172	5,657	2,496,527	2,020,576
Ratio		1.0000	0.3653	0.0101	0.0093	0.0000	0.0396	0.2240	0.0004	0.1566	0.1268
Actual	E10S	0.3942	0.1200	0.0030	0.0031	0.0000	0.0142	0.0776	0.0001	0.0534	0.1011
Actual	E10NS	0.6058	0.2453	0.0070	0.0062	0.0000	0.0254	0.1464	0.0002	0.1033	0.0257
Monthly Energy Requirements Weighted by Marginal Energy Costs											
Power Supply Service - Generation											
January	75.67	101,369,282	46,427,842	1,410,965	1,174,254	5,245	3,903,511	24,375,828	38,004	16,402,383	206,653
February	38.99	44,884,525	20,193,371	542,015	489,709	2,205	1,866,681	10,834,272	19,266	7,363,215	99,201
March	43.42	48,922,967	20,282,115	485,228	514,842	1,920	2,160,888	12,237,662	21,197	8,897,479	341,562
April	35.26	38,285,551	13,524,385	346,213	363,774	1,393	1,678,260	9,252,323	16,977	6,913,525	3,205,443
May	32.44	41,043,756	12,230,691	286,560	342,652	1,080	1,688,314	9,029,322	15,506	6,654,726	8,005,916
June	38.78	58,507,256	16,175,683	363,613	446,254	1,191	2,161,081	11,185,392	18,345	8,031,825	16,795,788
July	49.82	90,780,891	29,131,939	695,989	699,106	2,276	2,972,962	16,569,652	23,253	10,804,150	25,464,795
August	53.10	88,235,264	27,458,929	746,138	699,364	2,720	3,032,276	17,316,803	24,751	11,662,458	22,535,714
September	48.61	62,750,753	19,148,993	524,124	529,362	2,568	2,611,682	14,097,331	22,419	10,048,308	11,778,242
October	48.96	55,529,723	20,283,158	521,597	533,107	1,827	2,542,228	14,244,237	22,300	10,476,733	2,424,484
November	72.20	84,397,712	35,525,889	1,191,215	861,633	4,932	3,661,112	21,032,656	32,451	14,879,142	434,293
December	93.10	128,728,703	59,964,996	2,122,668	1,433,589	9,042	4,924,241	30,553,958	41,070	19,960,536	303,174
Total		843,436,384	320,347,991	9,236,326	8,087,644	36,399	33,203,234	190,729,435	295,539	132,094,480	91,595,266
Ratio		1.0000	0.3798	0.0110	0.0096	0.0000	0.0394	0.2261	0.0004	0.1566	0.1086
Weighted	E10S	0.3560	0.1090	0.0028	0.0028	0.0000	0.0128	0.0702	0.0001	0.0481	0.0908
Weighted	E10NS	0.6440	0.2708	0.0082	0.0068	0.0000	0.0266	0.1560	0.0002	0.1085	0.0178
Average	**E10S**	**0.3751**	**0.1145**	**0.0029**	**0.0030**	**0.0000**	**0.0135**	**0.0739**	**0.0001**	**0.0507**	**0.0959**
Average	**E10NS**	**0.6249**	**0.2581**	**0.0076**	**0.0065**	**0.0000**	**0.0260**	**0.1512**	**0.0002**	**0.1059**	**0.0218**
Total Ratio		1.0000	0.3726	0.0105	0.0095	0.0000	0.0395	0.2251	0.0004	0.1566	0.1177

IDAHO POWER COMPANY
DEVELOPMENT OF DEMAND AND ENERGY ALLOCATORS - RT DEL
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Month	Multiplier/ Marginal Cost	Total IPUC Jurisdiction	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
ENERGY RELATED ALLOCATION FACTORS										
Monthly Energy Requirements @ Generation Level									Net CEYW	
January		1,339,623	1,194	2,464	266	1,245,429	26,342	15,027	**52,825**	94,194
February		1,151,180	1,214	2,284	267	1,065,830	24,284	15,195	**45,871**	85,350
March		1,126,738	1,220	2,083	233	1,038,609	22,741	16,844	**48,544**	88,129
April		1,085,807	1,226	2,284	267	1,004,976	19,242	16,373	**45,216**	80,831
May		1,265,221	1,239	2,070	248	1,182,804	16,979	15,618	**49,820**	82,417
June		1,508,697	1,246	2,006	242	1,426,371	16,258	15,049	**51,018**	82,326
July		1,822,178	1,251	2,005	253	1,737,033	15,126	16,429	**53,590**	85,145
August		1,661,681	1,263	2,018	251	1,575,645	14,715	16,366	**54,956**	86,036
September		1,290,902	1,271	2,046	259	1,212,443	15,332	10,364	**52,763**	78,460
October		1,134,186	1,275	2,046	253	1,046,256	21,403	14,664	**51,863**	87,930
November		1,168,943	1,278	2,096	260	1,078,749	22,844	14,135	**53,215**	90,194
December		1,382,693	1,280	2,117	257	1,285,215	25,622	15,238	**56,618**	97,478
Total		15,937,848	14,956	25,518	3,059	14,899,359	240,889	181,300	616,300	1,038,489
Ratio		1.0000	0.0009	0.0016	0.0002	0.9348	0.0151	0.0114	0.0387	0.0652
Actual	E10S	0.3942	0.0003	0.0005	0.0001	0.3734	0.0039	0.0037	0.0133	0.0208
Actual	E10NS	0.6058	0.0006	0.0011	0.0001	0.5614	0.0113	0.0077	0.0253	0.0443
Monthly Energy Requirements Weighted by Margin										
Power Supply Service - Generation										
January	75.67	101,369,282	90,345	186,437	20,124	94,241,591	1,993,329	1,137,067	3,997,295	7,127,691
February	38.99	44,884,525	47,319	89,040	10,429	41,556,723	946,849	592,437	1,788,516	3,327,802
March	43.42	48,922,967	52,959	90,449	10,101	45,096,402	987,410	731,357	2,107,798	3,826,566
April	35.26	38,285,551	43,212	80,522	9,431	35,435,459	678,483	577,304	1,594,305	2,850,092
May	32.44	41,043,756	40,190	67,143	8,053	38,370,152	550,783	506,652	1,616,170	2,673,604
June	38.78	58,507,256	48,310	77,810	9,381	55,314,672	630,493	583,596	1,978,495	3,192,584
July	49.82	90,780,891	62,343	99,879	12,627	86,538,970	753,592	818,493	2,669,835	4,241,921
August	53.10	88,235,264	67,084	107,168	13,354	83,666,760	781,351	869,010	2,918,143	4,568,504
September	48.61	62,750,753	61,778	99,451	12,581	58,936,835	745,293	503,809	2,564,816	3,813,918
October	48.96	55,529,723	62,435	100,167	12,406	51,224,678	1,047,901	717,932	2,539,212	4,305,045
November	72.20	84,397,712	92,263	151,321	18,799	77,885,706	1,649,322	1,020,530	3,842,154	6,512,006
December	93.10	128,728,703	119,139	197,107	23,973	119,653,493	2,385,418	1,418,651	5,271,142	9,075,210
Total		843,436,384	787,375	1,346,492	161,260	787,921,441	13,150,224	9,476,838	32,887,881	55,514,943
Ratio		1.0000	0.0009	0.0016	0.0002	0.9342	0.0156	0.0112	0.0390	0.0658
Weighted	E10S	0.3560	0.0003	0.0005	0.0001	0.3373	0.0035	0.0033	0.0120	0.0188
Weighted	E10NS	0.6440	0.0006	0.0011	0.0001	0.5969	0.0121	0.0079	0.0270	0.0471
Average	**E10S**	**0.3751**	**0.0003**	**0.0005**	**0.0001**	**0.3553**	**0.0037**	**0.0035**	**0.0127**	**0.0198**
Average	**E10NS**	**0.6249**	**0.0006**	**0.0011**	**0.0001**	**0.5792**	**0.0117**	**0.0078**	**0.0262**	**0.0457**
Total Ratio		1.0000	0.0009	0.0016	0.0002	0.9345	0.0154	0.0113	0.0388	0.0655

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 46

IDAHO POWER COMPANY
REVENUE REQUIREMENT ADJUSTMENTS
TWELVE MONTHS ENDING DECEMBER 31, 2023
ALLOCATION TO CLASSES

	RESIDENTIAL	RES. OS	GEN SRV	GEN SRV OS	LRG SVR	LRG SRV - SEC	LIGHTING	IND	IRR	UNMETERED	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON	Total IPUC
	(1)	(6)	(7)	(8)	(9-P/T)	(9-S)	(15)	(19-S/P/T)	(24-S)	(40)	(41)	(42)	(30)	(29)	(26)	Jurisdiction
Bridger	$ 28,903,005	$ 763,736	$ 609,141	$ 2,743	$ 2,398,989	$ 14,297,391	$ -	$ 8,591,387	$ 8,259,745	$ 46,612	$ -	$ 9,533	$ 843,495	$ 527,469	$ 2,325,928	$ 67,579,174
Valmy	$ 15,806,391	$ 417,670	$ 333,125	$ 1,500	$ 1,311,952	$ 7,818,915	$ -	$ 4,698,433	$ 4,517,065	$ 25,491	$ -	$ 5,213	$ 461,288	$ 288,461	$ 1,271,997	$ 36,957,501
Storage ADITC	$ (9,045,603)	$ (239,022)	$ (190,639)	$ (859)	$ (750,797)	$ (4,474,570)	$ -	$ (2,688,796)	$ (2,585,004)	$ (14,588)	$ -	$ (2,983)	$ (263,984)	$ (165,079)	$ (727,932)	$ (21,149,854)
	$ 35,663,794	$ 942,384	$ 751,627	$ 3,385	$ 2,960,144	$ 17,641,736	$ -	$ 10,601,024	$ 10,191,807	$ 57,515	$ -	$ 11,763	$ 1,040,799	$ 650,851	$ 2,869,993	$ 83,386,821
Total D10BS	$ 14,790,945	$ 362,079	$ 273,171	$ 957	$ 1,053,987	$ 6,228,532	$ -	$ 3,603,894	$ 7,928,720	$ 19,349	$ -	$ 3,867	$ 257,774	$ 247,719	$ 1,061,879	$ 35,832,874
Total D10BNS	$ 20,872,849	$ 580,305	$ 478,455	$ 2,428	$ 1,906,156	$ 11,413,204	$ -	$ 6,997,130	$ 2,263,087	$ 38,166	$ -	$ 7,895	$ 783,025	$ 403,131	$ 1,808,114	$ 47,553,947
	$ 35,663,794	$ 942,384	$ 751,627	$ 3,385	$ 2,960,144	$ 17,641,736	$ -	$ 10,601,024	$ 10,191,807	$ 57,515	$ -	$ 11,763	$ 1,040,799	$ 650,851	$ 2,869,993	$ 83,386,821

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 47

IDAHO POWER COMPANY
CCOS ALTERNATE SCENARIOS
TWELVE MONTHS ENDING DECEMBER 31, 2023

2023 Class Cost-of-Service Alternate Scenarios Revenue Requirement Summary

		Total Idaho	Residential	Residential On-Site Gen	Small General Service	Small General Service On-Site Gen*	L. Gen Service - Prim. & Tran.	Large Gen Service -Sec.	Large Power Service	Irrigation	DOE	Simplot	Micron	Lighting
	Total Sales Revenue (NM)	**$1,293.0M**	**$566.1M**	**$13.0M**	**$17.8M**	**$48,160**	**$43.6M**	**$269.8M**	**$153.9M**	**$162.4M**	**$13.3M**	**$9.8M**	**$36.6M**	**$6.6M**
2011 Methodology	Revenue Requirement	$1,404,314,821	$622.7M	$19.6M	$20.1M	$100,951	$42.3M	$269.6M	$162.8M	$198.6M	$14.1M	$9.9M	$39.1M	$5.4M
	Revenue Deficiency / (Excess)	$111,304,981	$56.5M	$6.6M	$2.3M	$52,791	($1.2M)	($0.2M)	$8.9M	$36.1M	$0.8M	$0.0M	$2.5M	($1.2M)
	% Change Required	8.61%	9.98%	50.56%	13.08%	109.62%	-2.85%	-0.07%	5.79%	22.23%	6.15%	0.45%	6.96%	-18.05%
FV Classification Increm. Impact	Revenue Requirement	$0	$2.5M	$0.1M	$0.0M	$470	$0.1M	$1.0M	$0.0M	($3.7M)	$0.1M	($0.1M)	$0.0M	($0.1M)
	% Change Required	0.00%	0.43%	0.71%	0.19%	0.98%	0.24%	0.36%	0.02%	-2.27%	0.78%	-0.75%	0.13%	-0.92%
June - Sept. Summer Increm. Impact	Revenue Requirement	$0	$0.7M	$0.1M	($0.0M)	$37	$0.0M	$0.2M	$0.0M	($1.1M)	$0.0M	$0.0M	$0.0M	$0.0M
	% Change Required	0.00%	0.12%	0.50%	0.00%	0.08%	0.08%	0.07%	0.01%	-0.65%	0.16%	0.01%	0.10%	0.02%
Combined Impact	**Revenue Requirement**	**$0**	**$2.8M**	**$0.1M**	**$0.0M**	**$491**	**$0.1M**	**$1.1M**	**$0.0M**	**($4.3M)**	**$0.1M**	**($0.1M)**	**$0.1M**	**($0.1M)**
	Revenue Deficiency / (Excess)	**($0)**	**$2,849,947**	**$129,954**	**$33,859**	**$491**	**$122,526**	**$1,077,809**	**$39,582**	**($4,303,585)**	**$115,680**	**($73,376)**	**$66,675**	**($59,565)**
	% Change Required	**0.00%**	**0.50%**	**1.00%**	**0.19%**	**1.02%**	**0.28%**	**0.40%**	**0.03%**	**-2.65%**	**0.87%**	**-0.75%**	**0.18%**	**-0.90%**

**$ values in millions except for Small General Service On-Site Generation*

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 48

Idaho Power Company
Before the Idaho Public Utilities Commission
Revenue Allocation Summary
12 Months Ending December 31, 2023
Proformed Normalized Sales and Revenue

Line No.	Tariff Description	Rate Schedule No.	2023 Average Number of Customers	2023 Sales Normalized (kWh)	Proformed Normalized Revenue	Average Mills per kWh	Base Revenue Transfer
	Uniform Tariff Schedules						
1	Residential Service	1,3,5	492,481	5,425,559,433	501,479,142	92.43	64,656,991
2	Residential Service - On Site Gen	6	13,288	122,912,496	11,567,368	94.11	1,465,405
3	***Combined Residential***		***505,768***	***5,548,471,929***	***513,046,510***	***92.47***	***66,122,396***
4	Small General Service	7	30,401	138,285,160	16,102,622	116.45	1,658,298
5	Small General Service - On Site Gen	8	88	370,708	43,713	117.92	4,447
6	***Combined Small General Service***		***30,488***	***138,655,868***	***16,146,335***	***116.45***	***1,662,745***
7	Large General Service - Prim. & Trans.	9P, 9T	284	601,699,182	36,446,763	60.57	7,110,848
8	Large General Service - Secondary	9S	37,764	3,321,544,618	230,482,910	69.39	39,344,999
9	Dusk/Dawn Lighting	15	0	5,267,423	1,261,853	239.56	65,185
10	Large Power Service	19S, 19P, 19T	116	2,386,695,635	125,751,566	52.69	28,147,259
11	Irrigation Service	24	19,179	1,864,522,772	140,327,749	75.26	22,120,084
12	Unmetered Service	40	1,663	13,925,301	1,144,288	82.17	165,505
13	Municipal Street Lighting	41	2,980	23,760,014	3,463,322	145.76	287,095
14	Traffic Control Lighting	42	766	2,847,961	165,609	58.15	33,636
15	*Total Idaho Rates*		599,008	13,907,390,703	1,068,236,903	76.81	165,059,752
	Special Contracts						
16	Micron	26	1	591,344,540	29,622,353	50.09	6,969,186
17	Simplot	29	1	175,000,001	7,759,368	44.34	2,059,297
18	DOE/INL	30	1	234,100,000	10,547,708	45.06	2,755,273
19	*Total Specials*		3	1,000,444,541	47,929,429	47.91	11,783,756
20	Total Idaho Retail Sales*		599,011	14,907,835,244	1,116,166,332	74.87	176,843,508

**Sales exclude Black Mesa sales*

Idaho Power Company
Before the Idaho Public Utilities Commission
Revenue Allocation Summary
12 Months Ending December 31, 2023
4CP/12CP Cost-of-Service Results

Line No.	Tariff Description	Rate Schedule No.	COS Percent Change	COS Retail Sales W/ Trnsfr. Adj.	COS Revenue Change	Revenue Allocation at COS	Average Mills per kWh
	Uniform Tariff Schedules						
1	Residential Service	1,3,5	10.49%	566,136,133	59,368,700	625,504,833	115.29
2	Residential Service - On Site Gen	6	51.56%	13,032,773	6,719,340	19,752,112	160.70
3	***Combined Residential***		***11.41%***	***579,168,906***	***66,088,040***	***645,256,946***	***116.29***
4	Small General Service	7	13.27%	17,760,920	2,356,962	20,117,882	145.48
5	Small General Service - On Site Gen	8	110.64%	48,160	53,282	101,442	273.64
6	***Combined Small General Service***		***13.53%***	***17,809,080***	***2,410,244***	***20,219,324***	***145.82***
7	Large General Service - Prim. & Trans.	9P, 9T	-2.57%	43,557,610	(1,118,189)	42,439,422	70.53
8	Large General Service - Secondary	9S	0.33%	269,827,909	890,106	270,718,015	81.50
9	Dusk/Dawn Lighting	15	-44.41%	1,327,038	(589,394)	737,644	140.04
10	Large Power Service	19S, 19P, 19T	5.82%	153,898,825	8,949,254	162,848,079	68.23
11	Irrigation Service	24	19.59%	162,447,833	31,815,425	194,263,258	104.19
12	Unmetered Service	40	2.48%	1,309,792	32,435	1,342,227	96.39
13	Municipal Street Lighting	41	-24.67%	3,750,417	(925,400)	2,825,017	118.90
14	Traffic Control Lighting	42	117.51%	199,244	234,134	433,379	152.17
15	*Total Idaho Rates*		8.74%	1,233,296,655	107,786,657	1,341,083,312	96.43
	Special Contracts						
16	Micron	26	7.14%	36,591,539	2,613,571	39,205,110	66.30
17	Simplot	29	-0.30%	9,818,665	(29,165)	9,789,500	55.94
18	DOE/INL	30	7.02%	13,302,981	933,918	14,236,899	60.82
19	*Total Specials*		5.89%	59,713,185	3,518,324	63,231,509	63.20
20	**Total Idaho Retail Sales***		**8.61%**	**1,293,009,840**	**111,304,981**	**1,404,314,821**	**94.20**

Sales exclude Black Mesa sales

Idaho Power Company
Before the Idaho Public Utilities Commission
Revenue Allocation Summary
12 Months Ending December 31, 2023
First Pass Revenue Allocation

Line No.	Tariff Description	Rate Schedule No.	First Pass Percent Change	First Pass Revenue Change	First Pass Revenue Allocation
	Uniform Tariff Schedules				
1	Residential Service	1,3,5			
2	Residential Service - On Site Gen	6			
3	***Combined Residential***	1,3,5,6	11.41%	66,088,040	645,256,946
4	Small General Service	7			
5	Small General Service - On Site Gen	8			
6	***Combined Small General Service***	7,8	12.91%	2,299,564	20,108,644
7	Large General Service - Prim. & Trans.	9P, 9T	0.00%	0	43,557,610
8	Large General Service - Secondary	9S	0.33%	890,106	270,718,015
9	Dusk/Dawn Lighting	15	0.00%	0	1,327,038
10	Large Power Service	19S, 19P, 19T	5.82%	8,949,254	162,848,079
11	Irrigation Service	24	12.91%	20,975,772	183,423,605
12	Unmetered Service	40	2.48%	32,435	1,342,227
13	Municipal Street Lighting	41	0.00%	0	3,750,417
14	Traffic Control Lighting	42	12.91%	25,727	224,972
15	*Total Idaho Rates*		8.05%	99,260,898	1,332,557,553
	Special Contracts				
16	Micron	26	7.14%	2,613,571	39,205,110
17	Simplot	29	0.00%	0	9,818,665
18	DOE/INL	30	7.02%	933,918	14,236,899
19	*Total Specials*		5.94%	3,547,489	63,260,674
20	Total Idaho Retail Sales*		7.95%	102,808,387	1,395,818,227
21	Revenue Requirement Shortfall				8,496,594

**Sales exclude Black Mesa sales*

Idaho Power Company
Before the Idaho Public Utilities Commission
Revenue Allocation Summary
12 Months Ending December 31, 2023
Second Pass Revenue Allocation

Line No.	Tariff Description	Rate Schedule No.	Second Pass Revenue Change	Second Pass Percent Change	Second Pass Revenue Allocation
	Uniform Tariff Schedules				
1	Residential Service	1,3,5			
2	Residential Service - On Site Gen	6			
3	***Combined Residential***	1,3,5,6	4,836,319	12.25%	650,093,265
4	Small General Service	7			
5	Small General Service - On Site Gen	8			
6	***Combined Small General Service***	7,8	0	12.91%	20,108,644
7	Large General Service - Prim. & Trans.	9P, 9T	0	0.00%	43,557,610
8	Large General Service - Secondary	9S	2,029,081	1.08%	272,747,096
9	Dusk/Dawn Lighting	15	0	0.00%	1,327,038
10	Large Power Service	19S, 19P, 19T	1,220,576	6.61%	164,068,656
11	Irrigation Service	24	0	12.91%	183,423,605
12	Unmetered Service	40	10,060	3.24%	1,352,288
13	Municipal Street Lighting	41	0	0.00%	3,750,417
14	Traffic Control Lighting	42	0	12.91%	224,972
15	*Total Idaho Rates*		8,096,037	8.70%	1,340,653,590
	Special Contracts				
16	Micron	26	293,849	7.95%	39,498,960
17	Simplot	29	0	0.00%	9,818,665
18	DOE/INL	30	106,708	7.82%	14,343,607
19	*Total Specials*		400,558	6.61%	63,661,231
20	Total Idaho Retail Sales		8,496,594	8.61%	1,404,314,821
21	Revenue Requirement Shortfall				-

**Sales exclude Black Mesa sales*

Idaho Power Company
Before the Idaho Public Utilities Commission
Revenue Allocation Summary
12 Months Ending December 31, 2023
Final Revenue Allocation

Line No.	Tariff Description	Rate Schedule No.	Final Percent Change	Final Revenue Change	Final Revenue Allocation	Average Mills per kWh	Cost of Service Index
	Uniform Tariff Schedules						
1	Residential Service	1,3,5					
2	Residential Service - On Site Gen	6					
3	***Combined Residential***		***12.25%***	***$70,924,359***	***650,093,265***	*117.17*	*101%*
4	Small General Service	7					
5	Small General Service - On Site Gen	8					
6	***Combined Small General Service***		***12.91%***	***$2,299,564***	***20,108,644***	145.03	99%
7	Large General Service - Prim. & Trans.	9P, 9T	0.00%	$0	43,557,610	72.39	103%
8	Large General Service - Secondary	9S	1.08%	$2,919,187	272,747,096	82.11	101%
9	Dusk/Dawn Lighting	15	0.00%	$0	1,327,038	251.93	180%
10	Large Power Service	19S, 19P, 19T	6.61%	$10,169,831	164,068,656	68.74	101%
11	Irrigation Service	24	12.91%	$20,975,772	183,423,605	98.38	94%
12	Unmetered Service	40	3.24%	$42,495	1,352,288	97.11	101%
13	Municipal Street Lighting	41	0.00%	$0	3,750,417	157.85	133%
14	Traffic Control Lighting	42	12.91%	$25,727	224,972	78.99	52%
15	*Total Idaho Rates*		8.70%	$107,356,935	1,340,653,590	96.40	
	Special Contracts						
16	Micron	26	7.95%	$2,907,421	39,498,960	66.80	101%
17	Simplot	29	0.00%	$0	9,818,665	56.11	100%
18	DOE/INL	30	7.82%	$1,040,626	14,343,607	61.27	101%
19	*Total Specials*		6.61%	$3,948,046	63,661,231	63.63	
20	Total Idaho Retail Sales*		8.61%	$111,304,981	1,404,314,821	94.20	

**Sales exclude Black Mesa sales*

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 49

IDAHO POWER COMPANY
Development of Sales Based Adjustment Rate
2023 Test Year
Table I
Derivation of Energy-Related Generation Function Revenue Requirement

	A	B	C	D	E	F
	Rate Base	Expenses	Income Tax	A&G Expense Exclusion	Other Revenue	Subsidiary Income
Source	Ex. 38, L. 12	Ex. 38, L. 72 & 114	Table II, Col. E	See Note 1	See Note 2	Ex. 42, L. 35
Generation Function Energy-Related	53,590,613	494,937,324	495,994	1,855,842	29,557,875	1,759,534

	G	H	I	J	K
	Current Return	Desired Return	Revenue Short-Fall	Tax Gross-up	Total Revenue Requirement
Source	A x 7.172% (3)	A x 7.702% (4)	H-G	I x 1.34662 - I	B+C-D-E-F+H+J
Generation Function Energy-Related	3,843,519	4,127,549	284,030	98,451	$466,486,067

Notes:
(1) Exhibit 37, Lines 499-558. The portion of the overall A&G exclusion associated with the energy-releated generation function (Table 5; FERC accounts 900-935; 416)
(2) Exhibit 38, Line 132
(3) Exhibit 42, Line 38
(4) Exhibit 42, Line 43

IDAHO POWER COMPANY
Development of Sales Based Adjustment Rate
2023 Test Year
Table II
Derivation of Energy-Related Generation Function Revenue Requirement

	A	B	C	D	E
	Total Federal Income Tax	Total State Income Tax	Energy-Related Generation Function Rate Base	Total Rate Base	Allocated Income Taxes
Source	Ex. 42, L. 28	Ex 42, L. 29	Ex. 38, L. 12	Ex. 38, L. 60	(A + B) x (C / D)
Generation Function Energy-Related	39,040,245	(2,828,435)	53,590,613	3,912,569,823	495,994

IDAHO POWER COMPANY
Development of Sales Based Adjustment Rate
2023 Test Year
Table III
Derivation of Energy-Related Generation Function Revenue Requirement

	A	B	C
	Energy-Related Generation Function Revenue Requirement	2023 Test Year Idaho Retail Sales (MWh)	Sales Based Adjusted Rate ($/MWh)
Source	Table I, Col K.	Ex. 39, Table 23, L. 55 / 1000	A / B
Generation Function Energy-Related	$466,486,067	14,907,835	$31.29

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI
TESTIMONY

EXHIBIT NO. 50

IDAHO POWER COMPANY
Development of Fixed Cost Adjustment Rate
2023 Test Year
Table I
Class Cost of Service Functionalized Costs
Based Upon GRC Filing - IPC-E-23-11 - Filed June 01, 2023

			A	B	C	D	E	F
Line No.	Uniform Tariff Schedules	Rate Schedule No.	COS Revenue Requirement	Generation Fixed Costs	Transmission Fixed Costs	Distribution and Customer Fixed Costs	Total Fixed Costs	Fixed Cost % of Total Cost
							B+C+D	E ÷ A
1	Residential Service	1, 3 & 5	625,504,833	191,167,686	46,602,187	213,277,804	451,047,677	72.1%
2	Residential Service - On Site Gen	6	19,752,112	5,331,189	1,435,880	8,056,109	14,823,178	75.0%
3	Small General Service	7	20,117,882	4,025,369	998,664	10,663,801	15,687,835	78.0%
4	Small General Service - On Site Gen	8	101,442	19,596	5,628	56,871	82,095	80.9%
5	Large General Service	9	313,157,436	107,548,029	25,485,729	56,313,163	189,346,922	60.5%
6	Dusk/Dawn Lighting	15	737,644	-	-	573,342	573,342	77.7%
7	Large Power Service	19	162,848,079	56,747,920	14,142,328	18,565,502	89,455,750	54.9%
8	Irrigation Service	24	194,263,258	59,292,537	15,038,335	64,768,424	139,099,295	71.6%
9	Unmetered Service	40	1,342,227	301,332	72,191	530,532	904,055	67.4%
10	Municipal Street Lighting	41	2,825,017	-	-	2,078,765	2,078,765	73.6%
11	Traffic Control Lighting	42	433,379	72,432	22,281	248,391	343,103	79.2%
12	Special Contracts	26, 29, & 30	63,231,509	24,687,354	6,257,439	1,587,849	32,532,642	51.5%
13	Total FCA Tariff Schedules		1,404,314,821				935,974,660	

IDAHO POWER COMPANY
Development of Fixed Cost Adjustment Rate
2023 Test Year
Table II
Identification of Interclass Revenue Subsidy
Based Upon GRC Filing - IPC-E-23-11 - Filed June 01, 2023

			A	B	C	D	E	F	G
Line No.	Uniform Tariff Schedules	Schedule No.	Proposed Base Rate Revenue	COS Revenue Requirement	Difference	Revenue Short-Fall Identifier	Revenue Short-Fall	Fixed Cost % of Total Cost	Fixed Cost Portion of Rev. Short-Fall
				Table I, Col. A	A - B			Table I, Col. F	E x F
1	Residential Service	1, 3 & 5	635,369,891	625,504,833	9,865,057				
2	Residential Service - On Site Gen	6	14,723,374	19,752,112	(5,028,738)	X	(5,028,738)	75.0%	(3,773,869)
3	Small General Service	7	20,053,424	20,117,882	(64,458)	X	(64,458)	78.0%	(50,264)
4	Small General Service - On Site Gen	8	55,219	101,442	(46,223)	X	(46,223)	80.9%	(37,407)
5	Large General Service	9	316,304,706	313,157,436	3,147,270				
6	Dusk/Dawn Lighting	15	1,327,038	737,644	589,394				
7	Large Power Service	19	164,068,656	162,848,079	1,220,576				
8	Irrigation Service	24	183,423,605	194,263,258	(10,839,653)	X	(10,839,653)	71.6%	(7,761,571)
9	Unmetered Service	40	1,352,288	1,342,227	10,060				
10	Municipal Street Lighting	41	3,750,417	2,825,017	925,400				
11	Traffic Control Lighting	42	224,972	433,379	(208,407)	X	(208,407)	79.2%	(164,995)
12	Special Contracts	26, 29, & 30	63,661,231	63,231,509	429,722				
13	Total Uniform Tariff Schedules		1,404,314,821	1,404,314,821	0		(16,187,479)		(11,788,106)

Weighted Average Fixed Cost % of Short-Fall [a]
72.8%

Notes:
(a) The "Weighted Average Fixed Cost % of Short-Fall" is calculated by dividing the total "Fixed Cost Portion of Rev. Short-Fall" (Col. G) by the total "Revenue Short-Fall" (Col. E)

IDAHO POWER COMPANY
Development of Fixed Cost Adjustment Rate
2023 Test Year
Table III
Derivation of Fixed Cost per Customer and Fixed Cost per Energy Rates
Based Upon GRC Filing - IPC-E-23-11 - Filed June 01, 2023

Line No.	Uniform Tariff Schedules	Schedule No.	A 2023 Avg. Number of Customers	B 2023 Sales Normalized (kWh)	C COS Fixed Cost	D COS Variable Cost	E Share of Revenue Short-Fall/Subsidy	F Total Base Rate Revenue
					Table I, Col. E	Table I, Col. A - Col. C	Table II, Col. C	C+D+E
1	Residential Service	1, 3 & 5	492,481	5,425,559,433	451,047,677	174,457,157	9,865,057	635,369,891
2	Residential Service - On Site Gen	6	13,288	122,912,496	14,823,178	4,928,934	(5,028,738)	14,723,374
3	Small General Service	7	30,401	138,285,160	15,687,835	4,430,047	(64,458)	20,053,424
4	Small General Service - On Site Gen	8	88	370,708	82,095	19,347	(46,223)	55,219

Line No.	Uniform Tariff Schedules	Schedule No.	G COS Fixed Cost Revenue from Fixed Charges	H COS Fixed Cost Revenue from Energy Charges	I Fixed Cost Share of Revenue Short-Fall/Subsidy	J Total Fixed Cost Revenue from Energy Charges	K Calculation of FCC ($/Cust./Yr.)	L Calculation of FCE ($/kWh)
				C-G	E x 72.8	H + I	J ÷ A	J ÷ B
1 (Cont.)	Residential Service	1, 3 & 5*	91,198,683	359,848,994	7,183,968	367,032,962	**$ 745.27**	**$ 0.067649**
2 (Cont.)	Residential Service - On Site Gen	6	2,445,141	12,378,037	(3,662,046)	8,715,991	**$ 655.94**	**$ 0.070912**
3 (Cont.)	Small General Service	7	7,374,576	8,313,259	(46,940)	8,266,319	**$ 271.91**	**$ 0.059777**
4 (Cont.)	Small General Service - On Site Gen	8	21,216	60,879	(33,661)	27,218	**$ 311.07**	**$ 0.073423**

** FCE not applicable to Residential I05; see I05 FCE determination*

IDAHO POWER COMPANY
Development of Fixed Cost Adjustment Rate
2023 Test Year
Derivation of Fixed Cost per Customer and Fixed Cost per Energy Rates
Based Upon GRC Filing - IPC-E-23-11 - Filed June 01, 2023

	Uniform Tariff Schedules	Schedule No.	A 2023 Avg. Number of Customers	B 2023 Sales Normalized (kWh)	C Generation Fixed Costs	D Transmission Fixed Costs	E Distribution and Customer Fixed Costs	F Total Fixed Costs
								C + D + E
1	Residential Service	1, 3 & 5	492,481	5,425,559,433	191,167,686	46,602,187	213,277,804	451,047,677
2	Residential Service Fixed Cost Proportions	1, 3 & 5			42.4%	10.3%	47.3%	100.0%
3	Residential On-Site Gen Service	6	13,288	122,912,496	5,331,189	1,435,880	8,056,109	14,823,178
4	Residential On-Site Gen Service Fixed Cost Proportions	6			36.0%	9.7%	54.3%	100.0%
5	Small General Service	7	30,401	138,285,160	4,025,369	998,664	10,663,801	15,687,835
6	Small General Service Fixed Cost Proportions	7			25.7%	6.4%	68.0%	100.0%
7	Small General Service On-Site Gen	8	88	370,708	19,596	5,628	56,871	82,095
8	Small General Service On-Site Gen Fixed Cost Proportions	8			23.9%	6.9%	69.3%	100.0%

	Uniform Tariff Schedules	Schedule No.	G Fixed Cost Share of Revenue Short-Fall/Subsidy	H Distribution Share of Short-Fall/Subsidy	I COS Fixed Cost Revenue from Fixed Charges	J Total Fixed Cost Revenue from Energy Charges	K Calculation of FCC - Dist ($/Cust./Yr.)	L Calculation of FCE - Dist ($/kWh)
				(Proportion E) x G		E + H - I	J ÷ A	J ÷ B
1 (Cont.)	Residential Service	1, 3 & 5*	7,183,968	3,396,938	91,198,683	125,476,059	**$ 254.78**	**$ 0.023127**
3 (Cont.)	Residential On-Site Gen Service	6	(3,662,046)	(1,990,251)	2,445,141	3,620,717	**$ 272.49**	**$ 0.029458**
5 (Cont.)	Small General Service	7	(46,940)	(31,907)	7,374,576	3,257,318	**$ 107.15**	**$ 0.023555**
7 (Cont.)	Small General Service On-Site Gen	8	(33,661)	(23,318)	21,216	12,337	**$ 140.99**	**$ 0.033278**

** FCE not applicable to Residential I05; see I05 FCE determination*

IDAHO POWER COMPANY
Development of Fixed Cost Adjustment Rate
2023 Test Year
Derivation of Fixed Cost per Energy Rates - Schedule 5
Based Upon GRC Filing - IPC-E-23-11 - Filed June 01, 2023

			Existing January 1, 2024		New Customer January 1, 2024
Avg Customers			986.31		986.31
FCC		$	745.27	$	254.78
Total Fixed Cost Recovery		$	735,070	$	251,291.64
FCE		$	0.067649	$	0.023127
Total kWh			16,947,350		16,947,350
Fixed Cost Recovery in Energy		$	1,146,469	$	391,941
Revenue Collection					
Service Charge			$177,623	$	177,623
Summer Energy		$	587,925	$	587,925
Non-Summer Energy		$	1,138,777	$	1,138,777
Total Energy Collection		$	1,726,702	$	1,726,702
Total Revenue		$	1,904,324	$	1,904,324
Energy in Energy		$	580,233	$	1,334,761
Summer Share Energy in Energy		$	178,320.66	$	410,206.69
SONP Energy in Energy Rate		$	0.084817	$	0.195113
SOFP Energy in Energy Rate		$	0.021204	$	0.048778
	Check	*$*	*178,320.66*	*$*	*410,206.69*
Non-Summer Energy in Energy		$	401,912.16	$	924,553.86
NSONP Energy in Energy Rate		$	0.047556	$	0.109397
NSOFP Energy in Energy Rate		$	0.031704	$	0.072931
	Check	*$*	*401,912.16*	*$*	*924,553.86*
SONP Rate		$	0.279642	$	0.279642
SOFP Rate		$	0.069911	$	0.069911
NSONP Rate		$	0.134745	$	0.134745
NSOFP Rate		$	0.089830	$	0.089830
SONP FCE Rate		$	0.194825	$	0.084529
SOFP FCE Rate		$	0.048707	$	0.021133
NSONP FCE Rate		$	0.087189	$	0.025348
NSOFP FCE Rate		$	0.058126	$	0.016899

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 51

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Micron
Schedule 26

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue	Revenue Difference	Percent Change
1	Contract Demand ($/kW)	918,000	$ 1.67	$ 1,533,060	$ 3.11	$ 2,854,980	$ 1,321,920	86.23%
2	Billed kW ($/kW)	1,017,744	$ 10.98	11,174,829	$ 18.12	18,441,469	7,266,639	65.03%
3	Excess Demand kW ($/kW)	-	$ 0.291	-	$ 1.244	-	-	0.00%
4	Embedded Energy Fixed Cost Charge ($/kWh)	101,867,460	$ 0.002632	268,115	$ -	-	(268,115)	-100.00%
5	Billed kWh ($/kWh)	591,344,540	$ 0.028150	16,646,349	$ 0.030782	18,202,511	1,556,162	9.35%
6	Transfer Adjustment			6,969,186		-		
7	Subtotal			$ 36,591,539		$ 39,498,960	$ 2,907,421	7.95%

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Simplot
Schedule 29

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue	Revenue Difference	Percent Change
1	Contract Demand ($/kW)	300,000	$ 2.31	$ 693,000	$ 3.11	$ 933,000	$ 240,000	34.63%
1	Billed kW ($/kW)	267,258	$ 7.88	2,105,993	$ 13.43	3,589,135	1,483,142	70.42%
2	Excess Demand kW ($/kW)	-	$ 0.292	-	$ 1.244	-	-	
3	Billed kWh ($/kWh)	175,000,001	$ 0.028345	4,960,375	$ 0.030266	5,296,530	336,155	6.78%
4	Transfer Adjustment			2,059,297		-	(2,059,297)	
5	Subtotal			$ 9,818,665		$ 9,818,665	$ -	0.00%

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Department of Energy
Schedule 30

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue	Revenue Difference	Percent Change
1	Contract Demand ($/kW)	-	$ -	$ -	$ -	$ -	$ -	
2	Billed kW ($/kW)	422,686	$ 8.50	3,592,831	$ 16.90	7,143,781	3,550,950	98.83%
3	Excess Demand kW ($/kW)	-	$ -	-	$ -	-	-	
4	Billed kWh ($/kWh)	234,100,000	$ 0.029709	6,954,877	$ 0.030755	7,199,826	244,949	3.52%
5	Transfer Adjustment			2,755,273		-	(2,755,273)	
6	Subtotal			$ 13,302,981		$ 14,343,607	$ 1,040,626	7.82%

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Simplot Caldwell
Schedule 32

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue	Revenue Difference	Percent Change
1	Summer Contract Demand ($/kW)	88,000	$ 1.78	$ 156,640	$ 3.11	$ 273,680	$ 117,040	74.72%
2	Non-Summer Contract Demand ($/kW)	156,000	$ 1.78	$ 277,680	$ 3.11	$ 485,160	$ 207,480	74.72%
3	Summer Billed kW ($/kW)	87,371	$ 14.87	1,299,213	$ 19.71	1,721,983	$ 422,770	32.54%
4	Non-Summer Billed kW ($/kW)	153,465	$ 8.65	1,327,469	$ 16.32	2,504,297	$ 1,176,827	88.65%
5	Summer Excess Demand kW ($/kW)	-	$ 0.298	-	$ 1.244	-	$ -	
6	Non-Summer Excess Demand kW ($/kW)	-	$ 0.298	-	$ 1.244	-	$ -	
7	Summer Energy Charge ($/kWh)	56,000,000	$ 0.031252	1,750,112	$ 0.029262	1,638,653	$ (111,459)	-6.37%
8	Non-Summer Energy Charge ($/kWh)	106,000,000	$ 0.030664	3,250,384	$ 0.031591	3,348,649	$ 98,265	3.02%
9	Transfer Adjustment			1,904,406		-	$ (1,904,406)	
10	Subtotal			$ 9,965,904		$ 9,972,422	$ 6,518	0.07%

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Lamb Weston - Block 2 Billing Demand
Schedule 34

Line No.			
1	Annual Cost ($)	$	12,100,144
2	Proposed 19P Revenue	$	(8,867,527)
3	Remaining Cost for Block 2 capacity	$	3,232,617
4	Contract Demand ($/kW)		$3.11
5	Contract Demand Billing Determinant (kW)		144,000
6	less Contract Demand recovery	$	(447,840)
7	Block 2 Billed Demand Capacity Cost	$	2,784,777
8	Block 2 Demand Billing Determinant (kW)		117,000
9	**Billed Demand Charge ($/kW)**	**$**	**23.80**

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Brisbie - Block 2 Billing Demand
Schedule 33

Line No.			
1	Annual Cost ($)	$	9,603,080
2	Proposed 19T Revenue	$	(6,580,994)
3	Remaining Cost for Block 2 capacity	$	3,022,087
4	Contract Demand ($/kW)		($3.11)
5	Contract Demand Billing Determinant (kW)		120,000
6	less Contract Demand recovery	$	(373,200)
7	Block 2 Billed Demand Capacity Cost	$	2,648,887
8	Block 2 Demand Billing Determinant (kW)		120,000
9	**Billed Demand Charge ($/kW)**	**$**	**22.07**

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Derivation of Contract Demand Charge

OATT + Ancillary Services

			SOURCE
OATT Transmission Demand Charge	2.6183	$/kw month	August 26, 2022 OATT Final Informational Filing (FERC) for rates effective Oct 1, 2022 thru Sept 30, 2023
Ancillary Services			
Scheduling System Control & Dispatch	0		OATT Schedule 1 (Included in Transmission Demand Charge)
Reactive Supply & Voltage Control	0		OATT Schedule 2 (Included in Transmission Demand Charge)
Regulation and Frequency Response	0.0980	$/kw month	OATT Schedule 3 ($6.53 x 1.5%)
Operating Reserve - Spinning	0.1959	$/kw month	OATT Schedule 5 ($6.53 x (1.5% + 1.5%))
Operating Reserve - Supplemental	0.1959	$/kw month	OATT Schedule 6 ($6.53 x (1.5% + 1.5%))
TOTAL	**3.11**	**$/kw month**	

OATT Transmission Demand Charge - Firm Point-To-Point Transmission Services Provided Under Schedule 7:
https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/Effective_Rate_2022-08-26.xlsx
Schedule 3, 5, 6:
https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPC_OATT_Issued_2023-01-27.pdf

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Derivation of Daily Excess Demand Charge

CONTRACT DEMAND CHARGE			$3.11
Contract Demand --->	10,000	1,000	<--- Incremental MW above Contract Demand
		1	<--- Number of months for recovery
	Contract Demand Revenue (Contract MW)	Contract Demand Revenue (Incremental MW)	
Contract Demand Revenue	$373,200	$410,520	
	Difference	$37,320	$1.244
DAILY EXCESS DEMAND CHARGE			**$1.244**

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

GORALSKI, DI TESTIMONY

EXHIBIT NO. 52

Memorandum

Date: 2/16/2023

From: Yao Yin, Utilities Analyst, Idaho Public Utilities Commission

To: Connie Aschenbrenner, Idaho Power Company

Subject: Investigation in Methods to determine Marginal Cost of Energy for Schedule 20.

Background

Order No. 35428 directed Idaho Power to evaluate and compare other methods for determining a marginal cost of energy in addition to the use of Avoided Cost Averages in the Integrated Resource Plan for setting the Schedule 20 energy rate, before the next general rate case is developed and filed.

On January 31, 2013, Idaho Power met with Staff and discussed potential methods for determining marginal cost of energy for the Schedule 20 energy rate and possibly for other customers using marginal cost of energy for their energy rates. As a result of the meeting, Staff agreed to develop some criteria for the Company to consider for developing a method.

Criteria

Although this list may not be exhaustive, Staff identified the following criteria that could be used for determining the final method:

- The resources used in a model for determining marginal cost should be based on the resources that are highly likely to exist during the rate period.
- The amount of incremental load used to determine the marginal cost rate should reflect the amount of incremental load for the portion of load that will be priced at marginal cost.
- The marginal cost rates should have enough granularity to reflect time difference (e.g. seasonality, time of day) value of Marginal Cost within the Company's system to provide accurate price signals.
- If the marginal cost rates are based on a forecast, due to the lack of Marginal Costs being trued-up in the PCA, they should be updated often enough that they reflect current conditions or find a way to true up the marginal cost to actual marginal cost.
- If market costs are used, cost of transmission transaction and wheeling costs should be included.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

GRANT T. ANDERSON

Q. Please state your name, business address, and present position with Idaho Power Company (“Idaho Power” or “Company”).

A. My name is Grant T. Anderson. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as a Regulatory Consultant in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 2013, I received a Bachelor of Science degree in Microbiology from Oregon State University. In May of 2015, I earned a Master of Business Administration degree from Boise State University. In addition, I have attended the electric utility ratemaking course The Basics: Practical Regulatory Training for the Electric Industry, a course offered through New Mexico State University’s Center for Public Utilities.

Q. Please describe your work experience with Idaho Power.

A. In 2018, I was hired as a Regulatory Analyst in the Company’s Regulatory Affairs Department. My primary responsibilities as a Regulatory Analyst included supporting the Company's Commercial and Industrial customer classes’ rate design and general support of tariff rules and regulations. In 2021, I was promoted to my current position as a Regulatory Consultant. My responsibilities expanded to include the development of complex cost-related studies and support of the Company’s Residential and Small General Service ("R&SGS") and on-site generation customer classes’ rate design.

Q. What is the purpose of your testimony in this matter?

A. My testimony will address the Company’s rate design proposals for residential, on-site generation, large commercial, and industrial customers.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- First, I describe the Company’s proposed rate changes for residential service under Schedule 1, Residential Service Standard Plan (“Schedule 1”), Schedule 3, Master-Metered Mobile Home Park Residential Service (“Schedule 3”), and Schedule 5, Residential Service Time-of-Use (“Schedule 5”).
- Second, I describe the Company’s proposed Residential Price Modernization Plan for all residential service customers.
- Third, I describe the Company’s proposed rate changes for on-site generation under Schedule 6, Residential Service On-Site Generation (“Schedule 6”) and Schedule 8, Small General Service On-Site Generation (“Schedule 8”).
- Fourth, I describe the Company’s proposed rate changes for large commercial customers taking primary and transmission

service under Schedule 9, Large General Service ("Schedule 9") and for industrial customers taking service under Schedule 19, Large Power Service ("Schedule 19").

- Lastly, I will address updates to Schedule 68, Interconnections to Customer Distributed Energy Resources ("Schedule 68").

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Description
Exhibit No. 53	Calculation of Proposed Rates
Exhibit No. 54	Typical Monthly Billing Comparison
Exhibit No. 55	Residential Price Modernization Plan
Exhibit No. 56	Schedule 6/8 Non-Legacy Bill Comparison

I. RESIDENTIAL RATE DESIGN

Q. What are the Company's residential service schedules?

A. Idaho Power has four residential service schedules, Schedules 1, 3, 5, and 6. Schedule 1 is available to all customers taking service for general domestic use. Schedule 3 is available only to master-metered mobile home parks included on the Company's list of "grandfathered" mobile home parks. Schedule 5 is an optional, time-of-use pricing program with an on-peak and off-peak time-of-use period. Schedule 6 is an optional net metering service that I will more fully describe later in my testimony.

Q. What is the annual revenue requirement to be recovered from residential service customers?

A. The annual revenue requirement to be recovered from residential service customers, which includes Schedules 1, 3, 5, and 6, is $650,093,265, as shown on page 5 of Company Witness Mr. Paul Goralski's Exhibit No. 48, representing a 12.25 percent increase.

Q. What are the changes the Company is proposing to the current rate design for residential service?

A. For the residential service schedules, the Company is proposing to adjust each of the billing components to move closer to its cost of service. This includes a proposal to initially increase the Service Charge from the existing $5.00 per month to $15.00 for all residential schedules. Also, for Schedule 5, the Company is proposing modifications to the definitions of on- and off-peak to better align with the Company's hours of highest risk as informed by its Integrated Resource Plan ("IRP") as described in more detail in the Direct Testimony of Company Witness Ms. Connie Aschenbrenner.

Q. Where does the Company show a comparison of the present and proposed rates within each of the Company's service schedules?

A. Pages 1-5 of Exhibit No. 53 shows a comparison of the present and proposed rates for each of the residential service schedules, which I will describe later in my testimony.

A. Schedule 1, Residential Service Standard Plan

Q. Could you please describe the present rate structure under Schedule 1 for residential service?

A. Yes. Residential service under Schedule 1 has a present Service Charge of $5.00 per month and seasonal inclining block tiered rates where the price of energy is higher when a customer uses more than a given threshold during a monthly billing period. Table 1 provides a summary of the present base tariff rates under Schedule 1.

Table 1
Schedule 1 Residential Energy Rates – Present

	Summer	Non-Summer
Energy Charge, per kWh		
First 800 kWh	8.6518 ¢	8.0390 ¢
801-2,000 kWh	**10.4033 ¢**	**8.8627 ¢**
All Additional kWh Over 2,000	12.3585 ¢	9.8154 ¢

Q. How does the Company propose to spread the proposed revenue increase for Schedule 1 to the rates within that schedule?

A. The Company proposes to increase the Energy Charges - while slightly decreasing the price differential between the three energy blocks - and increase the Service Charge from $5.00 per month to $15.00 per month. The proposed Energy Charges are summarized below in Table 2. I will discuss the justification and rationale for the increase in the Service Charge later in my testimony.

Table 2
Schedule 1 Residential Energy Rates – Proposed

	Summer	Non-Summer
Energy Charge, per kWh		
First 800 kWh	10.2985 ¢	9.3050 ¢
801-2,000 kWh	**11.7937 ¢**	**10.0034 ¢**
All Additional kWh Over 2,000	13.9291 ¢	10.7014 ¢

Q. How will the proposal impact a residential customer with average consumption?

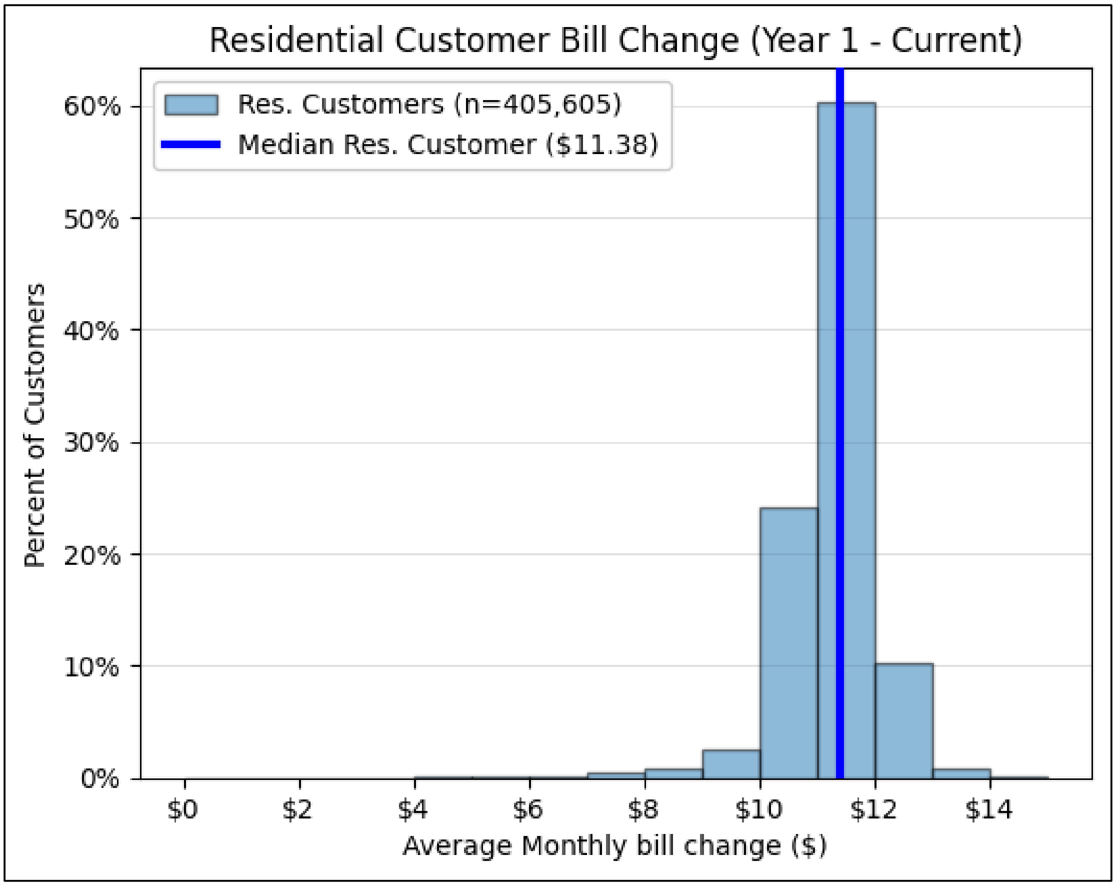
A. Inclusive of the increase to the Service Charge, the proposed bill changes for a customer on Schedule 1 using an average of 950 kilowatt hours (“kWh”) per month is $12.26 per month, or a 12.8 percent change in their electric bill. The present average monthly bill for 950 kWh is $95.73, and that would increase to $107.99. Page 1 of Exhibit No. 54 shows the bill comparison table for the bill change across different average monthly usage levels. The largest increase across the different usage levels shown is a $17.98 per month increase, or a 3.2 percent change in their electric bill, for a customer using 5,000 kWh.

Q. Did the Company evaluate the distribution of customer bill impacts for residential customers?

A. Yes. Figure 1 shows the distribution of Schedule 1 bill impacts reflective of the overall increase in revenue from the residential class of 12.25 percent and a $15.00

Service Charge. The median average monthly bill increase in the first year of the transition is $11.38. Based on historical 2022 energy consumption, 89 percent of residential customers would have an average monthly bill increase of $12 or less.

Figure 1
Residential Price Modernization Bill Impact
Year 1 vs Current



Q. Did the Company evaluate the distribution of customer bill impacts for low-income residential customers?

A. Yes. The Company prepared some of the same bill impact information, but specific to low-income customers. Because the Company does not track income information for its customers, this impact analysis relied on those customers identified as having received energy assistance through the Low-Income Home Energy Assistance Program (“LIHEAP”) as a proxy for a low-income customer segment. Figure 2 shows the distribution of low-income customer bill impacts reflective of the overall increase in revenue from the residential class of 12.25 percent and a $15.00 Service Charge. The median average monthly bill increase in the first year of the transition is $11.09. Approximately 95 percent of the low-income customer segment shown would have an average monthly bill increase of $12 or less as a result of the year one changes requested in this case.

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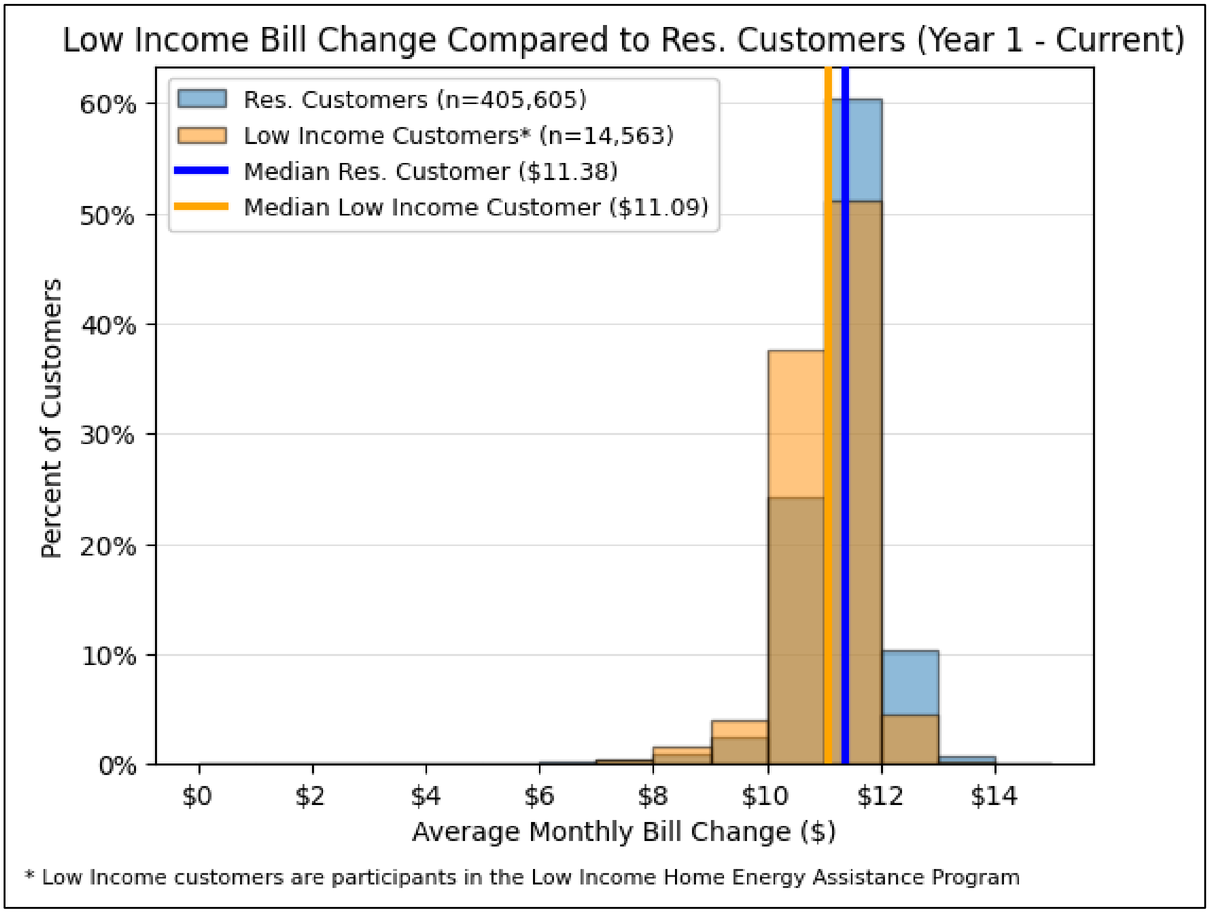
Figure 2
Residential Price Modernization Bill Impact – Low Income
Year 1 vs. Current



As shown in Figure 2, these low-income customers are not disproportionately negatively impacted under the Company's residential rate design proposal.

Q. Does the Company propose any other changes to Schedule 1?

A. Yes. The Company is proposing additional increases to the Service Charge while commensurately flattening the inclining block structure in 2025 and 2026. I will address this in more detail later in my testimony when describing the Company's proposed Residential Price

Modernization Plan. These additional proposed changes are designed to be revenue neutral relative to rates as proposed for 2024 in this docket.

B. Schedule 3, Master-Metered Mobile-Home Park Residential Service

Q. Do you propose any rate design changes for Schedule 3?

A. No. The only change to Schedule 3 is an increase in the Service Charge from $5.00 to $15.00 per month and a uniform decrease in the Energy Charge to achieve the required revenue for that schedule. The Company's proposed rate design for Schedule 3 is shown on page 4 of Exhibit No. 53.

C. Schedule 5, Residential Service Time-of-Use Plan

Q. Could you please describe the present rate structure under Schedule 5 for residential service?

A. Yes. Residential service under Schedule 5, currently has an on-peak and off-peak time block in both the summer and non-summer seasons. In the summer, the on-peak block is eight hours long and in the non-summer, the on-peak block is 14 hours long. The off-peak rate is the same for both summer and non-summer seasons. The summer on-peak rate is currently 1.7x higher than the off-peak rate, and the non-summer on-peak rate is 1.3x higher than the off-peak rate. Table 3 provides a summary of the present base tariff rates under Schedule 5.

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Table 3
Schedule 5 Residential Time-of-Use Energy Rates – Present

	Summer	Non-Summer
Energy Charge, per kWh		
On-Peak	12.8910 ¢	9.5159 ¢
Off-Peak	**7.3899 ¢**	**7.3899 ¢**
On:Off Differential	*1.7x*	*1.3x*

Q. How does the Company propose to spread the proposed revenue increase to Schedule 5 rates?

A. The Company proposes to shorten the on-peak periods, increase the price differential between on-peak and off-peak Energy Charge time blocks, and increase the Service Charge from $5.00 per month to $15.00 per month, consistent with all other residential service schedules. Table 4 summarizes the proposed Energy Charges.

Table 4
Schedule 5 Residential Time-of-Use Energy Rates – Proposed

	Summer	Non-Summer
Energy Charge, per kWh		
On-Peak	27.9642 ¢	13.4745 ¢
Off-Peak	**6.9911 ¢**	**8.9830 ¢**
On:Off Differential	*4.0x*	*1.5x*

Q. How will the proposal impact a residential time-of-use customer with average consumption?

A. Inclusive of the increase to the Service Charge, the proposed bill change for a Schedule 5 residential customer using an average of 1,400 kWh per month is $17.59 per month, or a 12.5 percent change in their electric bill. The present bill for 1,400 kWh is $140.25 and would increase to $157.84.

Page 3 of Exhibit No. 54 shows the bill comparison table for the bill change across different average monthly usage levels. The largest dollar increase across the different usage levels shown is a $37.10 per month increase, or 7.6 percent for a customer using 5,000 kWh per month.

This average monthly bill comparison assumes no change in usage. Presumably, a customer will respond to the price signal between the new on- and off-peak time-of-use blocks, resulting in the opportunity to reduce their energy bill.

Q. Did the Company evaluate the time-of-use periods for Schedule 5?

A. Yes. As I will describe later in my testimony, the Company is proposing changes to the definitions of the time blocks commensurate with increasing the price differential between on- and off-peak. I will describe the proposed changes to the time blocks as part of the Company’s Residential Price Modernization Plan.

Q. Are you proposing any other changes to Schedule 5?

A. Similar to Schedule 1, there are additional revenue neutral rate changes that I will describe in the context of the Residential Price Modernization Plan.

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II. RESIDENTIAL PRICE MODERNIZATION PLAN

A. Residential Price Modernization Plan Overview

Q. What is the Company's Residential Price Modernization Plan?

A. The Company proposes a three-year transition period to modify the structure of its residential rates to include the following:

1. Increase the Service Charge for residential service under Schedules 1, 3, 5, and 6 to $35.00 per month and lower Energy Charges commensurately. If the Company files a general rate case during the Residential Price Modernization Plan transition the rates would be updated to reflect any Commission approved rate changes.
2. Eliminate inclining block tiered rates for Schedules 1 and 6, resulting in Energy Charges that are flat for each season.
3. Update the time periods for on- and off-peak periods for Schedule 5 to better reflect the hours of system risk.

Q. When does the Company propose these changes occur?

A. The first Service Charge increase is included with the proposed revenue increase in this proceeding. The second- and third-year changes would go into effect on January 1, 2025, and January 1, 2026, respectively. As I previously described, the Company proposes to update the on- and off-peak periods under Schedule 5 effective January 1, 2024.

Q. Does the first year of the Residential Price Modernization Plan include more than just the transitioning?

A. Yes. The first year of the Residential Price Modernization Plan also includes the increase in revenue requirement. However, the second and third year of the Residential Price Modernization Plan transition is revenue neutral relative to the first year and does not increase the Company's Commission-approved revenue requirement as proposed in this docket.

B. Fixed Service Charge

Q. What is the Service Charge?

A. The Service Charge is a flat fixed amount that a customer pays every month irrespective of usage.

Q. How much is the Service Charge for residential service?

A. For residential service, the Service Charge is presently $5.00 per month.

Q. What proportion of a residential customer's cost of service is related to fixed costs?

A. On average, the cost of service for a residential customer is $105.84 per month, and $29.52 or about 28 percent of this value is energy related. The remaining $76.32 or about 72 percent is fixed and not energy related.

Q. What proportion of revenues from residential customers is recovered through the fixed Service Charge?

A. For Schedule 1, only about five percent of revenue is collected through the Service Charge. For Schedule 5, only about three percent of revenue is collected through the Service Charge.

Q. What Service Charge does the Company propose for the end of the three-year transition?

A. The Company proposes the Service Charge be set at $35.00 for all residential service schedules.

Q. Why is the Company proposing the same Service Charge for both Schedule 1 and Schedule 5?

A. Schedule 5 is an optional rate schedule that residential customers can choose to take service under. The Company would like residential customers to opt-in to time-of-use residential service because they want the opportunity to save money by shifting usage to off-peak periods – not because a Service Charge benefits them under a particular residential service offering. Therefore, having the same Service Charge for both Schedule 1 and Schedule 5 would prevent customers from choosing one schedule or the other based upon the dynamic between the fixed and volumetric charges.

Q. How does $35.00 per month compare to the fixed service or customer charge for other electric utilities in Idaho?

A. At $35.00 per month, the Company’s residential Service Charge would be within the range of the fixed monthly rates that other Idaho electric utilities charge for residential customers. Table 5 below shows the fixed monthly residential charges for all Idaho electric utilities with more than 1,000 customers.

Table 5
Fixed Monthly Residential Charges for Idaho Electric Utilities with More Than 1,000 Customers

Utility		Price
Avista	$	7.00
City of Idaho Falls		**20.00**
Fall River Rural Electric Cooperative		39.00
Inland Power & Light Company		**26.55**
Kootenai Electric Cooperative		32.50
Lower Valley Energy		**16.00**
Northern Lights		30.00
Raft Rural Electric Cooperative		**22.50**
Rocky Mountain Power		8.00
Salmon River Electric Cooperative		**43.00**
United Electric Cooperative		22.00
Average	**$**	**24.23**

Note: All fixed monthly charges available from each utility's website as of May 22, 2023.

Avista and Rocky Mountain Power have proposed similar changes to their fixed residential charges in current dockets. If both were approved as filed, the final year of their respective transition periods would increase the average fixed monthly residential charge in Table 5 from $24.23 to $28.32.[1]

C. Tiered Energy Charges

Q. How do the Company's current tiered energy charges work for Schedule 1?

A. Schedule 1 customers are subject to seasonal inclining block tiered rates where the price of energy is higher when a customer uses more than a given threshold during a monthly billing period. Additionally, energy charges vary in price by season, with higher energy pricing in the summer season of June through August and lower pricing in the non-summer season of September through May.

D. Time-of-Use

Q. What are the current time-of-use periods for Schedule 5 and what changes does the Company propose?

A. Currently, the on-peak period for Schedule 5 is weekdays from 1 p.m. to 9 p.m. during summer months and from 7 a.m. to 9 p.m. during non-summer months excluding holidays. The off-peak period is during all other hours. The summer season is defined as June through August and the non-summer season is defined as September through May.

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[1] *In the Matter of the Application of Avista Corporation for the Authority to Increase its Rates and Charges for Electric Natural Gas Customers in the State of Idaho,* Case Nos. AVU-E-23-01 and AVU-G-23-01, Miller Direct at 27(proposing Schedule 1 basic charge increasing from $7 to $35 over 5 years). *In the Matter of the Application of Rocky Mountain Power for Authority to Implement the Residential Rate Modernization Plan,* Case No. PAC-E-22-15, Meredith Direct at 2-3 (proposing basic charge increasing from $9 to $29.25 over 5 years).

As described in the Direct Testimony of Ms. Aschenbrenner, the Company is proposing the time-of-use definitions for applicable rate classes be updated to better align with hours of highest risk as informed by Idaho Power's IRP. Specifically for Schedule 5, the on-peak period proposed is Monday to Saturday from 7 p.m. to 11 p.m. during the summer months. During the non-summer months the on-peak period would be Monday to Saturday from 7 a.m. to 9 a.m. and 6 p.m. to 9 p.m.

The Company is also proposing to modify the summer season for all rate classes to June through September, which is described in more detail in the Direct Testimony of Ms. Aschenbrenner.

Q. What are the current price differentials between on- and off-peak?

A. The current summer on-peak rate is 12.8910 cents per kWh and the off-peak rate is 7.3899 cents per kWh, resulting in a 1.7x differential between on- and off-peak. The current non-summer on-peak rate is 9.5159 cents per kWh, resulting in a 1.3x differential between on- and off-peak.

Q. What price differentials is the Company proposing in its Residential Price Modernization Plan?

A. The Company is proposing an on-peak to off-peak price ratio of 4.0x for the summer and 1.5x for the non-summer.

Q. How did the Company develop its recommended pricing structure for residential time-of-use?

A. Ms. Aschenbrenner directed me to develop an offering in a manner that would be most effective at promoting a response to the price signal. From evaluating industry trends I found a common theme: as the price ratio increases, customers shift usage in greater amounts, but at a declining rate. A database of customer response to time-varying rates conducted by Brattle[2] shows a relationship between price response and price ratio where a 4.0x peak to off-peak price ratio could provide a peak impact of approximately 10 percent. For the non-summer season, the Company selected a 1.5 differential to only moderately increase the existing differential to send a price signal to customers during the more narrowly defined hours of highest system risk during the non-summer season. I believe this design will elicit customer adoption, incentivize customers to shift load outside of the highest risk hours, and provide customers an opportunity to reduce their electric bills.

E. Rate Design Calculations

Q. What prices does the Company propose for the three-year Residential Price Modernization Plan?

[2] The Brattle Group, *Arcturus 2.0: A Meta-analysis of Time-varying Rates for Electricity*, The Electricity Journal, vol. 30, issue 10 (Dec. 2017).

A. Exhibit No. 55 shows the proposed prices, billing determinants, and anticipated revenue for the Residential Price Modernization Plan. It is important to note, the anticipated residential revenue for each year of the transition does not increase in years two or three of the plan. Rather, in each successive year of the transition period, the revenue from the Service Charge increases and revenue from the Energy Charge decreases commensurately, which ensures a revenue neutral proposal. Additionally, for Schedules 1 and 6, the differences between the three energy blocks are eliminated by the final transition year. Table 6 summarizes the proposed prices for Schedules 1 and 6 for each year of the transition.

Table 6
Proposed Schedule 1 and 6 Prices by Transition Year

	Transition Year			
Description	**Current**	**Year 1**	**Year 2**	**Year 3**
Service Charge	$ 5.00	$ 15.00	$ 25.00	$ 35.00
Summer Energy Charges				
First 800 kWh	**8.6518 ¢**	**10.2985 ¢**	**9.5182 ¢**	**8.7379 ¢**
801-2,000 kWh	10.4033 ¢	11.7937 ¢	10.2658 ¢	8.7379 ¢
All Additional kWh	**12.3585 ¢**	**13.9291 ¢**	**11.5634 ¢**	**8.7379 ¢**
Non-Summer Energy Charges				
First 800 kWh	**8.0390 ¢**	**9.3050 ¢**	**8.3859 ¢**	**7.4669 ¢**
801-2,000 kWh	8.8627 ¢	10.0034 ¢	8.7351 ¢	7.4669 ¢
All Additional kWh	**9.8154 ¢**	**10.7014 ¢**	**9.0306 ¢**	**7.4669 ¢**

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Table 7 summarizes the proposed prices for Schedule 5 for each year of the transition.

Table 7
Proposed Schedule 5 Prices by Transition Year

	Transition Year			
Description	**Current**	**Year 1**	**Year 2**	**Year 3**
Service Charge	**$ 5.00**	**$ 15.00**	**$ 25.00**	**$ 35.00**
Summer Energy Charges				
On-Peak	**12.8910 ¢**	**27.9642 ¢**	**26.0477 ¢**	**24.1307 ¢**
Off-Peak	7.3899 ¢	6.9911 ¢	6.5119 ¢	6.0327 ¢
On:Off Differential	***1.7x***	***4.0x***	***4.0x***	***4.0x***
Non-Summer Energy Charges				
On-Peak	**9.5159 ¢**	**13.4745 ¢**	**12.5509 ¢**	**11.6273 ¢**
Off-Peak	7.3899 ¢	8.9830 ¢	8.3672 ¢	7.7515 ¢
On:Off Differential	***1.3x***	***1.5x***	***1.5x***	***1.5x***

Q. How were prices for the three-year Residential Price Modernization transition determined?

A. The $35.00 Service Charge was determined by taking residential revenue from Schedules 1, 3, and 5, and multiplying by the proportion of cost of service related to all other fixed costs besides generation and transmission costs and dividing by the number of monthly billings. The resulting $36.09 was rounded down to $35.00. To determine prices for the transition, the Service Charge was increased by one-third of the difference between the present $5.00 Service Charge and $35.00 in each year of the transition.

Flat seasonal Energy Charges in the final year of the transition were determined by applying the seasonal differential and solving for the remaining revenue required for the class after removing the proposed Service Charge revenue. Prices for each transition year were determined by decreasing the Energy Charge by one-third of the difference between the present and final transition year price in each subsequent period.

To determine the proposed Schedule 5 Energy Charges, the final transition year on- and off-peak Energy Charges were set to reflect a 4:1 differential while also reflecting the increase in recovery from the higher Service Charge.

Q. Why is the Company proposing to modify the on- and off-peak price differential?

A. The proposal is intended to send a more meaningful price signal to customers to shift energy usage to off-peak hours. Providing this price signal in conjunction with the shorter window of time for the on-peak period furthers two distinct objectives: (1) incenting customers to shift usage from highest risk hours, and (2) creating an opportunity for customers to reduce bills.

F. Customer Bill Impacts

Q. How would the Company's proposed rate increase and the Residential Price Modernization Plan impact customers at different usage levels?

A. Page 1 of Exhibit No. 54 shows a bill comparison table for the bill impact of the first year of the transition for Schedule 1 customers across different usage levels and page 2 shows the same for the change from the first year to the final year of the transition. The largest change shown over the transition is for a customer using 150 kWh, which would see a $10.38 per month increase in the first year. The increase for a customer using 150 kWh for the entire transition period is $27.76 per month. The difference between these values demonstrates the need to make the changes in price over the requested three-year period to moderate customer impacts. Pages 3 and 4 of Exhibit No. 54 shows the same information, except for the proposed transition for Schedule 5.

Q. Did the Company evaluate the distribution of customer bill impacts for the full transition of the Residential Price Modernization Plan?

A. Yes. Figure 3 shows the distribution for the final year of the transition period for Schedule 1 customers, as compared to the first year. The changes implemented in years two and three will be revenue neutral and the median average monthly bill increase in the final year of the transition, compared to the first year, is $3.06. Based on historical 2022 energy consumption, 86 percent of residential customers would have an average monthly bill increase of $12 or less between year one and year three of the plan.

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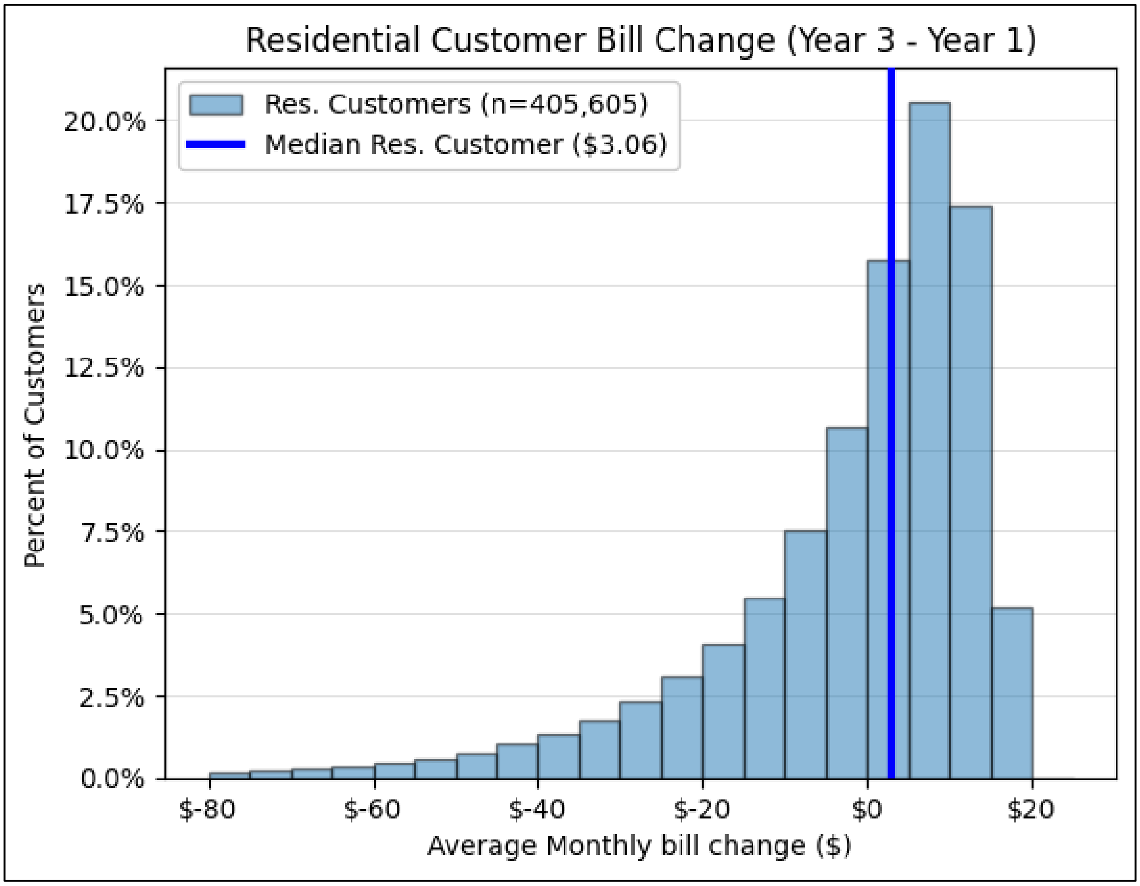
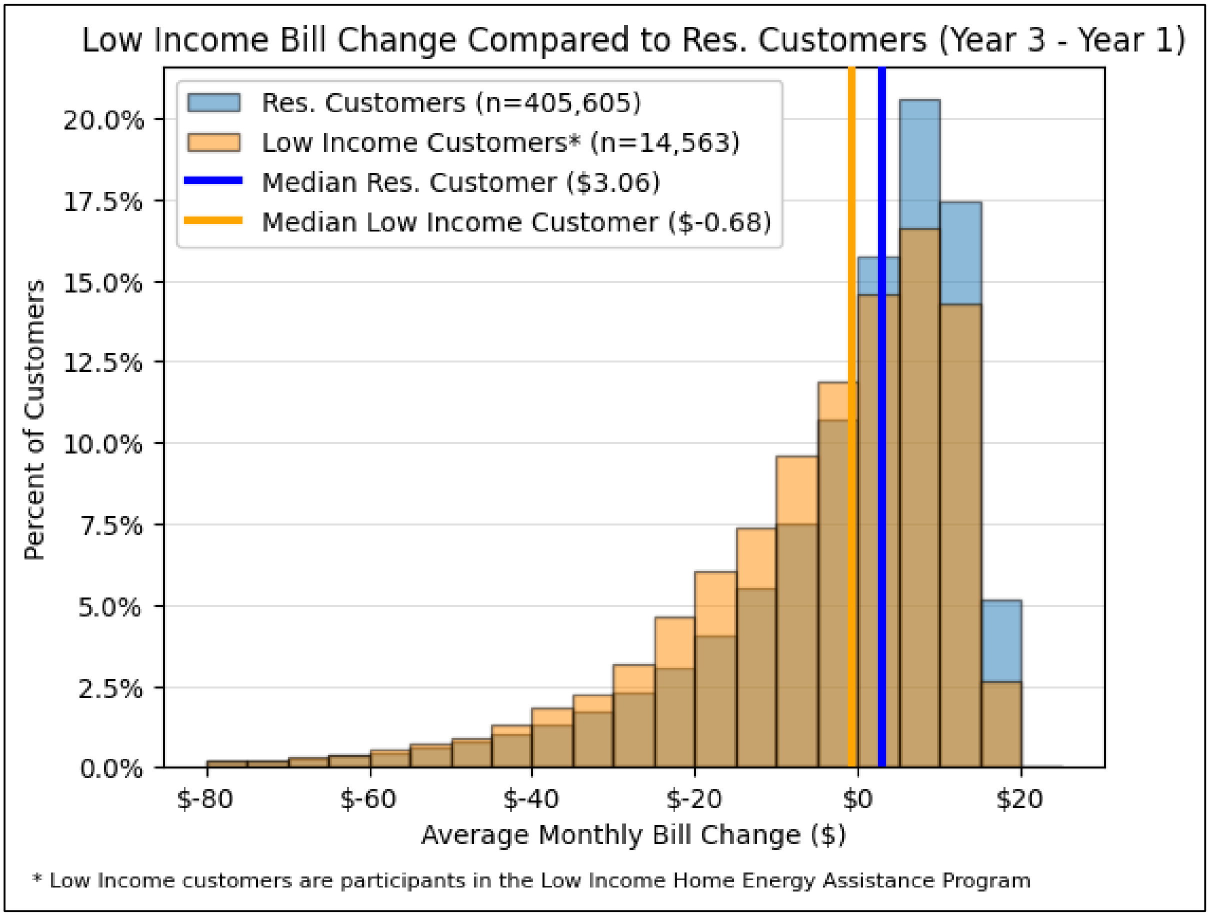
Figure 3
Residential Price Modernization Bill Impact
Final Year of Transition vs. Year 1



Q. Did the Company similarly evaluate the distribution of low-income customer bill impacts for the full transition of the Residential Price Modernization Plan?

A. Yes. Figure 4 shows the distribution for the final year of the transition for the low-income customer segment, compared to other residential customers. The median average monthly bill change in the final year of the transition, compared to the first year, is a $0.68 *decrease* and 90 percent of the low-income residential customer segment would have an average monthly bill increase of $12 or less.

Figure 4
Residential Price Modernization Bill Impact – Low Income
Final Year of Transition vs. Year 1



As shown in Figure 4, these low-income customers are not disproportionately negatively impacted under the Company's Residential Price Modernization Plan.

III. <u>ON-SITE GENERATION RATE DESIGN</u>

Q. What are the Company's on-site generation service schedules?

A. Idaho Power has three on-site generation service schedules; however, only Schedules 6 and 8 are separate customer classes with their own rate design and cost allocation. The third on-site generation service is under

Schedule 84, Customer Energy Production Net Metering Service ("Schedule 84"), where customers take their retail electric service under the applicable standard service schedule (e.g., Schedules 9, 19, or 24). For purposes of rate design discussion, on-site generation rate design for these customer classes is addressed under the applicable standard service schedule.

Q. What is the revenue requirement to be recovered from Schedules 6 and 8?

A. The annual revenue target to be recovered from Schedules 6 and 8 is $14,723,344 and $55,219, as shown on page 3 and 6 of Exhibit No. 53. As noted in the Direct Testimony of Ms. Aschenbrenner, the Class Cost-of-Service ("CCOS") study allocated costs to Schedules 6 and 8 are higher than revenue collection under rates that mirror the Service Charge and Energy Charges for the respective standard service under Schedules 1 and 7.

Q. What is the current rate design structure for on-site generation service under Schedules 6 and 8?

A. Schedules 6 and 8 rate design currently mirrors the structure and rates for residential and small general customers without on-site generation on Schedules 1 and 7, respectively. Both rate structures currently have a $5.00 Service Charge and an inclining block Energy Charge.

Q. Please summarize the Company’s proposed rate design changes for Schedules 6 and 8.

A. For Schedule 6, the Company is proposing in this case to retain the linkage with rates under Schedule 1. In addition, customers taking service under Schedule 6 will also have the option to elect to take time-of-use rates which would retain a linkage with rates under Schedule 5. All Schedule 6 rates, under the standard or time-of-use option would follow the Service Charge transition under the Company’s Residential Price Modernization Plan.

For Schedule 8, the Company is proposing in this case to retain the linkage with rates under Schedule 7. As described in the Direct Testimony of Company Witness Mr. Zack Thompson, the Company is proposing an increase in the Schedule 7 Service Charge from $5.00 to $20.00 per month.

Q. Why is Idaho Power requesting to maintain the relationship with the respective applicable retail service schedules?

A. The Company acknowledges that its proposal for these on-site generation schedules does not address that, as informed by the CCOS, the cost to serve these customers is higher than standard service. However, similar to the rationale for suggesting a three-year transition for the Residential Price Modernization Plan, the Company is proposing that residential rates be modified with gradualism in mind to moderate bill impacts on individual customers.

After the final year of the three-year transition, the Company will explore whether circumstances warrant further rate design modifications for on-site generation customer classes. For example, if all costs related to the distribution system and customer service were collected through the Service Charge for Schedule 6, the Service Charge would equate to approximately $50 per month. The Company suggests evaluating further movement towards the cost to serve in a future case after or near the end of the transition period for the Company’s Residential Price Modernization Plan.

Q. Have you prepared an exhibit that illustrates the rate design proposal for revenue recovery of Schedules 6 and 8?

A. Yes. Exhibit No. 53 shows the proposed prices, billing determinants, and anticipated revenue for Schedules 6 and 8. These rates align with the proposed rates for Schedules 1 and 7, respectively.

Q. Have you prepared an exhibit that shows the billing impact of this rate design proposal on customers receiving service under Schedules 6 and 8?

A. Yes. Exhibit No. 54 shows bill comparisons for the proposed transition period for rates under Schedules 1 and 5, which would be applicable to customers taking service under

Schedule 6. Pages 1 and 3 of Exhibit No. 54 shows a bill comparison for the first year of the transition for customers across different usage levels.

Additionally, Exhibit No. 56 shows a comparison for non-legacy Schedule 6 and 8 customers with 12 months of billing data in 2022 under the existing and proposed rates. The average monthly increase shown for Schedule 6 non-legacy customers is an 18 percent increase and for Schedule 8 is a 43 percent decrease.

IV. LARGE GENERAL SERVICE – SCHEDULE 9 (PRIMARY/TRANSMISSION)

Q. What is the revenue requirement for Schedule 9 customers taking service at the Primary and Transmission levels?

A. The annual revenue requirement for Schedule 9 Primary and Transmission level customers as shown on page 5 of Mr. Goralski’s Exhibit No. 48 is $43,557,610.

Q. What is the current rate structure for Schedule 9 Primary and Transmission Service?

A. All customers taking service under Schedule 9 Primary or Transmission Service pay seasonal time-of use Energy Charges, seasonal Demand Charges, a summer On-Peak Demand Charge, a Basic Charge, and a Service Charge. Customers may also pay a Facilities Charge for Company-owned facilities installed beyond Idaho Power’s Point of Delivery.

Q. Have you prepared an exhibit that illustrates the rate design proposal for Primary and Transmission Service under Schedule 9?

A. Yes. The rate design proposal for Schedule 9 Primary and Transmission Service is located on pages 7 and 8 of Exhibit No. 53 and targets the revenue shown on page 5 of Mr. Goralski’s Exhibit No. 48. For all rate components, the Company is proposing rates that represent a uniform 30 percent movement towards the costs to serve that rate component, and the Energy Charges are informed by the marginal price of energy for each time-of-use period. The costs to serve each rate component are indicated on page 6 of Mr. Goralski’s Exhibit No. 43.

Q. What other changes is the Company proposing for Schedule 9 Primary and Transmission Service rate design?

A. In addition to the incremental movement towards the costs to serve each of the rate components, the Company is proposing to change the definition of the time-of-use periods.

Q. What definition for on/mid/off-peak does the Company propose for Schedule 9?

A. The Company proposes to change the definition of the TOU periods for the summer season as follows:

- On-Peak: 7:00 p.m. to 11:00 p.m. Monday through Saturday, except holidays

- Mid-Peak: 3:00 p.m. to 7:00 p.m. and 11:00 p.m. to 12:00 a.m. Monday through Saturday, except holidays
- Off-Peak: 12:00 a.m. to 3:00 p.m. Monday through Saturday and all hours on Sunday and holidays.

For the non-summer season, the Company proposes to change the definition of the time-of-use periods to the following:

- On-Peak: 6:00 a.m. to 9:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday through Saturday, except holidays
- Mid-Peak: 9:00 a.m. to 12:00 p.m., 4:00 p.m. to 5:00 p.m., and 8:00 p.m. to 10:00 p.m. Monday through Saturday, except holidays
- Off-Peak: 10:00 p.m. to 6:00 a.m. and 12:00 p.m. to 4:00 p.m. Monday through Saturday and all hours on Sunday and holidays

Q. Why is the Company proposing to modify the definition of time-of-use hours?

A. Similar to the change in the definition of hours for residential time-of-use, the proposal better aligns these definitions with hours of highest risk on the Company's system. Aligning these hours with highest risk is consistent with the evaluation performed in the development of the Company's 2023 IRP.

Q. Have you prepared an exhibit that shows the billing impact of this rate design proposal on customers receiving Primary Service under Schedule 9?

A. Yes, page 5 of Exhibit No. 54 shows the billing comparisons between the existing rates and proposed rates for Schedule 9 Primary Service.

V. <u>LARGE POWER SERVICE, SCHEDULE 19</u>

Q. What is the revenue requirement to be recovered from Large Power Service customers taking service under Schedule 19?

A. The annual revenue requirement for Schedule 19 customers as shown on page 5 of Mr. Goralski’s Exhibit No. 48 is $164,068,656, representing a 6.61 percent increase.

Q. What is the current rate structure for customers taking service on Schedule 19?

A. Service under Schedule 19, similar to service under Schedule 9, is provided at Secondary, Primary, and Transmission Service levels. All customers taking service under Schedule 19 pay seasonal time-of-use Energy Charges, seasonal Demand Charges, a summer On-Peak Demand Charge, a Basic Charge, and a Service Charge. Customers taking Primary or Transmission Service may also pay a Facilities Charge for Company-owned facilities installed beyond Idaho Power’s Point of Delivery. In addition, Schedule 19 includes a 1,000 kilowatts per month minimum Billing Demand and Basic Load Capacity.

Q. Have you prepared an exhibit that illustrates the proposed rate design to recover the annual revenue requirement for Schedule 19?

A. Yes. The rate design proposal for Schedule 19 is shown on pages 9-11 of Exhibit No. 53 and targets the proposed class revenue increase. For all rate components, the Company is proposing rates that represent a uniform 30 percent movement towards the costs to serve that rate component, and the Energy Charges are informed by the marginal price of energy for each time-of-use period. The costs to serve each rate component are indicated on page 7 of Mr. Goralski’s Exhibit No. 43.

Q. What definition for on/mid/off-peak does the Company propose for Schedule 19?

A. The Company proposes the same definition for on/mid/off-peak as described for Schedule 9.

Q. Have you prepared an exhibit that shows the billing comparisons between the existing rates and the proposed rates for Schedule 19 Primary Service customers?

A. Page 6 of Exhibit No. 54 shows the billing comparisons between the existing rates and the proposed rates for Schedule 19 Primary Service customers. The higher load factor customers will see a lower overall increase as compared to low load factor customers.

VI. UPDATES TO SCHEDULE 68

Q. What other changes are addressed in your direct testimony?

A. In addition to the rate design proposals described herein, I will address the proposed revisions to Schedule 68. Attachment to the Application Nos. 1 and 2 show the revisions in clean and legislative format, respectively, for each of the respective tariff schedules.

Q. What is Schedule 68?

A. Schedule 68 is Idaho Power's tariff schedule that applies to the construction, operation, and maintenance of all interconnections to customer Distributed Energy Resources ("DER" or "DERs") interconnected in parallel – meaning operating and receiving voltage from Idaho Power's system.

Q. What changes is the Company proposing to Schedule 68?

A. The Company has proposed an update to the return trip charge and a modification to the applicability section regarding regenerative drives. Additionally, the Company has proposed several miscellaneous revisions to improve the administration of the interconnection process. Pages 68-1 to

68-13 in Attachment Nos. 1 and 2 show these administrative improvements.

Q. What is the return trip charge?

A. A return trip charge is billed to the customer each time Company personnel are dispatched to the job site but are unable to conduct the on-site inspection due to one or more conditions not being met that had been certified as complete by the customer or installer on the System Verification Form.

Q. Why is the Company updating the return trip charge?

A. The return trip charge of $61.00 was last updated in 2020 based on meter technician miles driven, number of inspections, vehicle rates, and labor rates. The updated return trip charge calculation includes the miles and number of inspections for the years 2020 through 2022 and updates the Company’s vehicle and labor rates for 2023.

Q. What is the change in the return trip charge?

A. The updated calculations result in a decrease to the return trip charge in Schedule 68 from $61.00 to $52.00. The change in the return trip charge is primarily driven by a reduction in the average miles per inspection and efficiency gains in time per inspection.

Q. What is a regenerative drive?

A. A regenerative drive allows electrical energy generated by a motor under braking conditions to be used again, or regenerated, rather than being completely lost to heat. Applications that involve frequent starts and stops, constant deceleration, or overhauling loads are candidates for this use case. Examples include elevators, downhill conveyers, and flywheels. The period of time during which regeneration routes electricity back to the utility is small, based on the limited amount of energy available from the driven load.

Q. Why does the Company believe a revision to Schedule 68 is needed for regenerative drives?

A. Regenerative drives provide a source of electric power independent from the bulk power system and is considered a Distributed Energy Resource ("DER") connected in parallel with the Company's system and pursuant to Schedule 68 is subject to the smart inverter requirements therein.

As described to me, regenerative drives do not typically raise the same concerns as other DERs with respect to grid stability and reliability that are addressed with smart inverters. For example, regenerative drives operate infrequently and only for a few seconds at a time. These short operations are not long enough to expect a change in reactive power output to meet the voltage/reactive power capability threshold for smart inverters. In addition, regenerative drives cannot function with the loss of utility source – if the grid loses power the drive will automatically also be de-energized and won’t be able to begin regenerating or continue regenerating, which effectively eliminates the risk of that it will contribute to an island condition and obviates the need for anti-islanding protection.

Q. What changes does the Company propose to accommodate the installation of regenerative drives?

A. To account for installations that are within the scope of Schedule 68 but do not implicate the same challenges that smart inverters are intended to address, the Company proposes to amend the Applicability section to address other technologies that use similar methods to generate electricity in parallel with the Company's system, including but not limited to regenerative drives used in elevators and other energy recapture systems.

Specifically, the Company proposes to evaluate the following criteria to determine whether a regenerative drive or other energy recapture system can be interconnected outside of the IEEE 1547 requirements: (1) magnitude of exports; (2) duration of the exports; and (3) ability of DER to operate during the loss of the utility source.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

//

DECLARATION OF GRANT T. ANDERSON

I, Grant T. Anderson, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Grant T. Anderson. I am employed by Idaho Power Company as a Regulatory Consultant in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 53 through 56 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: Grant T. Anderson
GRANT T. ANDERSON

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

ANDERSON, DI TESTIMONY

EXHIBIT NO. 53

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Residential Service
Schedule 1 and Schedule 6

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	6,057,159	$ 5.00	$ 30,285,794	$ 15.00	$ 90,857,381
2	Minimum Charge	72,347	2.00	144,694	3.00	217,041
3	Summer Energy (Jun-Aug)					
4	First 800 kWh	879,383,006	$ 0.086518	$ 76,082,459		
5	801-2,000 kWh	440,951,703	0.104033	45,873,529		
6	All Additional kWh	86,252,522	0.123585	10,659,518		
7	Subtotal - Summer Energy	1,406,587,230	$ 0.094282	$ 132,615,505		
8	Non-Summer Energy (Sep-May)					
9	First 800 kWh	2,579,932,201	$ 0.080390	$ 207,400,750		
10	801-2,000 kWh	1,101,608,616	0.088627	97,632,267		
11	All Additional kWh	438,920,446	0.098154	43,081,797		
12	Subtotal - Non-Summer Energy	4,120,461,263	$ 0.084484	$ 348,114,814		
13	Subtotal - Total Energy	5,527,048,493		$ 480,730,319		
14	Summer Energy (Jun-Sep)					
15	First 800 kWh	1,158,501,794			$ 0.102985	$ 119,308,307
16	801-2,000 kWh	534,019,069			0.117937	62,980,607
17	All Additional kWh	99,239,843			0.139291	13,823,217
18	Subtotal - Summer Energy	1,791,760,706			$ 0.109452	$ 196,112,131
19	Non-Summer Energy (Oct-May)					
20	First 800 kWh	2,305,593,411			$ 0.093050	$ 214,535,467
21	801-2,000 kWh	1,007,012,144			0.100034	100,735,453
22	All Additional kWh	422,682,232			0.107014	45,232,916
23	Subtotal - Non-Summer Energy	3,735,287,787			$ 0.096513	$ 360,503,836
24	Subtotal - Total Energy	5,527,048,493				$ 556,615,967
25	Transfer Adjustment Revenue			$ 65,867,385		
26	Total Adjusted Base Revenue			$ 577,028,192		$ 647,690,389

▪ **END** **END** ▪

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Residential Service
Schedule 1

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	5,897,706	$ 5.00	$ 29,488,531	$ 15.00	$ 88,465,592
2	Minimum Charge	70,865	2.00	141,730	3.00	212,595
3	Summer Energy (Jun-Aug)					
4	First 800 kWh	861,147,615	$ 0.086518	$ 74,504,769		
5	801-2,000 kWh	433,910,571	0.104033	45,141,018		
6	All Additional kWh	83,411,640	0.123585	10,308,428		
7	Subtotal - Summer Energy	1,378,469,826	$ 0.094274	$ 129,954,215		
8	Non-Summer Energy (Sep-May)					
9	First 800 kWh	2,525,398,940	$ 0.080390	$ 203,016,821		
10	801-2,000 kWh	1,077,473,224	0.088627	95,493,219		
11	All Additional kWh	422,794,007	0.098154	41,498,923		
12	Subtotal - Non-Summer Energy	4,025,666,171	$ 0.084460	$ 340,008,963		
13	Subtotal - Total Energy	5,404,135,997		$ 469,963,178		
14	Summer Energy (Jun-Sep)					
15	First 800 kWh	1,132,664,858			$ 0.102985	$ 116,647,490
16	801-2,000 kWh	526,078,657			0.117937	62,044,139
17	All Additional kWh	97,206,864			0.139291	13,540,041
18	Subtotal - Summer Energy	1,755,950,379			$ 0.109474	$ 192,231,670
19	Non-Summer Energy (Oct-May)					
20	First 800 kWh	2,253,877,358			$ 0.093050	$ 209,723,288
21	801-2,000 kWh	985,186,843			0.100034	98,552,181
22	All Additional kWh	409,121,417			0.107014	43,781,719
23	Subtotal - Non-Summer Energy	3,648,185,618			$ 0.096502	$ 352,057,188
24	Subtotal - Total Energy	5,404,135,997				$ 544,288,858
25	Transfer Adjustment Revenue			$ 64,401,980		
26	Total Adjusted Base Revenue			$ 563,995,419		$ 632,967,045

▪ END END ▪

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Residential Service On-Site Generation
Schedule 6

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	159,453	$ 5.00	$ 797,263	$ 15.00	$ 2,391,789
2	Minimum Charge	1,482	2.00	2,964	3.00	4,446
3	Summer Energy (Jun-Aug)					
4	First 800 kWh	18,235,390	$ 0.086518	$ 1,577,690		
5	801-2,000 kWh	7,041,132	0.104033	732,510		
6	All Additional kWh	2,840,881	0.123585	351,090		
7	Subtotal - Summer Energy	28,117,404	$ 0.094649	$ 2,661,290		
8	Non-Summer Energy (Sep-May)					
9	First 800 kWh	54,533,261	$ 0.080390	$ 4,383,929		
10	801-2,000 kWh	24,135,393	0.088627	2,139,047		
11	All Additional kWh	16,126,439	0.098154	1,582,874		
12	Subtotal - Non-Summer Energy	94,795,092	$ 0.085509	$ 8,105,851		
13	Subtotal - Total Energy	122,912,496		$ 10,767,141		
14	Summer Energy (Jun-Sep)					
15	First 800 kWh	25,836,936			$ 0.102985	$ 2,660,817
16	801-2,000 kWh	7,940,411			0.117937	936,468
17	All Additional kWh	2,032,980			0.139291	283,176
18	Subtotal - Summer Energy	35,810,327			$ 0.108362	$ 3,880,461
19	Non-Summer Energy (Oct-May)					
20	First 800 kWh	51,716,052			$ 0.093050	$ 4,812,179
21	801-2,000 kWh	21,825,301			0.100034	2,183,272
22	All Additional kWh	13,560,815			0.107014	1,451,197
23	Subtotal - Non-Summer Energy	87,102,169			$ 0.096974	$ 8,446,648
24	Subtotal - Total Energy	122,912,496				$ 12,327,109
25	Transfer Adjustment Revenue			$ 1,465,405		
26	Total Adjusted Base Revenue			$ 13,032,773		$ 14,723,344

▪ END END ▪

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Master-Metered Mobile Home Park Residential Service
Schedule 3

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	225	$ 5.00	$ 1,124	$ 15.00	$ 3,372
2	Energy Charge	4,476,086	$ 0.087075	389,755	$ 0.110625	495,167
3	Transfer Adjustment Revenue			53,271		
4	Total Adjusted Base Revenue			$ 444,150		$ 498,539

▪ END END ▪

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Residential Service - Time-of-Use
Schedule 5

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	11,836	$ 5.00	$ 59,179	$ 15.00	$ 177,536
2	Minimum Charge	29	2.00	58	3.00	87
3	Summer Energy (Jun-Aug)					
4	On-Peak	1,317,837	$ 0.128910	$ 169,882		
5	Off-Peak	2,932,059	0.073899	216,676		
6	Subtotal - Summer Energy	4,249,896	$ 0.090957	$ 386,559		
7	Non-Summer Energy (Sep-May)					
8	On-Peak	5,206,937	$ 0.095159	$ 495,487		
9	Off-Peak	7,490,517	0.073899	553,542		
10	Subtotal - Non-Summer Energy	12,697,455	$ 0.082617	$ 1,049,029		
11	Subtotal - Total Energy	16,947,350		$ 1,435,587		
12	Summer Energy (Jun-Sep)					
13	On-Peak	999,802			$ 0.279642	$ 279,587
14	Off-Peak	4,410,435			0.069911	308,338
15	Subtotal - Summer Energy	5,410,238			$ 0.108669	$ 587,925
16	Non-Summer Energy (Oct-May)					
17	On-Peak	2,279,827			$ 0.134745	$ 307,195
18	Off-Peak	9,257,286			0.089830	831,582
19	Subtotal - Non-Summer Energy	11,537,113			$ 0.098706	$ 1,138,777
20	Subtotal - Total Energy	16,947,350				$ 1,726,702
21	Transfer Adjustment Revenue			$ 201,741		
22	Total Adjusted Base Revenue			$ 1,696,564		$ 1,904,324

▪ END END ▪

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Small General Service On-Site Generation
Schedule 8

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	1,050	$ 5.00	$ 5,250	$ 20.00	$ 21,000
2	Minimum Charge	6	2.00	12	3.00	18
3	Summer Energy (Jun-Aug)					
4	0 - 300 kWh	26,347	$ 0.098633	$ 2,599		
5	All Additional kWh	56,107	0.117472	6,591		
6	Subtotal - Summer Energy	82,454	$ 0.111452	$ 9,190		
7	Non-Summer Energy (Sep-May)					
8	0 - 300 kWh	117,296	$ 0.098633	$ 11,569		
9	All Additional kWh	170,958	0.103486	17,692		
10	Subtotal - Non-Summer Energy	288,254	$ 0.101511	$ 29,261		
11	Subtotal - Total Energy	370,708		$ 38,451		
12	Summer Energy (Jun-Sep)					
13	0 - 300 kWh	41,132			$ 0.089863	$ 3,696
14	All Additional kWh	68,948			0.102694	7,081
15	Subtotal - Summer Energy	110,080			$ 0.097900	$ 10,777
16	Non-Summer Energy (Oct-May)					
17	0 - 300 kWh	105,075			$ 0.089863	$ 9,442
18	All Additional kWh	155,553			0.089887	13,982
19	Subtotal - Non-Summer Energy	260,628			$ 0.089877	$ 23,425
20	Subtotal - Total Energy	370,708				$ 34,201
21	Transfer Adjustment Revenue			$ 4,447		
22	Total Adjusted Base Revenue			$ 48,160		$ 55,219

▪ END END ▪

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Large General Service
Schedule 9 Primary Service

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	3,362	$ 285.00	$ 958,142	$ 335.00	$ 1,126,237
2	Minimum Charge	-	10.00	-	50.00	-
3	Basic Charge					
4	Total Basic Charge	1,935,320	$ 1.30	$ 2,515,916	$ 1.70	$ 3,290,044
5	Demand Charge (Current Seasons)					
6	Summer (Jun-Aug)	421,737	$ 5.16	$ 2,176,164		
7	Non-Summer (Sep-May)	1,129,739	4.52	5,106,419		
8	Total Demand	1,551,476		$ 7,282,583		
9	On-Peak Summer Demand (Jun-Aug)	394,562	$ 0.97	$ 382,725		
10	Demand Charge (Proposed Seasons)					
11	Summer (Jun-Sep)	562,598			$ 7.76	$ 4,365,759
12	Non-Summer (Oct-May)	988,878			7.36	7,278,143
13	Total Demand	1,551,476				$ 11,643,901
14	On-Peak Summer Demand (Jun-Sep)	525,669			$ 1.46	$ 767,477
15	Summer Energy (Jun-Aug)					
16	On-Peak	45,450,558	$ 0.049454	$ 2,247,712		
17	Mid-Peak	70,944,613	0.045633	3,237,416		
18	Off-Peak	46,864,805	0.043133	2,021,420		
19	Subtotal - Summer Energy	163,259,977	$ 0.045979	$ 7,506,547		
20	Non-Summer Energy (Sep-May)					
21	Mid-Peak	266,940,199	$ 0.040920	$ 10,923,193		
22	Off-Peak	167,941,864	0.039546	6,641,429		
23	Subtotal - Non-Summer Energy	434,882,062	$ 0.040389	$ 17,564,622		
24	Subtotal - Total Energy	598,142,039		$ 25,071,169		
25	Summer Energy (Jun-Sep)					
26	On-Peak	29,601,623			$ 0.050220	$ 1,486,593
27	Mid-Peak	41,637,317			0.050220	2,091,026
28	Off-Peak	143,727,301			0.044949	6,460,398
29	Subtotal - Summer Energy	214,966,240			$ 0.046696	$ 10,038,018
30	Non-Summer Energy (Oct-May)					
31	On-Peak	85,400,026			$ 0.045603	$ 3,894,497
32	Mid-Peak	87,831,834			0.043328	3,805,578
33	Off-Peak	209,943,940			0.041504	8,713,513
34	Subtotal - Non-Summer Energy	383,175,799			$ 0.042836	$ 16,413,588
35	Subtotal - Total Energy	598,142,039				$ 26,451,606
36	Transfer Adjustment Revenue			$ 7,068,745		
37	Total Adjusted Base Revenue			$ 43,279,279		$ 43,279,265

▪ END END ▪

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Large General Service
Schedule 9 Transmission Service

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	48	$ 285.00	$ 13,680	$ 335.00	$ 16,080
2	Minimum Charge	-	10.00	-	50.00	-
3	Basic Charge					
4	Total Basic Charge	17,008	$ 0.69	$ 11,736	$ 1.02	$ 17,348
5	Demand Charge (Current Seasons)					
6	Summer (Jun-Aug)	3,210	$ 4.84	$ 15,537		
7	Non-Summer (Sep-May)	10,676	4.36	46,546		
8	Total Demand	13,886		$ 62,083		
9	On-Peak Summer Demand (Jun-Aug)	2,749	$ 0.97	$ 2,667		
10	Demand Charge (Proposed Seasons)					
11	Summer (Jun-Sep)	4,400			$ 6.84	$ 30,093
12	Non-Summer (Oct-May)	9,486			5.99	56,823
13	Total Demand	13,886				$ 86,916
14	On-Peak Summer Demand (Jun-Sep)	3,767			$ 1.46	$ 5,500
15	Summer Energy (Jun-Aug)					
16	On-Peak	193,515	$ 0.048664	$ 9,417		
17	Mid-Peak	350,627	0.045000	15,778		
18	Off-Peak	236,395	0.042585	10,067		
19	Subtotal - Summer Energy	780,537	$ 0.045177	$ 35,262		
20	Non-Summer Energy (Sep-May)					
21	Mid-Peak	1,661,772	$ 0.040408	$ 67,149		
22	Off-Peak	1,114,834	0.039155	43,651		
23	Subtotal - Non-Summer Energy	2,776,606	$ 0.039905	$ 110,800		
24	Subtotal - Total Energy	3,557,143		$ 146,063		
25	Summer Energy (Jun-Sep)					
26	On-Peak	110,660			$ 0.049429	$ 5,470
27	Mid-Peak	169,020			0.049429	8,354
28	Off-Peak	760,683			0.044097	33,544
29	Subtotal - Summer Energy	1,040,363			$ 0.045530	$ 47,368
30	Non-Summer Energy (Oct-May)					
31	On-Peak	542,469			$ 0.044570	$ 24,178
32	Mid-Peak	572,351			0.042293	24,206
33	Off-Peak	1,401,959			0.040467	56,733
34	Subtotal - Non-Summer Energy	2,516,780			$ 0.041767	$ 105,117
35	Subtotal - Total Energy	3,557,143				$ 152,486
36	Transfer Adjustment Revenue			$ 42,103		
37	Total Adjusted Base Revenue			$ 278,331		$ 278,330

▪ END END ▪

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Large Power Service
Schedule 19 Secondary Service

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	12	$ 39.00	$ 468	$ 90.00	$ 1,080
2	Minimum Charge	-	5.00	-	5.00	-
3	Basic Charge					
4	Total Basic Charge	14,167	$ 0.93	$ 13,176	$ 1.98	$ 28,051
5	Demand Charge (Current Seasons)					
6	Summer (Jun-Aug)	3,233	$ 5.99	$ 19,365		
7	Non-Summer (Sep-May)	10,109	4.30	43,467		
8	Total Demand	13,342		$ 62,832		
9	On-Peak Summer Demand (Jun-Aug)	2,591	$ 1.03	$ 2,669		
10	Demand Charge (Proposed Seasons)					
11	Summer (Jun-Sep)	4,291			$ 10.32	$ 44,279
12	Non-Summer (Oct-May)	9,051			8.31	75,213
13	Total Demand	13,342				$ 119,492
14	On-Peak Summer Demand (Jun-Sep)	3,439			$ 1.78	$ 6,121
15	Summer Energy (Jun-Aug)					
16	On-Peak	423,806	$ 0.064456	$ 27,317		
17	Mid-Peak	563,279	0.051034	28,746		
18	Off-Peak	664,973	0.045292	30,118		
19	Subtotal - Summer Energy	1,652,057	$ 0.052166	$ 86,181		
20	Non-Summer Energy (Sep-May)					
21	Mid-Peak	2,894,106	$ 0.047466	$ 137,372		
22	Off-Peak	1,988,464	0.042171	83,856		
23	Subtotal - Non-Summer Energy	4,882,571	$ 0.045310	$ 221,227		
24	Subtotal - Total Energy	6,534,628		$ 307,408		
25	Summer Energy (Jun-Sep)					
26	On-Peak	324,610			$ 0.058686	$ 19,050
27	Mid-Peak	418,903			0.058686	24,584
28	Off-Peak	1,459,219			0.053432	77,969
29	Subtotal - Summer Energy	2,202,732			$ 0.055205	$ 121,603
30	Non-Summer Energy (Oct-May)					
31	On-Peak	937,724			$ 0.053148	$ 49,838
32	Mid-Peak	965,486			0.050867	49,111
33	Off-Peak	2,428,686			0.049038	119,098
34	Subtotal - Non-Summer Energy	4,331,896			$ 0.050335	$ 218,047
35	Subtotal - Total Energy	6,534,628				$ 339,650
36	Transfer Adjustment Revenue			$ 77,197		
37	Total Adjusted Base Revenue			$ 463,750		$ 494,394

▪ END END ▪

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Large Power Service
Schedule 19 Primary Service

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	1,356	$ 299.00	$ 405,444	$ 430.00	$ 583,080
2	Minimum Charge	-	10.00	-	50.00	-
3	Basic Charge					
4	Total Basic Charge	5,241,211	$ 1.28	$ 6,708,750	$ 2.18	$ 11,425,840
5	Demand Charge (Current Seasons)					
6	Summer (Jun-Aug)	1,200,164	$ 6.12	$ 7,345,004		
7	Non-Summer (Sep-May)	3,433,952	4.54	15,590,143		
8	Total Demand	4,634,116		$ 22,935,147		
9	On-Peak Summer Demand (Jun-Aug)	1,153,172	$ 0.97	$ 1,118,577		
10	Demand Charge (Proposed Seasons)					
11	Summer (Jun-Sep)	1,600,720			$ 9.87	$ 15,799,106
12	Non-Summer (Oct-May)	3,033,396			8.49	25,753,534
13	Total Demand	4,634,116				$ 41,552,640
14	On-Peak Summer Demand (Jun-Sep)	1,537,925			$ 1.57	$ 2,414,542
15	Summer Energy (Jun-Aug)					
16	On-Peak	155,742,275	$ 0.053049	$ 8,261,972		
17	Mid-Peak	258,777,524	0.042185	10,916,530		
18	Off-Peak	192,288,068	0.037639	7,237,531		
19	Subtotal - Summer Energy	606,807,867	$ 0.043533	$ 26,416,032		
20	Non-Summer Energy (Sep-May)					
21	Mid-Peak	1,014,622,007	$ 0.039765	$ 40,346,444		
22	Off-Peak	725,865,453	0.035550	25,804,517		
23	Subtotal - Non-Summer Energy	1,740,487,460	$ 0.038007	$ 66,150,961		
24	Subtotal - Total Energy	2,347,295,327		$ 92,566,993		
25	Summer Energy (Jun-Sep)					
26	On-Peak	115,731,721			$ 0.051210	$ 5,926,621
27	Mid-Peak	149,838,340			0.051210	7,673,221
28	Off-Peak	535,937,021			0.045951	24,626,842
29	Subtotal - Summer Energy	801,507,082			$ 0.047694	$ 38,226,685
30	Non-Summer Energy (Oct-May)					
31	On-Peak	334,235,604			$ 0.046309	$ 15,478,117
32	Mid-Peak	337,433,892			0.044028	14,856,539
33	Off-Peak	874,118,749			0.042198	36,886,063
34	Subtotal - Non-Summer Energy	1,545,788,245			$ 0.043486	$ 67,220,719
35	Subtotal - Total Energy	2,347,295,327				$ 105,447,404
36	Transfer Adjustment Revenue			$ 27,682,780		
37	Total Adjusted Base Revenue			$ 151,417,691		$ 161,423,506

▪ END END ▪

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Large Power Service
Schedule 19 Transmission Service

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	24	$ 299.00	$ 7,176	$ 430.00	$ 10,320
2	Minimum Charge	-	10.00	-	50.00	-
3	Basic Charge					
4	Total Basic Charge	60,014	$ 0.71	$ 42,610	$ 1.83	$ 109,825
5	Demand Charge (Current Seasons)					
6	Summer (Jun-Aug)	15,188	$ 5.93	$ 90,063		
7	Non-Summer (Sep-May)	43,455	4.41	191,638		
8	Total Demand	58,643		$ 281,700		
9	On-Peak Summer Demand (Jun-Aug)	14,437	$ 0.97	$ 14,004		
10	Demand Charge (Proposed Seasons)					
11	Summer (Jun-Sep)	20,063			$ 10.02	$ 201,034
12	Non-Summer (Oct-May)	38,580			8.62	332,556
13	Total Demand	58,643				$ 533,590
14	On-Peak Summer Demand (Jun-Sep)	19,071			$ 1.57	$ 29,941
15	Summer Energy (Jun-Aug)					
16	On-Peak	2,000,915	$ 0.052447	$ 104,942		
17	Mid-Peak	3,704,369	0.041889	155,172		
18	Off-Peak	2,838,258	0.037394	106,134		
19	Subtotal - Summer Energy	8,543,543	$ 0.042868	$ 366,248		
20	Non-Summer Energy (Sep-May)					
21	Mid-Peak	13,775,429	$ 0.039577	$ 545,190		
22	Off-Peak	10,546,708	0.035383	373,174		
23	Subtotal - Non-Summer Energy	24,322,137	$ 0.037758	$ 918,364		
24	Subtotal - Total Energy	32,865,680		$ 1,284,612		
25	Summer Energy (Jun-Sep)					
26	On-Peak	1,516,856			$ 0.051063	$ 77,455
27	Mid-Peak	1,908,973			0.051063	97,478
28	Off-Peak	7,883,515			0.045777	360,884
29	Subtotal - Summer Energy	11,309,344			$ 0.047378	$ 535,817
30	Non-Summer Energy (Oct-May)					
31	On-Peak	4,606,525			$ 0.046042	$ 212,094
32	Mid-Peak	4,608,196			0.043759	201,650
33	Off-Peak	12,341,615			0.041928	517,459
34	Subtotal - Non-Summer Energy	21,556,336			$ 0.043199	$ 931,203
35	Subtotal - Total Energy	32,865,680				$ 1,467,020
36	Transfer Adjustment Revenue			$ 387,282		
37	Total Adjusted Base Revenue			$ 2,017,384		$ 2,150,696

END **END**

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

ANDERSON, DI TESTIMONY

EXHIBIT NO. 54

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison - First Year Change
IPC-E-23-11
Schedule 1 - Residential Service

	Monthly Billing				Change				Weighted Average Change[1]	
	Test Year		Year 1		$		%			
kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
150	$ 19.77	$ 18.85	$ 30.45	$ 28.96	$ 10.68	$ 10.11	54.0%	53.7%	$ 10.38	54.4%
250	$ 29.61	$ 28.08	$ 40.75	$ 38.26	$ 11.14	$ 10.19	37.6%	36.3%	$ 10.63	37.4%
350	$ 39.45	$ 37.31	$ 51.04	$ 47.57	$ 11.59	$ 10.26	29.4%	27.5%	$ 10.88	28.8%
450	$ 49.30	$ 46.54	$ 61.34	$ 56.87	$ 12.05	$ 10.33	24.4%	22.2%	$ 11.14	23.6%
550	$ 59.14	$ 55.77	$ 71.64	$ 66.18	$ 12.50	$ 10.41	21.1%	18.7%	$ 11.39	20.1%
650	$ 68.98	$ 65.00	$ 81.94	$ 75.48	$ 12.96	$ 10.48	18.8%	16.1%	$ 11.64	17.6%
750	$ 78.83	$ 74.23	$ 92.24	$ 84.79	$ 13.41	$ 10.56	17.0%	14.2%	$ 11.89	15.8%
850	$ 89.55	$ 83.87	$ 103.28	$ 94.44	$ 13.74	$ 10.57	15.3%	12.6%	$ 12.10	14.2%
950	$ 101.14	$ 93.93	$ 115.08	$ 104.45	$ 13.94	$ 10.52	13.8%	11.2%	$ 12.26	12.8%
1,000	$ 106.94	$ 98.95	$ 120.98	$ 109.45	$ 14.04	$ 10.49	13.1%	10.6%	$ 12.34	12.2%
1,200	$ 130.13	$ 119.06	$ 144.56	$ 129.45	$ 14.43	$ 10.39	11.1%	8.7%	$ 12.66	10.4%
1,400	$ 153.32	$ 139.17	$ 168.15	$ 149.46	$ 14.83	$ 10.29	9.7%	7.4%	$ 12.98	9.1%
1,600	$ 176.51	$ 159.28	$ 191.74	$ 169.47	$ 15.23	$ 10.19	8.6%	6.4%	$ 13.30	8.1%
1,800	$ 199.70	$ 179.39	$ 215.33	$ 189.47	$ 15.63	$ 10.08	7.8%	5.6%	$ 13.62	7.4%
2,000	$ 222.89	$ 199.50	$ 238.91	$ 209.48	$ 16.02	$ 9.98	7.2%	5.0%	$ 13.94	6.8%
2,500	$ 290.64	$ 254.53	$ 308.56	$ 262.99	$ 17.92	$ 8.45	6.2%	3.3%	$ 14.62	5.5%
3,000	$ 358.39	$ 309.57	$ 378.20	$ 316.49	$ 19.81	$ 6.92	5.5%	2.2%	$ 15.29	4.8%
5,000	$ 629.40	$ 529.71	$ 656.79	$ 530.52	$ 27.39	$ 0.81	4.4%	0.2%	$ 17.98	3.2%

[1] Includes change to four-month summer season.

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison - Final Year of Transition vs Year 1
IPC-E-23-11
Schedule 1 - Residential Service

	Monthly Billing				Change				Weighted	
	Year 1		Year 3		$		%		Average Change	
kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
150	$ 30.45	$ 28.96	$ 48.11	$ 46.20	$ 17.66	$ 17.24	58.0%	59.5%	$ 17.38	59.0%
250	$ 40.75	$ 38.26	$ 56.84	$ 53.67	$ 16.10	$ 15.40	39.5%	40.3%	$ 15.64	40.0%
350	$ 51.04	$ 47.57	$ 65.58	$ 61.13	$ 14.54	$ 13.57	28.5%	28.5%	$ 13.89	28.5%
450	$ 61.34	$ 56.87	$ 74.32	$ 68.60	$ 12.98	$ 11.73	21.2%	20.6%	$ 12.14	20.8%
550	$ 71.64	$ 66.18	$ 83.06	$ 76.07	$ 11.42	$ 9.89	15.9%	14.9%	$ 10.40	15.3%
650	$ 81.94	$ 75.48	$ 91.80	$ 83.53	$ 9.86	$ 8.05	12.0%	10.7%	$ 8.65	11.1%
750	$ 92.24	$ 84.79	$ 100.53	$ 91.00	$ 8.30	$ 6.21	9.0%	7.3%	$ 6.91	7.9%
850	$ 103.28	$ 94.44	$ 109.27	$ 98.47	$ 5.99	$ 4.03	5.8%	4.3%	$ 4.68	4.8%
950	$ 115.08	$ 104.45	$ 118.01	$ 105.94	$ 2.93	$ 1.49	2.5%	1.4%	$ 1.97	1.8%
1,000	$ 120.98	$ 109.45	$ 122.38	$ 109.67	$ 1.40	$ 0.22	1.2%	0.2%	$ 0.62	0.5%
1,200	$ 144.56	$ 129.45	$ 139.85	$ 124.60	$ (4.71)	$ (4.85)	(3.3%)	(3.7%)	$ (4.80)	(3.6%)
1,400	$ 168.15	$ 149.46	$ 157.33	$ 139.54	$ (10.82)	$ (9.92)	(6.4%)	(6.6%)	$ (10.22)	(6.6%)
1,600	$ 191.74	$ 169.47	$ 174.81	$ 154.47	$ (16.93)	$ (15.00)	(8.8%)	(8.8%)	$ (15.64)	(8.8%)
1,800	$ 215.33	$ 189.47	$ 192.28	$ 169.40	$ (23.04)	$ (20.07)	(10.7%)	(10.6%)	$ (21.06)	(10.6%)
2,000	$ 238.91	$ 209.48	$ 209.76	$ 184.34	$ (29.15)	$ (25.14)	(12.2%)	(12.0%)	$ (26.48)	(12.1%)
2,500	$ 308.56	$ 262.99	$ 253.45	$ 221.67	$ (55.11)	$ (41.32)	(17.9%)	(15.7%)	$ (45.91)	(16.5%)
3,000	$ 378.20	$ 316.49	$ 297.14	$ 259.01	$ (81.07)	$ (57.49)	(21.4%)	(18.2%)	$ (65.35)	(19.4%)
5,000	$ 656.79	$ 530.52	$ 471.90	$ 408.35	$ (184.89)	$ (122.18)	(28.2%)	(23.0%)	$ (143.08)	(25.0%)

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison - First Year Change
IPC-E-23-11
Schedule 5 - Optional Time-of-Day Plan

	Monthly Billing[1]				Change				Weighted Average Change[2]	
	Test Year		Year 1		$		%			
kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
150	$ 20.43	$ 19.18	$ 31.30	$ 29.81	$ 10.87	$ 10.63	53.2%	55.4%	$ 10.81	55.5%
250	$ 30.72	$ 28.63	$ 42.17	$ 39.68	$ 11.45	$ 11.05	37.3%	38.6%	$ 11.36	39.0%
350	$ 41.00	$ 38.08	$ 53.03	$ 49.55	$ 12.03	$ 11.46	29.3%	30.1%	$ 11.90	30.7%
450	$ 51.29	$ 47.53	$ 63.90	$ 59.42	$ 12.61	$ 11.88	24.6%	25.0%	$ 12.44	25.7%
550	$ 61.57	$ 56.99	$ 74.77	$ 69.29	$ 13.19	$ 12.30	21.4%	21.6%	$ 12.98	22.3%
650	$ 71.86	$ 66.44	$ 85.63	$ 79.16	$ 13.78	$ 12.72	19.2%	19.1%	$ 13.52	19.9%
750	$ 82.15	$ 75.89	$ 96.50	$ 89.03	$ 14.36	$ 13.14	17.5%	17.3%	$ 14.07	18.2%
850	$ 92.43	$ 85.34	$ 107.37	$ 98.90	$ 14.94	$ 13.56	16.2%	15.9%	$ 14.61	16.8%
950	$ 102.72	$ 94.80	$ 118.24	$ 108.77	$ 15.52	$ 13.98	15.1%	14.7%	$ 15.15	15.7%
1,000	$ 107.86	$ 99.52	$ 123.67	$ 113.71	$ 15.81	$ 14.18	14.7%	14.3%	$ 15.42	15.2%
1,200	$ 128.43	$ 118.43	$ 145.40	$ 133.45	$ 16.97	$ 15.02	13.2%	12.7%	$ 16.50	13.6%
1,400	$ 149.01	$ 137.33	$ 167.14	$ 153.19	$ 18.13	$ 15.86	12.2%	11.5%	$ 17.59	12.5%
1,600	$ 169.58	$ 156.23	$ 188.87	$ 172.93	$ 19.29	$ 16.69	11.4%	10.7%	$ 18.67	11.7%
1,800	$ 190.15	$ 175.14	$ 210.60	$ 192.67	$ 20.45	$ 17.53	10.8%	10.0%	$ 19.76	11.0%
2,000	$ 210.72	$ 194.04	$ 232.34	$ 212.41	$ 21.62	$ 18.37	10.3%	9.5%	$ 20.84	10.5%
2,500	$ 262.15	$ 241.30	$ 286.67	$ 261.76	$ 24.52	$ 20.46	9.4%	8.5%	$ 23.55	9.6%
3,000	$ 313.58	$ 288.56	$ 341.01	$ 311.12	$ 27.42	$ 22.55	8.7%	7.8%	$ 26.26	8.9%
5,000	$ 519.31	$ 477.61	$ 558.34	$ 508.53	$ 39.04	$ 30.92	7.5%	6.5%	$ 37.10	7.6%

[1] Bills are calculated on class average on-peak to off-peak ratio by season. Does not account for behavioral response to new price signal.
[2] Includes change to four-month summer season.

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison - Final Year of Transition vs Year 1
IPC-E-23-11
Schedule 5 - Optional Time-of-Day Plan

	Monthly Billing[1]				Change				Weighted	
	Year 1		Year 3		$		%		Average Change	
kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
150	$ 51.13	$ 28.64	$ 66.18	$ 51.29	$ 15.05	$ 22.65	29.4%	79.1%	$ 20.11	55.7%
250	$ 75.22	$ 37.74	$ 86.97	$ 62.15	$ 11.74	$ 24.41	15.6%	64.7%	$ 20.19	40.2%
350	$ 99.31	$ 46.84	$ 107.75	$ 73.01	$ 8.44	$ 26.18	8.5%	55.9%	$ 20.27	31.5%
450	$ 123.40	$ 55.93	$ 128.54	$ 83.88	$ 5.14	$ 27.95	4.2%	50.0%	$ 20.34	25.9%
550	$ 147.49	$ 65.03	$ 149.32	$ 94.74	$ 1.84	$ 29.71	1.2%	45.7%	$ 20.42	22.1%
650	$ 171.57	$ 74.12	$ 170.11	$ 105.60	$ (1.46)	$ 31.48	(0.9%)	42.5%	$ 20.50	19.2%
750	$ 195.66	$ 83.22	$ 190.90	$ 116.46	$ (4.77)	$ 33.24	(2.4%)	39.9%	$ 20.57	17.0%
850	$ 219.75	$ 92.31	$ 211.68	$ 127.32	$ (8.07)	$ 35.01	(3.7%)	37.9%	$ 20.65	15.3%
950	$ 243.84	$ 101.41	$ 232.47	$ 138.18	$ (11.37)	$ 36.77	(4.7%)	36.3%	$ 20.73	13.9%
1,000	$ 255.88	$ 105.96	$ 242.86	$ 143.61	$ (13.02)	$ 37.66	(5.1%)	35.5%	$ 20.76	13.3%
1,200	$ 304.06	$ 124.15	$ 284.43	$ 165.34	$ (19.63)	$ 41.19	(6.5%)	33.2%	$ 20.92	11.4%
1,400	$ 352.24	$ 142.34	$ 326.01	$ 187.06	$ (26.23)	$ 44.72	(7.4%)	31.4%	$ 21.07	9.9%
1,600	$ 400.41	$ 160.53	$ 367.58	$ 208.78	$ (32.83)	$ 48.25	(8.2%)	30.1%	$ 21.22	8.8%
1,800	$ 448.59	$ 178.72	$ 409.15	$ 230.51	$ (39.44)	$ 51.78	(8.8%)	29.0%	$ 21.37	8.0%
2,000	$ 496.77	$ 196.92	$ 450.72	$ 252.23	$ (46.04)	$ 55.31	(9.3%)	28.1%	$ 21.53	7.3%
2,500	$ 617.21	$ 242.39	$ 554.66	$ 306.54	$ (62.55)	$ 64.14	(10.1%)	26.5%	$ 21.91	6.0%
3,000	$ 737.65	$ 287.87	$ 658.59	$ 360.84	$ (79.07)	$ 72.97	(10.7%)	25.3%	$ 22.29	5.1%
5,000	$ 1,219.42	$ 469.79	$ 1,074.31	$ 578.07	$ (145.11)	$ 108.28	(11.9%)	23.0%	$ 23.82	3.3%

[1] Bills are calculated on class average on-peak to off-peak ratio by season. Does not account for behavioral response to new price signal.

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison
IPC-E-23-11
Schedule 9 - Large General Service - Primary

			Monthly Billing[1]				Change				Weighted	
Load Size	Load		Current		Proposed		$		%		Average Change[2]	
kW	Factor	kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
250	40%	73,000	$ 6,426.46	$ 5,631.53	$ 6,555.42	$ 5,832.15	$ 128.96	$ 200.62	2.0%	3.6%	$ 242.98	4.2%
	50%	92,000	$ 7,524.60	$ 6,623.47	$ 7,442.64	$ 6,646.03	(81.96)	22.56	(1.1%)	0.3%	62.81	0.9%
	60%	110,000	$ 8,564.94	$ 7,563.20	$ 8,283.16	$ 7,417.07	(281.78)	(146.13)	(3.3%)	(1.9%)	(107.87)	(1.4%)
	70%	128,000	$ 9,605.29	$ 8,502.93	$ 9,123.69	$ 8,188.11	(481.60)	(314.82)	(5.0%)	(3.7%)	(278.55)	(3.2%)
	80%	146,000	$ 10,645.63	$ 9,442.66	$ 9,964.21	$ 8,959.15	(681.42)	(483.51)	(6.4%)	(5.1%)	(449.23)	(4.6%)
350	40%	102,000	$ 8,871.48	$ 7,759.71	$ 9,034.25	$ 8,022.44	$ 162.77	$ 262.74	1.8%	3.4%	$ 322.06	4.0%
	50%	128,000	$ 10,374.20	$ 9,117.09	$ 10,248.34	$ 9,136.17	(125.86)	19.08	(1.2%)	0.2%	75.52	0.8%
	60%	154,000	$ 11,876.92	$ 10,474.48	$ 11,462.43	$ 10,249.90	(414.49)	(224.58)	(3.5%)	(2.1%)	(171.02)	(1.6%)
	70%	179,000	$ 13,321.85	$ 11,779.66	$ 12,629.83	$ 11,320.79	(692.02)	(458.87)	(5.2%)	(3.9%)	(408.07)	(3.4%)
	80%	205,000	$ 14,824.57	$ 13,137.05	$ 13,843.92	$ 12,434.52	(980.65)	(702.53)	(6.6%)	(5.3%)	(654.61)	(4.8%)
450	40%	132,000	$ 11,374.30	$ 9,940.09	$ 11,559.77	$ 10,255.57	$ 185.47	$ 315.49	1.6%	3.2%	$ 391.67	3.8%
	50%	165,000	$ 13,281.60	$ 11,662.93	$ 13,100.74	$ 11,669.15	(180.87)	6.22	(1.4%)	0.1%	78.75	0.7%
	60%	198,000	$ 15,188.90	$ 13,385.76	$ 14,641.70	$ 13,082.73	(547.20)	(303.04)	(3.6%)	(2.3%)	(234.16)	(1.7%)
	70%	231,000	$ 17,096.20	$ 15,108.60	$ 16,182.66	$ 14,496.30	(913.54)	(612.30)	(5.3%)	(4.1%)	(547.08)	(3.5%)
	80%	264,000	$ 19,003.50	$ 16,831.44	$ 17,723.62	$ 15,909.88	(1,279.88)	(921.56)	(6.7%)	(5.5%)	(860.00)	(4.9%)
550	40%	161,000	$ 13,819.33	$ 12,068.26	$ 14,038.60	$ 12,445.87	$ 219.28	$ 377.61	1.6%	3.1%	$ 470.75	3.8%
	50%	201,000	$ 16,131.20	$ 14,156.55	$ 15,906.43	$ 14,159.29	(224.77)	2.74	(1.4%)	0.0%	91.46	0.6%
	60%	242,000	$ 18,500.88	$ 16,297.04	$ 17,820.96	$ 15,915.55	(679.91)	(381.49)	(3.7%)	(2.3%)	(297.31)	(1.8%)
	70%	282,000	$ 20,812.75	$ 18,385.33	$ 19,688.79	$ 17,628.98	(1,123.96)	(756.35)	(5.4%)	(4.1%)	(676.60)	(3.6%)
	80%	322,000	$ 23,124.63	$ 20,473.62	$ 21,556.63	$ 19,342.41	(1,568.01)	(1,131.22)	(6.8%)	(5.5%)	(1,055.90)	(5.0%)
650	40%	190,000	$ 16,264.35	$ 14,196.43	$ 16,517.43	$ 14,636.16	$ 253.08	$ 439.73	1.6%	3.1%	$ 549.84	3.7%
	50%	238,000	$ 19,038.60	$ 16,702.38	$ 18,758.83	$ 16,692.27	(279.77)	(10.11)	(1.5%)	(0.1%)	94.69	0.5%
	60%	285,000	$ 21,755.06	$ 19,156.12	$ 20,953.53	$ 18,705.55	(801.53)	(450.57)	(3.7%)	(2.4%)	(350.98)	(1.8%)
	70%	333,000	$ 24,529.31	$ 21,662.06	$ 23,194.93	$ 20,761.66	(1,334.38)	(900.41)	(5.4%)	(4.2%)	(806.13)	(3.6%)
	80%	381,000	$ 27,303.56	$ 24,168.01	$ 25,436.33	$ 22,817.77	(1,867.24)	(1,350.24)	(6.8%)	(5.6%)	(1,261.28)	(5.1%)
750	40%	220,000	$ 18,767.17	$ 16,376.81	$ 19,042.96	$ 16,869.29	$ 275.79	$ 492.48	1.5%	3.0%	$ 619.44	3.6%
	50%	275,000	$ 21,946.00	$ 19,248.21	$ 21,611.23	$ 19,225.25	(334.78)	(22.96)	(1.5%)	(0.1%)	97.92	0.5%
	60%	329,000	$ 25,067.04	$ 22,067.40	$ 24,132.80	$ 21,538.37	(934.24)	(529.02)	(3.7%)	(2.4%)	(414.13)	(1.8%)
	70%	384,000	$ 28,245.87	$ 24,938.80	$ 26,701.07	$ 23,894.34	(1,544.80)	(1,044.46)	(5.5%)	(4.2%)	(935.65)	(3.6%)
	80%	439,000	$ 31,424.70	$ 27,810.19	$ 29,269.33	$ 26,250.30	(2,155.36)	(1,559.90)	(6.9%)	(5.6%)	(1,457.18)	(5.1%)

[1] Bills are based on class average energy consumption by time period and season.
[2] Includes change to four-month summer season.

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison
IPC-E-23-11
Schedule 19 - Large Power Service - Primary

			Monthly Billing[1]				Change				Annual	
Load Size	Load		Current		Proposed		$		%		Average Change[2]	
kW	Factor	kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
1,000	40%	295,000	$ 25,119.95	$ 20,977.87	$ 28,343.70	$ 24,214.07	$ 3,223.75	$ 3,236.20	12.8%	15.4%	$ 3,577.22	16.3%
	50%	365,000	$ 28,992.79	$ 24,463.92	$ 31,682.25	$ 27,258.12	2,689.46	2,794.20	9.3%	11.4%	3,136.69	12.3%
	60%	440,000	$ 33,142.26	$ 28,198.96	$ 35,259.26	$ 30,519.59	2,117.00	2,320.63	6.4%	8.2%	2,664.70	9.1%
	70%	510,000	$ 37,015.10	$ 31,685.01	$ 38,597.81	$ 33,563.64	1,582.71	1,878.63	4.3%	5.9%	2,224.17	6.7%
	80%	585,000	$ 41,164.57	$ 35,420.05	$ 42,174.82	$ 36,825.12	1,010.25	1,405.07	2.5%	4.0%	1,752.17	4.8%
2,500	40%	730,000	$ 61,936.44	$ 51,622.67	$ 69,856.56	$ 59,564.03	$ 7,920.12	$ 7,941.36	12.8%	15.4%	$ 8,793.76	16.2%
	50%	915,000	$ 72,171.79	$ 60,835.79	$ 78,679.86	$ 67,609.01	6,508.07	6,773.22	9.0%	11.1%	7,629.50	12.0%
	60%	1,100,000	$ 82,407.15	$ 70,048.91	$ 87,503.16	$ 75,653.99	5,096.01	5,605.08	6.2%	8.0%	6,465.24	8.8%
	70%	1,280,000	$ 92,365.88	$ 79,013.02	$ 96,087.99	$ 83,481.53	3,722.11	4,468.51	4.0%	5.7%	5,332.45	6.5%
	80%	1,465,000	$ 102,601.24	$ 88,226.13	$ 104,911.29	$ 91,526.51	2,310.05	3,300.38	2.3%	3.7%	4,168.19	4.5%
3,500	40%	1,025,000	$ 86,757.39	$ 72,301.55	$ 97,770.26	$ 83,348.10	$ 11,012.87	$ 11,046.55	12.7%	15.3%	$ 12,239.98	16.1%
	50%	1,280,000	$ 100,865.59	$ 85,000.71	$ 109,932.11	$ 94,437.13	9,066.52	9,436.42	9.0%	11.1%	10,635.19	12.0%
	60%	1,535,000	$ 114,973.78	$ 97,699.86	$ 122,093.95	$ 105,526.15	7,120.17	7,826.28	6.2%	8.0%	9,030.41	8.9%
	70%	1,795,000	$ 129,358.61	$ 110,648.03	$ 134,494.27	$ 116,832.61	5,135.66	6,184.58	4.0%	5.6%	7,394.15	6.4%
	80%	2,050,000	$ 143,466.80	$ 123,347.19	$ 146,656.11	$ 127,921.63	3,189.31	4,574.44	2.2%	3.7%	5,789.37	4.5%
5,000	40%	1,465,000	$ 123,850.50	$ 103,195.35	$ 139,521.59	$ 118,915.49	$ 15,671.08	$ 15,720.14	12.7%	15.2%	$ 17,425.05	16.1%
	50%	1,830,000	$ 144,044.59	$ 121,372.58	$ 156,929.72	$ 134,788.02	12,885.13	13,415.44	8.9%	11.1%	15,128.00	11.9%
	60%	2,195,000	$ 164,238.67	$ 139,549.81	$ 174,337.85	$ 150,660.54	10,099.18	11,110.73	6.1%	8.0%	12,830.95	8.8%
	70%	2,560,000	$ 184,432.76	$ 157,727.04	$ 191,745.98	$ 166,533.07	7,313.22	8,806.03	4.0%	5.6%	10,533.90	6.4%
	80%	2,930,000	$ 204,903.47	$ 176,153.27	$ 209,392.58	$ 182,623.02	4,489.11	6,469.75	2.2%	3.7%	8,205.39	4.5%
7,000	40%	2,050,000	$ 173,215.78	$ 144,304.09	$ 195,110.53	$ 166,266.20	$ 21,894.75	$ 21,962.11	12.6%	15.2%	$ 24,348.96	16.1%
	50%	2,560,000	$ 201,432.17	$ 169,702.41	$ 219,434.22	$ 188,444.25	18,002.05	18,741.84	8.9%	11.0%	21,139.39	11.9%
	60%	3,075,000	$ 229,925.19	$ 195,349.73	$ 243,996.38	$ 210,839.73	14,071.18	15,490.00	6.1%	7.9%	17,898.35	8.8%
	70%	3,585,000	$ 258,141.59	$ 220,748.05	$ 268,320.06	$ 233,017.78	10,178.48	12,269.73	3.9%	5.6%	14,688.77	6.4%
	80%	4,100,000	$ 286,634.61	$ 246,395.37	$ 292,882.22	$ 255,413.26	6,247.61	9,017.89	2.2%	3.7%	11,447.73	4.5%
8,500	40%	2,490,000	$ 210,308.89	$ 175,197.90	$ 236,861.85	$ 201,833.59	$ 26,552.96	$ 26,635.69	12.6%	15.2%	$ 29,534.03	16.1%
	50%	3,110,000	$ 244,611.17	$ 206,074.29	$ 266,431.83	$ 228,795.14	21,820.65	22,720.86	8.9%	11.0%	25,632.20	11.9%
	60%	3,735,000	$ 279,190.09	$ 237,199.68	$ 296,240.27	$ 255,974.12	17,050.19	18,774.45	6.1%	7.9%	21,698.89	8.8%
	70%	4,355,000	$ 313,492.37	$ 268,076.06	$ 325,810.25	$ 282,935.67	12,317.88	14,859.61	3.9%	5.5%	17,797.06	6.4%
	80%	4,980,000	$ 348,071.28	$ 299,201.46	$ 355,618.69	$ 310,114.65	7,547.41	10,913.20	2.2%	3.6%	13,863.75	4.5%

[1] Bills are based on class average energy consumption by time period and season.
[2] Includes change to four-month summer season.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

ANDERSON, DI TESTIMONY

EXHIBIT NO. 55

Idaho Power Company
State of Idaho
Residential Price Modernization Plan
Filed June 1, 2023
IPC-E-23-11

Residential Service
Schedule 1 and Schedule 6

Line No.	Description	Adjusted 2023 Units	Test Year Price	Test Year Revenue Dollars	Year 1 Price	Year 1 Revenue Dollars	Year 2 Price	Year 2 Revenue Dollars	Year 3 Price	Year 3 Revenue Dollars
1	Service Charge	6,057,159	$ 5.00	$ 30,285,794	$ 15.00	$ 90,857,381	$ 25.00	$ 151,428,968	$ 35.00	$ 212,000,555
2	Minimum Charge	72,347	3.00	217,041	3.00	217,041	3.00	217,041	3.00	217,041
3	Summer Energy (Jun-Sep)									
4	First 800 kWh	1,158,501,794	$ 0.110788	$ 128,347,806	$ 0.102985	$ 119,308,307	$ 0.095182	$ 110,268,518	$ 0.087379	$ 101,228,728
5	801-2,000 kWh	534,019,069	0.133216	71,139,884	0.117937	62,980,607	0.102658	54,821,330	0.087379	46,662,052
6	All Additional kWh	99,239,843	0.158253	15,704,970	0.139291	13,823,217	0.115634	11,475,500	0.087379	8,671,478
7	Subtotal - Summer Energy	1,791,760,706	$ 0.120101	$ 215,192,661	$ 0.109451	$ 196,112,131	$ 0.098543	$ 176,565,347	$ 0.087379	$ 156,562,259
8	Non-Summer Energy (Oct-May)									
9	First 800 kWh	2,305,593,411	$ 0.102240	$ 235,724,142	$ 0.093050	$ 214,535,467	$ 0.083859	$ 193,344,758	$ 0.074669	$ 172,156,354
10	801-2,000 kWh	1,007,012,144	0.112716	113,506,327	0.100034	100,735,453	0.087351	87,963,518	0.074669	75,192,590
11	All Additional kWh	422,682,232	0.124832	52,764,437	0.107014	45,232,916	0.090306	38,170,742	0.074669	31,561,260
12	Subtotal - Non-Summer Energy	3,735,287,787	$ 0.107621	$ 401,994,906	$ 0.096513	$ 360,503,836	$ 0.085530	$ 319,479,017	$ 0.074669	$ 278,910,204
13	Subtotal - Total Energy	5,527,048,493		$ 617,187,567		$ 556,615,967		$ 496,044,365		$ 435,472,463
14	Total Adjusted Base Revenue			$ 647,690,401		$ 647,690,389		$ 647,690,373		$ 647,690,058

▪ END END ▪

Idaho Power Company
State of Idaho
Residential Price Modernization Plan
Filed June 1, 2023
IPC-E-23-11

Master-Metered Mobile Home Park Residential Service
Schedule 3

Line No.	Description	Adjusted 2023 Units	Test Year Price	Test Year Revenue Dollars	Year 1 Price	Year 1 Revenue Dollars	Year 2 Price	Year 2 Revenue Dollars	Year 3 Price	Year 3 Revenue Dollars
1	Service Charge	225	$ 5.00	$ 1,124	$ 15.00	$ 3,372	$ 25.00	$ 5,620	$ 35.00	$ 7,868
2	Summer Energy (Jun-Sep)	4,476,086	$ 0.111127	497,416	$ 0.110625	495,167	$ 0.110123	492,920	$ 0.109621	490,673
3	Total Adjusted Base Revenue			$ 498,540	$ 0.110625	$ 498,539		$ 498,540		$ 498,541

▪ END END ▪

Idaho Power Company
State of Idaho
Residential Price Modernization Plan
Filed June 1, 2023
IPC-E-23-11

Residential Service - Time-of-Use
Schedule 5

Line No.	Description	Adjusted 2023 Units	Test Year Price	Test Year Revenue Dollars	Year 1 Price	Year 1 Revenue Dollars	Year 2 Price	Year 2 Revenue Dollars	Year 3 Price	Year 3 Revenue Dollars
1	Service Charge	11,836	$ 5.00	$ 59,179	$ 15.00	$ 177,536	$ 25.00	$ 295,893	$ 35.00	$ 414,250
2	Minimum Charge	29	3.00	87	3.00	87	3.00	87	3.00	87
3	Summer Energy (Jun-Sep)									
4	On-Peak	999,802	$ 0.298812	$ 298,753	$ 0.279642	$ 279,587	$ 0.260477	$ 260,425	$ 0.241307	$ 241,259
5	Off-Peak	4,410,435	0.074703	329,473	0.069911	308,338	0.065119	287,203	0.060327	266,068
6	Subtotal - Summer Energy	5,410,238	$ 0.116118	$ 628,226	$ 0.108669	$ 587,925	$ 0.101221	$ 547,629	$ 0.093772	$ 507,328
7	Non-Summer Energy (Oct-May)									
8	On-Peak	2,279,827	$ 0.143981	$ 328,251	$ 0.134745	$ 307,195	$ 0.125509	$ 286,139	$ 0.116273	$ 265,082
9	Off-Peak	9,257,286	0.095987	888,581	0.089830	831,582	0.083672	774,576	0.077515	717,579
10	Subtotal - Non-Summer Energy	11,537,113	$ 0.105471	$ 1,216,832	$ 0.098706	$ 1,138,777	$ 0.091939	$ 1,060,714	$ 0.085174	$ 982,661
11	Subtotal - Total Energy	16,947,350		$ 1,845,058		$ 1,726,702		$ 1,608,343		$ 1,489,988
12	Total Adjusted Base Revenue			$ 1,904,324		$ 1,904,324		$ 1,904,323		$ 1,904,325

■ END　　END ■

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

ANDERSON, DI TESTIMONY

EXHIBIT NO. 56

Schedule 6 - Residential On-Site Generation — Non-Legacy Bill Impact - 2023 GRC

Average Energy Delivered/Imported

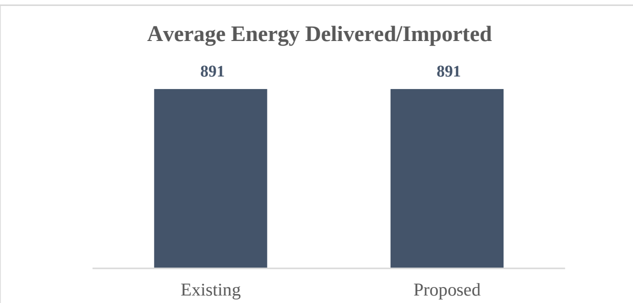
Category	Count	Energy Delivered Existing	Energy Delivered Proposed
0 kWh	2	-	-
1 ≤ 500 kWh	986	384	384
500 ≤ 900 kWh	1,475	674	674
900 ≤ 1,300 kWh	629	1,075	1,075
1,300 ≤ 1,700 kWh	313	1,484	1,484
1,700 kWh+	349	2,387	2,387
All Customers	**3,754**	**891**	**891**

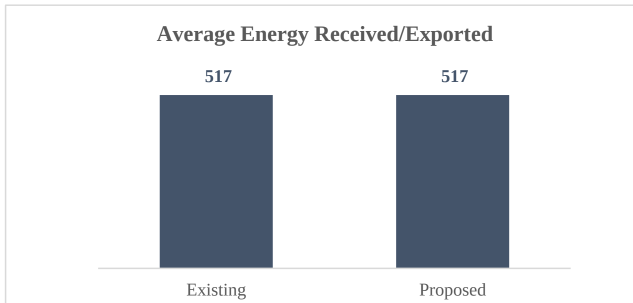
Average Energy Received/Exported

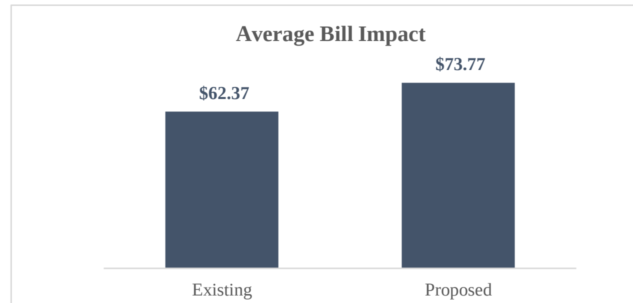
Category	Count	Energy Exported Existing	Energy Exported Proposed
0 kWh	2	465	465
1 ≤ 500 kWh	986	361	361
500 ≤ 900 kWh	1,475	459	459
900 ≤ 1,300 kWh	629	603	603
1,300 ≤ 1,700 kWh	313	747	747
1,700 kWh+	349	846	846
All Customers	**3,754**	**517**	**517**

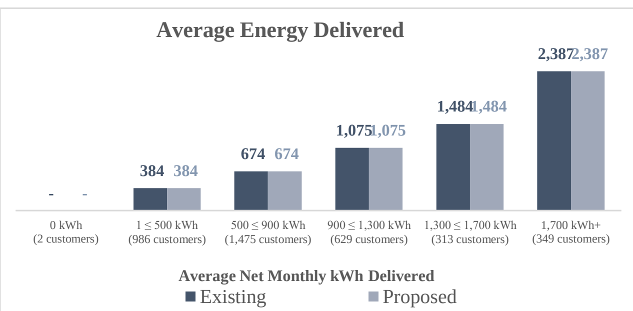
Average Bill Impact

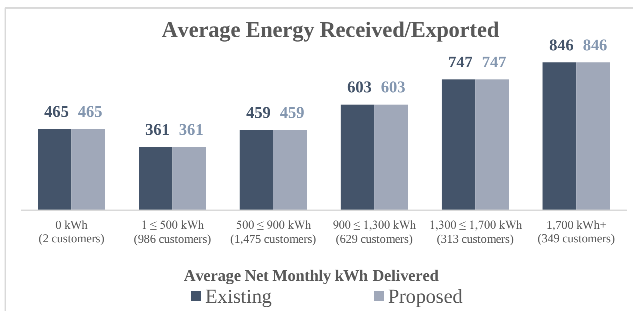
Category	Count	Avg. Monthly Bill Existing	Avg. Monthly Bill Proposed
0 kWh	2	$ 5.00	$ 15.00
1 ≤ 500 kWh	986	$ 21.54	$ 32.18
500 ≤ 900 kWh	1,475	$ 42.91	$ 54.48
900 ≤ 1,300 kWh	629	$ 73.91	$ 85.78
1,300 ≤ 1,700 kWh	313	$ 106.96	$ 118.87
1,700 kWh+	349	$ 199.56	$ 211.05
All Customers	**3,754**	**$ 62.37**	**$ 73.77**

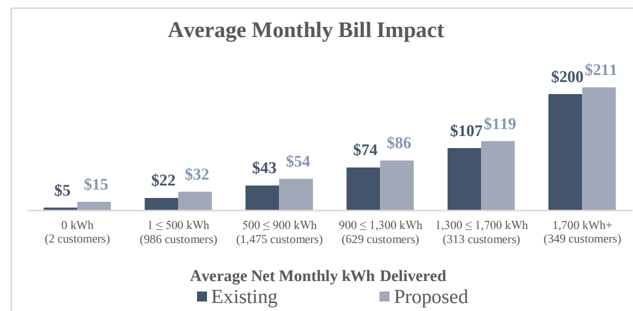












Schedule 8 - Small General Service On-Site Generation

Non-Legacy Bill Impact - 2023 GRC

Average Energy Delivered/Imported

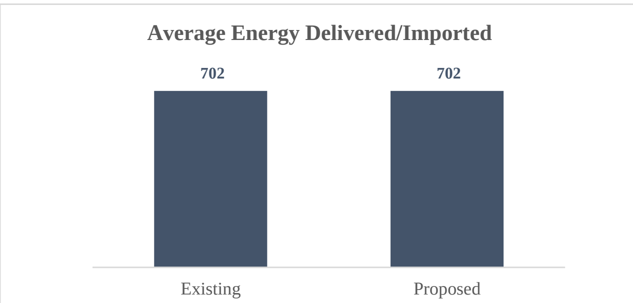
Category	Count	Energy Delivered Existing	Energy Delivered Proposed
0 kWh	-	-	-
1 ≤ 200 kWh	1	126	126
200 ≤ 400 kWh	2	348	348
400 ≤ 600 kWh	5	549	549
600 ≤ 800 kWh	1	685	685
800 kWh+	4	1,216	1,216
All Customers	**13**	**702**	**702**

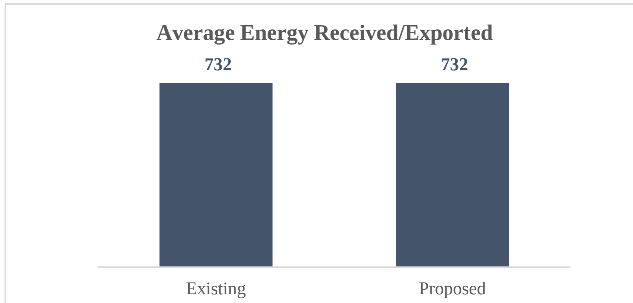
Average Energy Received/Exported

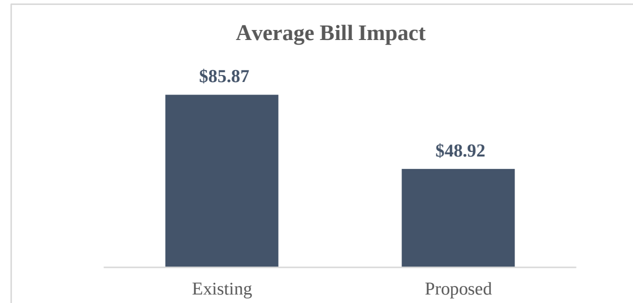
Category	Count	Energy Exported Existing	Energy Exported Proposed
0 kWh	-	-	-
1 ≤ 200 kWh	1	1,563	1,563
200 ≤ 400 kWh	2	517	517
400 ≤ 600 kWh	5	741	741
600 ≤ 800 kWh	1	761	761
800 kWh+	4	614	614
All Customers	**13**	**732**	**732**

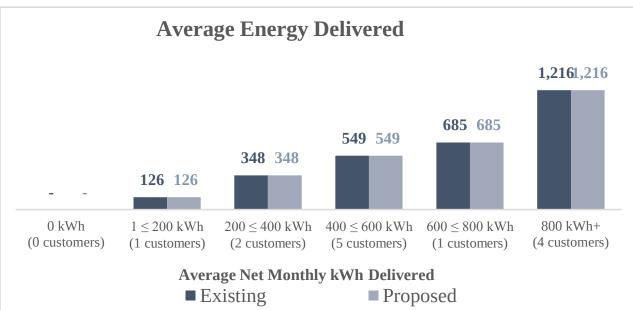
Average Bill Impact

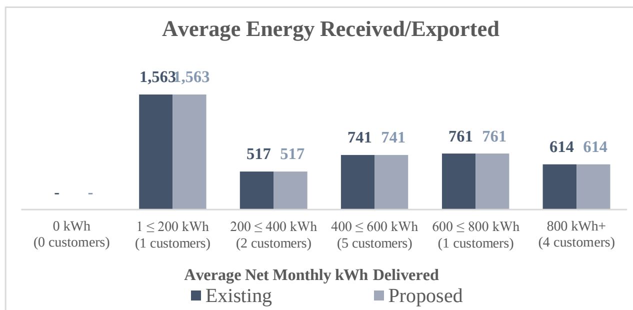
Category	Count	Avg. Monthly Bill Existing	Avg. Monthly Bill Proposed
0 kWh	-	$ -	$ -
1 ≤ 200 kWh	1	$ 19.05	$ 20.00
200 ≤ 400 kWh	2	$ 44.28	$ 20.61
400 ≤ 600 kWh	5	$ 67.94	$ 33.96
600 ≤ 800 kWh	1	$ 83.89	$ 37.91
800 kWh+	4	$ 146.28	$ 91.75
All Customers	**13**	**$ 85.87**	**$ 48.92**

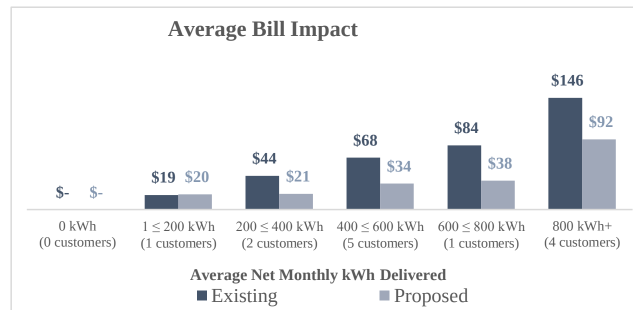












BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

ROBERT Z. THOMPSON

Q. Please state your name and business address.

A. My name is Robert Z. Thompson. I go by my middle name, and therefore, Zack Thompson is my preferred name. My business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. By whom are you employed, and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Regulatory Analyst in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 2008, I received a Bachelor of Arts degree in Business, Organizations, and Society with a minor in Economics from Franklin & Marshall College in Lancaster, Pennsylvania. In May of 2014, I received a Master of Business Administration degree with a specialization in Finance from Louisiana State University in Baton Rouge, Louisiana. I have also attended "The Basics: Practical Regulatory Training for the Electric Industry," an electric utility ratemaking course offered through the New Mexico State University's Center for Public Utilities, "Electric Utility Fundamentals and Insights," an electric utility course offered by Western Energy Institute, and "Electric Rates Advanced Course," an electric utility ratemaking course offered through Edison Electric Institute.

Q. Please describe your work experience with Idaho Power.

A. In 2020, I was hired as a Regulatory Analyst in the Company’s Regulatory Affairs Department. My primary responsibilities include supporting activities associated with demand-side management as well as rate design for the small general service, large general secondary service, lighting, and irrigation customer classes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe proposed changes and updates to Schedule 7, Small General Service (“Schedule 7”), Schedule 9, Large General Secondary Service (“Schedule 9S”), Schedule 24, Agricultural Irrigation Service (“Schedule 24”), Schedule 15, Dusk to Dawn Customer Lighting (“Schedule 15”), Schedule 41, Street Lighting Service (“Schedule 41”), Schedule 42, Traffic Control Signal Lighting Service (“Schedule 42”), and Schedule 40, Non-metered General Service (“Schedule 40”).

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Description
Exhibit No. 57	Calculation of Proposed Rates
Exhibit No. 58	Typical Monthly Billing Comparison

I. <u>SMALL GENERAL SERVICE & LARGE GENERAL SERVICE (SECONDARY)</u>

A. Schedule 7, Small General Service

Q. What is the revenue requirement to be recovered from Schedule 7 customers?

A. The annual revenue requirement to be recovered from Schedule 7 and Schedule 8 customers is $20,108,644 as shown on page 5 of Company Witness Mr. Paul Goralski's Exhibit No. 48, which represents the capped 12.91 percent increase in overall collection from the class.

Q. What is the present rate structure for Small General Service under Schedule 7?

A. Customers taking service under Schedule 7 pay a monthly Service Charge, a monthly seasonal Energy Charge for the first 300 kilowatt-hours ("kWh") used, and a separate seasonal Energy Charge for all usage over 300 kWh in a month. Summer Energy Charges begin on June 1 of each year and end on August 31 of each year while the non-summer Energy Charges begin on September 1 of each year and end on May 31 of each year. Schedule 7 customers do not have a Demand Charge.

Q. Please describe the proposed rate design adjustments for Schedule 7.

A. The Company is not proposing any structural changes to the Schedule 7 rate design. However, the Company is proposing to make three updates. The first update is increasing the service charge to $20.00, or an increase of $15.00, to move closer to the class cost of service. The second update is “flattening” the inclining energy block tiers to move closer towards flat energy rates. The third update is moving the summer seasonal rates from June 1 to August 31 to June 1 to September 30, or a three-month summer season to a four-month summer season, as explained by Company Witness Ms. Connie Aschenbrenner in her testimony.

Q. What did Idaho Power consider in making its $20.00 service charge proposal for Schedule 7 customers?

A. Beyond moving closer to cost of service, a primary focus was placed on maintaining a smooth transition if customers move from Schedule 7 to Schedule 9S because they exceed the eligibility criteria for continued service under Schedule 7.

Q. Have you prepared an exhibit that illustrates the rate design proposal for revenue recovery under Schedule 7?

A. Yes, the rate design proposal for Schedule 7 is included on page 1 of Exhibit No. 57.

Q. Have you prepared an exhibit that illustrates the impact of the proposed rate adjustments on Small General Service customers?

A. Yes, page 1 of Exhibit No. 58 shows the billing comparison between Schedule 7 existing rates and proposed rates for typical billing levels.

B. *Schedule 9, Large General Service*

Q. What is the revenue requirement to be recovered from customers taking Secondary Service under Schedule 9?

A. The annual revenue requirement to be recovered from customers taking Secondary Service under Schedule 9 is $272,747,096 as shown on page 5 of Mr. Goralski's Exhibit No. 48, which represents a 1.08 percent increase in overall collection from the class.

Standard Service Rate Design

Q. What is the current rate structure for Schedule 9S?

A. The current rate structure for Schedule 9S includes a two-tier declining block Energy Charge along with a block Demand Charge and a block Basic Charge. Under this rate structure, the first block Energy Charge applies to the first 2,000 kWh of usage per month and the second block Energy Charge applies to all usage greater than 2,000 kWh per month.

Under the Demand Charge, the first rate block applies to the first 20 kilowatts ("kW") of Billing Demand and the second block applies to all additional kW. For the

Basic Charge, the first rate block applies to the first 20 kW of Basic Load Capacity and the second block applies to all additional kW.

Q. Have you prepared an exhibit that illustrates the rate design proposal for revenue recovery under Schedule 9 Secondary Service?

A. Yes, the rate design proposal for Schedule 9 Secondary Service is included on page 3 of Exhibit No. 57.

Q. What changes is the Company proposing to the Schedule 9S structure?

A. The Company is proposing to: (1) change the 0-20 kW basic load capacity charge ("BLC") and demand charge blocks to assess a single rate for all kW, and (2) move from declining block energy rates to flat energy rates for both the summer and non-summer seasons.

Q. What other changes is the Company proposing for Schedule 9S?

A. The Company is proposing to increase the service charge to $25.00, or an increase of $9.00, to move closer to the class cost of service. The Company is also proposing moving the summer seasonal rates from June 1 to August 31 to June 1 to September 30, or a three-month summer season to a four-month summer season, as explained by Ms. Aschenbrenner in her testimony. Finally, for all non-service charge rate components, the Company is proposing rates that represent a 30 percent incremental movement towards the costs to serve that rate component.

Q. Have you prepared an exhibit that shows the bill impact for the proposed Schedule 9S rate design?

A. Yes. Pages 2 through 4 of Exhibit No. 58 show the billing comparison between the Schedule 9S existing rates and proposed rates for typical billing levels. As can be seen from this exhibit, generally for each Demand level, the higher load factor customers will see a decrease in their overall bills as compared to low load factor customers that will see an increase. For the Demand levels below 20 kW, customers will generally see bill decreases based on the removal of the 0-20 kW BLC and Demand blocks.

Optional Time-of-Use Service Schedule

Q. How did you develop the proposed optional Schedule 9S time-of-use ("TOU") service offering?

A. The optional Schedule 9S TOU service offering will incorporate the same structure as the proposed Schedule 9S standard service offering described above except that instead of seasonal flat energy charges there will be seasonal time-differentiated energy rates which include on-, mid-, and off-peak blocks for the summer and non-summer seasons. Ms. Aschenbrenner explains in greater detail in her testimony the rationale for offering customers the optional TOU Service under Schedule 9S.

Q. What definition for on-, mid-, and off-peak does the Company propose for Schedule 9S?

A. The proposed TOU periods will mirror those proposed for the other large general and large power service schedules, as described by Company Witness Mr. Grant Anderson. Accordingly, the proposed definition of the TOU periods for the summer season are:

- On-Peak: 7:00 p.m. to 11:00 p.m. Monday through Saturday, except holidays
- Mid-Peak: 3:00 p.m. to 7:00 p.m. and 11:00 p.m. to 12:00 a.m. Monday through Saturday, except holidays
- Off-Peak: 12:00 a.m. to 3:00 p.m. Monday through Saturday and all hours on Sunday and holidays

For the non-summer season, the Company proposes to change the definition of the TOU periods to the following:

- On-Peak: 6:00 a.m. to 9:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday through Saturday, except holidays
- Mid-Peak: 9:00 a.m. to 12:00 p.m., 4:00 p.m. to 5:00 p.m., and 8:00 p.m. to 10:00 p.m. Monday through Saturday, except holidays
- Off-Peak: 10:00 p.m. to 6:00 a.m. and 12:00 p.m. to 4:00 p.m. Monday through Saturday and all hours on Sunday and holidays

Q. Have you prepared an exhibit that illustrates the rate design proposal for the optional TOU service under Schedule 9S?

A. Yes, the rate design proposal for the optional TOU service under Schedule 9S is included on page 4 of Exhibit No. 57.

II. <u>IRRIGATION</u>

A. Schedule 24, Agricultural Irrigation Service

Q. What is the revenue requirement to be recovered from Schedule 24?

A. The annual revenue to be recovered from Schedule 24 customers is $183,423,605, as shown on page 5 of Mr. Goralski’s Exhibit No. 48, which represents the capped 12.91 percent increase in overall collection from the class.

Q. What is the current rate structure for Schedule 24?

A. Service under Schedule 24 is classified as being either “in-season” or “out-of-season.” The in-season for each customer begins with the customer’s meter reading for the May billing period and ends with the customer’s meter reading for the September billing period. The out-of-season encompasses all other billing periods.

For the in-season, customers pay a higher monthly Service Charge than during the out-of-season to encourage customers to continue service throughout the out-of-season period.

Customers pay both an Energy Charge and a Demand Charge for metered usage in-season. The Energy Charge utilizes a load-factor pricing mechanism by separating charges into two energy blocks. The first block charges irrigation customers a monthly rate per kWh for the first 164 kWh per kW of demand. The second block charges customers a lower monthly energy rate per kWh for all other energy use to encourage installation of energy efficient irrigation systems with reduced demand and longer hours of operation. Customers pay an in-season Demand Charge only. During the out-of-season, customers pay a flat Energy Charge per kWh for all energy use.

Both Secondary Service and Transmission Service are available under Schedule 24, although no customers are currently taking Transmission Service.

Q. What is Idaho Power’s rate design proposal for Schedule 24?

A. The Company is proposing one structural change to the Schedule 24 rate design along with one update. The structural change includes removing the in-season load factor energy pricing and only charging a flat rate per kWh, which is the same structure as the out-of-season energy charge. The current in-season load factor energy rate structure was intended to collect demand related costs in the first block rather than increasing the demand charge. This helped the Company collect some of its fixed costs as long as customers ran their pumps for about 7 days within a month. However, from a customer understandability standpoint, it has sometimes been a source of confusion, particularly because the out-of-season rate does not have the load factor pricing structure. Therefore, the Company is proposing both the in-season and out-of-season volumetric rates have the same structure.

The proposed update to the Schedule 24 rate design increases both the in-season and out-of-season service charges from $22.00 and $3.50 to $30.00 and $6.00, respectively, for an increase of $8.00 for in-season and $2.50 for out-of-season, to move closer to the class cost of service.

Consistent with the overall rate design objectives, the Company is proposing to move the other non-service charge rate components closer to their cost-of-service with rates that represent a 30 percent incremental movement towards the costs to serve that rate component.

Q. Have you prepared an exhibit that illustrates the rate design proposal for revenue recovery under Schedule 24?

A. Yes, the rate design proposal for Schedule 24 is included on page 5 of Exhibit No. 57.

Q. How were the rates for Transmission Service determined?

A. Because no customers take Transmission Service under Schedule 24, once the percentage revenue changes for each rate component were determined for Secondary Service, the same percentage changes were applied to each component for Transmission Service to maintain the same relationship between the service levels that currently exists.

Q. Have you prepared an exhibit that shows the billing impact of the rate design on Schedule 24 irrigation service customers?

A. Yes, pages 5 through 7 of Exhibit No. 58 show the impact on customers’ bills of the proposed rate adjustments for Schedule 24 Secondary Service. As can be seen page 7 from Exhibit No. 58, with the transition from load factor pricing to flat energy rate pricing and an increased demand charge, customers with the highest percentage increase in annual bills have the lowest average load factors. Because the rate design promotes using the system efficiently, the higher a customer's load factor, the more beneficial the rate structure tends to be.

III. <u>LIGHTING & NON-METERED</u>

Q. How have you organized the discussion of the rate design proposals for area lighting, unmetered service, street lighting and traffic control signal lighting?

A. The discussion of rate design proposals for lighting will address Schedules 15 (Dusk to Dawn Customer Lighting), 41 (Street Lighting Service), 42 (Traffic Control Signal Lighting Service), and 40 (Non-metered General Service), respectively.

A. Schedule 15, Dusk to Dawn Customer Lighting

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 15?

A. The annual revenue requirement to be recovered from Schedule 15 customers is $1,327,038 as shown on page 5 of Mr. Goralski’s Exhibit No. 48 which represents a zero percent increase in overall collection from the class.

Q. What is the current rate structure for Dusk to Dawn Customer Lighting under Schedule 15?

A. Customers taking service under Schedule 15 are charged on a per lamp basis. Lamps currently served under Schedule 15 include 100, 200, and 400 watt high pressure sodium vapor area lighting, 40, 85, and 200 watt Light Emitting Diode (“LED”) area lighting; 200 and 400 watt high pressure sodium vapor flood lighting, 85, 150, and 300 watt

LED flood lighting, and 400 and 1,000 watt metal halide flood lighting.

Q. What is the status of the Company's LED conversion project authorized per Order No. 34452?

A. The Company is on schedule to complete its LED conversion project before September 30, 2023. At that time, all lighting fixtures under Schedules 15 and 41 will have been converted to LED fixtures and the Company will no longer support high pressure sodium vapor or metal halide fixtures.

Q. Have you prepared an exhibit that illustrates the rate design proposal for Schedule 15?

A. Yes. The rate design proposal for Schedule 15 is included on page 7 of Exhibit No. 57 which includes base rate increases to recover the proposed revenue requirement. The Company proposes to allocate the class revenue requirement to the rate components based on a separate lighting cost-of-service study ("Lighting Study") conducted for both Schedules 15 and 41 for each fixture size offered under those schedules. The Lighting Study is contained in my workpapers.

Q. Is the Company proposing any other changes to Schedule 15?

A. As mentioned above, the Company will have completed its LED conversion project by September 30, 2023.

Therefore, the high pressure sodium vapor and metal halide options are being removed with only the LED area lighting and flood lighting rates remaining in the tariff.

B. Schedule 41, Street Lighting Service

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 41?

A. The annual revenue requirement to be recovered from Schedule 41 is $3,750,417 as shown on page 5 of Mr. Goralski's Exhibit No. 48, which represents a zero percent increase in overall collection from the class.

Q. What is the present rate structure for Street Lighting Service under Schedule 41?

A. The current rate structure for Schedule 41 has three service options for street lighting customers as follows:

- "A" – Idaho Power-Owned, Idaho Power-Maintained System
- "B"- Customer-Owned, Idaho Power-Maintained System
- "C" – Customer-Owned, Customer-Maintained System

Option "A" provides for Idaho Power-owned and Idaho Power-maintained street lighting systems. Street lighting systems under this option are not metered and customers pay monthly lamp charges based on high pressure sodium vapor lamps of 70, 100, 200, 250 or 400 watts or their LED equivalents of 40, 85, 140, and 200 watts. The monthly lamp charges under Option “A” reflect the Company’s cost to provide energy, install the street lighting system, and provide ongoing maintenance.

Option “B” provides for metered or unmetered Customer-Owned, Idaho Power-Maintained systems using 70, 100, 200, 250, or 400 watt high pressure sodium vapor lamps. Option “B” is currently not open to new service and will close by September 30, 2023, per Order No. 34452.

Option “C” provides for customers choosing to own and install their own street lighting systems. Under this option, street lighting systems may be metered or non-metered. For metered and non-metered systems, maintenance is provided by the customer.

Q. Please describe the proposed updates to Option “A”.

A. Beyond the proposed rate changes informed by the Lighting Study for Schedules 15 and 41 contained in my workpapers, the Company proposes to remove language referencing “the Accelerated Replacement of Existing Fixtures” as this charge was only related to the LED conversion project and allowed customers to convert to LED fixtures at an additional cost before the Company had them scheduled. The Company also proposes to update the Dark Sky Lighting option to remove the high-pressure sodium vapor lens and replace with an LED shield with a cost of $27.50 for customers who want to alter their LED fixtures for dark sky lighting. The derivation of this value is shown in my workpapers.

Q. What changes are being proposed to Option “C” in Schedule 41?

A. Beyond the proposed rate changes informed by the Lighting Study for Schedules 15 and 41 contained in my workpapers, no other changes are being proposed for Option “C”. There will continue to be metered and non-metered service for customer-owned, customer-maintained systems.

Q. Is the Company proposing any other changes to Schedule 41?

A. Yes, the Company proposes to remove all high-pressure sodium vapor language and wattages leaving the schedule to only reference LED fixtures and to remove all contents from the tariff associated with Option “B” as this option will be closed by September 30, 2023.

Q. Have you prepared an exhibit that illustrates the rate design proposal for Schedule 41?

A. Yes, the rate design proposal for Schedule 41 is included on pages 8 through 11 of Exhibit No. 57.

C. Schedule 42, Traffic Control Signal Lighting Service

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 42?

A. The annual revenue requirement to be recovered from Schedule 42 customers is $224,972 as shown on page 5 of Mr. Goralski's Exhibit No. 48, which represents the capped 12.91 percent increase in overall collection from the class.

Q. What is the present rate structure for Traffic Control Signal Lighting Service, Schedule 42?

A. Customers taking service under Schedule 42 pay an Energy Charge for each kWh of estimated energy use for non-metered systems and for each kWh of actual usage for metered systems. For non-metered systems, usage is estimated based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated. There is no minimum charge under Schedule 42.

Q. Please describe the rate design proposal for Schedule 42.

A. The rate design proposal for Schedule 42 is included on page 12 of Exhibit No. 57. The Company is proposing to increase the energy charge to target the proposed capped class revenue increase of 12.91 percent shown on page 5 of Mr. Goralski's Exhibit No. 48.

D. Schedule 40, Unmetered General Service

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 40?

A. The annual revenue requirement to be recovered from Schedule 40 customers is $1,352,288 as shown on page 5 of Mr. Goralski’s Exhibit No. 48, which represents a 3.24 percent increase in overall collection from the class.

Q. What is the present rate structure for Unmetered General Service under Schedule 40?

A. Customers taking service under Schedule 40 are non-metered but have energy loads and periods of operation which are fixed. Accordingly, a customer’s estimated usage is charged a flat Energy Charge which recovers all costs assigned to the class. The minimum bill for service under Schedule 40 is $1.50 per month. At the Company’s discretion, an Intermittent Usage Charge, per unit, per month, may be charged to municipalities or agencies of federal, state, or county governments having the potential of intermittent variations in energy usage.

Q. Please describe the rate design proposal for Schedule 40.

A. The rate design proposal for Schedule 40 is included on page 13 of Exhibit No. 57. The Company is proposing to increase the Intermittent Usage Charge from $1.00 to $1.50, or an increase of $0.50, as well as increase the energy charge to target the proposed class revenue increase of 3.24 percent as shown on page 5 of Mr. Goralski’s Exhibit No. 48.

Q. Are any other changes being proposed to Schedule 40?

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

//

DECLARATION OF ROBERT Z. THOMPSON

I, Robert Z. Thompson, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Robert Z. Thompson. I am employed by Idaho Power Company as a Regulatory Analyst in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 57 through 58 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: ______________________________
ROBERT Z. THOMPSON

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

THOMPSON, DI TESTIMONY

EXHIBIT NO. 57

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Small General Service
Schedule 7 and Schedule 8 Combined

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	365,860	$ 5.00	$ 1,829,301	$ 20.00	$ 7,317,204
2	Minimum Charge	2,183	2.00	4,366	3.00	6,549
3	Summer Energy (Jun-Aug)					
4	0 - 300 kWh	15,552,833	$ 0.098633	$ 1,534,023		
5	All Additional kWh	19,695,659	0.117472	2,313,688		
6	Subtotal - Summer Energy	35,248,492	$ 0.109160	$ 3,847,711		
7	Non-Summer Energy (Sep-May)					
8	0 - 300 kWh	48,683,072	$ 0.098633	$ 4,801,757		
9	All Additional kWh	54,724,304	0.103486	5,663,199		
10	Subtotal - Non-Summer Energy	103,407,376	$ 0.101201	$ 10,464,957		
11	Subtotal - Total Energy	138,655,868		$ 14,312,668		
12	Summer Energy (Jun-Sep)					
13	0 - 300 kWh	20,489,851			$ 0.089863	$ 1,841,279
14	All Additional kWh	25,224,107			0.102694	2,590,364
15	Subtotal - Summer Energy	45,713,958			$ 0.096943	$ 4,431,644
16	Non-Summer Energy (Oct-May)					
17	0 - 300 kWh	43,567,779			$ 0.089863	$ 3,915,131
18	All Additional kWh	49,374,131			0.089887	4,438,093
19	Subtotal - Non-Summer Energy	92,941,910			$ 0.089876	$ 8,353,224
20	Subtotal - Total Energy	138,655,868				$ 12,784,868
21	Transfer Adjustment Revenue			$ 1,662,745		
22	Total Adjusted Base Revenue			$ 17,809,080		$ 20,108,621

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Small General Service
Schedule 7

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	364,810	$ 5.00	$ 1,824,051	$ 20.00	$ 7,296,204
2	Minimum Charge	2,177	2.00	4,354	3.00	6,531
3	Summer Energy (Jun-Aug)					
4	0 - 300 kWh	15,526,486	$ 0.098633	$ 1,531,424		
5	All Additional kWh	19,639,552	0.117472	2,307,097		
6	Subtotal - Summer Energy	35,166,038	$ 0.109154	$ 3,838,521		
7	Non-Summer Energy (Sep-May)					
8	0 - 300 kWh	48,565,776	$ 0.098633	$ 4,790,188		
9	All Additional kWh	54,553,347	0.103486	5,645,508		
10	Subtotal - Non-Summer Energy	103,119,122	$ 0.101200	$ 10,435,696		
11	Subtotal - Total Energy	138,285,160		$ 14,274,217		
12	Summer Energy (Jun-Sep)					
13	0 - 300 kWh	20,448,718			$ 0.089863	$ 1,837,583
14	All Additional kWh	25,155,159			0.102694	2,583,284
15	Subtotal - Summer Energy	45,603,878			$ 0.096941	$ 4,420,867
16	Non-Summer Energy (Oct-May)					
17	0 - 300 kWh	43,462,704			$ 0.089863	$ 3,905,689
18	All Additional kWh	49,218,578			0.089887	4,424,110
19	Subtotal - Non-Summer Energy	92,681,282			$ 0.089876	$ 8,329,799
20	Subtotal - Total Energy	138,285,160				$ 12,750,666
21	Transfer Adjustment Revenue			$ 1,658,298		
22	Total Adjusted Base Revenue			$ 17,760,920		$ 20,053,401

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Large General Service
Schedule 9 Secondary Standard Service

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	453,162	$ 16.00	$ 7,250,592	$ 25.00	$ 11,329,050
2	Minimum Charge	1,784	5.00	8,920	3.00	5,352
3	Basic Charge					
4	Total Basic Charge (Current)	8,516,555	$ 1.03	$ 8,772,052		
5	Total Basic Charge (Proposed)	15,010,667			$ 1.47	$ 22,065,681
6	Demand Charge (Current)					
7	0-20 kW	5,349,195	$ -	$ -		
8	Over 20 kW - Summer	1,562,250	6.06	9,467,238		
9	Over 20 kW - Non-Summer	4,230,876	4.45	18,827,398		
10	Total Demand	11,142,321		$ 28,294,636		
11	Demand Charge (Proposed)					
12	Summer kW	3,897,816			$ 7.60	$ 29,623,401
13	Non-Summer kW	7,244,505			5.99	43,394,587
14	Total Demand	11,142,321				$ 73,017,988
15	Summer Energy (Current)					
16	0-2,000 kWh	166,185,698	$ 0.105250	$ 17,491,045		
17	Over 2,000 kWh	705,756,622	0.048716	34,381,640		
18	Subtotal - Summer Energy	871,942,320	$ 0.059491	$ 51,872,684		
19	Non-Summer Energy (Current)					
20	0-2,000 kWh	514,806,364	$ 0.094742	$ 48,773,785		
21	Over 2,000 kWh	1,934,795,934	0.044196	85,510,241		
22	Subtotal - Non-Summer Energy	2,449,602,298	$ 0.054819	$ 134,284,026		
23	Subtotal - Total Energy	3,321,544,618		$ 186,156,710		
24	Summer Energy (Jun-Sep)					
25	All kWh	1,143,297,617			$ 0.051289	$ 58,638,591
26	Non-Summer Energy (Oct-May)					
27	All kWh	2,178,247,001			$ 0.049439	$ 107,690,353
28	Subtotal - Total Energy	3,321,544,618				$ 166,328,945
29	Transfer Adjustment Revenue			$ 39,344,999		
30	Total Adjusted Base Revenue			$ 269,827,909		$ 272,747,016

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Large General Service
Schedule 9 Secondary TOU Service

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Service Charge	453,162	$ 16.00	$ 7,250,592	$ 25.00	$ 11,329,050
2	Minimum Charge	1,784	5.00	8,920	3.00	5,352
3	Basic Charge					
4	Total Basic Charge (Current)	8,516,555	$ 1.03	$ 8,772,052		
5	Total Basic Charge (Proposed)	15,010,667			$ 1.47	$ 22,065,681
6	Demand Charge (Current)					
7	0-20 kW	5,349,195	$ -	$ -		
8	Over 20 kW - Summer	1,562,250	6.06	9,467,238		
9	Over 20 kW - Non-Summer	4,230,876	4.45	18,827,398		
10	Total Demand	11,142,321		$ 28,294,636		
11	Demand Charge (Proposed)					
12	Summer kW	3,897,816			$ 7.60	$ 29,623,401
13	Non-Summer kW	7,244,505			5.99	43,394,587
14	Total Demand	11,142,321				$ 73,017,988
15	Summer Energy (Current)					
16	0-2,000 kWh	166,185,698	$ 0.105250	$ 17,491,045		
17	Over 2,000 kWh	705,756,622	0.048716	34,381,640		
18	Subtotal - Summer Energy	871,942,320	$ 0.059491	$ 51,872,684		
19	Non-Summer Energy (Current)					
20	0-2,000 kWh	514,806,364	$ 0.094742	$ 48,773,785		
21	Over 2,000 kWh	1,934,795,934	0.044196	85,510,241		
22	Subtotal - Non-Summer Energy	2,449,602,298	$ 0.054819	$ 134,284,026		
23	Subtotal - Total Energy	3,321,544,618		$ 186,156,710		
24	Summer Energy (Jun-Sep)					
25	On-Peak	158,721,787			$ 0.054902	$ 8,714,144
26	Mid-Peak	229,027,384			0.054902	12,574,061
27	Off-Peak	755,548,446			0.049431	37,347,515
28	Subtotal - Summer Energy	1,143,297,617			$ 0.051286	$ 58,635,720
29	Non-Summer Energy (Oct-May)					
30	On-Peak	482,938,805			$ 0.052290	$ 25,252,870
31	Mid-Peak	506,997,039			0.049947	25,322,981
32	Off-Peak	1,188,311,158			0.048066	57,117,364
33	Subtotal - Non-Summer Energy	2,178,247,001			$ 0.049440	$ 107,693,215
34	Subtotal - Total Energy	3,321,544,618				$ 166,328,936
35	Transfer Adjustment Revenue			$ 39,344,999		
35	Total Adjusted Base Revenue			$ 269,827,909		$ 272,747,007

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed June 1, 2023
IPC-E-23-11

Agricultural Irrigation Service
Schedule 24 Secondary Service

Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
1	Bills-In Season	77,670	$ 22.00	$ 1,708,747	$ 30.00	$ 2,330,109
2	Bills-Out Season	152,477	3.50	533,668	6.00	914,859
3	Mininum Charge	379	1.50	568	3.00	1,136
4	Total Service Charge	230,525		$ 2,242,982		$ 3,246,104
5	Demand Charge					
6	Total In-Season	4,065,427	$ 7.06	$ 28,701,912	$ 15.08	$ 61,306,634
7	Total Out-Season	-	-	-	-	$ -
8	Total Demand	4,065,427		$ 28,701,912		$ 61,306,634
9	In-Season Energy (Current)					
10	First 164 kWh per kW	610,778,359	$ 0.058436	$ 35,691,444		
11	All Other kWh In-Season	897,748,435	0.055483	49,809,776		
12	Subtotal - In-Season Energy	1,508,526,794	$ 0.056679	$ 85,501,221		
13	Out-Season Energy (Current)					
14	All kWh	355,995,978	$ 0.067084	$ 23,881,634		
15	Subtotal - Total Energy	1,864,522,772		$ 109,382,855		
16	In-Season Energy (Proposed)					
17	All kWh	1,508,526,794			$ 0.061572	$ 92,883,012
18	Out-Season Energy (Proposed)					
19	All kWh	355,995,978			$ 0.073000	$ 25,987,706
20	Subtotal - Total Energy	1,864,522,772				$ 118,870,718
21	Transfer Adjustment Revenue			$ 22,120,084		
22	Total Adjusted Base Revenue			$ 162,447,833		$ 183,423,455

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
IPC-E-23-11 General Rate Case
IPC-E-23-11

Agricultural Irrigation Service
Schedule 24 Transmission Service

Line No	Description	(1) Use	(2) Current Rate	(3) Current Revenue	(4) Prposed Structure	(5) Proposed Use	(6) Proposed Rate	(7) Proposed Revenue
1	Bills-In Season	0	$ 299.00	$ -	Bills-In Season	0	$ 430.00	$ -
2	Bills-Out Season	0	$ 3.50	$ -	Bills-Out Season	0	$ 6.00	$ -
3	Demand Charge				Demand Charge			
4	Total In-Season	0	$ 6.66	$ -	Total In-Season	0	$ 14.23	$ -
5	Total Out-Season	0	$ -	$ -	Total Out-Season	0	$ -	$ -
6	Total kW	0		$ -	Total Demand	0		$ -
7	Energy Charge				Energy Charge			
8	First 164 kWh per kW	0	$ 0.055978	$ -	In-Season Energy	0	$ 0.058972	$ -
9	All Other kWh In-Season	0	$ 0.053233	$ -	Out-Season Energy	0	$ 0.069670	$ -
10					Total Energy	0		$ -
11	Total Out-Season	0	$ 0.064032	$ -				
12	Total Energy	0		$ -	Total Adjusted Base Revenue			$ -
13	Total Adjusted Base Revenue			$ -				

Idaho Power Company
Calculation of Proposed Rates
State of Idaho
IPC-E-23-11 General Rate Case
Filed June 1, 2023

Dusk-to-Dawn Customer Lighting
Schedule 15

Line No	Description	(1) Annual Lamps	(2) kWh Use	(3) Current Base Rate	(4) Current Base Revenue	(5) Proposed Structure	(6) Annual Lamps	(7) kWh Use	(8) Proposed Base Rate	(9) Proposed Base Revenue
1	Lamps					Area Lighting				
2	100-Watt Sodium Vapor (A)	89,714	0	$ 9.63	$ 863,946	40 Watt Max	89,714	0	$ 9.46	$ 848,694
3	200-Watt Sodium Vapor (A)	9,459	0	$ 11.50	$ 108,777	85 Watt Max	9,459	0	$ 11.52	$ 108,966
4	400-Watt Sodium Vapor (A)	1,801	0	$ 15.57	$ 28,035	200 Watt Max	1,801	0	$ 16.62	$ 29,925
5	200-Watt Sodium Vapor (D)	9,599	0	$ 13.78	$ 132,280					
6	400-Watt Sodium Vapor (D)	5,387	0	$ 16.24	$ 87,493	Flood Lighting				
7	400-Watt Metal Halide (D)	1,164	0	$ 14.91	$ 17,356	85 Watt Max	9,599	0	$ 18.81	$ 180,565
8	1000-Watt Metal Halide(D)	956	0	$ 23.71	$ 22,665	150 Watt Max	6,552	0	$ 20.70	$ 135,618
9						300 Watt Max	956	0	$ 24.34	$ 23,267
10	Total	118,080	5,267,423		$ 1,260,552					
11						Total	118,080	5,267,423		$ 1,327,035
12	Mininum Charge	434		$ 3.00	$ 1,301					
13						Mininum Charge	434		$ -	$ -
14	Transfer Adjustment				$ 65,185					
15						Transfer Adjustment				$ -
16	Total Adjusted Base Revenue				$ 1,327,038					
17						Total Adjusted Base Revenue				$ 1,327,035

Idaho Power Company
Calculation of Proposed Rates
State of Idaho
IPC-E-23-11 General Rate Case
Filed June 1, 2023

Street Lighting Service
Schedule 41

Summary

Line No	Description	(1) Current Use	(2) Current Base Revenue	(3) Proposed Use	(4) Proposed Base Revenue
1	A - Company-Owned, Non-Metered, Maintenance	4,153,143	$ 2,359,648	4,153,143	$ 2,421,861
2	B - Customer-Owned, Non-Metered, Maintenance	2,214,987	$ 149,735	0	$ -
4	BM - Customer-Owned, Metered, Maintenance	78,103	$ 4,750	0	$ -
5	C - Customer-Owned, Non-Metered, No Maintenance	10,704,238	$ 560,902	12,919,225	$ 820,758
6	CM - Customer-Owned, Metered, No Maintenance	6,609,543	$ 388,286	6,687,646	$ 507,785
7	Total Bills	35,760		35,760	
8	Total kWh	23,760,014		23,760,014	
9	Transfer Adjustment		$ 287,095		$ -
10	Total Adjusted Base Revenue		$ 3,750,417		$ 3,750,405

Idaho Power Company
Calculation of Proposed Rates
State of Idaho
IPC-E-23-11 General Rate Case
Filed June 1, 2023

Street Lighting Service (cont'd)
Schedule 41

A - Company-Owned, Non-Metered, Maintenance

Line No	Description	(1) Annual Lamps		(2) Current Base Rate		(3) Current Base Revenue	(4) Proposed Structure	(5) Annual Lamps		(6) Proposed Base Rate		(7) Proposed Base Revenue
1	Sodium Vapor / LED						LED					
2	70-Watt / 40-Watt Max	431	$	11.55	$	4,978	40-Watt Max	180,477	$	11.50	$	2,075,481
3	100-Watt / 40-Watt Max	180,046	$	11.01	$	1,982,302	85-Watt Max	20,137	$	13.44	$	270,644
4	200-Watt / 85-Watt Max	20,137	$	14.75	$	297,024	140-Watt Max	2,799	$	15.42	$	43,161
5	250-Watt / 140-Watt Max	2,799	$	16.05	$	44,924	200-Watt Max	1,486	$	19.10	$	28,379
6	400-Watt / 200-Watt Max	1,486	$	18.30	$	27,190	Total LED	204,899			$	2,417,665
7	Total Sodium Vapor / LED	204,899			$	2,356,419						
8	Non-Metered - Variable Energy Use	43,270	$	0.07464	$	3,230		43,270	$	0.09697	$	4,196
9	A - Company-Owned, Non-Metered, Maintenance				$	2,359,648					$	2,421,861

Idaho Power Company
Calculation of Proposed Rates
State of Idaho
IPC-E-23-11 General Rate Case
Filed June 1, 2023

Street Lighting Service (cont'd)
Schedule 41

B - Customer-Owned, Non-Metered, Maintenance

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Structure	(5) Annual Lamps	(6) Proposed Base Rate	(7) Proposed Base Revenue
1	70-Watt	0	$ 3.11	$ -	N/A	0	$ -	$ -
2	100-Watt	23,799	$ 3.48	$ 82,821	N/A	0	$ -	$ -
3	200-Watt	1,226	$ 5.03	$ 6,167	N/A	0	$ -	$ -
4	250-Watt	8,039	$ 6.20	$ 49,842	N/A	0	$ -	$ -
5	400-Watt	1,245	$ 8.76	$ 10,906	N/A	0	$ -	$ -
6	Total Sodium Vapor	34,309		$ 149,735		0		$ -
7	Non-Metered - Variable Energy Use	0	$ 0.07464	$ -	N/A	0	$ -	$ -
8	B - Customer-Owned, Non-Metered, Maintenance			$ 149,735				$ -

BM - Customer-Owned, Metered, Maintenance

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Structure	(5) Annual Lamps	(6) Proposed Base Rate	(7) Proposed Base Revenue
9	Sodium Vapor							
10	70-Watt	0	$ 1.37	$ -	N/A	0	$ -	$ -
11	100-Watt	0	$ 1.28	$ -	N/A	0	$ -	$ -
12	200-Watt	0	$ 1.27	$ -	N/A	0	$ -	$ -
13	250-Watt	396	$ 1.37	$ 543	N/A	0	$ -	$ -
14	400-Watt	0	$ 1.37	$ -	N/A	0	$ -	$ -
15	Total Lamp Charges	396		$ 543		0		$ -
16	Service Charge	61	$ 3.36	$ 205	N/A	0	$ -	$ -
17	Energy Charge							
18	Per kWh	78,103	$ 0.05125	$ 4,003	N/A	0	$ -	$ -
19	BM - Customer-Owned, Metered, Maintenance			$ 4,750				$ -

Idaho Power Company
Calculation of Proposed Rates
State of Idaho
IPC-E-23-11 General Rate Case
Filed June 1, 2023

Street Lighting Service (cont'd)
Schedule 41

C - Customer-Owned, Non-Metered, No Maintenance

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Structure	(5) Use	(6) Proposed Base Rate	(7) Proposed Base Revenue
1	Energy Charge				Energy Charge			
2	Per kWh	10,704,238	$ 0.05240	$ 560,902	Per kWh	12,919,225	$ 0.06353	$ 820,758
3	C - Customer-Owned, Non-Metered, No Maintenance			$ 560,902				$ 820,758

CM - Customer-Owned, Metered, No Maintenance

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Structure	(5) Use	(6) Proposed Base Rate	(7) Proposed Base Revenue
4	Service Charge	14,746	$ 3.36	$ 49,547	Service Charge	14,807	$ 5.60	$ 82,919
5	Energy Charge				Energy Charge			
6	Per kWh	6,609,543	$ 0.05125	$ 338,739	Per kWh	6,687,646	$ 0.06353	$ 424,866
7	CM - Customer-Owned, Metered, No Maintenance			$ 388,286				$ 507,785

Idaho Power Company
Calculation of Proposed Rates
State of Idaho
IPC-E-23-11 General Rate Case
Filed June 1, 2023

Traffic Control Signal Lighting Service
Schedule 42

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue
1	No. of Billings	9,192.0	$ -	$ -	$ -	$ -
2	Energy	2,847,961	$ 0.05815	$ 165,609	$ 0.07899	$ 224,960
3	Transfer Adjustment			$ 33,636		$ -
4	Total Adjusted Base Revenue			$ 199,244		$ 224,960

Idaho Power Company
Calculation of Proposed Rates
State of Idaho
IPC-E-23-11 General Rate Case
Filed June 1, 2023

Non-metered General Service
Schedule 40

Line No	Description	(1) Use		(2) Current Base Rate		(3) Current Base Revenue		(4) Proposed Base Rate		(5) Proposed Base Revenue
1	Number of Bills	19,956.0	$	-	$	-	$	-	$	-
2	Mininum Charge	846.8	$	1.50	$	1,270	$	2.00	$	1,694
3	Total Energy	13,925,301	$	0.08207	$	1,142,849	$	0.09697	$	1,350,336
4	Intermittent Usage	168	$	1.00	$	168	$	1.50	$	252
5	Transfer Adjustment				$	165,505			$	-
6	Total Adjusted Base Revenue				$	1,309,792			$	1,352,282

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

THOMPSON, DI TESTIMONY

EXHIBIT NO. 58

Idaho Power Company
State of Idaho
Typical Monthly Billing Comparison
IPC-E-23-11 General Rate Case
Filed June 1, 2023
Schedule 7, Small General Service

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Summer			Non-Summer			Avg Mth Cost -12 Mths[1]			
Line No	Energy kWh	Current Revenue	Proposed Revenue	Percent Difference	Current Revenue	Proposed Revenue	Percent Difference	Current Revenue	Proposed Revenue	Difference (8) - (7)	Percent Difference
1	100	$ 16.06	$ 28.99	80.46%	$ 16.06	$ 28.99	80.46%	$ 16.06	$ 28.99	$ 12.92	80.46%
2	200	$ 27.12	$ 37.97	39.99%	$ 27.12	$ 37.97	39.99%	$ 27.12	$ 37.97	$ 10.85	39.99%
3	300	$ 38.19	$ 46.96	22.97%	$ 38.19	$ 46.96	22.97%	$ 38.19	$ 46.96	$ 8.77	22.97%
4	400	$ 51.13	$ 57.23	11.92%	$ 49.74	$ 55.95	12.49%	$ 50.08	$ 56.37	$ 6.29	12.56%
5	500	$ 64.08	$ 67.50	5.33%	$ 61.28	$ 64.94	5.96%	$ 61.98	$ 65.79	$ 3.81	6.14%
6	600	$ 77.03	$ 77.77	0.96%	$ 72.83	$ 73.93	1.50%	$ 73.88	$ 75.21	$ 1.33	1.79%
7	700	$ 89.97	$ 88.04	-2.15%	$ 84.38	$ 82.91	-1.74%	$ 85.78	$ 84.62	$ (1.16)	-1.35%
8	800	$ 102.92	$ 98.31	-4.48%	$ 95.93	$ 91.90	-4.19%	$ 97.67	$ 94.04	$ (3.64)	-3.72%
9	900	$ 115.87	$ 108.58	-6.29%	$ 107.47	$ 100.89	-6.13%	$ 109.57	$ 103.45	$ (6.12)	-5.58%
10	1,000	$ 128.81	$ 118.84	-7.74%	$ 119.02	$ 109.88	-7.68%	$ 121.47	$ 112.87	$ (8.60)	-7.08%
11	1,100	$ 141.76	$ 129.11	-8.92%	$ 130.57	$ 118.87	-8.96%	$ 133.37	$ 122.28	$ (11.08)	-8.31%
12	1,200	$ 154.70	$ 139.38	-9.90%	$ 142.12	$ 127.86	-10.03%	$ 145.26	$ 131.70	$ (13.57)	-9.34%
13	1,300	$ 167.65	$ 149.65	-10.74%	$ 153.67	$ 136.85	-10.95%	$ 157.16	$ 141.11	$ (16.05)	-10.21%
14	1,400	$ 180.60	$ 159.92	-11.45%	$ 165.21	$ 145.83	-11.73%	$ 169.06	$ 150.53	$ (18.53)	-10.96%
15	1,500	$ 193.54	$ 170.19	-12.07%	$ 176.76	$ 154.82	-12.41%	$ 180.96	$ 159.95	$ (21.01)	-11.61%
16	1,600	$ 206.49	$ 180.46	-12.61%	$ 188.31	$ 163.81	-13.01%	$ 192.85	$ 169.36	$ (23.49)	-12.18%
17	1,700	$ 219.44	$ 190.73	-13.08%	$ 199.86	$ 172.80	-13.54%	$ 204.75	$ 178.78	$ (25.97)	-12.69%
18	1,800	$ 232.38	$ 201.00	-13.51%	$ 211.40	$ 181.79	-14.01%	$ 216.65	$ 188.19	$ (28.46)	-13.13%
19	1,900	$ 245.33	$ 211.27	-13.88%	$ 222.95	$ 190.78	-14.43%	$ 228.55	$ 197.61	$ (30.94)	-13.54%
20	2,000	$ 258.28	$ 221.54	-14.22%	$ 234.50	$ 199.77	-14.81%	$ 240.44	$ 207.02	$ (33.42)	-13.90%

[1] Includes change to four-month summer season

Idaho Power Company
State of Idaho
Typical Monthly Billing Comparison
IPC-E-23-11 General Rate Case
Filed June 1, 2023
Schedule 9, Large General Service - Secondary
Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	13	20%	1,440	$ 184.62	$ 194.66	$ 10.04	5.44%
2	10	13	35%	2,520	$ 281.68	$ 250.05	$ (31.63)	-11.23%
3	10	13	50%	3,600	$ 347.09	$ 305.44	$ (41.65)	-12.00%
4	10	13	65%	4,680	$ 412.50	$ 360.84	$ (51.66)	-12.52%
5	10	13	80%	5,760	$ 477.90	$ 416.23	$ (61.67)	-12.91%
6	20	27	20%	2,880	$ 310.64	$ 364.32	$ 53.68	17.28%
7	20	27	35%	5,040	$ 441.45	$ 475.10	$ 33.65	7.62%
8	20	27	50%	7,200	$ 572.26	$ 585.89	$ 13.63	2.38%
9	20	27	65%	9,360	$ 703.07	$ 696.67	$ (6.40)	-0.91%
10	20	27	80%	11,520	$ 833.89	$ 807.46	$ (26.43)	-3.17%
11	50	67	20%	7,200	$ 795.69	$ 873.30	$ 77.61	9.75%
12	50	67	35%	12,600	$ 1,122.72	$ 1,150.26	$ 27.54	2.45%
13	50	67	50%	18,000	$ 1,449.75	$ 1,427.22	$ (22.53)	-1.55%
14	50	67	65%	23,400	$ 1,776.78	$ 1,704.18	$ (72.60)	-4.09%
15	50	67	80%	28,800	$ 2,103.82	$ 1,981.14	$ (122.68)	-5.83%
16	100	135	20%	14,400	$ 1,604.11	$ 1,721.60	$ 117.49	7.32%
17	100	135	35%	25,200	$ 2,258.17	$ 2,275.52	$ 17.34	0.77%
18	100	135	50%	36,000	$ 2,912.24	$ 2,829.44	$ (82.80)	-2.84%
19	100	135	65%	46,800	$ 3,566.30	$ 3,383.36	$ (182.94)	-5.13%
20	100	135	80%	57,600	$ 4,220.36	$ 3,937.28	$ (283.08)	-6.71%
21	300	404	20%	43,200	$ 4,837.80	$ 5,114.79	$ 276.99	5.73%
22	300	404	35%	75,600	$ 6,799.99	$ 6,776.55	$ (23.43)	-0.34%
23	300	404	50%	108,000	$ 8,762.18	$ 8,438.32	$ (323.86)	-3.70%
24	300	404	65%	140,400	$ 10,724.36	$ 10,100.08	$ (624.28)	-5.82%
25	300	404	80%	172,800	$ 12,686.55	$ 11,761.84	$ (924.71)	-7.29%
26	500	674	20%	72,000	$ 8,071.48	$ 8,507.98	$ 436.50	5.41%
27	500	674	35%	126,000	$ 11,341.80	$ 11,277.59	$ (64.21)	-0.57%
28	500	674	50%	180,000	$ 14,612.11	$ 14,047.19	$ (564.92)	-3.87%
29	500	674	65%	234,000	$ 17,882.43	$ 16,816.80	$ (1,065.63)	-5.96%
30	500	674	80%	288,000	$ 21,152.74	$ 19,586.41	$ (1,566.34)	-7.40%
31	750	1,010	20%	108,000	$ 12,113.59	$ 12,749.47	$ 635.88	5.25%
32	750	1,010	35%	189,000	$ 17,019.06	$ 16,903.88	$ (115.18)	-0.68%
33	750	1,010	50%	270,000	$ 21,924.54	$ 21,058.29	$ (866.25)	-3.95%
34	750	1,010	65%	351,000	$ 26,830.01	$ 25,212.70	$ (1,617.31)	-6.03%
35	750	1,010	80%	432,000	$ 31,735.48	$ 29,367.11	$ (2,368.37)	-7.46%

Idaho Power Company
State of Idaho
Typical Monthly Billing Comparison
IPC-E-23-11 General Rate Case
Filed June 1, 2023
Schedule 9, Large General Service - Secondary
Non-Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh		(1) Current Rate		(2) Proposed Rate		(3) Difference 2-1	(4) Percent Difference
1	10	13	20%	1,440	$	169.49	$	175.90	$	6.41	3.78%
2	10	13	35%	2,520	$	258.32	$	229.29	$	(29.03)	-11.24%
3	10	13	50%	3,600	$	318.84	$	282.68	$	(36.16)	-11.34%
4	10	13	65%	4,680	$	379.37	$	336.08	$	(43.29)	-11.41%
5	10	13	80%	5,760	$	439.89	$	389.47	$	(50.42)	-11.46%
6	20	27	20%	2,880	$	285.64	$	326.79	$	41.15	14.41%
7	20	27	35%	5,040	$	406.69	$	433.58	$	26.89	6.61%
8	20	27	50%	7,200	$	527.74	$	540.37	$	12.63	2.39%
9	20	27	65%	9,360	$	648.79	$	647.16	$	(1.64)	-0.25%
10	20	27	80%	11,520	$	769.84	$	753.94	$	(15.90)	-2.06%
11	50	67	20%	7,200	$	702.87	$	779.48	$	76.61	10.90%
12	50	67	35%	12,600	$	1,005.49	$	1,046.45	$	40.96	4.07%
13	50	67	50%	18,000	$	1,308.12	$	1,313.42	$	5.30	0.41%
14	50	67	65%	23,400	$	1,610.74	$	1,580.39	$	(30.35)	-1.88%
15	50	67	80%	28,800	$	1,913.36	$	1,847.36	$	(66.00)	-3.45%
16	100	135	20%	14,400	$	1,398.25	$	1,533.96	$	135.71	9.71%
17	100	135	35%	25,200	$	2,003.49	$	2,067.90	$	64.40	3.21%
18	100	135	50%	36,000	$	2,608.74	$	2,601.84	$	(6.90)	-0.26%
19	100	135	65%	46,800	$	3,213.99	$	3,135.78	$	(78.21)	-2.43%
20	100	135	80%	57,600	$	3,819.24	$	3,669.72	$	(149.51)	-3.91%
21	300	404	20%	43,200	$	4,179.76	$	4,551.87	$	372.11	8.90%
22	300	404	35%	75,600	$	5,995.50	$	6,153.69	$	158.19	2.64%
23	300	404	50%	108,000	$	7,811.24	$	7,755.52	$	(55.72)	-0.71%
24	300	404	65%	140,400	$	9,626.98	$	9,357.34	$	(269.64)	-2.80%
25	300	404	80%	172,800	$	11,442.72	$	10,959.16	$	(483.56)	-4.23%
26	500	674	20%	72,000	$	6,961.27	$	7,569.78	$	608.51	8.74%
27	500	674	35%	126,000	$	9,987.50	$	10,239.49	$	251.99	2.52%
28	500	674	50%	180,000	$	13,013.74	$	12,909.19	$	(104.54)	-0.80%
29	500	674	65%	234,000	$	16,039.97	$	15,578.90	$	(461.07)	-2.87%
30	500	674	80%	288,000	$	19,066.21	$	18,248.61	$	(817.60)	-4.29%
31	750	1,010	20%	108,000	$	10,438.16	$	11,342.17	$	904.02	8.66%
27	750	1,010	35%	189,000	$	14,977.51	$	15,346.73	$	369.22	2.47%
28	750	1,010	50%	270,000	$	19,516.86	$	19,351.29	$	(165.57)	-0.85%
29	750	1,010	65%	351,000	$	24,056.21	$	23,355.85	$	(700.36)	-2.91%
30	750	1,010	80%	432,000	$	28,595.57	$	27,360.41	$	(1,235.16)	-4.32%

Idaho Power Company
State of Idaho
Typical Monthly Billing Comparison
IPC-E-23-11 General Rate Case
Filed June 1, 2023
Schedule 9, Large General Service - Secondary
Weighted Monthly Average[1]

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	13	20%	1,440	$ 173.27	$ 182.15	$ 8.88	5.13%
2	10	13	35%	2,520	$ 264.16	$ 236.21	$ (27.95)	-10.58%
3	10	13	50%	3,600	$ 325.90	$ 290.27	$ (35.63)	-10.93%
4	10	13	65%	4,680	$ 387.65	$ 344.33	$ (43.32)	-11.17%
5	10	13	80%	5,760	$ 449.39	$ 398.39	$ (51.00)	-11.35%
6	20	27	20%	2,880	$ 291.89	$ 339.30	$ 47.41	16.24%
7	20	27	35%	5,040	$ 415.38	$ 447.42	$ 32.04	7.71%
8	20	27	50%	7,200	$ 538.87	$ 555.54	$ 16.67	3.09%
9	20	27	65%	9,360	$ 662.36	$ 663.66	$ 1.30	0.20%
10	20	27	80%	11,520	$ 785.85	$ 771.78	$ (14.07)	-1.79%
11	50	67	20%	7,200	$ 726.07	$ 810.75	$ 84.68	11.66%
12	50	67	35%	12,600	$ 1,034.80	$ 1,081.05	$ 46.25	4.47%
13	50	67	50%	18,000	$ 1,343.53	$ 1,351.35	$ 7.83	0.58%
14	50	67	65%	23,400	$ 1,652.25	$ 1,621.65	$ (30.60)	-1.85%
15	50	67	80%	28,800	$ 1,960.98	$ 1,891.95	$ (69.02)	-3.52%
16	100	135	20%	14,400	$ 1,449.71	$ 1,596.50	$ 146.79	10.13%
17	100	135	35%	25,200	$ 2,067.16	$ 2,137.10	$ 69.94	3.38%
18	100	135	50%	36,000	$ 2,684.62	$ 2,677.71	$ (6.91)	-0.26%
19	100	135	65%	46,800	$ 3,302.07	$ 3,218.31	$ (83.76)	-2.54%
20	100	135	80%	57,600	$ 3,919.52	$ 3,758.91	$ (160.61)	-4.10%
21	300	404	20%	43,200	$ 4,344.27	$ 4,739.51	$ 395.24	9.10%
22	300	404	35%	75,600	$ 6,196.62	$ 6,361.31	$ 164.69	2.66%
23	300	404	50%	108,000	$ 8,048.97	$ 7,983.12	$ (65.86)	-0.82%
24	300	404	65%	140,400	$ 9,901.33	$ 9,604.92	$ (296.41)	-2.99%
25	300	404	80%	172,800	$ 11,753.68	$ 11,226.72	$ (526.96)	-4.48%
26	500	674	20%	72,000	$ 7,238.82	$ 7,882.52	$ 643.69	8.89%
27	500	674	35%	126,000	$ 10,326.08	$ 10,585.52	$ 259.44	2.51%
28	500	674	50%	180,000	$ 13,413.33	$ 13,288.53	$ (124.80)	-0.93%
29	500	674	65%	234,000	$ 16,500.59	$ 15,991.53	$ (509.05)	-3.09%
30	500	674	80%	288,000	$ 19,587.84	$ 18,694.54	$ (893.30)	-4.56%
31	750	1,010	20%	108,000	$ 10,857.01	$ 11,811.27	$ 954.26	8.79%
27	750	1,010	35%	189,000	$ 15,487.90	$ 15,865.78	$ 377.88	2.44%
28	750	1,010	50%	270,000	$ 20,118.78	$ 19,920.29	$ (198.49)	-0.99%
29	750	1,010	65%	351,000	$ 24,749.66	$ 23,974.80	$ (774.86)	-3.13%
30	750	1,010	80%	432,000	$ 29,380.55	$ 28,029.31	$ (1,351.24)	-4.60%

[1] Includes change to four-month summer season

Idaho Power Company
State of Idaho
Typical Monthly Billing Comparison
IPC-E-23-11 General Rate Case
Filed June 1, 2023
Schedule 24, Agricultural Irrigation Service - Secondary
In-Season

Line No	Demand kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	20%	1,440	$ 193.83	$ 269.46	$ 75.63	39.02%
2	10	35%	2,520	$ 267.16	$ 335.96	$ 68.80	25.75%
3	10	50%	3,600	$ 339.89	$ 402.46	$ 62.57	18.41%
4	10	65%	4,680	$ 412.63	$ 468.96	$ 56.33	13.65%
5	10	80%	5,760	$ 485.36	$ 535.45	$ 50.09	10.32%
6	50	20%	7,200	$ 881.16	$ 1,227.32	$ 346.16	39.28%
7	50	35%	12,600	$ 1,247.78	$ 1,559.81	$ 312.02	25.01%
8	50	50%	18,000	$ 1,611.45	$ 1,892.30	$ 280.84	17.43%
9	50	65%	23,400	$ 1,975.13	$ 2,224.78	$ 249.66	12.64%
10	50	80%	28,800	$ 2,338.80	$ 2,557.27	$ 218.47	9.34%
11	100	20%	14,400	$ 1,740.32	$ 2,424.64	$ 684.32	39.32%
12	100	35%	25,200	$ 2,473.57	$ 3,089.61	$ 616.05	24.91%
13	100	50%	36,000	$ 3,200.91	$ 3,754.59	$ 553.68	17.30%
14	100	65%	46,800	$ 3,928.25	$ 4,419.57	$ 491.32	12.51%
15	100	80%	57,600	$ 4,655.60	$ 5,084.55	$ 428.95	9.21%
16	300	20%	43,200	$ 5,176.95	$ 7,213.91	$ 2,036.96	39.35%
17	300	35%	75,600	$ 7,376.70	$ 9,208.84	$ 1,832.15	24.84%
18	300	50%	108,000	$ 9,558.73	$ 11,203.78	$ 1,645.05	17.21%
19	300	65%	140,400	$ 11,740.76	$ 13,198.71	$ 1,457.95	12.42%
20	300	80%	172,800	$ 13,922.79	$ 15,193.64	$ 1,270.85	9.13%
21	500	20%	72,000	$ 8,613.58	$ 12,003.18	$ 3,389.61	39.35%
22	500	35%	126,000	$ 12,279.83	$ 15,328.07	$ 3,048.25	24.82%
23	500	50%	180,000	$ 15,916.55	$ 18,652.96	$ 2,736.41	17.19%
24	500	65%	234,000	$ 19,553.27	$ 21,977.85	$ 2,424.58	12.40%
25	500	80%	288,000	$ 23,189.99	$ 25,302.74	$ 2,112.75	9.11%
26	750	20%	108,000	$ 12,909.36	$ 17,989.78	$ 5,080.41	39.35%
27	750	35%	189,000	$ 18,408.74	$ 22,977.11	$ 4,568.37	24.82%
28	750	50%	270,000	$ 23,863.82	$ 27,964.44	$ 4,100.62	17.18%
29	750	65%	351,000	$ 29,318.90	$ 32,951.77	$ 3,632.87	12.39%
30	750	80%	432,000	$ 34,773.98	$ 37,939.10	$ 3,165.12	9.10%

Idaho Power Company
State of Idaho
Typical Monthly Billing Comparison
IPC-E-23-11 General Rate Case
Filed June 1, 2023
Schedule 24, Agricultural Irrigation Service - Secondary
Out-of-Season

Line No	Demand kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference 2-1	(4) Percent Difference
1	10	20%	1,440	$ 117.18	$ 111.12	$ (6.06)	-5.18%
2	10	35%	2,520	$ 202.45	$ 189.96	$ (12.49)	-6.17%
3	10	50%	3,600	$ 287.71	$ 268.80	$ (18.91)	-6.57%
4	10	65%	4,680	$ 372.98	$ 347.64	$ (25.34)	-6.79%
5	10	80%	5,760	$ 458.24	$ 426.48	$ (31.76)	-6.93%
6	50	20%	7,200	$ 571.92	$ 531.60	$ (40.32)	-7.05%
7	50	35%	12,600	$ 998.24	$ 925.80	$ (72.44)	-7.26%
8	50	50%	18,000	$ 1,424.56	$ 1,320.00	$ (104.56)	-7.34%
9	50	65%	23,400	$ 1,850.88	$ 1,714.20	$ (136.68)	-7.38%
10	50	80%	28,800	$ 2,277.19	$ 2,108.40	$ (168.79)	-7.41%
11	100	20%	14,400	$ 1,140.35	$ 1,057.20	$ (83.15)	-7.29%
12	100	35%	25,200	$ 1,992.98	$ 1,845.60	$ (147.38)	-7.40%
13	100	50%	36,000	$ 2,845.62	$ 2,634.00	$ (211.62)	-7.44%
14	100	65%	46,800	$ 3,698.25	$ 3,422.40	$ (275.85)	-7.46%
15	100	80%	57,600	$ 4,550.89	$ 4,210.80	$ (340.09)	-7.47%
16	300	20%	43,200	$ 3,414.04	$ 3,159.60	$ (254.44)	-7.45%
17	300	35%	75,600	$ 5,971.94	$ 5,524.80	$ (447.14)	-7.49%
18	300	50%	108,000	$ 8,529.85	$ 7,890.00	$ (639.85)	-7.50%
19	300	65%	140,400	$ 11,087.75	$ 10,255.20	$ (832.55)	-7.51%
20	300	80%	172,800	$ 13,645.66	$ 12,620.40	$ (1,025.26)	-7.51%
21	500	20%	72,000	$ 5,687.73	$ 5,262.00	$ (425.73)	-7.49%
22	500	35%	126,000	$ 9,950.91	$ 9,204.00	$ (746.91)	-7.51%
23	500	50%	180,000	$ 14,214.08	$ 13,146.00	$ (1,068.08)	-7.51%
24	500	65%	234,000	$ 18,477.25	$ 17,088.00	$ (1,389.25)	-7.52%
25	500	80%	288,000	$ 22,740.43	$ 21,030.00	$ (1,710.43)	-7.52%
26	750	20%	108,000	$ 8,529.85	$ 7,890.00	$ (639.85)	-7.50%
27	750	35%	189,000	$ 14,924.61	$ 13,803.00	$ (1,121.61)	-7.52%
28	750	50%	270,000	$ 21,319.37	$ 19,716.00	$ (1,603.37)	-7.52%
29	750	65%	351,000	$ 27,714.13	$ 25,629.00	$ (2,085.13)	-7.52%
30	750	80%	432,000	$ 34,108.89	$ 31,542.00	$ (2,566.89)	-7.53%

Idaho Power Company
State of Idaho
Typical Monthly Billing Comparison
IPC-E-23-11 General Rate Case
Filed June 1, 2023
Schedule 24, Agricultural Irrigation Service - Secondary
Weighted Average Monthly[1]

Line No	Demand kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	20%	1,440	$ 104.84	$ 128.86	$ 24.02	22.91%
2	10	35%	2,520	$ 157.70	$ 177.31	$ 19.61	12.43%
3	10	50%	3,600	$ 210.37	$ 225.75	$ 15.39	7.31%
4	10	65%	4,680	$ 263.03	$ 274.20	$ 11.17	4.24%
5	10	80%	5,760	$ 315.70	$ 322.64	$ 6.95	2.20%
6	50	20%	7,200	$ 485.53	$ 588.31	$ 102.78	21.17%
7	50	35%	12,600	$ 749.84	$ 830.54	$ 80.69	10.76%
8	50	50%	18,000	$ 1,013.17	$ 1,072.77	$ 59.59	5.88%
9	50	65%	23,400	$ 1,276.50	$ 1,314.99	$ 38.49	3.02%
10	50	80%	28,800	$ 1,539.83	$ 1,557.22	$ 17.39	1.13%
11	100	20%	14,400	$ 961.39	$ 1,162.61	$ 201.23	20.93%
12	100	35%	25,200	$ 1,490.02	$ 1,647.07	$ 157.06	10.54%
13	100	50%	36,000	$ 2,016.68	$ 2,131.53	$ 114.86	5.70%
14	100	65%	46,800	$ 2,543.33	$ 2,615.99	$ 72.66	2.86%
15	100	80%	57,600	$ 3,069.99	$ 3,100.45	$ 30.45	0.99%
16	300	20%	43,200	$ 2,864.83	$ 3,459.84	$ 595.01	20.77%
17	300	35%	75,600	$ 4,450.71	$ 4,913.21	$ 462.50	10.39%
18	300	50%	108,000	$ 6,030.69	$ 6,366.59	$ 335.90	5.57%
19	300	65%	140,400	$ 7,610.67	$ 7,819.97	$ 209.30	2.75%
20	300	80%	172,800	$ 9,190.65	$ 9,273.35	$ 82.70	0.90%
21	500	20%	72,000	$ 4,768.27	$ 5,757.06	$ 988.79	20.74%
22	500	35%	126,000	$ 7,411.41	$ 8,179.36	$ 767.95	10.36%
23	500	50%	180,000	$ 10,044.71	$ 10,601.65	$ 556.94	5.54%
24	500	65%	234,000	$ 12,678.01	$ 13,023.95	$ 345.94	2.73%
25	500	80%	288,000	$ 15,311.31	$ 15,446.25	$ 134.94	0.88%
26	750	20%	108,000	$ 7,147.57	$ 8,628.59	$ 1,481.02	20.72%
27	750	35%	189,000	$ 11,112.28	$ 12,262.04	$ 1,149.75	10.35%
28	750	50%	270,000	$ 15,062.23	$ 15,895.48	$ 833.25	5.53%
29	750	65%	351,000	$ 19,012.18	$ 19,528.92	$ 516.75	2.72%
30	750	80%	432,000	$ 22,962.12	$ 23,162.37	$ 200.24	0.87%

[1] Bills are based on four months of in-season, fours month of out-season, and four months of zero usage.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

RILEY MALONEY

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Riley Maloney. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as a Regulatory Analyst in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Economics from Boise State University in 2013. I have also attended "The Basics: Practical Regulatory Training for the Electric Industry," an electric utility ratemaking course offered through the New Mexico State University's Center for Public Utilities, "Electric Utility Fundamentals and Insights," an electric utility course offered by Western Energy Institute, and "Electric Rates Advanced Course," an electric utility ratemaking course offered through Edison Electric Institute.

Q. Please describe your work experience with Idaho Power.

A. In 2020 I was hired as a Regulatory Analyst in the Company's Regulatory Affairs Department. My primary responsibilities include supporting activities involving tariff administration and regulatory compliance filings. I provide regulatory support to the Company's operations business units to ensure consistent application of the Company's rules and regulations, authorized by its Commission-approved tariff, and the Idaho Public Utilities Commission's ("Commission") Utility Customer Relations Rules. I also act as a liaison for customer service-related issues.

Q. What is the purpose of your testimony in this matter?

A. My testimony will describe the proposed updates to the Company's Schedule 31, Agreement for Supply of Standby Electric Service for the Amalgamated Sugar Company, and Schedule 45, Standby Service (collectively, "Standby Service"); Schedule 46, Alternate Distribution Service; Schedule 66, Miscellaneous Charges; Schedule 72, Generator Interconnections to PURPA Qualifying Facility Sellers; and Schedule 95, Adjustment for Municipal Franchise Fees. I will also address the changes and updates being proposed within several of the Company's service provisions in its "General Rules, Regulations and Rates."

I. SCHEDULES 45 AND 31, STANDBY SERVICE

Q. Please describe Schedule 45, Standby Service.

A. Standby Service under Schedule 45 is an optional, firm power service offering available to customers who have their own on-site source of electric generation, but request that the Company back up a portion of such source of customer-owned generation in the event of an outage. Standby Service was first made available pursuant to Commission Order No. 22887, issued in Case No. IPC-E-89-04, for customers taking large power service and was subsequently updated in Case No. IPC-E-94-05 to include generation and transmission cost components. Since its inception, and because of customers' expressed interest, Standby Service has subsequently been expanded through various tariff advice filings to also be available to customers taking large general service. The Company currently has two primary service level customers taking Standby Service.

Q. What is the benefit of a customer taking Standby Service?

A. Because the Company includes the requested amount of capacity within its load forecasts, customers electing to take Standby Service are afforded reasonable assurance of continued electric service during periods of planned or unexpected outages to their on-site generating equipment.

Q. Are customers who are eligible required to take Standby Service?

A. No. However, in the event an eligible customer does not elect to take Standby Service and their on-site generation goes offline, the necessary amount of backup power may not be available for taking from the Company’s system as the Company will not have planned to serve the additional, temporary load within the area.

Q. Is the Company proposing any rate adjustments to Schedule 45, Standby Service?

A. Yes. Idaho Power reviewed the currently in effect methodology approved by the Commission in past general rate cases and various tariff advice filings and determined it to still be representative of the cost to provide the respective service, with exception to the derivation of standby generation and transmission cost components and excess demand charges. The proposed rate adjustments revise the charges to include the Company’s Open Access Transmission Tariff (“OATT”) rate components and incorporate updated unit cost information resulting from the cost-of-service studies for Schedule 19 Primary Service and Schedule 9 Primary and Secondary Services, as presented on pages 5 – 7 of Exhibit No. 43 to the Direct Testimony of Mr. Paul Goralski. The derivations of the updated charges are included in my workpapers.

Q. Please describe Schedule 31, Agreement for Supply of Standby Electric Service for the Amalgamated Sugar Company.

A. The Company has a contract with the Amalgamated Sugar Company to provide customized standby service. The Company’s initial contract with the Amalgamated Sugar Company to provide standby service was entered into on April 6, 1998, and approved by Commission Order No. 27708, issued in Case No. IPC-E-98-07. Currently, Amalgamated Sugar Company is provided standby service under the provisions of a revised Standby Electric Service Agreement dated December 7, 2005, which was approved by Commission Order No. 29958, issued in Case No. IPC-E-05-37.

Q. Is the Company proposing any rate adjustments to the standby charges for Amalgamated Sugar Company under Schedule 31?

A. Yes. Idaho Power reviewed the currently in effect methodology approved by the Commission in past general rate cases and found it to still be representative of the cost to provide the respective service, with exception to the derivation of standby generation and transmission cost components and excess demand charges. The proposed rate adjustments revise the charges to include the Company’s OATT rate components and incorporate updated unit cost information resulting from the aforementioned cost-of-service study for Schedule 19 Primary Service. The derivations of the updated charges are included in my workpapers.

Q. Why is the Company proposing to change how the standby generation and transmission cost component for Schedule 31 and Schedule 45 is derived?

A. The Company is proposing to use its OATT rate components within the derivation of Schedule 31 and Schedule 45's standby reservation charges to remain consistent with the methodology most recently relied upon when determining its special contracts' rates, as addressed by Company Witness Mr. Paul Goralski.

Q. Please describe the excess demand charge and the changes to the charge's derivation being proposed within Schedules 31 and 45.

A. Excess demand charges are incurred when a customer taking Standby Service exceeds their total amount of contract demand during a billing period. The proposed excess demand charge is derived from the Company's OATT rate components and represents the annual cost for an incremental megawatt accessed at those OATT rate components, collected each day over one month. Any excess demand charges assessed to a customer will continue to be in addition to all standby demand charges and energy charges incurred for the additional amount of load consumed.

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II. SCHEDULE 46, ALTERNATE DISTRIBUTION SERVICE

Q. What is Alternate Distribution Service?

A. Alternate Distribution Service is an optional service offering for commercial and industrial customers desiring redundancy and, in the event of a distribution-related outage, automatic switching of electric service to an alternate distribution circuit serving their premises. This service was first made available pursuant to Commission Order No. 22887, issued in Case No. IPC-E-89-04, for customers taking large power service or large general service. The Company currently has six customers taking Alternate Distribution Service.

Q. What is the benefit of a customer taking Alternate Distribution Service?

A. Alternate Distribution Service provides customers an extra measure of reliability that does not exist with only one source of distribution service. Absent on-site backup generation, a customer's operations may cease in the event of a distribution-related outage affecting the distribution circuit serving their premises. Though not guaranteed, Alternate Distribution Service may minimize the chance of a customer's operations from being disrupted in such a scenario.

Q. Is the Company proposing any rate adjustments to Schedule 46, Alternate Distribution Service?

A. Yes. After reviewing the currently in effect methodology approved by the Commission in past general rate cases, the Company found the method to continue to be reasonable, with one exception. When reviewing the methodology used to derive the Capacity Charge, the Company identified that generation and transmission-related capacity cost components had previously been inadvertently included. As such, the Capacity Charge being proposed as part of this case corrects for this and does not include any generation or transmission-related capacity cost components.

The proposed Capacity Charge rate includes updated unit cost information resulting from the cost-of-service study for Schedule 19 Primary Service. Additionally, the Company proposes to update the mileage charge and average distribution line length covered by Schedule 19 customers' rates utilizing the same methodology previously relied upon.

The updated Capacity Charge is derived by summing the Distribution demand revenue requirement for Substations, Primary Lines, and Primary Transformers for Schedule 19 Primary Service ($7,435,654; $11,058,271; and $1,575,448, respectively), and dividing this sum by the total billed kilowatt ("kW") of 5,315,392. The respective revenue requirement for each of these facilities and total billed kW can be found on page 7 of Exhibit No. 43 to the Direct Testimony of Mr. Goralski, and the derivation of the updated Capacity Charge using these amounts is included in my workpapers.

Q. Please describe Schedule 46’s mileage charge and the methodology used to derive it.

A. Schedule 46’s mileage charge is intended to recover the distribution facilities’ ongoing operating and maintenance expenses based upon the proportion of capacity committed and length of line constructed to provide alternate distribution service to an individual customer. To derive this charge, the Company determined the per-mile cost to build a three-phase overhead distribution circuit, applied the facilities charge rate for facilities installed more than 31 years, as proposed below, and then divided by the three-phase overhead distribution circuit’s total capacity.

III. SCHEDULE 66, MISCELLANEOUS CHARGES

Q. How did you approach updating the Company’s Schedule 66’s charges?

A. I started by reviewing the methodology that was relied upon for each charge’s most recent update to determine whether that methodology continued to reasonably reflect the requirements to provide the respective type of service. To the extent circumstances have changed since the charge was last updated, I developed a new recommendation.

Q. How do you propose to update the Current Transformer Charges within Schedule 66?

A. The proposed Current Transformer Charges simply update the cost of materials to better reflect and recover the Company's current costs of supplying the respective services. The methodology used to derive the proposed Current Transformer Charges was most recently reviewed by the Commission in 2010 as part of Tariff Advice No. 10-01.

Q. Why is the Company proposing to remove the option for customers to request the installation of non-Advanced Metering Infrastructure current transformer metering?

A. The Company predominately installs Advanced Metering Infrastructure ("AMI") meters within its service area and has generally stopped procuring non-AMI capable meters. Because of this, the Company is proposing to strike the option to install non-AMI current transformer metering to avoid customer confusion. In areas where a customer-requested current transformer is installed but AMI functionality is not available, an AMI capable meter would still be installed but the AMI-specific functionality would not be utilized until possible.

Q. Why is the Company proposing to increase its customer-requested Special Meter Test charge?

A. This charge was last updated during Case No. IPC-E-94-05 and was based on the then-applicable hourly labor rate for the Company’s meter technicians. As such, the Company is proposing to update the charge from $30 to $85 to be more representative of the Company’s current labor cost for providing the service. However, pursuant to Section 4, Meter Tests, of Rule D of the Company’s tariff, Customers will continue to be provided one Special Meter Test free of charge every twelve months, and a Special Meter Test charge will be refunded in instances where the average registration error of the tested meter exceeds plus or minus two percent.

Q. Please describe the Service Establishment Charge within Schedule 66.

A. The Service Establishment Charge is assessed when a customer desires to initiate a new service contract with the Company at a location where the Point of Delivery is already energized. This charge is intended to recover the costs associated with recording or updating the customer’s pertinent information into the Company’s customer information system and initiating service. Compared to the existing Service Establishment Charge amount of $20, the proposed Service Establishment Charge amount of $30 is more reflective of the Company’s current costs for performing the necessary work.

Q. Has the methodology used to derive the proposed Service Establishment Charge been modified?

A. No. The methodology used to derive the Service Establishment Charge remains largely the same as of that approved in Case No. IPC-E-03-13, which is the last time this charge was updated. The only adjustment made in deriving the proposed Service Establishment Charge is updating the type of employees that perform the respective work and weighting their differing hourly costs accordingly.

Q. Please describe the Continuous Service Charge within Schedule 66.

A. The Continuous Service Charge provides property managers a cost-effective option to have electric service at their properties automatically transfer into their names when tenants request their service be discontinued. By requesting to implement a continuous service arrangement, property managers can automatically retain electric service between tenants to prevent damage from occurring and to have electricity available for maintenance and/or marketing of their property. Additionally, property managers electing to receive this service are also provided notice from Idaho Power each time service is transferred into their name, electric service at the property is subject to termination, or a tenant's application for electric service is denied. Idaho Power also provides enrolled property managers with an annual inventory of all their properties where an active continuous service arrangement exists.

Q. Is there benefit to the Company in offering property managers a continuous service arrangement?

A. Yes. When property managers request a continuous service arrangement, there is less of a need for them to contact the Company each time a tenant requests to discontinue service. As a result, Company resources are optimized as those representatives can handle other customer needs.

Q. How was the proposed Continuous Service Charge amount determined?

A. Using the methodology approved in Case No. IPC-E-05-28, the Company proposes to continue pricing the Continuous Service Charge at 50 percent of the proposed Service Establishment Charge amount, or $15, to balance the costs of operating the offering while still maintaining an incentive to encourage participation amongst property managers.

Q. Please describe the Field Visit Charge within Schedule 66.

A. The Field Visit Charge is designed to recover costs incurred by the Company when a Company representative is dispatched to connect or disconnect service, but due to customer action, the Company representative is unable to complete such action at the time of visit. This charge is applicable to non-collection as well as collection-related visits to customers' premises.

Q. Has the methodology used to derive the proposed Field Visit Charge been modified?

A. No. The methodology used to derive the Field Visit Charge is nearly the same as that approved in Case No. IPC-E-03-13, which is the last time this charge was updated. The only adjustment made in deriving the proposed Field Visit Charge amounts is removing administrative support costs because no administrative support work is currently required within a Field Visit's scope of work. The proposed $25 and $45 Field Visit Charge amounts are more reflective of the Company's current costs incurred in respect to visiting a customer's premises with the intention of connecting or disconnecting service but being unable to do so because of customer action.

Q. Please describe the Service Connection Charges within Schedule 66.

A. A Service Connection Charge is assessed anytime a customer desires to initiate a new service contract with the Company at a location where the Point of Delivery is currently disconnected from the Company's system and remote connection is not available. Like the Service Establishment Charge, the Service Connection Charge also seeks to recover the costs associated with recording or updating the customer's pertinent information into the Company's customer information system, as well as having to dispatch Company personnel to physically connect and initiate service. Compared to the existing Service Connection Charge amounts of $20 and $40, the proposed Service Connection Charge amounts of $30 and $50, respectively, are more reflective of the Company's current cost for performing the necessary work.

Q. Will a customer be charged both the Service Establishment Charge and a Service Connection Charge?

A. No. Because the Service Connection Charge includes the costs associated with the tasks of service establishment plus the cost to physically connect service, only the Service Connection Charge is assessed.

Q. Why are there differing Field Visit and Service Connection Charges based on customer class?

A. The Field Visit and Service Connection Charges remain bifurcated to continue reflecting the difference in skill level required of the employee(s) dispatched to perform the requested type of work, which is generally dependent on the voltage at which each customer class typically takes service.

Q. Can customers request connection of service outside of the Company’s normal business hours?

A. Yes. The charges by rate schedule outlined within Attachment 1 to the Company’s application include two after-hours blocks and their associated charges. The block-hour structure remains the same as that currently in place; however, the charges have been updated to be more reflective of the Company’s current costs for performing the work during the respective hours.

Q. Why does the Company continue to propose block-hour Service Connection Charges?

A. As first approved in Case No. IPC-E-03-13, the block-hour methodology recognizes the higher cost of serving customer requests for connection after normal working hours due to the overtime rate paid to employees during these hours. Additionally, during the third block-hours of 9:01 p.m. to 7:29 a.m., two employees may be dispatched for safety reasons. The proposed block-hour Service Connection Charges continue to reflect the Company’s costs to serve customers based on the time of day that a customer requests the Company provide connection of service.

Q. Why are the proposed Service Connection charges priced at a slight premium for the second and third block-hours?

A. Some of the Company’s currently approved second and third block-hour Service Connection Charges, last updated in Case No. IPC-E-03-13, include a slight premium, which is intended to encourage customers to request the service be performed within normal working hours at the lower price. The Company has found after-hour time frames can pose safety concerns for the Company’s employees.

Q. Please describe the Remote Service Connection Charge within Schedule 66.

A. The Remote Service Connection charge is assessed anytime a customer requests connection of service at a location where the Point of Delivery is currently disconnected from the Company’s system, but a meter with remote connect capability has been installed. Unlike the Service Establishment or Service Connection Charges, the Remote Service Connection Charge only includes the cost of back-office operations necessary to remotely connect and re-establish service; no field-related costs are incurred and therefore are not included within the derivation of the proposed Remote Service Connection Charge.

Q. How many locations within the Company's service area can be remotely connected?

A. As of the end of 2022, the Company has installed approximately 41,500 meters equipped with remote connect/disconnect functionality within its Idaho service area. Additionally, the Company continues to objectively identify locations where deployment of remote connect/disconnect capable meters can reduce costs paid by all customers, via the Company incurring lower annual operating expenses, as well as increase the satisfaction of customers residing at these locations through the provision of faster, more predictable, and cheaper connection of service.

Q. Why has the Remote Service Connection Charge decreased compared to the currently approved charge?

A. Likely as a result of technological advancements and process improvements, the cost of performing remote service connections has decreased on a per transaction basis compared to that of the current charge, which was implemented and approved as part of Case No. GNR-U-14-01.

Q. In his testimony on page 13, Company Witness Mr. Matthew Larkin refers to a forecast to Account 451's Miscellaneous Service Revenues based on the proposed changes to Schedule 66. Can you please explain the basis for this forecasted amount?

A. Yes. The workpapers accompanying my testimony detail the difference in revenues from Schedule 66's current charge amounts to the proposed charge amounts for these services.

Q. Please describe Schedule 66's proposed Fractional Period Minimum Billing amounts.

A. "Fractional Period Minimum Billings" specifies the minimum bill requirements for each service schedule when service is taken for a partial billing period. The minimum bill amounts have been updated to be more reflective of each customer class's allocated costs associated with bill preparation and meter reading.

The proposed Fractional Period Minimum Billing amounts are informed based on each customer class's respective cost-of-service unit cost for meter reading and customer accounting expenses multiplied by the proportion of functionalized customer accounting expenses for providing customer records to the total functionalized customer records expense. Mr. Goralski's Exhibit Nos. 37 and 43 contain the information to derive the functionalized customer account expense proportion, and each customer class's meter reading and customer account expense unit costs, respectively.

Q. What monthly rates is the Company proposing for facilities charges?

A. The Company is proposing to update the monthly facilities charge rates to the following:

Table 1 Proposed Facilities Charge Rates

Rate Schedule	**Facilities Installed 31 Years or Less**	**Facilities Installed More Than 31 Years**
Schedule 9	**1.38%**	**0.61%**
Schedule 15	**1.66%**	**1.66%**
Schedule 19	**1.38%**	**0.61%**
Schedule 24	**1.38%**	**0.61%**
Schedule 29	**1.38%**	**0.61%**
Schedule 32	**1.38%**	**0.61%**
Schedule 41	**1.17%**	**1.17%**
Schedule 45	**1.38%**	**0.61%**
Schedule 46	**1.38%**	**0.61%**

Q. Please describe the individual cost components that are used to derive the Company's facilities charges.

A. The cost components used to derive the Company's facilities charges are the same components included in the Company's revenue requirement for like facilities. Descriptions of each cost component are as follows:

Rate of Return – Idaho Power's cost of financing its original investment in facilities. This uses a weighted average of the Company's cost of debt and cost of equity. The facilities charge methodology uses a level payment stream to simplify the rate calculation and the administration of the facilities charge. The Rate of Return used to determine the facilities charge will be the Rate of Return ordered by the Commission in this case.

Booked Depreciation – The straight-line annual depreciation of assets based on a levelized 31-year basis.

Income Taxes – The tax that Idaho Power pays on the amount of revenue received from the equity portion of the Rate of Return.

Property Taxes – The tax that Idaho Power pays for its distribution facilities. Each dollar the Company invests beyond the Point of Delivery is assessed property taxes.

Other Taxes (Regulatory Fees) – The taxes and fees that Idaho Power pays to the Idaho Public Utilities Commission and Oregon Public Utility Commission. A portion of these fees are tied to the Company's distribution investment which includes facilities installed beyond the Company's Point of Delivery.

Operation and Maintenance Expenses – Includes all of Idaho Power's costs to operate and maintain its distribution facilities. This cost component represents an average maintenance rate for all distribution equipment.

Administration and General Expenses – Represents an expense based on total Administration and General expense as a percentage of total plant investment.

Working Capital – Working Capital is the carrying cost of inventory. Working Capital is based on the cost of capital to finance the distribution facilities inventory and the property taxes that the Company pays on its inventory.

Insurance – The insurance rate reflects the additional cost Idaho Power incurs for insurance premiums resulting from facilities installed beyond the Company's Point of Delivery. This insurance rate covers property, casualty, and worker's compensation. It does not cover facility replacement costs for failed facilities.

Q. Is the Company proposing changes to the methodology used to derive facilities charges?

A. No. The Company proposes to rely on the same methodology and cost components that the Commission approved in Case No. IPC-E-11-08.

Q. What are the proposed percentage amounts for each cost component by rate class?

A. The proposed percentage amounts used to derive the proposed facilities charge rates are as follows:

Table 2 Facilities Charge Cost Components				
	Cost Components	**Rate 15**	**Rates 9/19/24/29/ 32/45/46**	**Rate 41**
1	Rate of Return	**4.85%**	**4.85%**	**4.85%**
2	Book Depreciation	**3.23%**	**3.23%**	**3.23%**
3	Income Taxes	**1.16%**	**1.16%**	**1.16%**
4	Property Taxes	**0.36%**	**0.36%**	**0.36%**
5	Other Taxes (Regulatory Fees)	**0.04%**	**0.04%**	**0.04%**
6	Operation & Maintenance	**7.37%**	**3.95%**	**1.46%**
7	Administration & General	**2.32%**	**2.32%**	**2.32%**
8	Working Capital	**0.34%**	**0.34%**	**0.34%**
9	Insurance	**0.30%**	**0.30%**	**0.30%**
10	Annual Total **(ΣLines 1-9)**	**20.0%**	**16.5%**	**14.0%**
11	**Monthly Rate (Line 10/12)**	1.66%	1.38%	1.17%

Q. What cost components have contributed to the proposed reduction in the facilities charge rate for facilities installed 31 years or less?

A. Decreases in the Company's requested overall rate-of-return and income and property tax rates are the primary drivers for the reduction in the proposed facilities charge rate for facilities installed 31 years or less.

Q. What cost components have driven the proposed increase in the facilities charge rate for facilities installed more than 31 years?

A. Increased working capital costs; and slightly elevated administrative and general expenses, and distribution-related operations and maintenance costs; have driven the proposed increase in the facilities charge rate for facilities installed more than 31 years.

Q. What is the estimated change in the Company's revenue from the proposed facilities charge rates?

A. Overall, the Company estimates that its proposed facilities charge rates will result in a reduction in revenue received through facilities charges of approximately $184,400 per year.

IV. SCHEDULE 72, GENERATOR INTERCONNECTIONS TO PURPA QUALIFYING FACILITY SELLERS

Q. What is the purpose of Schedule 72, Generator Interconnections to Public Utility Regulatory Policies Act of 1978 ("PURPA") Qualifying Facility Sellers?

A. Similar to how Rule H of the Company’s tariff outlines the requirements for customers seeking to interconnect to the Company’s distribution system, Schedule 72 details the Idaho Commission’s process and requirements for non-utility generators contracting, or seeking to contract, with the Company to interconnect a PURPA-qualifying generation facility in order to sell electric energy to the Company.

Q. What updates does the Company propose within Schedule 72?

A. Outside of the various edits intended to better clarify Schedule 72’s existing provisions, the Company is proposing to modify Schedule 72’s vested interest provisions so that they are consistent with provisions currently existing for the same within Rule H of the Company’s tariff.

Q. Why do the vested interest provisions in Schedule 72 and Rule H currently differ?

A. Prior to Case No. IPC-E-94-05, the bulk of the Company’s existing Rule H practices were included within its tariff under Schedule 71 which, in many respects, was very similar to Schedule 72 as it currently exists. However, as part of Case No. IPC-E-95-18, the Commission approved modifications to Rule H’s vested interest provisions to achieve greater simplicity of administration.

Similar vested interest modifications were, however, not simultaneously incorporated into Schedule 72.

Q. What challenges do the existing Schedule 72 vested interest provisions present?

A. The existing vested interest provisions under Schedule 72 require the Company to collect a vested interest charge not only for the entity that originally funded the interconnection facilities' construction cost, but also for all "Additional Applicants" that have subsequently connected and who also hold a vested interest. This practice is not only complex to administer, but it often results in numerous and minimal vested interest refund checks being sent to "Additional Applicants."

Q. What vested interest provisions does Idaho Power now seek to add to or update within Schedule 72?

A. Idaho Power proposes to update Schedule 72's vested interest provisions to allow for only one seller, person or entity to hold a vested interest at a time in a section of interconnection facilities. Additionally, the Company proposes to add an option for an "Additional Applicant" to pay the current vested interest so that they may in-turn hold a vested interest in the interconnection facilities and therefore be eligible to receive refunds. Finally, the Company proposes to limit the total amount and number of refunds that a Schedule 72 vested interest holder is eligible to receive to be no more than 80 percent of their original interconnection cost, until receipt of four vested interest refunds has occurred, or until eligibility to receive vested interest refunds has expired, which is 5 years after the date the Company completes construction of its portion of the interconnection facilities. These proposed updates will allow for Schedule 72 and Rule H's vested interest provisions to be applied and administered in a consistent manner.

V. __SCHEDULE 95, ADJUSTMENT FOR MUNICIPAL FRANCHISE FEES__

Q. Please explain the updates being proposed within Schedule 95.

A. Schedule 95 lists all franchise fees that Idaho Power currently pays to Idaho municipalities, which range from 1 percent to 3 percent of amounts billed for electric service to customers residing within the corporate limits of each listed municipality. When there is a change to a municipality's franchise fee amount, the Company files a tariff advice with the Commission to update the franchise fee rate listed in Schedule 95.

Schedule 95 also lists the municipal ordinance number for the municipality's franchise agreement with Idaho Power. When an existing franchise agreement expires and the Company enters into a new franchise agreement with the municipality, the new franchise agreement will contain a new number for the municipal ordinance that approved the new franchise agreement. In these cases, if the franchise fee rate under the new franchise agreement did not change, the Company has not historically filed a tariff advice with the Commission merely to update the ordinance number. Instead, the Company has typically only filed a tariff advice if a municipality's franchise fee rate changes as part of a new franchise agreement.

Idaho Power is proposing to update all ordinance numbers listed in Schedule 95 where the currently listed ordinance number has been replaced by a new franchise agreement with a new ordinance number, but the new ordinance number was not previously updated in Schedule 95 because the new franchise agreement did not include a change in the franchise fee rate.

Going forward, the Company intends to include updated municipal ordinance numbers as part of any tariff advice where it provides new or updated franchise fee rates.

VI. IDAHO POWER'S GENERAL RULES AND REGULATIONS

Q. How did you arrive at the proposed changes to the Company's General Rules and Regulations?

A. The changes I propose to the Company's General Rules and Regulations are the result of collaborative efforts between representatives from various business units within the Company, as well as from guidance by Company Witness Ms. Connie Aschenbrenner.

Q. Do you intend to discuss each of the proposed changes to the tariff?

A. No. While a number of the changes I discuss are substantive in nature, a significant number of other changes are "form" or "housekeeping" in nature only and do not materially change the scope, effect, or application of the respective rules and regulations. The specific changes to the service provisions I address are detailed within Attachment 2 to the Company's application. These revisions are shown in legislative format within Attachment 2 so that parties reviewing them will be able to readily identify the proposed changes.

Rule B

Q. What changes is the Company proposing be made to Rule B (Definitions) of its tariff?

A. Rule B of the Company's tariff has been modified to better clarify the Company's definition of a "Premises."

Q. Why does the Company believe modification to its definition of "Premises" is required?

A. With the recent increase in the number of prospective developments constructed in the Company's service area, some developers have expressed confusion regarding the Company's service requirements - specifically regarding what constitutes a "Premises" and whether such Premises can be served at more than one Point of Delivery. By more thoroughly detailing the criteria that the Company uses to define a Premises, developers are provided a clearer understanding of the Company's existing service requirements, which are in place to serve customers most cost-effectively. This modification will further enable developers to initially design and construct their buildings in conformance with the Company's service requirements, thereby reducing possible post-construction confusion and retrofits.

Rule C

Q. What change is the Company proposing to Rule C (Service and Limitations) of its tariff?

A. The Company proposes that Section 2 of Rule C, Supplying of Service, be clarified to highlight that the construction of any necessary line extensions or the installation of service facilities will only be performed in conformance with the Company's construction standards. While not a change in existing practice and already implied given the Company's ownership and ongoing responsibility for the operation and maintenance of all such facilities, the proposed language simply makes the requirement explicitly clear in instances where a customer may desire use of an alternative construction standard.

Rule D

Q. What changes is the Company proposing be made to Rule D (Metering) of its tariff?

A. Aside from relocating reference to certain services' funding mechanism from Schedule 66 to within Rule D itself, the Company is proposing to eliminate its optional, Off-site Meter Reading Service offering. Second, the Company proposes to update how costs are recovered for certain customers requesting receipt of optional, Load Profile Metering services, as well as including a general waiver and release of liability for such services. Finally, the Company seeks to remove offering its optional, Surge Protection Device Service and update certain meter reading-related verbiage to reflect technological advancements.

Q. Why is the Company proposing to require work order costs within Rule D for the installation of Secondary Service voltage transformers?

A. Secondary Service voltage transformers are infrequently installed and are typically only requested when a customer prefers to be served at a non-standard voltage. Because the cost and type of voltage transformer installed for each request may differ, the Company believes it reasonable to require work order costs for these installations to better recover the cost of installation from the customer requesting the service be provided.

Q. Why is the Company proposing to eliminate its optional, Off-site Meter Reading Service?

A. Following the Company's installation of AMI meters throughout its service area, as approved by the Commission in IPC-E-08-16, nearly all customers' meters innately contain the capability to be remotely read. Because of the Company's standardization of installing AMI meters, the need for a subscription-based offsite meter reading offering has become obsolete.

Q. How does the Company currently recover costs when customers request to receive Load Profile Metering services?

A. Under the current monthly subscription-based model, customers requesting to receive Load Profile Metering services pay a fixed upfront charge for the installation of the new metering equipment and an ongoing monthly charge thereafter. The ongoing monthly charge intends to recoup the installed facilities' incremental costs over a levelized three-year period. In the event a customer receiving Load Profile Metering service cancels such service within the first three years, the customer is required to pay a fixed removal fee.

Q. How does the Company propose it recover costs going forward when requested to provide Load Profile Metering services?

A. The Company proposes that work order cost be assessed for the installation and removal, if requested, of Load Profile Metering services. Using a work order cost approach is more consistent with the Company’s tariff for other installations that customers may request, such as those provided for under Rule H, and is better aligned with cost causation principles by removing the Company’s current risk of not recovering the cost of its investment should a customer cancel receipt of Load Profile Metering services within the first 3 years after installation.

Q. Why is the Company seeking to add a general waiver and release of liability for Load Profile Metering services?

A. Though the Company does not promote the utilization of Load Profile Metering data for customers to automate their operations, the Company has become aware of some customers desiring to use the service for that purpose. As a result of technological advancements allowing for such automation options, and the numerous factors that may impede the Company’s ability to provide Load Profile Metering data reliably or on a prescribed cadence, such as an outage or routine maintenance, the Company believes it prudent to include a general waiver and release of liability as part of customers' receipt of Load Profile Metering services to minimize the risk of damages being sought by customers using the services in an unadvised manner.

Q. Why is the Company proposing to remove the option for customers to request Surge Protection Device Services?

A. This is no longer a service the Company is positioned to offer. While the provision has been included in the Company's tariff since 1999, the Company has not had recent success in receiving an acceptable indemnification agreement from surge protection device vendors, as required under the offering's current provisions. Because third-party providers exist that can install whole-house surge protection in a more time-efficient manner, the Company believes it reasonable to remove this optional service offering from its tariff in order to prevent customer confusion and frustration that may occur as a result of customers requesting a service that the Company is not currently positioned to deliver.

Q. Please describe the changes proposed under Rule D's Section 2, Measurement of Energy, and Section 6, Meter Reading.

A. The verbiage being proposed to these sections incorporates changes to the Company's meter reading practices made possible through technological advancements. Specifically, the existing verbiage contemplates the Company manually reading meters, typically on an interval of once per billing period. However, because technological advancements in metering equipment have allowed for customers' meters to be remotely read and at greater interval frequency, the Company has updated the sections' verbiage to also indicate that multiple meter readings can occur during a customer's billing period, as well as clarifying the threshold amount of unscaled hourly meter reads required during a customer's billing period before their bill will be designated as an estimate.

Q. Under what circumstances is the Company unable to obtain remote meter readings?

A. While infrequent, the Company may not be able to remotely obtain customers' meter readings due to situations resulting from, but not limited to, a communication outage at the substation, line interference, or maintenance work.

Q. Please explain what you mean by "unscaled hourly meter reads."

A. An unscaled hourly meter read is an estimate of a customer's usage during the respective hour and occurs when the Company is unable to infer a customer’s missing hourly usage data based on other known meter readings and usage patterns for such customer at the same premises. Conversely, a scaled hourly read occurs when an hourly meter read is unable to be obtained but, because the delta of unrecorded energy is known, the Company can proportion the total unrecorded amount of consumed energy over any missing intervals based on customers’ historical usage patterns at the premises.

Rule E

Q. What changes is the Company proposing be made to Rule E (Master Metering Standards) of its tariff?

A. Rule E of the Company’s tariff has historically adopted most of the language found in IDAPA 31.26.01, which contains the Commission’s Master-Metering Rules for Electric Utilities (“Commission’s Master Metering Rules”). As such, most of the proposed updates to Rule E are to simply align the Company’s master-metering rules to the Commission’s Master Metering Rules. Should any of the Commission’s Master Metering Rules be revised as part of the efforts currently taking place within Case No. RUL-U-23-03, the Company will modify the proposed language within Rule E accordingly.

Q. Are there any notable differences in the Company’s Rule E compared to the Commission’s Master-Metering Rules?

A. No. However, under Section 2(b) of the Company’s Rule E, there is reference to Schedule 3 – Master-Metered Mobile Home Park - Residential Service. This reference is in conformance with Commission Order No. 30754 which approved such rate schedule to be used in instances where eligible park operators bill master-metered tenants for electric service.

Rule H

Q. What changes is the Company proposing be made to Rule H (New Service Attachments and Distribution Line Installations or Alterations) of its tariff?

A. First, the Company is proposing to update Section 7 of Rule H’s verbiage regarding the provision of Company-funded allowances. This section has been updated to better clarify that Rule H’s allowances only offset the cost of installed terminal facilities, which is comprised of a transformer and service attachment.

Second, the Company is proposing that existing customers be eligible to receive a Company-funded allowance when such customers increase their load and are responsible for upgrading terminal facilities that currently serve two or more customers taking residential, general service or irrigation service.

Finally, the Company is proposing a handful of edits within Rule H for streamlining and clarity purposes, as well as updating the provisions governing unusual conditions and irrevocable letters of credit to better align with current construction and work order reconciliation timelines.

Q. Please describe the Company's current practice for providing allowances pursuant to Rule H.

A. Currently, if installation of a new service conductor is required to serve a new request for service, a Company-funded allowance or salvage credit, whichever is greater, is provided to offset a portion of the new or upgraded terminal facilities' cost of installation. The amount of the Company-funded allowance provided in these instances is dependent upon the then effective cost of "Standard Terminal Facilities," whether the request is for single phase or three phase service, and the extent of terminal facilities required to be installed.

For example, if a new customer's service request only requires the installation of a new overhead service conductor, such service conductor's installation cost will be offset by up to the then effective and applicable allowance amount. Similarly, if a new customer's service request requires the installation of transformation and overhead service conductor, these facilities' installation cost will be offset by up to the then effective and applicable allowance amount.

Any installation costs in excess of a customer's eligible allowance or salvage credit remains the requesting customer's responsibility to fund.

Q. Are existing customers currently eligible to receive an allowance if their load request requires terminal facilities to be upgraded?

A. No. Existing customers increasing their load and necessitating upgraded terminal facilities are currently financially responsible for funding the entire cost, less any applicable salvage credit, of the required upgraded terminal facilities.

Q. Why is the Company proposing that existing customers also be eligible to receive a Company-funded allowance under certain circumstances?

A. As the Commission noted within Order No. 30955, "[d]epending on the geographic configuration of customer locations, transformers can serve multiple customers." While it is certainly most economical to serve, when possible, multiple customers taking Secondary Service from a single transformer, each customer connected to such "shared" transformer may have otherwise been afforded the entirety of an allowance if not but for the geographic configuration that allowed for such sharing of transformation to occur. Further, if each of these customers were served from individual terminal facilities, the need to upgrade said terminal facilities as a result of adding load may have been avoided.

Recognizing these factors, the Company believes it reasonable to begin contributing, in qualifying circumstances, towards a portion of the upgraded terminal facilities' costs, up to the financially responsible customer's effective allowance amount, given the upgraded terminal facilities will continue serving multiple customers.

Q. Why is the Company removing the definition of Point of Delivery within Rule H?

A. Defining "Point of Delivery" within Rule H is duplicative of the same definition also existing within Rule B of the Company's tariff. Because Point of Delivery is frequently used throughout the Company's tariff, its broad definition is most appropriately included within Rule B to limit potential confusion.

Q. Why is the Company proposing to remove reference to a 200-amperage meter base within Rule H's definition of Standard Terminal Facilities?

A. Customers are responsible for providing an acceptable meter base to accommodate their requested level of service. Removal of the existing “to serve a 200-amperage meter base” verbiage within the definition of “Standard Terminal Facilities” helps eliminate any ambiguity of this requirement and better specifies the facilities installed by the Company and used in determining allowance amounts.

Q. Why is the Company proposing to remove “meter” from the definition of Terminal Facilities?

A. In accordance with Rule D of the Company’s tariff, meters are typically provided at no cost to customers, unless a customer requests a meter type not required by the Company or necessitates more than one primary voltage meter. As a result, the Company recommends removing reference of a meter within the definition of Terminal Facilities in order to eliminate potential confusion as to which facilities’ costs are offset via a Company-funded allowance.

Q. Please explain the Company’s proposed revision regarding Rule H’s Unusual Conditions.

A. Because the Company’s reconciliation of a project’s work order can be dependent on external parties’ timely submission of information, a 90-day timeframe to return unencountered unusual conditions amounts can often be difficult to achieve. As such, the Company is proposing to adjust the reconciliation timing language to provide flexibility for various types of scenarios while simultaneously also ensuring that once such reconciliation of work order costs has been completed, customers are refunded any eligible amounts within 30 days.

Q. Are there any other notable modifications being proposed to Rule H?

A. Though infrequently used by customers, the Company is proposing the Commission give Idaho Power latitude to determine, on a case-by-case basis, when the Company will accept an irrevocable letter of credit for the estimated cost of unusual conditions. Because of the length of time that it may take to complete the construction and reconciliation of actual costs for certain projects, a customer-provided irrevocable letter of credit could expire, thereby putting the Company at risk of not being able to collect the cost of unusual conditions associated with customer-requested construction work. By having the flexibility of being able to determine when to accept an irrevocable letter of credit, the Company may be able to limit risk of not being able to collect the cost of unusual conditions seemingly “guaranteed” by an irrevocable letter of credit.

Q. Is the Company proposing to change Rule H's fixed charges, credits or overhead rate as part of its Application?

A. In keeping with Commission Order Nos. 30853, 30955 and 32472, the Company submits for the Commission's review updated Rule H charges, credits and the general overhead rate prior to January 1st of each year. To avoid duplicative efforts and potential customer confusion, and in recognition that the existing charges, credits and general overhead rate were just updated on March 15, 2023, the Company believes it reasonable at this time to defer updating these Rule H charges and credits until its routine annual compliance filing.

Rule J

Q. What changes is the Company proposing be made to Rule J (Continuity, Curtailment and Interruption of Electric Service) of its tariff?

A. Rule J should be updated to include reference to the service voltage ranges described in the current edition of standard C84.1 of the American National Standards Institute – *American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60Hz)*. Because the Company currently adheres to the referenced service voltage standard, inclusion of the reference will not result in a change to how the Company operates or designs its system; however, it will provide greater clarity and transparency to customers.

Rule L

Q. What changes are you proposing be made to Rule L (Deposits) of Idaho Power's tariff?

A. Rule L has been updated to provide the Company flexibility to return a large commercial or special contract customer's collected deposit, and any accrued interest, early if such customer establishes good credit prior to the deposit being held for 12 months. This change better aligns Rule L's deposit retention requirements with IDAPA 31.21.01.107.04, which allows for the early return of deposits and accrued interest to residential and small commercial customers.

Rule M

Q. What changes is the Company proposing be made to Rule M (Facilities Charge Service) of its tariff?

A. Section 4 of Rule M has been updated to plainly state that the monthly facilities charge amount assessed for Company-owned facilities installed at the customer's request on the customer's side of the Point of Delivery is independent of a customer's monthly energy usage. The Company also seeks to clarify that a facilities charge customer remains financially responsible for their monthly facilities charge bill until either another customer requests to assume responsibility for such facilities charge arrangement, and the Company is agreeable to providing Rule M services to such requesting customer, or the facilities charge customer pays the non-salvable cost associated with the removal of all Company-owned facilities beyond the Point of Delivery.

Q. Does the proposed verbiage update to Section 4 of Rule M change how the Company assesses facilities charges to customers?

A. No. The Company currently bills facilities charges in the manner described within the proposed verbiage within Section 4 of Rule M. This proposed update simply provides customers with greater transparency of the Company's practices associated with this optional service.

VII. MISCELLANEOUS SCHEDULE UPDATES

Q. What other schedules is the Company proposing to update as part of its application?

A. The Company is proposing to remove schedules that are no longer active, eliminate water and space heating provisions within its residential service schedules, update the past due threshold amount necessitating a Tier 2 deposit under Schedule 24, Agricultural Irrigation Service, and update the Company-provided payment amount under Schedule 61, Payment for Home Wiring Audit.

Q. What schedules is the Company proposing to remove from its tariff?

A. The Company is proposing to remove the below listed schedules from its tariff since the schedules are either suspended or unused by customers.

- Schedule 4, Residential Service Energy Watch Pilot Plan
- Schedule 60, Solar Photovoltaic Service Pilot Program
- Schedule 63, Community Solar Pilot Program

Q. Why is the Company proposing to remove the space and water heater provisions from its residential service schedules?

Q. The Company's proposal is intended to streamline and simplify its residential service schedules and their respective interconnection requirements. These provisions are also already generally covered within Rule K, Customer's Load and Operations, of the Company's tariff. Additionally, the Company's Customer Requirements for Electric Service document remains updated with relevant provisions, industry standards, and/or best practices.

Q. Please explain the update being proposed to Schedule 24's past due threshold amount necessitating a Tier 2 deposit.

A. The Company is proposing to increase Schedule 24's past due threshold amount necessitating a Tier 2 deposit from $1,000 to $1,500 to better align with the amount of inflation that has materialized since Schedule 24's Tier 2 deposit requirements were first authorized by Commission Order No. 29639, issued in Case No. IPC-E-04-20.

Q. Please explain the updated Company-provided payment amount being proposed within Schedule 61.

A. The Company proposes to raise the payment for customers who undergo a home wiring audit from $40 to $60. The proposed Company-provided payment amount of $60 is based on escalating the existing payment amount by the amount of inflation that has materialized since the existing payment amount was established as part of Case No. IPC-E-07-08.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF RILEY MALONEY

I, Riley Maloney, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Riley Maloney. I am employed by Idaho Power Company as a Regulatory Analyst in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony in this matter.

3. To the best of my knowledge, my pre-filed direct testimony is true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of June 2023, at Boise, Idaho.

Signed: ____________________________
RILEY MALONEY