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May 30, 2025
IDAHO PUBLIC
UTILITIES COMMISSION

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 AUTHORITY TO IMPLEMENT CERTAIN MEASURES TO MITIGATE THE IMPACT OF REGULATORY LAG.	)	CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

GRANT T. ANDERSON

I. INTRODUCTION

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 the Pricing and Tariff Administration Leader in the Company's Regulatory Affairs Department.

Q. Please describe your educational background and work experience before Idaho Power.

A. I received a Bachelor of Science degree in Microbiology from Oregon State University in May 2013 and earned a Master of Business Administration degree from Boise State University in May 2015. In March 2015, I accepted a position as a Corporate Development Analyst for Albertsons and was later promoted to Corporate Development Manager in 2017. I served in that capacity until I joined Idaho Power in 2018. I have also completed the electric utility ratemaking course "Practical Regulatory Training for the Electric Industry" through New Mexico State University's Center for Public Utilities, as well as the "Utility Finance and Accounting" course through the Financial Accounting Institute.

Q. Please describe your work experience with Idaho Power.

A. I began working at Idaho Power in 2018 as a Regulatory Analyst in the Company's Regulatory Affairs Department. In that role, I supported rate design and tariff activities for the Company's Commercial and Industrial customer classes. In 2021, I was promoted to a Regulatory Consultant and assumed responsibilities for developing complex cost-of-service studies, pricing strategies, and supporting the Company's class cost-of-service efforts. In April 2025, I was promoted to my current role as Pricing and Tariff Administration Leader, where I manage the Company's overall pricing strategy and oversee the administration of all tariff schedules and rules.

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

A. The purpose of my direct testimony is to present and support Idaho Power's proposed pricing changes for each of the Company's major customer classes, including residential, general service, irrigation, large power, lighting, and special contract customers. My testimony also addresses proposed updates to select tariff schedules and rules.

Q. Are you sponsoring any Exhibits that accompany your testimony?

A. Yes. I supervised the preparation of, and am sponsoring, Exhibit No. 44 – Calculation of Proposed Rates and Exhibit No. 45 – Monthly Adjusted Base Revenue Comparison for

the Company's retail service schedules. A table of contents for my testimony is as follows:

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II. RESIDENTIAL SERVICE PRICING

A. Residential Service Overview

Q. What are the Company's residential service schedules?

A. Idaho Power offers four residential service schedules: Schedules 1, 3, 5, and 6. Schedule 1 is the standard residential service and is available to all customers receiving electric service for general domestic use. Schedule 3 is limited to master-metered mobile home parks that are included on the Company's list of "grandfathered" mobile home parks. Schedule 5 is a time-of-use pricing option that includes distinct time periods for energy pricing. Schedule 6 is an optional service for customers with on-site generation.

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 customers served under Schedules 1, 3, 5, and 6, is $814,155,998, as shown on page 2 of Company Witness Mr. Riley Maloney's Exhibit No. 41, representing a 17.02 percent change.

Q. What pricing changes is the Company proposing for residential service?

A. The Company is proposing to revise each of the billing components for residential customers to better align with the cost of providing service as informed by the Company's proposed class cost of service ("CCOS") study presented in this case. Specifically, the Company proposes to increase the monthly Service Charge from $15.00 to $25.00. In addition to the Service Charge, Energy Charges within each schedule will be adjusted to recover the targeted revenue requirement.

Q. Where can the comparison of present and proposed rates be found?

A. A comparison of the present and proposed rates for each of the Company's residential service schedules is provided on pages 1 through 7 of Exhibit No. 44, which I will discuss later in my testimony.

B. Schedule 1, Residential Service Standard Plan

Q. Could you please describe the present pricing structure under Schedule 1?

A. Yes. Under the current Schedule 1, customers pay a monthly Service Charge of $15.00 and Energy Charges that are based on a three-tier structure. Tier 1 applies to usage from 0 to 800 kilowatt-hours ("kWh") per month; Tier 2 applies to usage from 801 to 2,000 kWh; and Tier 3 applies to all usage over 2,000 kWh per month. Each of these tiers has distinct pricing for summer and non-summer seasons.

Q. How does the Company propose to spread the proposed revenue increase for Schedule 1 across the pricing components within the schedule?

A. The Company proposes to recover the revenue requirement for Schedule 1 by increasing both the monthly Service Charge and the Energy Charges. The Service Charge would increase from $15.00 to $25.00 per month. The Energy Charges for each tier would also increase; however, the Company proposes to reduce the differential between tiers as described more fully later in my testimony. The proposed changes to Schedule 1 are shown on page 2 of Exhibit No. 44.

Q. What is the proposed bill impact for a typical residential customer?

A. For a residential customer using an average of 900 kWh per month, the proposed rate changes would result in a

bill increase of approximately $19.89 per month, or a 19.3 percent increase. Under current rates, the monthly bill for a customer using 900 kWh is approximately $103.30, which would increase to $123.19 under the proposed rates. A detailed bill comparison across various usage levels is provided on page 1 of Exhibit No. 45.

C. Schedule 3, Master-Metered Mobile-Home Park Residential Service

Q. Does the Company propose any changes to the pricing structure for Schedule 3?

A. The Company is not proposing any changes to the existing pricing structure for Schedule 3. This schedule will continue to include a monthly Service Charge and a single-tier Energy Charge applicable to all usage.

Q. How does the Company propose to spread the proposed revenue increase for Schedule 3 across the pricing components within the schedule?

A. To recover the proposed revenue requirement for Schedule 3, the Company proposes to increase the monthly Service Charge from $15.00 to $25.00. In addition, the Energy Charge will increase to meet the required revenue target for this schedule. The proposed changes to Schedule 3 are shown on page 4 of Exhibit No. 44.

D. Schedule 5, Residential Service Time-of-Use Plan

Q. Could you please describe the present pricing structure under Schedule 5?

A. Schedule 5 includes a monthly Service Charge of $15.00 and time-of-use Energy Charges that vary by season and time of day. During the summer season, there are three time-of-use periods: on-peak, mid-peak, and off-peak. In the non-summer season, there are two time-of-use periods: on-peak and off-peak.

Q. How does the Company propose to spread the proposed revenue increase for Schedule 5 across the pricing components within the schedule?

A. The Company proposes to increase the monthly Service Charge from $15.00 to $25.00 and to increase the Energy Charges proportionally while maintaining the current differential between the time-of-use periods. The proposed changes to Schedule 5 are shown on page 6 of Exhibit No. 44.

Q. What is the proposed impact on a typical Schedule 5 customer?

A. For a residential customer using an average of 1,500 kWh per month, the proposed pricing changes would result in a bill increase of approximately $29.58 per month, or 17.2 percent. Under current rates, a customer with this usage would pay approximately $171.78 per month, which would increase to $201.36 under the proposed rates. A bill comparison across different usage levels is provided on page 2 of Exhibit No. 45.

Q. Did the Company evaluate the time-of-use periods for Schedule 5 to determine whether modifications were warranted?

A. Yes. The Company reviewed the current time-of-use periods to assess whether they continue to align with the hours of highest system risk. The existing definitions remain generally representative of the Company's reliability risk profile.

The time-of-use periods were most recently updated in the Company's 2023 general rate case, and no further modifications are proposed in this proceeding. Because Schedule 5 is an optional service that requires customers to actively manage their usage in response to time-varying prices, changes to the time periods should be infrequent to provide customers with a stable and predictable framework for managing their energy consumption.

E. Schedule 6, Residential On-Site Generation Service

Q. Could you please describe the present pricing structure under Schedule 6?

A. The current pricing structure for residential customers served under Schedule 6 mirrors the pricing of Schedule 1 for standard pricing and Schedule 5 for the optional time-of-use pricing. In other words, customers on Schedule 6 are subject to the same Service Charge and Energy Charges as customers on the corresponding retail schedule,

depending on whether they elect standard or time-of-use pricing.

Q. What pricing structure is the Company proposing under Schedule 6?

A. The Company proposes to maintain the existing pricing relationship between Schedule 6 and the applicable retail schedule. Customers taking service under Schedule 6 would continue to be priced according to either Schedule 1 or Schedule 5, depending on their selected pricing option.

Q. Why is the Company proposing to retain this pricing structure for Schedule 6?

A. While the Company's CCOS study indicates that the cost to serve customers on Schedule 6 is higher than that of customers receiving standard service, the Company believes that pricing changes should be implemented gradually to avoid rate shock to individual customers. As was the case in the Company's 2023 general rate case, Idaho Power continues to evaluate options for aligning Schedule 6 pricing more closely with the cost to serve and may bring forward proposals in future proceedings.

F. Residential Service Charge

Q. Please summarize the Company's proposal for the residential Service Charge in this proceeding.

A. The Company proposes to continue progress in the residential Service Charge to better align prices with the

fixed costs of serving customers. In the Company's 2023 general rate case, Idaho Power introduced a multi-year plan to increase the Service Charge. The Commission approved the first two steps of that plan in Order No. 36042. An additional step, an increase to $25.00 per month effective January 1, 2026, is proposed in this proceeding.

Table 1

Residential Monthly Service Charge

Effective January 1	**Schedule 1/3/5/6**
2024	$10.00
2025 (Current)	$15.00
2026 (Proposed)	$25.00

Q. Why is the Company proposing a multiyear transition for the Service Charge?

A. The Company believes a gradual transition helps moderate bill impacts, particularly for lower-use customers, and avoids rate shock. This phased approach aims to balance the goal of aligning fixed charges with fixed costs while remaining sensitive to customer impacts.

Q. What is the cost basis for increasing the residential Service Charge?

A. A large portion of the Company's costs — such as distribution plant and associated operations — are fixed and do not vary with customer usage. The total monthly customer-allocated costs, as shown in Mr. Maloney's Exhibit No. 37, page 1, are approximately $42.84 per customer per month. The

Company believes it is appropriate to recover a greater share of these fixed costs through the Service Charge. When the Service Charge is set too low, the Company must recover fixed costs through higher volumetric Energy Charges, resulting in high-usage customers subsidizing low-usage customers.

Q. How does the Company's proposed $25.00 residential Service Charge compare to those of other electric utilities in Idaho?

A. The proposed $25.00 per month Service Charge is generally in line with the fixed monthly charges assessed by other Idaho electric utilities serving more than 1,000 customers. The table below shows a comparison of current fixed charges among these utilities.

Table 2

Fixed Monthly Residential Charges for Idaho Electric Utilities

Utility	Price
Avista	$ 20.00
City of Idaho Falls	$ 23.00
Fall River Rural Electric Cooperative	$ 39.00
Idaho Power	$ 15.00
Inland Power & Light Company	$ 31.52
Kootenai Electric Cooperative	$ 32.50
Lower Valley Energy	$ 18.00
Northern Lights	$ 30.00
Raft Rural Electric Cooperative	$ 25.50
Rocky Mountain Power Idaho	$ 16.50
Salmon River Electric Cooperative	$ 46.00
United Electric Cooperative	$ 26.00
Average	**$ 26.92**
Note: All fixed monthly charges available from each utility's website as of May 23, 2025.	

Q. Has the Commission supported aligning fixed cost collection with fixed charges?

A. The approved residential Service Charge changes in Idaho Power's 2023 general rate case were part of the Commission-approved Settlement Stipulation. Additionally, in Order No. 35909, the Commission approved a similar proposal by Avista to increase its residential Service Charge. In that order, the Commission stated:

> The Commission is persuaded by the Company's testimony on the average cost of service for customers including distribution plant and operating costs to provide reliable service. The Commission believes that accurately assigning costs is a fair component of rate design, and the misalignment of costs can create revenue recovery distortions and give an incorrect perception of the cost and value of the Company's services. The proposed change to the basic charge is movement to ensure that all customers are paying a proper amount of fixed costs required to serve them.
>
> The Commission is sensitive to customer concerns with the potential impact of increasing the basic charge; however, the Commission is not persuaded by ICL/NWEC's claims that the proposed changes will send a negative price signal for energy efficiency and conservation, and disproportionately effect low-income and low-usage customers. Further, the Commission does not believe that at this time any alteration is necessary to the Company's cost-effectiveness calculation for energy efficiency, nor is it necessary at this time to require the Company to increase funding for low-income customers. Similarly, the Commission does not believe that it is necessary at this time to open an investigatory docket into the interplay between the high fixed charges and revenue decoupling.

G. Residential Tiered Energy Charges

Q. Please describe the structure of the Company's current tiered Energy Charges in Schedule 1?

A. Schedule 1 includes seasonal inclining block Energy Charges, meaning the price per kWh increases once a customer exceeds a set monthly usage threshold. In addition to the tiered pricing, Energy Charges vary seasonally, with higher prices in the summer season of June through September and lower prices in the non-summer season of October through May.

Q. Historically, why were tiered Energy Charges implemented?

A. Inclining block pricing has historically been used as a tool to encourage lower energy usage. The first block is priced lower to help maintain bill affordability, while subsequent blocks are priced higher to provide an incentive for customers to reduce their consumption. Under this design, energy-efficient actions — such as replacing lighting with LEDs — would yield greater bill savings for customers using electricity in the higher tiers.

Q. Do tiered Energy Charges necessarily encourage energy efficiency?

A. Not necessarily. A customer's total monthly usage may be influenced by factors unrelated to energy efficiency, such as the number of occupants in the home or the primary fuel source for heating. These factors can result in higher usage independent of conservation behavior.

Q. Why is the Company proposing to reduce the differential between energy tiers?

A. While a tiered pricing structure is well-intentioned, it has created challenges in pricing. The Company believes that tiered Energy Charges are not economically justified and result in unfair cost allocation among customers. The proposed change reflects a gradual movement away from tiered pricing to improve fairness and align prices more closely with cost causation.

Q. Please explain why tiered Energy Charges are not economically justified.

A. There is no cost-based rationale for charging a higher rate for the kWh consumed beyond an arbitrary threshold such as 800 or 2,000 kWh. Unlike the timing of energy consumption — which can impact costs due to system load or market prices — higher monthly energy use alone does not increase the utility's cost to deliver the next unit of energy. Cost drivers are more closely tied to time of energy consumption and load factor, rather than total monthly usage.

Q. How do tiered Energy Charges result in unfair cost allocation?

A. Inclining block pricing shifts a larger share of the cost burden to customers with higher monthly usage, who may use more energy for reasons outside their control. For example, customers who heat with electricity or have larger

households are more likely to fall into higher usage tiers. In contrast, customers using natural gas for heating or living alone may remain in lower tiers and pay less, even though the cost to serve each customer does not differ as dramatically.

Q. Is there another benefit to reducing or removing tiered Energy Charges?

A. Yes. Flattening the tiered structure makes it easier for customers to compare Schedule 1 with Schedule 5, the optional residential time-of-use schedule. This simplification helps customers make more informed decisions about which pricing plan best meets their needs. The Company believes flattening the tiers in this case will also better position the Company to consider a future transition to default or mandatory time-of-use rates.

Q. What specific change is the Company proposing to the Schedule 1 energy tiers?

A. The Company proposes to reduce the differentials between the current tiered prices but is not proposing to eliminate tiered pricing entirely in this proceeding. This approach balances cost alignment with gradualism to moderate customer bill impacts. The proposed tiered prices are shown on page 2 of Exhibit No. 44.

H. Residential TOU Bill Protection

Q. Are there any additional changes proposed for Schedule 5?

A. Yes. The Company is proposing to implement a bill protection program for residential customers who begin taking service under Schedule 5 effective January 1, 2026.

Q. What is the purpose of introducing bill protection for customers on Schedule 5?

A. The purpose of bill protection is to reduce financial uncertainty for customers transitioning from Schedule 1 to Schedule 5. The program is intended to encourage participation in the optional TOU pricing by ensuring customers will not pay more than $10 above what they would have paid under Schedule 1 for their first twelve months of service on Schedule 5. This customer protection feature lowers the barrier to entry and supports broader adoption of TOU rates.

Q. How does the proposed bill protection mechanism work?

A. After twelve consecutive months of service on Schedule 5, a customer's actual billed energy charges will be compared to what the customer would have paid under Schedule 1 for the same usage. If the Schedule 5 charges for the first twelve months exceed the Schedule 1 charges by more than $10 on an annual basis, the customer will receive a one-time bill credit for the amount above the $10 threshold.

Q. Who is eligible for this bill protection program?

A. Residential customers who begin taking service under Schedule 5 on or after January 1, 2026, are eligible. To qualify, customers must remain on Schedule 5 at the same premises for a full twelve consecutive months. Customers who have previously received service under Schedule 5, do not complete the full twelve-month period, or are served under Schedule 6 are not eligible for the program.

Q. Is bill protection available beyond the first year of a customer's enrollment in Schedule 5?

A. No. Bill protection is only available during the first twelve consecutive months that a customer takes service under Schedule 5 at a given premises. The intent of the program is to provide a transitional safety net for customers who are new to time-of-use pricing. After the first year, customers will continue service under Schedule 5 without bill protection or they may self-select out of the optional service and revert to the standard plan under Schedule 1.

Q. What are the expected benefits of this proposal for customers and the Company?

A. For customers, the bill protection program offers a low-risk opportunity to try TOU pricing, which may help them reduce their bills by shifting usage to lower priced off-peak periods. For the Company, broader TOU participation can support load management and help reduce peak demand, which may lower overall system costs over time.

Q. Did the Company evaluate the potential financial impact to the Company?

A. Yes. The Company has considered the potential financial implications of the bill protection program on the FCA mechanism. If a customer opts in to Schedule 5 and exhibits higher usage during the on-peak and mid-peak periods, they are more likely to trigger the bill protection provision. In those cases, while the customer receives a bill credit, the FCA will reflect a higher level of fixed cost recovery due to the elevated volumetric energy charges associated with peak-period usage. This may result in a lower FCA deferral than what would have occurred under Schedule 1 pricing for those customers that trigger the TOU Bill Protection.

Q. Is the Company proposing to implement a tracking mechanism?

A. Not currently – the Company does not anticipate the initial rate of adoption to result in a material financial impact. However, depending on the level of customer adoption of Schedule 5 and the number of customers who ultimately receive a bill credit through the bill protection mechanism, the cumulative impact could necessitate a future evaluation of a tracking mechanism to mitigate financial harm to the Company.

III. GENERAL SERVICE PRICING

A. Schedule 7 and 8, Small General Service

Q. What are the Company's small general service schedules?

A. Idaho Power offers two small general service schedules: Schedules 7, the standard small general service, and Schedule 8, which is an optional service for small general service customers with on-site generation.

Q. What is the annual revenue requirement to be recovered from small general service under Schedules 7 and 8?

A. The annual revenue requirement to be recovered from small general service customers under Schedules 7 and 8 is $23,641,536, as shown on page 2 of Mr. Maloney's Exhibit No. 41, representing a 17.02 percent change.

Q. What pricing structure changes is the Company proposing for small general service?

A. The Company is not proposing any changes to the existing pricing structure for either Schedule 7 or Schedule 8.

Q. What is the present pricing structure under Schedules 7 and 8?

A. Both Schedule 7 and Schedule 8 currently include a monthly Service Charge of $25.00 and a two-tier Energy Charge structure. Tier 1 applies to the first 300 kWh of monthly usage, and Tier 2 applies to all usage above 300 kWh.

Q. Why is the Company proposing to retain this pricing structure for Schedule 8?

A. While the Company's class cost of service study indicates that the cost to serve Schedule 8 customers is higher than for customers receiving standard service, the Company believes pricing changes should be made gradually to avoid rate shock. As in the Company's 2023 general rate case, Idaho Power continues to evaluate options for aligning Schedule 8 pricing more closely with cost of service and may bring forward proposals in future proceedings.

Q. How does the Company propose to spread the proposed revenue increase for Schedules 7 and Schedule 8 to the pricing components within the schedules?

A. The Company proposes to recover the increased revenue requirement for Schedules 7 and 8 by increasing both the monthly Service Charge and the tiered Energy Charges. The Service Charge would increase from $25.00 to $30.00 per month. The Energy Charge for each tier would also increase. The proposed changes to Schedule 7 and Schedule 8 are shown on page 8 of Exhibit No. 44.

Q. Have you prepared an exhibit that shows the billing impact of this pricing proposal?

A. Yes. Page 3 of Exhibit No. 45 presents a billing comparison between the present and proposed rates for Schedule 7.

B. Schedule 9, Large General Service (Secondary)

Q. What is the annual revenue requirement to be recovered from large general service customers under Schedule 9 Secondary Service?

A. The annual revenue requirement to be recovered from large general service customers under Schedule 9 Secondary Service is $331,880,068, as shown on page 2 of Mr. Maloney's Exhibit No. 41, representing a 7.19 percent change.

Q. What pricing structure changes is the Company proposing for Schedule 9 Secondary Service?

A. The Company is not proposing any changes to the existing pricing structure for Schedule 9 Secondary Service.

Q. What is the present pricing structure under Schedule 9 Secondary Service?

A. The current pricing structure under Schedule 9 Secondary Service includes a monthly Service Charge, a Basic Charge, and seasonal Billing Demand and Energy Charges. The Energy Charges are available under either a default or optional time-of-use pricing structure.

Q. How does the Company propose to spread the proposed revenue increase for Schedule 9 Secondary Service to the pricing components within that schedule?

A. For all pricing components, the Company is proposing prices that represent a uniform 20 percent movement toward the costs to serve that pricing component. For the

optional time-of-use pricing the Energy Charge differentials are informed by the three-year average hourly Energy Imbalance Market ("EIM") prices for each time-of-use period. The costs to serve each rate component are identified on page 5 of Mr. Maloney's Exhibit No. 37, and the proposed changes to Schedule 9 Secondary Service are shown on pages 11 and 12 of Exhibit No. 44.

Q. Have you prepared an exhibit that shows the billing impact of this pricing proposal?

A. Yes. Page 4 of Exhibit No. 45 presents a billing comparison between the present and proposed rates for Schedule 9 Secondary Service. In general, higher load factor customers would experience a smaller percentage increase in their bills than lower load factor customers.

C. Schedule 9, Large General Service (Primary/Transmission)

Q. What is the annual revenue requirement to be recovered from large general service customers under Schedule 9 Primary and Transmission Service?

A. The annual revenue requirement to be recovered from large general service customers under Schedule 9 Primary and Transmission Service is $56,288,766, as shown on page 2 of Mr. Maloney's Exhibit No. 41, representing a 6.88 percent change.

Q. What pricing structure changes is the Company proposing for Schedule 9 Primary and Transmission Service?

A. The Company is not proposing any changes to the existing pricing structure for Schedule 9 Primary and Transmission Service.

Q. What is the present pricing structure for Schedule 9 Primary and Transmission Service?

A. The current pricing structure under Schedule 9 Primary and Transmission Service includes a monthly Service Charge, a Basic Charge, seasonal Demand Charges, a summer On-Peak Demand Charge, and seasonal time-of-use Energy Charges. In addition, customers may pay a Facilities Charge if Company-owned facilities are installed beyond Idaho Power's Point of Delivery.

Q. How does the Company propose to spread the proposed revenue increase for Schedule 9 Primary and Transmission Service to the pricing components within the schedule?

A. The Company is proposing to increase the Service Charge to align with cost of service. For all other pricing components, the Company is proposing prices that represent a uniform 20 percent movement towards the costs to serve that pricing component, and Energy Charges informed by the three-year average hourly EIM prices for each time-of-use period. The costs to serve each rate component are identified on page 6 of Mr. Maloney's Exhibit No. 37, and the proposed change to

Schedule 9 Primary and Transmission Service are shown on pages 13 and 14 of Exhibit No. 44.

Q. Have you prepared an exhibit that shows the billing impact of this pricing proposal?

A. Yes. Page 5 of Exhibit No. 45 presents a billing comparison between the present and proposed pricing for Schedule 9 Primary Service. In general, customers with higher load factors would experience a lower overall increase in their monthly bills compared to customers with lower load factors.

IV. LARGE POWER SERVICE PRICING

Q. What is the annual revenue requirement to be recovered from Large Power Service customers taking service under Schedule 19?

A. The annual revenue requirement for customers taking service under Schedule 19 is $176,645,167, as shown on page 2 of Mr. Maloney's Exhibit No. 41, representing a 9.97 percent increase.

Q. What pricing structure changes is the Company proposing for Schedule 19?

A. The Company is not proposing any changes to the existing pricing structure for Schedule 19.

Q. What is the present pricing structure under Schedule 19?

A. Service under Schedule 19 is available at the Secondary, Primary, and Transmission service levels. The current pricing structure includes a monthly Service Charge, a Basic Charge, seasonal Demand Charges, a summer On-Peak Demand Charge, and seasonal time-of-use Energy Charges. Customers taking Primary or Transmission service may also pay a Facilities Charge for Company-owned facilities installed beyond Idaho Power's Point of Delivery. Additionally, Schedule 19 includes a minimum Billing Demand of 1,000 kilowatts per month and a minimum Basic Load Capacity.

Q. How does the Company propose to spread the proposed revenue increase for Schedule 19 across the pricing components within the schedule?

A. For all pricing components, the Company is proposing prices that represent a uniform 20 percent movement toward the costs to serve that pricing component, and Energy Charges informed by the three-year average hourly EIM prices for each time-of-use period. The costs to serve each pricing component are identified on page 7 of Mr. Maloney's Exhibit No. 37, and the proposed change to Schedule 19 are shown on pages 15 - 17 of Exhibit No. 44.

Q. Have you prepared an exhibit that shows the billing impact of this pricing proposal?

A. Yes. Page 6 of Exhibit No. 45 presents a billing comparison between the present and proposed pricing for

Schedule 19. In general, customers with higher load factors would experience a smaller overall increase in their monthly bills compared to customers with lower load factors.

V. IRRIGATION SERVICE PRICING

A. Schedule 24, Agricultural Irrigation Service

Q. What is the annual revenue requirement to be recovered from irrigation customers under Schedule 24?

A. The annual revenue requirement to be recovered from customers taking service under Schedule 24 is $209,823,654, as shown on page 2 of Mr. Maloney's Exhibit No. 41, representing a 17.02 percent change.

Q. What pricing structure changes is the Company proposing for Schedule 24?

A. The Company is not proposing any changes to the existing pricing structure for Schedule 24. However, the Company is proposing a change to the definition of the in-season and out-of-season periods, which I will address later in my testimony.

Q. What is the present pricing structure for Schedule 24?

A. Schedule 24 classifies service as either "in-season" or "out-of-season." The in-season currently begins with the customer's meter reading for the May billing period and ends with the meter reading for the September billing period. The out-of-season includes all other billing periods.

Customers pay a higher monthly Service Charge during the in-season period and a lower Service Charge during the out-of-season period. The purpose of the reduced out-of-season charge is to encourage customers to maintain year-round service rather than frequently disconnecting and reconnecting around the irrigation season.

During the in-season, customers pay both a Demand Charge and an Energy Charge based on metered usage. During the out-of-season, customers pay only an Energy Charge. Both Secondary Service and Transmission Service are available under Schedule 24, although no customers are currently taking service at the transmission level.

Q. How does the Company propose to spread the proposed revenue increase for Schedule 24 to the pricing components within the schedule?

A. The Company is proposing to increase the monthly Service Charge to move closer to cost-of-service-informed pricing. Specifically, the in-season Service Charge would increase from $30 to $35, while the out-of-season Service Charge would increase from $6 to $9. For the in-season Demand Charge, the Company is not proposing additional movement towards cost of service in this proceeding. The costs to serve each pricing component is identified on page 8 of Mr. Maloney's Exhibit No. 37, and the proposed changes to Schedule 24 Secondary Service are shown on page 18 of Exhibit No. 44.

Q. Why is the Company proposing essentially no movement towards cost-of-service informed pricing as part of its proposal for Schedule 24?

A. In the 2023 general rate case, the approved rate design for Schedule 24 implemented a 30 percent movement towards cost-of-service, including approximately a 100 percent increase in the billing demand price. While that shift was supported by the underlying class cost-of-service study, it resulted in larger bill impacts for low load factor customers due to the transition from energy-based to demand-based collection. In recognition of those impacts and consistent with the principle of gradualism, the Company is not proposing additional movement toward cost-of-service for Schedule 24 in this case and instead proposes to maintain the pricing relationship established in the prior general rate case.

Q. How were the prices for Transmission Service determined?

A. Although no customers currently take Transmission Service under Schedule 24, the Company developed Transmission Service prices by applying the same percentage increase to each pricing component as was applied to Secondary Service. This approach maintains the current proportional relationship between Transmission and Secondary Service pricing components.

Q. Have you prepared an exhibit that shows the billing impact of this pricing proposal on customers taking service under Schedule 24?

A. Yes. Page 7 of Exhibit No. 45 provides a comparison of the present and proposed pricing for Schedule 24. In general, customers with higher load factors would experience a lower overall increase in their monthly bills compared to customers with lower load factors.

B. Irrigation In-Season Period

Q. What is the present seasonal structure for irrigation service under Schedule 24?

A. Service under Schedule 24 is classified as either "in-season" or "out-of-season." Under the current structure, the in-season period begins with each customer's meter reading for the May billing period and ends with the meter reading for the September billing period. The out-of-season period includes all other billing months.

Q. Is the Company proposing a change to the definition of the seasonal periods under Schedule 24?

A. Yes. The Company is proposing to define the in-season period as June 1 through September 30 and the out-of-season period as October 1 through May 31.

Q. Why is the Company proposing to revise the definition of the seasonal periods?

A. The proposed revision is intended to establish a more consistent, equitable, and easily understood definition for when the irrigation in-season begins and ends each year. The Company's evaluation and proposal in this proceeding are based on three primary drivers:

First, consistency and transparency. Under the current structure, seasonal definitions are tied to each service point's meter read cycle. This results in seasonal periods varying by customer. For example, an irrigation service on an early meter read cycle could begin the in-season as early as April 29 and end around August 30, while another customer on a later cycle may begin in-season service on May 29 and end around September 26. This variability creates inconsistency across customers.

Second, customer understanding and administrative simplicity. The current structure can be confusing for customers, particularly those with multiple irrigation service points that may have different seasonal start and end dates. The dates for each service can also shift slightly from year to year based on the meter reading schedule. A consistent definition for all irrigation customers improves transparency and is expected to reduce confusion.

Third, alignment with future system upgrades. The current seasonal structure, which is tied to individual meter read dates, would require additional customization and

complexity as the Company transitions to a new Customer Information System. By adopting a fixed calendar-based definition of the in-season and out-of-season periods, the Company can avoid unnecessary customization, reduce costs, and simplify system implementation.

Q. Has the Company discussed the proposed change to the definition of the irrigation in-season period with customers?

A. Yes. On March 20, 2025, Idaho Power representatives participated in a meeting hosted by the Idaho Irrigation Pumpers Association ("IIPA"), during which the proposed change to the in-season period was presented. Feedback from IIPA members — many of whom are Idaho Power irrigation customers — was generally positive, particularly with respect to improving the customer experience and enhancing the clarity of seasonal definitions.

VI. LIGHTING & NON-METERED PRICING

Q. What are the Company's lighting and non-metered service schedules?

A. The Company's lighting and non-metered service schedules include Schedule 15 (Dusk to Dawn Customer Lighting), Schedule 41 (Street Lighting Service), Schedule 42 (Traffic Control Signal Lighting Service), and Schedule 40 (Non-Metered General Service).

A. Schedule 15, Dusk to Dawn Customer Lighting

Q. What is the annual 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 $1,430,757, as shown on page 2 of Mr. Maloney's Exhibit No. 41, representing a 3.93 percent change.

Q. What is the current pricing structure under Schedule 15?

A. Customers taking service under Schedule 15 are charged on a per-lamp basis. Fixtures available under this schedule include 40, 85, and 200 watt Light Emitting Diode ("LED") area lighting, and 85, 150, and 300 watt LED flood lighting.

Q. Has the Company prepared an exhibit that illustrates the pricing proposal for Schedule 15?

A. Yes. The pricing proposal for Schedule 15 is provided on page 20 of Exhibit No. 44. The Company proposes to allocate the class revenue requirement to pricing components based on a separate lighting cost-of-service study conducted for both Schedules 15 and 41.

B. Schedule 40, Non-Metered General Service

Q. What is the annual revenue requirement to be recovered from customers taking service under Schedule 40?

A. The annual revenue requirement for Schedule 40 customers is $1,619,008, as shown on page 2 of Mr. Maloney's Exhibit No. 41, representing an 8.21 percent change.

Q. What is the current pricing structure under Schedule 40?

A. Customers under Schedule 40 are non-metered but have fixed loads and usage profiles. A flat Energy Charge is applied to estimated usage. The current minimum monthly charge is $2.00. An Intermittent Usage Charge may also be applied to qualifying municipal or government agency loads with variable usage patterns.

Q. What pricing changes is the Company proposing for Schedule 40?

A. The pricing proposal for Schedule 40 is shown on page 21 of Exhibit No. 44. The Company proposes to increase the Energy Charge to recover the proposed revenue requirement and increase the Intermittent Usage Charge from $2.00 to $2.50.

C. Schedule 41, Street Lighting Service

Q. What is the annual revenue requirement to be recovered from customers taking service under Schedule 41?

A. The annual revenue requirement to be recovered from Schedule 41 customers is $4,160,824, as shown on page 2 of Mr. Maloney's Exhibit No. 41, representing a 3.93 percent change.

Q. What is the current pricing structure for Schedule 41?

A. Schedule 41 includes two service options. Option A applies to Idaho Power-owned and maintained systems. Option C applies to customer-owned, customer-maintained systems. Option A includes unmetered lighting billed on a per-lamp basis. Fixtures include LED equivalents of 40, 85, 140, and 200 watts. Option C allows for both metered and non-metered systems, with maintenance performed by the customer.

Q. Has the Company prepared an exhibit that illustrates the pricing proposal for Schedule 41?

A. Yes. The pricing proposal for Schedule 41 is shown on pages 22 and 23 of Exhibit No. 44.

D. Schedule 42, Traffic Control Signal Lighting Service

Q. What is the annual revenue requirement to be recovered from customers taking service under Schedule 42?

A. The annual revenue requirement for Schedule 42 customers is $291,430, as shown on page 2 of Mr. Maloney's Exhibit No. 41, representing a 17.02 percent change.

Q. What is the current pricing structure under Schedule 42?

A. Customers pay an Energy Charge based on actual or estimated energy use. For non-metered service, energy use is estimated based on lamp type and typical operating hours. There is no minimum monthly charge under this schedule.

Q. Has the Company prepared an exhibit that illustrates the pricing proposal for Schedule 42?

A. The pricing proposal for Schedule 42 is shown on page 24 of Exhibit No. 44.

VII. SPECIAL CONTRACT PRICING

Q. Please provide an overview of the Company's Special Contract customers.

A. The Company currently serves six customers under Commission-approved Special Contracts, each with an associated Energy Services Agreement and tariff schedule. These include: Schedule 26 (Micron Technology, Inc.), Schedule 29 (J.R. Simplot Company – Pocatello), Schedule 30 (United States Department of Energy), Schedule 32 (J.R. Simplot Company – Caldwell), Schedule 33 (Brisbie, LLC), and Schedule 34 (Lamb Weston, Inc.).

Q. What pricing structure changes is the Company proposing for Special Contract customers?

A. The Company proposes to maintain the existing pricing structures for each Special Contract. These pricing structures generally include a Contract Demand Charge, Billing Demand Charge, and Energy Charges. While the Company is not proposing to modify the pricing structures, the Company proposes to move each pricing component toward its cost to serve. This includes reestablishing Contract Demand Charges

using the same methodology approved in the Company's 2023 general rate case.

Q. How was the Contract Demand Charge derived?

A. The Contract Demand Charge is based on the Company's Open Access Transmission Tariff ("OATT") rate effective October 1, 2024. This approach is consistent with the methodology used to set Contract Demand pricing in the 2023 general rate case. The OATT-based charge reflects the reservation cost that any other entity would pay for transmission service on Idaho Power's system. The Billing Demand Charge is then adjusted to recover any remaining fixed costs not collected through the Contract Demand Charge. For Brisbie and Lamb Weston, the pricing includes a two-block structure: Block 1 Billing Demand Charges are derived from Schedule 19 pricing, while Block 2 Billing Demand Charges are based on embedded costs.

Q. What other pricing components are proposed to be updated based on cost to serve?

A. The Company proposes to update the Energy Charges to reflect the embedded energy cost as identified on pages 9 - 13 of Mr. Maloney's Exhibit No. 37. For Brisbie and Lamb Weston, the pricing includes a two-block structure: Block 1 Energy Charges are derived from Schedule 19 pricing, while Block 2 Energy Charges are based on marginal cost pricing principles.

Q. Has the Company prepared an exhibit illustrating the proposed pricing for Special Contract customers?

A. Yes. The pricing proposal for each Special Contract customer, including a comparison of the present and proposed pricing, is shown on pages 25 - 30 of Exhibit No. 44.

VIII. OTHER SERVICE SCHEDULES

A. Schedule 20, Speculative High-Density Load

Q. Does the Company currently have any customers taking service under Schedule 20, or are any such customers included in the 2025 test year?

A. No. There are no active customers currently taking service under Schedule 20, and none were included in the 2025 test year.

Q. Is the Company proposing any changes to Schedule 20 pricing in this proceeding?

A. Yes. The Company proposes to continue aligning embedded pricing components for Schedule 20 under the previously adopted methodology, with the cost basis of Schedules 9 and 19 until enough Schedule 20 customers exist to support a class-specific cost assignment. The Company is not proposing changes to the marginal cost-based energy component at this time, as that component is updated annually through a separate filing process. The Company's proposed pricing for Schedule 20 incorporates the relevant pricing for Schedule 9

and Schedule 19 and the marginal cost-based energy pricing update as presented in Case No. IPC-E-25-17.

B. Schedule 45 and Schedule 31, Standby Service

Q. Please describe the Company's Standby Service offerings.

A. The Company provides Standby Service under Schedule 45, which is available to customers with on-site generation who wish to reserve capacity from Idaho Power in case their generation becomes unavailable. The service is optional and is currently available to both large general service and large power service customers. The Company also provides a customized standby service to Amalgamated Sugar Company under Schedule 31 pursuant to a Commission-approved agreement.

Q. What is the benefit of electing Standby Service?

A. Customers who elect Standby Service are assured access to backup capacity during planned or unplanned outages of their on-site generation. Idaho Power includes the reserved capacity in its system planning and load forecasts to ensure reliability. Customers who choose not to take Standby Service may find that the Company is not able to serve the full load during outages, as that demand was not anticipated.

Q. Is the Company proposing pricing changes for Schedule 45?

A. Yes. While the overall pricing structure remains unchanged, the Company is proposing updates to the derivation of standby generation, transmission components, and excess demand charges. These updates incorporate the Company's Open Access Transmission Tariff ("OATT") rate effective October 1, 2024, and revised cost inputs from the Company's class cost-of-service study for Schedule 9 Secondary and Primary Service and Schedule 19 Primary Service.

Q. Is the Company proposing pricing changes for Schedule 31?

A. Yes. The Company is also proposing to update the standby charges for Amalgamated Sugar Company under Schedule 31, using the same methodology described for Schedule 45. This includes applying the OATT rate components and updated unit costs from the Schedule 19 Primary Service cost-of-service study. These changes are consistent with the methodology from the Company's last general rate case and is the same method used for special contract pricing.

C. Schedule 46, Alternate Distribution Service

Q. What is Alternate Distribution Service?

A. Alternate Distribution Service is an optional offering available to commercial and industrial customers who desire increased reliability through redundancy. The service allows for automatic switching to an alternate distribution circuit in the event of a distribution-related outage on the

customer's primary circuit. This service is currently utilized by six customers and is available to those taking service under the Company's large general service or large power service schedules.

Q. What is the benefit of electing Alternate Distribution Service?

A. Alternate Distribution Service provides an additional layer of reliability by reducing the risk of a complete service interruption caused by a single distribution circuit failure. While the service does not guarantee uninterrupted power, it reduces the likelihood that a distribution-related outage will disrupt a customer's operations—particularly for customers without on-site backup generation.

Q. Is the Company proposing pricing changes for Schedule 46?

A. Yes. The proposed Capacity Charge derivation is consistent with the Company's last general rate case. These costs are based on updated unit cost data from the class cost-of-service study for Schedule 19 Primary Service. Additionally, the Company proposes updates to the mileage charge and average distribution line length, calculated using the same methodology previously accepted by the Commission.

Q. How is the proposed Capacity Charge derived?

A. The Capacity Charge is calculated using the distribution demand-related revenue requirement components for substations, primary lines, and primary transformers allocated to Schedule 19 Primary Service. Specifically, these components total $16,697,494 and are divided by a total billed demand of 4,907,546 kilowatts. These values are identified on page 7 of Mr. Maloney's Exhibit No. 37.

Q. How is the mileage charge calculated?

A. The mileage charge is designed to recover the operating and maintenance costs associated with constructing and maintaining the additional distribution facilities required to provide Alternate Distribution Service. The charge is calculated based on the per-mile cost of constructing a three-phase overhead distribution circuit, adjusted by the Company's proposed facilities charge for assets older than 31 years. This total is then divided by the total capacity of the circuit to arrive at a per-mile, per-kilowatt cost.

D. Schedule 66, Miscellaneous Charges

Q. Is the Company proposing any changes to charges for Schedule 66?

A. Yes. The Company is proposing to update the Rule M Monthly Facilities Charge Rate. All other miscellaneous charges were updated in the Company's 2023 general rate case and the Company is not proposing changes in this proceeding.

Q. What monthly rates is the Company proposing for facilities charges?

A. The Company is proposing to update the monthly facilities charge rates as listed in Table 3.

Table 3

Proposed Facilities Charge Rates

Rate Schedule	Facilities Installed 31 Years or Less	Facilities Installed More Than 31 Years
Schedule 9	1.42%	0.65%
Schedule 15	1.77%	1.77%
Schedule 19	1.42%	0.65%
Schedule 24	1.42%	0.65%
Schedule 29	1.42%	0.65%
Schedule 32	1.42%	0.65%
Schedule 41	1.21%	1.21%
Schedule 45	1.42%	0.65%
Schedule 46	1.42%	0.65%

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 and IPC-E-23-11.

Q. What is driving the proposed increase in the monthly facilities charge rates?

A. The proposed increase in the monthly facilities charge rates — 0.08 percent for facilities installed 31 years or less and 0.04 percent for facilities installed more than 31

years — is driven by increases in the requested rate of return, operations and maintenance expenses, administrative and general, and working capital requirements. These cost increases are partially offset by a decrease in property tax expense.

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 an increase to revenue received through facilities charges of approximately $631,800 per year.

IX. 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 certain rules and schedules within its tariff. These changes are intended to ensure clarity, transparency, and consistency. I supervised the coordination with internal customer-facing teams to develop recommendations for these updates. Attachment Nos. 1 and 2 to the Application contain the legislative and clean versions of the requested tariff changes.

Q. How did you arrive at the proposed changes to the Company's General Rules and Regulations?

A. The changes proposed to the Company's General Rules and Regulations are the result of collaborative efforts between representatives from various business units within the Company.

Q. Do you intend to discuss each of the proposed changes to the tariff?

A. No. While some proposed changes are substantive, many are purely administrative or stylistic and do not materially affect the function or interpretation of the tariff provisions. Accordingly, I will explain the rationale for each of the more substantive changes in the sections that follow.

E. Schedule 6, Schedule 8, and Schedule 84

Q. What changes is the Company proposing to Schedules 6, 8, and 84?

A. The Company proposes several clarifying edits to improve the transparency and administration of the existing provisions. These changes are not intended to modify the intent of prior Commission orders but instead aim to more clearly reflect that intent in the tariff language. In addition to administrative edits, the Company proposes modifications related to the treatment of remaining financial credits when a customer ends service, application of the eligibility cap for irrigation customers, and revisions to the process for determining project size when historical billing demand is unavailable.

Q. Please summarize the proposed clarifying edits.

A. In the Applicability section, the Company is proposing two changes to the conditions for maintaining Legacy status. First, Customers who expand their systems beyond Legacy criteria do not need to agree to separate metering if they do not wish to retain Legacy status for the original system. The current tariff language could be interpreted to mean the customer must agree to separate metering, which is not consistent with the prior case history. The Company is also proposing to add a condition to clarify that a customer with Legacy status may self-forfeit that status. This clarification is consistent with Staff's Reply Comments in Case No. IPC-E-23-14, which describe how termination of legacy status may occur including when a self-generator self-forfeits their legacy status.[1] Including clarifying language in the tariff for these elements will ease administration of the Legacy conditions for Company representatives.

The Company also proposes adding definitions for "Financial Credit" and "kWh Credit" to distinguish between credit types under Net Billing and Net Energy Metering without changing how credits are administered.

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[1] *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, Staff Reply Comments at 7 (Nov. 2, 2023).

Q. How does the Company currently administer excess financial credits once a customer ends service?

A. Excess financial credits carry forward at a given service point so long as the customer maintains electric service at that point of delivery. If a customer ends service, two conditions apply: (1) the financial credit can be transferred in the event the customer is relocating within the Company's service area, and (2) if a customer discontinues service and does not intend to reestablish service in the Company's service area, the unused credits will be paid out at the time the final bill is prepared. In its order directing this treatment, the Commission found:

> [I]t reasonable that accumulated financial credits be transferrable when a customer relocates within the Company's service area. At this time no time limit will be set for such a transfer. Additionally, if a customer completely discontinues service with the Company, any accumulated unused financial credits shall be paid out to the customer. The Commission is cognizant of the potential behavior impacts inherent in a system that pays out financial credits; however, the Commission believes that the limited conditions under which a customer may receive a payout mitigates those impacts.[2]

Q. What challenges has the Company experienced in administering this requirement?

A. If a customer ends service and does not immediately establish a new account, Idaho Power must track

[2] Case No. IPC-E-23-14, Order No. 36048 at 19 (Dec. 29, 2023).

the credit indefinitely. It is then the customer's responsibility to request a transfer when reestablishing service. This process can result in confusion and inconsistent customer experiences.

Q. What is the Company proposing?

A. The Company proposes to pay out any unused financial credits at the time of final billing for Schedules 6, 8, and 84, consistent with how other customer credit account balances are treated when a final bill is prepared. This change will streamline internal processes and improve clarity for customer support representatives.

Q. How does the Company propose to address existing credit balances?

A. If the proposed changes are approved, Idaho Power will issue refunds for any financial credits currently being tracked, consistent with its standard refund practices.

Q. What is the current project eligibility cap for Schedule 84 customers?

A. For commercial, industrial, and irrigation customers taking service under Schedule 84, the project eligibility cap is the greater of 100 kW or 100 percent of the customer's demand at the service point. This provision has been in effect since January 1, 2024, pursuant to Order No. 36048.

Q. Has the Company proposed modifications to this cap?

A. Yes. Based on its experience implementing the cap, the Company submitted a clarifying tariff advice filing, IPC-TAE-24-02, on June 17, 2024. The Commission approved the revisions at its July 23, 2024, decision meeting.

Q. Has the Company identified further issues in administering this provision?

A. Yes. While the provisions for commercial and industrial customers generally provide sufficient safeguards, the Company has found that, for irrigation customers, the existing criteria may allow installations that exceed actual demand.

Q. Please explain the Company's concerns.

A. Irrigation customers — unlike commercial or industrial customers — generally have highly predictable demand determined by the installed motor and pump equipment. Once equipment is installed, irrigation load does not typically fluctuate. Pumps operate in binary fashion: either "on" or "off," and when operating, they run at a fixed capacity based on motor and pump specifications. Additionally, irrigation service points experience relatively high turnover due to crop rotations, ownership changes, or lease arrangements, which may result in extended periods with no historical billing data.

Under the current tariff, if a customer lacks 12 months of recent billing history, they may qualify for alternate sizing methods — including submission of equipment documentation for use with a conversion factor. However, in practice, many irrigation systems have only the motor nameplate visible, and a customer may submit an application based on an oversized motor even if the associated pump limits actual usage. This could result in systems being sized in excess of what is reasonably needed to serve the expected load.

Q. What changes is the Company proposing?

A. The Company proposes to revise the tariff to separate the project sizing provisions that apply to commercial and industrial customers from those that apply to irrigation customers. For commercial and industrial customers, the existing options — such as relying on similar facilities or third-party analysis — would remain. For irrigation customers, the Company proposes to add specific criteria based on the predictable nature of pump operation and motor-to-pump sizing. The revised language would clarify how the conversion factor is to be applied and prevent reliance solely on motor nameplate ratings in cases where historical demand is unavailable but the installed equipment has not changed. The Company believes these proposed changes are consistent with the intent of Order No. 36048 and will improve transparency,

reduce customer confusion, and ensure more accurate system sizing for irrigation applicants.

F. Schedule 68, Interconnections to Customer Distributed Energy Resources

Q. What changes to Schedule 68 is the Company proposing as part of this case?

A. The Company is proposing several administrative and housekeeping edits to Schedule 68, in addition to targeted changes to improve clarity and transparency in the interconnection application process.

Q. Please describe the current interconnection application process.

A. Customers seeking to interconnect new or expanded on-site generation systems must submit a completed application that includes system specifications and a non-refundable application fee. Once the application is received, customers have one year to complete interconnection before the application expires.

Q. Why is the Company proposing changes to the application process, and what specific changes are included?

A. While most customers complete the interconnection process within the current timeframes, the Company has identified several opportunities to improve the administration of Schedule 68 and enhance customer understanding. The proposed changes include:

(1) Adding a definition for "Incomplete Application,"

(2) Clarifying the process for prospective customers who do not yet have established electric service with Idaho Power,

(3) Refining requirements for customer generators when additional studies are needed beyond a Feasibility Study, and

(4) Modifying the timeline for transitioning existing customers to the appropriate on-site generation service schedule.

Q. Why is the Company proposing to define "Incomplete Application"?

A. The current tariff is silent on how to handle applications that are missing required information. Company representatives attempt to contact applicants to resolve deficiencies, but in many cases, customers who are no longer interested do not respond. Holding incomplete applications open for the full year creates unnecessary administrative burden. The Company proposes that if required information is not received within 60 days of initial submission, the application will be considered withdrawn.

Q. What is the Company proposing for applicants who do not yet have established electric service?

A. Some interconnection applications are submitted for new construction projects or for customers who have not yet begun taking service from Idaho Power. In these cases, the Company proposes that the expiration of the interconnection application be tied to the expected in-service date provided in the application, rather than defaulting to a one-year expiration. This change will reduce administrative burden and improve alignment with project development timelines.

Q. Why is the Company proposing to modify the timeline for moving a customer to the applicable on-site generation schedule?

A. The Company has found that for customers taking service under schedules with a Basic Load Capacity ("BLC") component — such as Schedules 9 and 19 — transitioning customers mid-billing cycle results in a loss of billing history necessary to accurately calculate BLC. This occurs because the billing system "closes" the account when the contract is ended and "opens" a new contract under the new rate schedule. To preserve this history, the Company proposes that the rate schedule change occur no later than the next billing cycle. This change will maintain billing accuracy while ensuring customers are placed on the correct schedule in a timely manner.

G. Schedule 24, Agricultural Irrigation Service

Q. What administrative changes to Schedule 24 is the Company requesting as part of this case?

A. The Company is proposing changes to Schedule 24 to refine the Tier 1 and Tier 2 deposit criteria and to revise the definition of "New Irrigation Customer" to improve accuracy in customer records and simplify administration.

Q. Why is the Company proposing to revise the definition of a New Irrigation Customer?

A. The current definition is restrictive, particularly in cases where a customer has been financially responsible for a Schedule 24 account but was not listed as the account holder. This has created an unintended incentive for customers to avoid account name changes in order to bypass the deposit requirement applicable to new irrigation customers. To address this, the Company proposes incorporating a "financially responsible party" component into the definition, which will better reflect actual customer behavior and improve billing accuracy.

Q. How does the Company currently administer Tier 1 Deposits?

A. A Tier 1 Deposit is assessed on all Schedule 24 accounts when the customer meets any of the following conditions: (1) receipt of two or more payment reminder notices within the last twelve months; (2) service termination

for nonpayment within the last four years with no subsequent resumption of Schedule 24 service; or (3) a prior Tier 2 Deposit was required in the previous irrigation season.

Q. What changes is the Company proposing to Tier 1 deposit criteria?

A. The Company is proposing to add a screening criterion to ensure that reminder notices are associated with accounts that represent a meaningful portion of the customer's total irrigation billing. Specifically, a Tier 1 Deposit would only be assessed if the total annual billed amount on the accounts that received reminder notices is equal to or greater than 15 percent of the customer's total annual billed amount across all its Schedule 24 accounts.

The Company encourages customers with multiple service points to enroll in joint invoicing to simplify billing and improve account visibility. However, in rare cases, some accounts may remain outside of the joint invoice and generate separate bills. This can lead to confusion if one of these "orphaned" accounts receives two or more reminder notices and, under current criteria, triggers a Tier 1 Deposit across all accounts — even if the customer is otherwise in good standing.

Q. How are Tier 2 Deposits currently administered?

A. Tier 2 Deposits are required when a customer's Cumulative Past Due Balance — defined as the total of all past due Schedule 24 accounts under the customer's responsibility —

equals or exceeds $1,500 on December 31. The deposit is assessed across all Schedule 24 accounts.

Q. What changes is the Company proposing to Tier 2 deposit criteria?

A. The Company proposes three refinements:

(1) Grace Period Extension – Allowing an additional five days beyond December 31 to satisfy the past due balance before a Tier 2 Deposit is triggered. This adjustment is intended to account for postal delays that may impact customers' ability to submit timely payments.

(2) Per-Service Threshold – A Tier 2 Deposit would only be assessed if the Cumulative Past Due Balance is equal to or greater than $1,500 and the average past due balance per service point is equal to or greater than $750. This means that customers with many accounts and a relatively small balance per account would not trigger a deposit requirement unless both conditions are met.

(3) Absolute Threshold – Regardless of the number of service points, if the customer’s total past due balance equals or exceeds $10,000, a Tier 2 Deposit would be required.

These changes are intended to improve fairness and transparency while preserving the Company’s ability to manage financial risk associated with past-due irrigation accounts. The proposed balance thresholds will allow the Company to

better assign deposits to its highest risk customers and avoid unwarranted impact to its lower credit risk customers.

H. Rule H, New Service Attachments and Distribution Line Installations or Alterations

Q. What changes is the Company proposing to Rule H?

A. The Company is proposing one minor change to allow greater flexibility on removals of unused distribution equipment located in high fire risk zones and is proposing to expand the tariff-based charges in Rule H to include a standard charge for Three-Phase Underground Service Attachment requests involving a single run of cable. Currently, these requests require a customer-specific work order, even for relatively standardized installations. This change would align the treatment of single-run three-phase installations with the Company's existing tariff-based approach for single-phase underground services – as outlined on Page H-7, Section 4(b)(iii) - and improve administrative efficiency.

Q. How does the Company currently administer charges for Three-Phase Underground Service Attachments?

A. Under current practice, applicants requesting Three-Phase Underground Service must pay a non-refundable charge equal to the full estimated Work Order Cost. This process requires customers to submit a formal service request, pay applicable engineering fees, and wait for the Company to complete the cost estimate—typically a two- to three-week timeline.

Q. Why is the Company proposing to move to tariff-based charges for these requests?

A. Single-run three-phase underground installations are relatively standard in design and cost, much like single-phase underground services. Moving to a tariff-based charge for these installations will streamline the process for customers and reduce internal administrative workload, while maintaining fair and consistent pricing for all applicants.

Q. How does the Company propose to calculate the new tariff-based charge for Three-Phase Underground Service?

A. The proposed charge is based on a standard installation scenario: 100 feet of cable installed by a two-person crew with 30 minutes of travel time. The calculation uses the same methodology and overhead factors employed in the Company's most recent Rule H annual update, consistent with Commission Order Nos. 30853, 30955, and 32472.

Q. Is the Company proposing any changes to other charges, credits, or rates under Rule H?

A. No. In accordance with Commission Order Nos. 30853, 30955 and 32472, the Company will continue to submit its annual update to Rule H charges, credits, and overhead rates prior to January 1 each year. The Company is not proposing changes to any other components of Rule H in this proceeding. The proposed Three-Phase Underground Service

Attachment charge will be incorporated into future annual updates.

I. Rule N, Special Arrangements for Substation Allowances and Transmission Vested Interest

Q. Please describe the Company's proposed Rule N.

A. The Company is proposing to incorporate the existing Substation Allowance and Transmission Vested Interest provisions currently located in Schedule 19 into a "rule" to be more consistent with other general rules that could apply to multiple customer classes. These provisions would be removed from Schedule 19 and relocated into Rule N for improved administrative consistency and broader applicability.

Q. Why is the Company proposing to move these provisions into Rule N?

A. The Company believes that the Substation Allowance and Transmission Vested Interest provisions are better suited, for administrative purposes, within a general tariff rule rather than being limited to a specific schedule. While relatively uncommon, there are instances where a Schedule 9 customer may be required to fund substation upgrades in anticipation of increasing load and ultimately transitioning to Schedule 19.

Currently, because the Substation Allowance provisions reside solely in Schedule 19, such customers are ineligible for the allowance at the time the upgrades are made. Relocating these provisions to Rule N ensures that eligibility

is based on the nature of the investment and service characteristics—rather than a customer's current schedule designation—and provides for more consistent and equitable administration across similarly situated large service customers.

Q. Beyond relocating the provisions to a rule and expanding eligibility to Schedule 9, is the Company proposing any changes to how the Substation Allowance or Transmission Vested Interest provisions are administered?

A. No. The Company is not proposing substantive changes to how the Substation Allowance or Transmission Vested Interest provisions are administered. The proposed relocation to Rule N is intended solely to improve administrative consistency and expand eligibility to Schedule 9 customers, without modifying the existing criteria, calculation methodology, or application of the provisions.

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

A. Yes, it does.

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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 the Pricing and Tariff Administration Leader in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 44 and 45 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 30th day of May 2025, at Boise, Idaho.

Grant T. Anderson

Signed: _____
Grant T. Anderson

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

ANDERSON, DI TESTIMONY

EXHIBIT NO. 44

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Filed May 30, 2025
IPC-E-25-16

Residential Service
Schedule 1 and Schedule 6

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	6,449,658	$ 15.00	$ 96,744,876	$ 25.00	$ 161,241,460
(2)	Minimum Charge	54,848	3.00	164,543	3.00	164,543
(3)	Summer Energy (Jun-Sep)					
(4)	First 800 kWh	1,264,784,734	$ 0.101779	$ 128,728,525	$ 0.125685	$ 158,964,469
(5)	801-2,000 kWh	543,222,448	0.122380	66,479,563	0.137920	74,921,240
(6)	All Additional kWh	95,968,279	0.145385	13,952,348	0.151580	14,546,872
(7)	Subtotal - Summer Energy	1,903,975,460	$ 0.109855	$ 209,160,437	$ 0.130481	$ 248,432,581
(8)	Non-Summer Energy (Oct-May)					
(9)	First 800 kWh	2,550,684,323	$ 0.089569	$ 228,462,244	$ 0.099581	$ 253,999,696
(10)	801-2,000 kWh	1,029,597,595	0.098750	101,672,763	0.104567	107,661,932
(11)	All Additional kWh	358,232,694	0.109361	39,176,686	0.110331	39,524,171
(12)	Subtotal - Non-Summer Energy	3,938,514,612	$ 0.093769	$ 369,311,692	$ 0.101862	$ 401,185,799
(13)	Subtotal - Total Energy	5,842,490,073		$ 578,472,129		$ 649,618,380
(14)	Transfer Adjustment Revenue			17,688,957		
(15)	Total Adjusted Base Revenue			$ 693,070,505		$ 811,024,383

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Residential Service Standard Plan
Schedule 1

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	6,223,666	$ 15.00	$ 93,354,993	$ 25.00	$ 155,591,655
(2)	Minimum Charge	54,176	3.00	162,527	3.00	162,527
(3)	Summer Energy (Jun-Sep)					
(4)	First 800 kWh	1,224,254,394	$ 0.101779	$ 124,603,388	$ 0.125685	$ 153,870,414
(5)	801-2,000 kWh	532,104,954	0.122380	65,119,004	0.137920	73,387,915
(6)	All Additional kWh	93,673,900	0.145385	13,618,780	0.151580	14,199,090
(7)	Subtotal - Summer Energy	1,850,033,248	$ 0.109912	$ 203,341,172	$ 0.130515	$ 241,457,419
(8)	Non-Summer Energy (Oct-May)					
(9)	First 800 kWh	2,464,568,540	$ 0.089569	$ 220,748,940	$ 0.099581	$ 245,424,200
(10)	801-2,000 kWh	997,228,306	0.098750	98,476,295	0.104567	104,277,172
(11)	All Additional kWh	343,191,848	0.109361	37,531,804	0.110331	37,864,700
(12)	Subtotal - Non-Summer Energy	3,804,988,695	$ 0.093760	$ 356,757,039	$ 0.101857	$ 387,566,072
(13)	Subtotal - Total Energy	5,655,021,943		$ 560,098,211		$ 629,023,490
(14)	Transfer Adjustment Revenue			17,121,371		
(15)	Total Adjusted Base Revenue			$ 670,737,102		$ 784,777,672

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Residential Service On-Site Generation
Schedule 6

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	225,992	$ 15.00	$ 3,389,883	$ 25.00	$ 5,649,805
(2)	Minimum Charge	672	3.00	2,016	3.00	2,016
(3)	Summer Energy (Jun-Sep)					
(4)	First 800 kWh	40,530,339	$ 0.101779	$ 4,125,137	$ 0.125685	$ 5,094,056
(5)	801-2,000 kWh	11,117,494	0.122380	1,360,559	0.137920	1,533,325
(6)	All Additional kWh	2,294,379	0.145385	333,568	0.151580	347,782
(7)	Subtotal - Summer Energy	53,942,212	$ 0.107880	$ 5,819,265	$ 0.129308	$ 6,975,162
(8)	Non-Summer Energy (Oct-May)					
(9)	First 800 kWh	86,115,783	$ 0.089569	$ 7,713,305	$ 0.099581	$ 8,575,496
(10)	801-2,000 kWh	32,369,289	0.098750	3,196,467	0.104567	3,384,759
(11)	All Additional kWh	15,040,846	0.109361	1,644,882	0.110331	1,659,472
(12)	Subtotal - Non-Summer Energy	133,525,918	$ 0.094024	$ 12,554,654	$ 0.102001	$ 13,619,727
(13)	Subtotal - Total Energy	187,468,130		$ 18,373,918		$ 20,594,889
(14)	Transfer Adjustment Revenue			567,586		
(15)	Total Adjusted Base Revenue			$ 22,333,403		$ 26,246,710

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Master-Metered Mobile Home Park Residential Service
Schedule 3

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	227	$ 15.00	$ 3,406	$ 25.00	$ 5,677
(2)	Total Energy	5,073,613	0.109482	555,469	0.131324	666,287
(3)	Transfer Adjustment Revenue			15,361		
(4)	Total Adjusted Base Revenue			$ 574,237		$ 671,964

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Residential Service - Time-of-Use
Schedule 5 + 6 TOU

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	12,228	$ 15.00	$ 183,414	$ 25.00	$ 305,690
(2)	Minimum Charge	14	3.00	42	3.00	42
(3)	Summer Energy (Jun-Sep)					
(4)	On-Peak	1,031,679	$ 0.252957	$ 260,970	$ 0.322968	$ 333,199
(5)	Mid-Peak	1,078,494	0.126480	136,408	0.161484	174,160
(6)	Off-Peak	3,821,764	0.063241	241,692	0.080742	308,577
(7)	Subtotal - Summer Energy	5,931,938	$ 0.107734	$ 639,071	$ 0.137550	$ 815,936
(8)	Non-Summer Energy (Oct-May)					
(9)	On-Peak	3,071,371	$ 0.131150	$ 402,810	$ 0.143396	$ 440,422
(10)	Off-Peak	9,388,580	0.087433	820,872	0.095597	897,520
(11)	Subtotal - Non-Summer Energy	12,459,952	$ 0.098209	$ 1,223,682	$ 0.107380	$ 1,337,942
(12)	Subtotal - Total Energy	18,391,889		$ 1,862,753		$ 2,153,878
(13)	Transfer Adjustment Revenue			55,684		
(14)	Total Adjusted Base Revenue			$ 2,101,892		$ 2,459,610

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Residential Service - Time-of-Use Plan
Schedule 5

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	11,882	$ 15.00	$ 178,224	$ 25.00	$ 297,040
(2)	Minimum Charge	11	3.00	33	3.00	33
(3)	Summer Energy (Jun-Sep)					
(4)	On-Peak	1,017,779	$ 0.252957	$ 257,454	$ 0.322968	$ 328,710
(5)	Mid-Peak	1,073,980	0.126480	135,837	0.161484	173,431
(6)	Off-Peak	3,741,492	0.063241	236,616	0.080742	302,096
(7)	Subtotal - Summer Energy	5,833,251	$ 0.107986	$ 629,907	$ 0.137871	$ 804,236
(8)	Non-Summer Energy (Oct-May)					
(9)	On-Peak	3,016,127	$ 0.131150	$ 395,565	$ 0.143396	$ 432,500
(10)	Off-Peak	9,173,697	0.087433	802,084	0.095597	876,978
(11)	Subtotal - Non-Summer Energy	12,189,823	$ 0.098250	$ 1,197,649	$ 0.107424	$ 1,309,478
(12)	Subtotal - Total Energy	18,023,075		$ 1,827,556		$ 2,113,715
(13)	Transfer Adjustment Revenue			54,567		
(14)	Total Adjusted Base Revenue			$ 2,060,380		$ 2,410,788

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Residential Service - Time-of-Use
Schedule 6 TOU

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	346	$ 15.00	$ 5,190	$ 25.00	$ 8,650
(2)	Minimum Charge	3	3.00	9	3.00	9
(3)	Summer Energy (Jun-Sep)					
(4)	On-Peak	13,900	$ 0.252957	$ 3,516	$ 0.322968	$ 4,489
(5)	Mid-Peak	4,514	0.126480	571	0.161484	729
(6)	Off-Peak	80,273	0.063241	5,077	0.080742	6,481
(7)	Subtotal - Summer Energy	98,686	$ 0.092855	$ 9,164	$ 0.118553	$ 11,700
(8)	Non-Summer Energy (Oct-May)					
(9)	On-Peak	55,245	$ 0.131150	$ 7,245	$ 0.143396	$ 7,922
(10)	Off-Peak	214,884	0.087433	18,788	0.095597	20,542
(11)	Subtotal - Non-Summer Energy	270,128	$ 0.096374	$ 26,033	$ 0.105373	$ 28,464
(12)	Subtotal - Total Energy	368,815		$ 35,197		$ 40,164
(13)	Transfer Adjustment Revenue			1,117		
(14)	Total Adjusted Base Revenue			$ 41,512		$ 48,822

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Small General Service
Schedule 7 and Schedule 8

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	361,406	$ 25.00	$ 9,035,148	$ 30.00	$ 10,842,177
(2)	Minimum Charge	294	3.00	881	3.00	881
(3)	Summer Energy (Jun-Sep)					
(4)	First 300 kWh	21,553,455	$ 0.074534	$ 1,606,465	$ 0.088802	$ 1,913,990
(5)	All Additional kWh	25,566,818	0.085176	2,177,679	0.101485	2,594,649
(6)	Subtotal - Summer Energy	47,120,273	$ 0.080308	$ 3,784,145	$ 0.095684	$ 4,508,638
(7)	Non-Summer Energy (Oct-May)					
(8)	First 300 kWh	44,503,584	$ 0.074534	$ 3,317,030	$ 0.088802	$ 3,952,007
(9)	All Additional kWh	48,834,292	0.074552	3,640,694	0.088827	4,337,804
(10)	Subtotal - Non-Summer Energy	93,337,877	$ 0.074543	$ 6,957,724	$ 0.088815	$ 8,289,811
(11)	Subtotal - Total Energy	140,458,150		$ 10,741,869		$ 12,798,449
(12)	Transfer Adjustment Revenue			425,257		
(13)	Total Adjusted Base Revenue			$ 20,203,154		$ 23,641,507

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Small General Service
Schedule 7

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	360,412	$ 25.00	$ 9,010,298	$ 30.00	$ 10,812,357
(2)	Minimum Charge	294	3.00	881	3.00	881
(3)	Summer Energy (Jun-Sep)					
(4)	First 300 kWh	21,484,436	$ 0.074534	$ 1,601,321	$ 0.088802	$ 1,907,861
(5)	All Additional kWh	25,463,564	0.085176	2,168,885	0.101485	2,584,170
(6)	Subtotal - Summer Energy	46,948,000	$ 0.080306	$ 3,770,205	$ 0.095681	$ 4,492,031
(7)	Non-Summer Energy (Oct-May)					
(8)	First 300 kWh	44,366,384	$ 0.074534	$ 3,306,804	$ 0.088802	$ 3,939,824
(9)	All Additional kWh	48,613,690	0.074552	3,624,248	0.088827	4,318,208
(10)	Subtotal - Non-Summer Energy	92,980,074	$ 0.074543	$ 6,931,052	$ 0.088815	$ 8,258,032
(11)	Subtotal - Total Energy	139,928,074		$ 10,701,257		$ 12,750,063
(12)	Transfer Adjustment Revenue			423,652		
(13)	Total Adjusted Base Revenue			$ 20,136,088		$ 23,563,301

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Small General Service On-Site Generation
Schedule 8

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	994	$ 25.00	$ 24,850	$ 30.00	$ 29,820
(2)	Minimum Charge	-	3.00	-	3.00	-
(3)	Summer Energy (Jun-Sep)					
(4)	First 300 kWh	69,019	$ 0.074534	$ 5,144	$ 0.088802	$ 6,129
(5)	All Additional kWh	103,254	0.085176	8,795	0.101485	10,479
(6)	Subtotal - Summer Energy	172,273	$ 0.080912	$ 13,939	$ 0.096404	$ 16,608
(7)	Non-Summer Energy (Oct-May)					
(8)	First 300 kWh	137,200	$ 0.074534	$ 10,226	$ 0.088802	$ 12,184
(9)	All Additional kWh	220,603	0.074552	16,446	0.088827	19,595
(10)	Subtotal - Non-Summer Energy	357,803	$ 0.074545	$ 26,672	$ 0.088817	$ 31,779
(11)	Subtotal - Total Energy	530,076		$ 40,611		$ 48,387
(12)	Transfer Adjustment Revenue			1,605		
(13)	Total Adjusted Base Revenue			$ 67,066		$ 78,207

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Large General Service
Schedule 9 Secondary Service - Standard (Default)

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	474,816	$ 25.00	$ 11,870,403	$ 30.00	$ 14,244,483
(2)	Minimum Charge	247	3.00	742	3.00	742
(3)	Basic Charge					
(4)	Total Basic Charge	15,582,930	$ 1.58	$ 24,621,029	$ 2.03	$ 31,633,347
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	4,171,093	$ 8.12	$ 33,869,272	$ 10.14	$ 42,294,879
(7)	Non-Summer (Oct-May)	7,373,578	6.39	47,117,161	8.16	60,168,393
(8)	Total Demand	11,544,670		$ 80,986,433		$ 102,463,272
(9)	Energy Charge					
(10)	Summer (Jun-Sep)	1,204,733,146	$ 0.054658	$ 65,848,304	$ 0.054088	$ 65,161,606
(11)	Non-Summer (Oct-May)	2,200,115,815	0.052721	115,992,306	0.053804	118,375,031
(12)	Subtotal - Total Energy	3,404,848,961		$ 181,840,610		$ 183,536,638
(13)	Transfer Adjustment Revenue			10,308,657		
(14)	Total Adjusted Base Revenue			$ 309,627,873		$ 331,878,482
				$ 299,319,216		

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Large General Service
Schedule 9 Secondary Service - Time-of-Use (Optional)

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	474,816	$ 25.00	$ 11,870,403	$ 30.00	$ 14,244,483
(2)	Minimum Charge	247	3.00	742	3.00	742
(3)	Basic Charge					
(4)	Total Basic Charge	15,582,930	$ 1.58	$ 24,621,029	$ 2.03	$ 31,633,347
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	4,171,093	$ 8.12	$ 33,869,272	$ 10.14	$ 42,294,879
(7)	Non-Summer (Oct-May)	7,373,578	6.39	47,117,161	8.16	60,168,393
(8)	Total Demand	11,544,670		$ 80,986,433		$ 102,463,272
(9)	Summer Energy (Jun-Sep)					
(10)	On-Peak	165,847,351	$ 0.058489	$ 9,700,246	$ 0.071725	$ 11,895,401
(11)	Mid-Peak	238,538,268	0.058489	13,951,865	0.060348	14,395,307
(12)	Off-Peak	800,347,526	0.052709	42,185,518	0.048568	38,871,279
(13)	Subtotal - Summer Energy	1,204,733,146	$ 0.054649	$ 65,837,628	$ 0.054088	$ 65,161,987
(14)	Non-Summer Energy (Oct-May)					
(15)	On-Peak	491,567,320	$ 0.055755	$ 27,407,336	$ 0.059560	$ 29,277,750
(16)	Mid-Peak	516,485,446	0.053259	27,507,498	0.054608	28,204,237
(17)	Off-Peak	1,192,063,049	0.051273	61,120,649	0.051083	60,894,157
(18)	Subtotal - Non-Summer Energy	2,200,115,815	$ 0.052741	$ 116,035,483	$ 0.053805	$ 118,376,144
(19)	Subtotal - Total Energy	3,404,848,961		$ 181,873,111		$ 183,538,131
(20)	Transfer Adjustment Revenue			10,308,657		
(21)	Total Adjusted Base Revenue			$ 309,660,375		$ 331,879,975

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Large General Service
Schedule 9 Primary Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	3,501	$ 340.00	$ 1,190,272	$ 360.00	$ 1,260,288
(2)	Minimum Charge	2	50.00	100	50.00	100
(3)	Basic Charge					
(4)	Total Basic Charge	2,079,364	$ 1.83	$ 3,805,236	$ 2.22	$ 4,616,188
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	476,216	$ 8.35	$ 3,976,402	$ 11.04	$ 5,257,422
(7)	Non-Summer (Oct-May)	1,198,406	7.91	9,479,390	9.91	11,876,202
(8)	Total Demand	1,674,622		$ 13,455,792		$ 17,133,624
(9)	On-Peak Summer Demand (Jun-Sep)	468,866	$ 1.59	$ 745,497	$ 2.10	$ 984,618
(10)	Summer Energy (Jun-Sep)					
(11)	On-Peak	32,775,131	$ 0.053937	$ 1,767,792	$ 0.066710	$ 2,186,429
(12)	Mid-Peak	46,014,976	0.053937	2,481,910	0.055532	2,555,304
(13)	Off-Peak	161,805,090	0.048346	7,822,629	0.043957	7,112,466
(14)	Subtotal - Summer Energy	240,595,198	$ 0.050177	$ 12,072,331	$ 0.049270	$ 11,854,199
(15)	Non-Summer Energy (Oct-May)					
(16)	On-Peak	93,275,039	$ 0.048995	$ 4,570,011	$ 0.054064	$ 5,042,822
(17)	Mid-Peak	96,201,361	0.046579	4,480,963	0.049269	4,739,745
(18)	Off-Peak	224,818,193	0.044649	10,037,908	0.045854	10,308,813
(19)	Subtotal - Non-Summer Energy	414,294,594	$ 0.046076	$ 19,088,881	$ 0.048495	$ 20,091,380
(20)	Subtotal - Total Energy	654,889,792		$ 31,161,212		$ 31,945,579
(21)	Transfer Adjustment Revenue			1,982,771		
(22)	Total Adjusted Base Revenue			$ 52,340,880		$ 55,940,398

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Large General Service
Schedule 9 Transmission Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	68	$ 340.00	$ 23,120	$ 360.00	$ 24,480
(2)	Minimum Charge	-	50.00	-	50.00	-
(3)	Basic Charge					
(4)	Total Basic Charge	18,439	$ 1.09	$ 20,099	$ 0.96	$ 17,702
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	5,575	$ 7.38	$ 41,142	$ 8.63	$ 48,110
(7)	Non-Summer (Oct-May)	8,873	6.46	57,319	8.44	74,887
(8)	Total Demand	14,448		$ 98,460		$ 122,997
(9)	On-Peak Summer Demand (Jun-Sep)	3,731	$ 1.59	$ 5,933	$ 2.10	$ 7,836
(10)	Summer Energy (Jun-Sep)					
(11)	On-Peak	135,603	$ 0.053305	$ 7,228	$ 0.068460	$ 9,283
(12)	Mid-Peak	213,681	0.053305	11,390	0.056891	12,157
(13)	Off-Peak	958,526	0.047648	45,672	0.044914	43,051
(14)	Subtotal - Summer Energy	1,307,810	$ 0.049159	$ 64,290	$ 0.049312	$ 64,491
(15)	Non-Summer Energy (Oct-May)					
(16)	On-Peak	510,120	$ 0.048079	$ 24,526	$ 0.054073	$ 27,584
(17)	Mid-Peak	558,666	0.045663	25,510	0.049282	27,532
(18)	Off-Peak	1,214,966	0.043725	53,124	0.045870	55,731
(19)	Subtotal - Non-Summer Energy	2,283,752	$ 0.045172	$ 103,161	$ 0.048537	$ 110,846
(20)	Subtotal - Total Energy	3,591,562		$ 167,451		$ 175,338
(21)	Transfer Adjustment Revenue			10,874		
(22)	Total Adjusted Base Revenue			$ 325,937		$ 348,352

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Large Power Service
Schedule 19 Secondary Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	12	$ 85.00	$ 1,020	$ 125.00	$ 1,500
(2)	Minimum Charge	-	3.00	-	3.00	-
(3)	Basic Charge					
(4)	Total Basic Charge	14,300	$ 2.01	$ 28,743	$ 2.47	$ 35,321
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	4,155	$ 10.50	$ 43,629	$ 13.99	$ 58,130
(7)	Non-Summer (Oct-May)	8,540	8.45	72,163	12.01	102,565
(8)	Total Demand	12,695		$ 115,791		$ 160,695
(9)	On-Peak Summer Demand (Jun-Sep)	3,811	$ 1.82	$ 6,936	$ 2.42	$ 9,222
(10)	Summer Energy (Jun-Sep)					
(11)	On-Peak	306,402	$ 0.059941	$ 18,366	$ 0.073300	$ 22,459
(12)	Mid-Peak	387,352	0.059941	23,218	0.062088	24,050
(13)	Off-Peak	1,413,300	0.054287	76,724	0.050473	71,333
(14)	Subtotal - Summer Energy	2,107,054	$ 0.056149	$ 118,308	$ 0.055928	$ 117,843
(15)	Non-Summer Energy (Oct-May)					
(16)	On-Peak	944,371	$ 0.054204	$ 51,189	$ 0.060834	$ 57,450
(17)	Mid-Peak	976,851	0.051783	50,584	0.055984	54,688
(18)	Off-Peak	2,418,525	0.049842	120,544	0.052530	127,045
(19)	Subtotal - Non-Summer Energy	4,339,747	$ 0.051228	$ 222,317	$ 0.055115	$ 239,183
(20)	Subtotal - Total Energy	6,446,801		$ 340,625		$ 357,026
(21)	Transfer Adjustment Revenue			19,519		
(22)	Total Adjusted Base Revenue			$ 512,634		$ 563,764

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Large Power Service
Schedule 19 Primary Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
(1)	Service Charge	1,560	$ 415.00	$ 647,442	$ 490.00	$ 764,449
(2)	Minimum Charge	-	50.00	-	50.00	-
(3)	Basic Charge					
(4)	Total Basic Charge	4,818,510	$ 2.21	$ 10,648,907	$ 2.60	$ 12,528,125
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	1,468,360	$ 10.04	$ 14,742,330	$ 13.09	$ 19,220,827
(7)	Non-Summer (Oct-May)	2,805,397	8.64	24,238,630	11.93	33,468,387
(8)	Total Demand	4,273,757		$ 38,980,961		$ 52,689,214
(9)	On-Peak Summer Demand (Jun-Sep)	1,297,943	$ 1.59	$ 2,063,729	$ 2.07	$ 2,686,742
(10)	Summer Energy (Jun-Sep)					
(11)	On-Peak	104,043,423	$ 0.052314	$ 5,442,928	$ 0.066358	$ 6,904,113
(12)	Mid-Peak	134,487,570	0.052314	7,035,583	0.055115	7,412,282
(13)	Off-Peak	492,482,409	0.046655	22,976,767	0.043474	21,410,180
(14)	Subtotal -Summer Energy	731,013,402	$ 0.048502	$ 35,455,277	$ 0.048873	$ 35,726,576
(15)	Non-Summer Energy (Oct-May)					
(16)	On-Peak	308,030,308	$ 0.047227	$ 14,547,347	$ 0.053897	$ 16,601,910
(17)	Mid-Peak	315,781,072	0.044805	14,148,571	0.049044	15,487,167
(18)	Off-Peak	795,765,487	0.042863	34,108,896	0.045589	36,278,153
(19)	Subtotal - Non-Summer Energy	1,419,576,868	$ 0.044242	$ 62,804,814	$ 0.048160	$ 68,367,229
(20)	Subtotal - Total Energy	2,150,590,270		$ 98,260,092		$ 104,093,805
(21)	Subtotal 19P Excluding Clean Energy Your Way			$ 150,601,129		$ 172,762,335
(22)	*Schedule 62 Clean Energy Your Way - Optional*					
(23)	Summer Embedded Energy Fixed Cost (June-Sep)					
(24)	On-Peak	2,391,844	$ 0.010012	$ 23,947	$ 0.016993	$ 40,645
(25)	Mid-Peak	5,945,167	0.010012	59,523	0.016993	101,026
(26)	Off-Peak	262,608	0.009611	2,524	0.016993	4,462
(27)	Subtotal - Summer Embedded Energy Fixed (	8,599,619	$ 0.010000	$ 85,994	$ 0.016993	$ 146,133
(28)	Non-Summer Embedded Energy Fixed Cost (Oct-May)					
(29)	On-Peak	3,128,757	$ 0.018270	$ 57,162	$ 0.016745	$ 52,391
(30)	Mid-Peak	5,411,634	0.018130	98,113	0.016745	90,618
(31)	Off-Peak	1,024,877	0.018018	18,466	0.016745	17,162
(32)	Subtotal - Non-Summer Embedded Energy Fi	9,565,268	$ 0.018164	$ 173,742	$ 0.016745	$ 160,170
(33)	Subtotal - Total Embedded Energy Fixed Cost	18,164,887		$ 259,736		$ 306,304
(34)	Transfer Adjustment Revenue			6,511,213		
(35)	Total Adjusted Base Revenue			$ 157,372,078		$ 173,068,639

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Schedule 19 Transmission Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	36	$ 415.00	$ 14,940	$ 490.00	$ 17,640
(2)	Minimum Charge	-	50.00	-	50.00	-
(3)	Basic Charge					
(4)	Total Basic Charge	74,736	$ 1.87	$ 139,756	$ 1.72	$ 128,546
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	23,215	$ 10.20	$ 236,791	$ 14.18	$ 329,185
(7)	Non-Summer (Oct-May)	48,951	8.78	429,791	12.42	607,974
(8)	Total Demand	72,166		$ 666,582		$ 937,159
(9)	On-Peak Summer Demand (Jun-Sep)	18,352	$ 1.59	$ 29,180	$ 2.07	$ 37,990
(10)	Summer Energy (Jun-Sep)					
(11)	On-Peak	1,722,227	$ 0.052142	$ 89,800	$ 0.067062	$ 115,496
(12)	Mid-Peak	2,183,930	0.052142	113,874	0.055665	121,568
(13)	Off-Peak	9,142,393	0.046451	424,673	0.043865	401,031
(14)	Subtotal - Summer Energy	13,048,549	$ 0.048155	$ 628,348	$ 0.048902	$ 638,095
(15)	Non-Summer Energy (Oct-May)					
(16)	On-Peak	5,624,628	$ 0.046927	$ 263,947	$ 0.053955	$ 303,477
(17)	Mid-Peak	5,644,025	0.044504	251,182	0.049099	277,116
(18)	Off-Peak	14,737,529	0.042561	627,244	0.045641	672,636
(19)	Subtotal - Non-Summer Energy	26,006,182	$ 0.043927	$ 1,142,373	$ 0.048190	$ 1,253,228
(20)	Subtotal - Total Energy	39,054,731		$ 1,770,721		$ 1,891,324
(21)	Transfer Adjustment Revenue			118,244		
(22)	Total Adjusted Base Revenue			$ 2,739,423		$ 3,012,658

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Agricultural Irrigation Service
Schedule 24 Secondary Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	*Current Season - Meter Read Cycle*					
(2)	Service Charge In-Season	78,564	$ 30.00	$ 2,356,905		
(3)	Service Charge Out-of-Season	158,480	6.00	950,880		
(4)	Minimum Charge	538	3.00	1,615		
(5)	Demand Charge (Current Season)					
(6)	In-Season	3,891,290	$ 15.06	$ 58,602,829		
(7)	Out-of-Season	-	-	-		
(8)	Energy Charge (Current Season)					
(9)	In-Season	1,441,717,277	$ 0.061295	$ 88,370,060		
(10)	Out-of-Season	328,446,778	0.072053	23,665,576		
(11)	Total Energy	1,770,164,055		$ 112,035,636		
(12)	*Proposed Season - Calendar Month*					
(13)	Service Charge In-Season	78,564			$ 35.00	$ 2,749,723
(14)	Service Charge Out-of-Season	158,480			9.00	1,426,320
(15)	Minimum Charge	538			3.00	1,615
(16)	Demand Charge (Proposed Season)					
(17)	In-Season	3,790,953			$ 18.75	$ 71,080,369
(18)	Out-of-Season	-			-	-
(19)	Energy Charge (Proposed Season)					
(20)	In-Season	1,398,685,535			$ 0.074279	$ 103,892,963
(21)	Out-of-Season	371,525,754			0.082558	30,672,423
(22)	Total Energy	1,770,211,289				$ 134,565,386
(23)	Transfer Adjustment Revenue			5,359,420		
(24)	Total Adjusted Base Revenue			$ 179,307,284		$ 209,823,412

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Schedule 24 Transmission Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge In-Season	-	$ 415.00	$ -	$ 490.00	$ -
(2)	Service Charge Out-of-Season	-	6.00	-	9.00	-
(3)	Minimum Charge	-	3.00	-	3.00	-
(4)	Demand Charge					
(5)	In-Season	-	$ 13.92	$ -	$ 17.33	$ -
(6)	Out-of-Season	-	-	-		
(7)	Energy Charge					
(8)	In-Season	-	$ 0.057529	$ -	$ 0.069715	$ -
(9)	Out-of-Season	-	0.067352	-	0.077172	-
(10)	Total Energy	-		$ -		$ -
(11)	Transfer Adjustment Revenue			-		
(12)	Total Adjusted Base Revenue			$ -		$ -

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Dusk to Dawn Customer Lighting
Schedule 15

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Annual Lamps**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Lamps					
(2)	Area Lighting					
(3)	40 Watt Max	88,276	$ 9.82	$ 866,869	$ 11.17	$ 986,041
(4)	85 Watt Max	9,549	11.95	114,116	11.89	113,543
(5)	200 Watt Max	1,792	17.27	30,945	14.73	26,394
(6)	Subtotal - Lamps			$ 1,011,930		
(7)	Flood Lighting					
(8)	85 Watt Max	15,893	$ 19.50	$ 309,912	$ 16.49	$ 262,074
(9)	150 Watt Max	933	21.47	20,035	17.43	16,265
(10)	300 Watt Max	1,145	25.28	28,946	23.01	26,347
(11)	Subtotal - Lamps			$ 358,893		
(12)	Transfer Adjustment Revenue			5,865		
(13)	Total Adjusted Base Revenue			$ 1,376,688		1,430,664

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Non-Metered General Service
Schedule 40

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	22,284	$ -	$ -	$ -	$ -
(2)	Minimum Bills	1,385	2.00	2,770	2.00	2,770
(3)	Total Energy	14,484,473	0.100058	1,449,287	0.111557	1,615,844
(4)	Intermittent Usage	156	2.00	312	2.50	390
(5)	Transfer Adjustment Revenue			43,854		
(6)	Total Adjusted Base Revenue			$ 1,496,223		$ 1,619,004

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Street Lighting Service
Schedule 41 - Summary

Column	(A)	(B)	(C)	(D)
Line No.	**Description**	**Test Year Usage**	**Test Year Base Revenue**	**Proposed Effective Revenue**
(1)	A - Company-Owned, Non-Metered, Maintena	2,275,478	$ 2,603,947	$ 3,340,555
(2)	C - Customer-Owned, Non-Metered, No Mair	11,659,258	791,780	504,741
(3)	CM - Customer-Owned, Metered, No Mainten	6,484,878	546,033	315,511
(4)	Total kWh	20,419,614		
(5)	Transfer Adjustment Revenue		$ 61,823	
(6)	Total Adjusted Base Revenue		$ 4,003,584	$ 4,160,807

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Street Lighting Service

A - Company-Owned, Non-Metered, Maintenance

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Description	Annual Lamps	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
(7)	**LED Fixture**					
(8)	40W Max	181,437	$ 12.30	$ 2,231,678	$ 15.98	$ 2,898,560
(9)	85W Max	20,240	14.31	289,640	17.29	349,981
(10)	140W Max	2,674	16.43	43,936	18.82	50,314
(11)	200W Max	1,680	20.44	34,342	21.93	36,848
(12)	Total LED	206,032		$ 2,599,596		$ 3,335,703
(13)	Non-Metered - Variable Energy Use	43,492	$ 0.100058	$ 4,352	$ 0.111557	$ 4,852
(14)	A - Company-Owned, Non-Metered, Maintenance			$ 2,603,947		$ 3,340,555

NM Adj
$ 0.023549

C - Customer-Owned, Non-Metered, No Maintenance

Line No.	Description	Test Year Usage	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
(15)	Energy Charge					
(16)	Per kWh	11,659,258	$ 0.067910	$ 791,780	$ 0.043291	$ 504,741
(17)	C - Customer-Owned, Non-Metered, No Maintenance			$ 791,780		$ 504,741

CM - Customer-Owned, Metered, No Maintenance

Line No.	Description	Test Year Usage	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
(18)	Service Charge per Meter	18,899	$ 5.59	$ 105,645	$ 1.84	$ 34,774
(19)	Energy Charge					
(20)	Per kWh	6,484,878	$ 0.067910	$ 440,388	$ 0.043291	$ 280,737
(21)	CM - Customer-Owned, Metered, No Maintenance			$ 546,033		$ 315,511

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Traffic Control Signal Lighting Service
Schedule 42

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	10,308	$ -	$ -	$ -	$ -
(2)	Total Energy	3,056,155	0.078462	239,792	0.095358	291,429
(3)	Transfer Adjustment Revenue			9,253		
(4)	Total Adjusted Base Revenue			$ 249,045		$ 291,429

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Micron Technology, Inc.
Schedule 26

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Contract Demand	1,062,000	$ 3.37	$ 3,578,940	$ 3.12	$ 3,313,440
(2)	Billing Demand	1,027,098	17.83	18,313,161	23.35	23,982,743
(3)	Excess Demand	-	1.288	-	1.248	-
(4)	Embedded Energy Fixed Cost	-	-	-	-	-
(5)	Total Energy	635,708,728	$ 0.030394	19,321,731	$ 0.027585	17,536,025
(6)	Transfer Adjustment Revenue			1,924,697		
(7)	Total Adjusted Base Revenue			$ 43,138,529		$ 44,832,208

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J.R. Simplot Company - Pocatello
Schedule 29

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Contract Demand	300,000	$ 3.25	$ 975,000	$ 3.12	$ 936,000
(2)	Billing Demand	330,992	14.80	4,898,679	18.55	6,139,898
(3)	Excess Demand	-	1.267	-	1.248	-
(4)	Total Energy	211,750,000	0.031006	6,565,521	0.030782	6,518,089
(5)	Transfer Adjustment Revenue			641,103		
(6)	Total Adjusted Base Revenue			$ 13,080,302		$ 13,593,987

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United States Department of Energy
Schedule 30

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Contract Demand					
(2)	Billing Demand	434,422	$ 10.17	$ 4,418,073	$ 19.80	$ 8,601,557
(3)	Excess Demand					
(4)	Total Energy	241,000,000	$ 0.042488	$ 10,239,608	$ 0.030664	$ 7,390,024
(5)	Transfer Adjustment Revenue			729,661		
(6)	Total Adjusted Base Revenue			$ 15,387,342		$ 15,991,581

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J.R. Simplot Company - Caldwell
Schedule 32

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Contract Demand					
(2)	Summer	100,000	$ 3.30	$ 330,000	$ 3.12	$ 312,000
(3)	Non-Summer	200,000	3.30	660,000	3.12	624,000
(4)	Billing Demand					
(5)	Summer	87,426	$ 19.60	$ 1,713,554	$ 23.99	$ 2,097,355
(6)	Non-Summer	163,126	16.20	2,642,635	20.39	3,326,132
(7)	Excess Demand					
(8)	Summer	-	$ 1.293	$ -	$ 1.248	$ -
(9)	Non-Summer	-	1.293	-	1.248	-
(10)	Energy					
(11)	Summer	54,274,353	$ 0.030405	$ 1,650,212	$ 0.031464	$ 1,707,688
(12)	Non-Summer	100,725,647	0.032844	3,308,233	0.031073	3,129,848
(13)	Transfer Adjustment Revenue			469,284		
(14)	Total Adjusted Base Revenue			$ 10,773,918		$ 11,197,023

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Brisbie, LLC.
Schedule 33

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	*Block 1*					
(2)	Service Charge	12	$ 415.00	$ 4,980	$ 490.00	$ 5,880
(3)	Basic Charge					
(4)	Total Basic Charge	240,000	$ 1.87	$ 448,800	$ 1.72	$ 412,800
(5)	Demand Charges					
(6)	Summer (Jun-Sep)	80,000	$ 10.20	$ 816,000	$ 14.18	$ 1,134,400
(7)	Non-Summer (Oct-May)	160,000	8.78	1,404,800	12.42	1,987,200
(8)	Total Demand	240,000		$ 2,220,800		$ 3,121,600
(9)	On-Peak Summer Demand (Jun-Sep)	-	$ 1.59	$ -	$ 2.07	$ -
(10)	Summer Energy (Jun-Sep)					
(11)	On-Peak	-	$ 0.052142	$ -	$ 0.067062	$ -
(12)	Mid-Peak	-	0.052142	-	0.055665	-
(13)	Off-Peak	-	0.046451	-	0.043865	-
(14)	Subtotal - Summer Energy	-		$ -		$ -
(15)	Non-Summer Energy (Oct-May)					
(16)	On-Peak	-	$ 0.046927	$ -	$ 0.053955	$ -
(17)	Mid-Peak	-	0.044504	-	0.049099	-
(18)	Off-Peak	-	0.042561	-	0.045641	-
(19)	Subtotal - Non-Summer Energy	-		$ -		$ -
(20)	Subtotal - Total Energy	-		-		-
(21)	Subtotal - Block 1			$ 2,674,580		$ 3,540,280
(22)	*Block 2*					
(23)	Contract Demand	120,000	$ 3.28	$ 393,600	$ 3.12	$ 374,400
(24)	Billing Demand	-	22.29	-	22.29	-
(25)	Excess Demand	-	1.293	-	1.248	-
(26)	Subtotal - Block 2			$ 393,600		$ 374,400
(27)	Transfer Adjustment Revenue			-		-
(28)	Total Adjusted Base Revenue			$ 3,068,180		$ 3,914,680

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Lamb Weston, Inc.
Schedule 34

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	*Block 1*					
(2)	Service Charge	12	$ 415.00	$ 4,980	$ 490.00	$ 5,880
(3)	Basic Charge					
(4)	Total Basic Charge	240,000	$ 2.21	$ 530,400	$ 2.60	$ 624,000
(5)	Demand Charges					
(6)	Summer (Jun-Sep)	80,000	$ 10.04	$ 803,200	$ 13.09	$ 1,047,200
(7)	Non-Summer (Oct-May)	160,000	8.64	1,382,400	11.93	1,908,800
(8)	Total Demand			$ 2,185,600		$ 2,956,000
(9)	On-Peak Summer Demand (Jun-Sep)	78,960	$ 1.59	$ 125,546	$ 2.07	$ 163,447
(10)	Summer Energy (Jun-Sep)					
(11)	On-Peak	6,161,916	$ 0.052314	$ 322,354	$ 0.066358	$ 408,892
(12)	Mid-Peak	7,907,125	0.052314	413,653	0.055115	435,801
(13)	Off-Peak	29,384,248	0.046655	1,370,922	0.043474	1,277,451
(14)	Subtotal - Summer Energy	43,453,289		$ 2,106,930		$ 2,122,144
(15)	Non-Summer Energy (Oct-May)					
(16)	On-Peak	6,269	$ 0.047227	$ 296	$ 0.053897	$ 338
(17)	Mid-Peak	88,577,191	0.044805	3,968,701	0.049044	4,344,180
(18)	Off-Peak	17,021	0.042863	730	0.045589	776
(19)	Subtotal - Non-Summer Energy	88,600,480		$ 3,969,727		$ 4,345,294
(20)	Subtotal - Total Energy	132,053,769		6,076,657		6,467,438
(21)	Subtotal - Block 1			$ 8,923,183		$ 10,216,765
(22)	*Block 2*					
(23)	Contract Demand	48,000	$ 3.30	$ 158,400	$ 3.12	$ 149,760
(24)	Billing Demand	31,778	24.19	768,704	9	286,000
(25)	Excess Demand		1.293	-	1.248	-
(26)	Subtotal - Block 2			$ 927,104		$ 435,760
(27)	Transfer Adjustment Revenue			399,811		-
(28)	Total Adjusted Base Revenue			$ 10,250,099		$ 10,652,525

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

ANDERSON, DI
TESTIMONY

EXHIBIT NO. 45

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison
Filed May 30, 2025
IPC-E-25-16

Residential Service - Standard Plan
Schedule 1

Column	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Monthly Billing				Change				Weighted	
Line		Current		Proposed		$		%		Average Change	
No.	kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
1	100	$ 25.48	$ 24.26	$ 37.57	$ 34.96	$ 12.09	$ 10.70	47.4%	44.1%	$ 11.16	45.2%
2	200	35.96	33.52	50.14	44.92	14.18	11.40	39.4%	34.0%	12.32	35.9%
3	300	46.44	42.78	62.71	54.87	16.26	12.10	35.0%	28.3%	13.48	30.6%
4	400	56.92	52.04	75.27	64.83	18.35	12.79	32.2%	24.6%	14.65	27.3%
5	500	67.40	61.30	87.84	74.79	20.44	13.49	30.3%	22.0%	15.81	25.0%
6	600	77.88	70.56	100.41	84.75	22.53	14.19	28.9%	20.1%	16.97	23.2%
7	700	88.36	79.82	112.98	94.71	24.61	14.89	27.9%	18.7%	18.13	21.9%
8	800	98.85	89.08	125.55	104.66	26.70	15.59	27.0%	17.5%	19.29	20.9%
9	900	111.39	99.26	139.34	115.12	27.95	15.87	25.1%	16.0%	19.90	19.3%
10	1,000	123.93	109.43	153.13	125.58	29.21	16.15	23.6%	14.8%	20.50	17.9%
11	1,200	149.01	129.79	180.72	146.49	31.71	16.70	21.3%	12.9%	21.70	15.9%
12	1,400	174.09	150.14	208.30	167.41	34.21	17.26	19.7%	11.5%	22.91	14.5%
13	1,600	199.17	170.50	235.88	188.32	36.71	17.82	18.4%	10.5%	24.12	13.4%
14	1,800	224.25	190.85	263.47	209.23	39.22	18.38	17.5%	9.6%	25.32	12.5%
15	2,000	249.33	211.21	291.05	230.15	41.72	18.93	16.7%	9.0%	26.53	11.8%
16	2,500	323.54	267.40	366.84	285.31	43.30	17.91	13.4%	6.7%	26.37	9.2%
17	3,000	397.75	323.60	442.63	340.48	44.88	16.88	11.3%	5.2%	26.21	7.5%
18	5,000	694.57	548.38	745.79	561.14	51.22	12.76	7.4%	2.3%	25.58	4.3%

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison
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Residential Service - Time-of-Use Plan
Schedule 5

Column	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Monthly Billing				Change				Weighted	
Line		Current		Proposed		$		%		Average Change	
No.	kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
1	100	$ 26.10	$ 25.13	$ 38.79	$ 35.74	$ 12.69	$ 10.61	48.6%	42.2%	$ 11.31	44.4%
2	200	37.20	35.26	52.57	46.48	15.37	11.23	41.3%	31.9%	12.61	35.1%
3	300	48.30	45.38	66.36	57.23	18.06	11.84	37.4%	26.1%	13.92	30.0%
4	400	59.41	55.51	80.15	67.97	20.74	12.46	34.9%	22.4%	15.22	26.8%
5	500	70.51	65.64	93.94	78.71	23.43	13.07	33.2%	19.9%	16.53	24.6%
6	600	81.61	75.77	107.72	89.45	26.11	13.69	32.0%	18.1%	17.83	22.9%
7	700	92.71	85.89	121.51	100.20	28.80	14.30	31.1%	16.7%	19.14	21.7%
8	800	103.81	96.02	135.30	110.94	31.49	14.92	30.3%	15.5%	20.44	20.7%
9	900	114.91	106.15	149.08	121.68	34.17	15.53	29.7%	14.6%	21.75	19.9%
10	1,000	126.01	116.28	162.87	132.42	36.86	16.15	29.2%	13.9%	23.05	19.3%
11	1,250	153.77	141.60	197.34	159.28	43.57	17.68	28.3%	12.5%	26.31	18.1%
12	1,500	181.52	166.92	231.81	186.14	50.29	19.22	27.7%	11.5%	29.58	17.2%
13	1,750	209.27	192.24	266.27	212.99	57.00	20.76	27.2%	10.8%	32.84	16.6%
14	2,000	237.03	217.56	300.74	239.85	63.72	22.29	26.9%	10.2%	36.10	16.1%
15	2,250	264.78	242.87	335.21	266.70	70.43	23.83	26.6%	9.8%	39.36	15.7%
16	2,500	292.53	268.19	369.68	293.56	77.14	25.37	26.4%	9.5%	42.63	15.4%
17	3,000	348.04	318.83	438.61	347.27	90.57	28.44	26.0%	8.9%	49.15	15.0%
18	5,000	570.07	521.39	714.36	562.12	144.29	40.73	25.3%	7.8%	75.25	14.0%

Bills are calculated using the average time-of-use (TOU) energy proportions by season for existing Schedule 5 customers. Actual TOU energy proportions for customers may vary.

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison
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Small General Service
Schedule 7

Column	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Monthly Billing				Change				Weighted	
Line		Current		Proposed		$		%		Average Change	
No.	kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
1	50	$ 28.88	$ 28.88	$ 34.44	$ 34.44	$ 5.56	$ 5.56	19.3%	19.3%	$ 5.56	19.3%
2	150	36.63	36.63	43.32	43.32	6.69	6.69	18.3%	18.3%	6.69	18.3%
3	250	44.39	44.39	52.20	52.20	7.81	7.81	17.6%	17.6%	7.81	17.6%
4	350	52.68	52.15	61.71	61.08	9.04	8.93	17.2%	17.1%	8.97	17.1%
5	450	61.50	59.91	71.86	69.96	10.36	10.06	16.9%	16.8%	10.16	16.8%
6	550	70.32	67.66	82.01	78.85	11.69	11.18	16.6%	16.5%	11.35	16.6%
7	650	79.14	75.42	92.16	87.73	13.02	12.31	16.5%	16.3%	12.55	16.4%
8	750	87.96	83.18	102.31	96.61	14.35	13.43	16.3%	16.1%	13.74	16.2%
9	850	96.78	90.94	112.46	105.50	15.68	14.56	16.2%	16.0%	14.93	16.1%
10	950	105.60	98.70	122.61	114.38	17.00	15.68	16.1%	15.9%	16.12	16.0%
11	1,050	114.42	106.45	132.75	123.26	18.33	16.81	16.0%	15.8%	17.32	15.9%
12	1,150	123.24	114.21	142.90	132.14	19.66	17.93	16.0%	15.7%	18.51	15.8%
13	1,250	132.06	121.97	153.05	141.03	20.99	19.06	15.9%	15.6%	19.70	15.7%
14	1,350	140.88	129.73	163.20	149.91	22.32	20.18	15.8%	15.6%	20.89	15.7%
15	1,450	149.70	137.49	173.35	158.79	23.65	21.31	15.8%	15.5%	22.09	15.6%
16	1,550	158.52	145.24	183.50	167.67	24.97	22.43	15.8%	15.4%	23.28	15.6%
17	1,650	167.34	153.00	193.65	176.56	26.30	23.56	15.7%	15.4%	24.47	15.5%
18	1,750	176.16	160.76	203.79	185.44	27.63	24.68	15.7%	15.4%	25.66	15.5%
19	1,850	184.98	168.52	213.94	194.32	28.96	25.81	15.7%	15.3%	26.86	15.4%
20	1,950	193.80	176.27	224.09	203.21	30.29	26.93	15.6%	15.3%	28.05	15.4%

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison
Filed May 30, 2025
IPC-E-25-16

Large General - Secondary Service
Schedule 9

Column	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
				Monthly Billing				Change				Weighted	
Line	Load Size	Load		Current		Proposed		$		%		Average Change	
No.	kW	Factor	kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
1	10	20%	1,000	$ 185.21	$ 165.98	$ 212.89	$ 192.80	$ 27.68	$ 26.83	14.9%	16.2%	$ 27.11	15.7%
2		35%	3,000	300.58	277.47	321.06	300.41	20.48	22.94	6.8%	8.3%	22.12	7.8%
3		50%	4,000	358.27	333.22	375.15	354.22	16.88	21.00	4.7%	6.3%	19.62	5.7%
4		65%	5,000	415.95	388.97	429.24	408.02	13.29	19.05	3.2%	4.9%	17.13	4.3%
5		80%	6,000	473.64	444.72	483.33	461.82	9.69	17.11	2.0%	3.8%	14.63	3.2%
6	20	20%	3,000	$ 403.11	$ 362.70	$ 449.87	$ 409.41	$ 46.76	$ 46.71	11.6%	12.9%	$ 46.73	12.4%
7		35%	5,000	518.48	474.20	558.04	517.02	39.56	42.82	7.6%	9.0%	41.74	8.5%
8		50%	7,000	633.85	585.69	666.22	624.63	32.36	38.94	5.1%	6.6%	36.75	6.1%
9		65%	10,000	806.91	752.94	828.48	786.04	21.57	33.10	2.7%	4.4%	29.26	3.8%
10		80%	12,000	922.28	864.44	936.66	893.65	14.38	29.21	1.6%	3.4%	24.27	2.7%
11	50	20%	7,000	$ 941.43	$ 841.37	$ 1,052.62	$ 951.63	$ 111.19	$ 110.26	11.8%	13.1%	$ 110.57	12.6%
12		35%	13,000	1,287.55	1,175.87	1,377.15	1,274.46	89.60	98.59	7.0%	8.4%	95.59	7.9%
13		50%	18,000	1,575.98	1,454.61	1,647.59	1,543.48	71.61	88.87	4.5%	6.1%	83.12	5.6%
14		65%	24,000	1,922.09	1,789.10	1,972.12	1,866.30	50.03	77.20	2.6%	4.3%	68.14	3.7%
15		80%	29,000	2,210.52	2,067.84	2,242.56	2,135.32	32.04	67.48	1.4%	3.3%	55.66	2.6%
16	100	20%	15,000	$ 1,915.55	$ 1,713.50	$ 2,129.33	$ 1,927.07	$ 213.78	$ 213.57	11.2%	12.5%	$ 213.64	12.0%
17		35%	26,000	2,550.09	2,326.73	2,724.30	2,518.91	174.20	192.18	6.8%	8.3%	186.19	7.8%
18		50%	37,000	3,184.64	2,939.97	3,319.26	3,110.76	134.63	170.79	4.2%	5.8%	158.74	5.3%
19		65%	48,000	3,819.18	3,553.20	3,914.23	3,702.60	95.05	149.40	2.5%	4.2%	131.28	3.6%
20		80%	59,000	4,453.72	4,166.44	4,509.20	4,294.44	55.48	128.01	1.2%	3.1%	103.83	2.4%
21	300	20%	44,000	$ 5,638.97	$ 5,034.74	$ 6,273.90	$ 5,667.40	$ 634.93	$ 632.66	11.3%	12.6%	$ 633.41	12.1%
22		35%	77,000	7,542.60	6,874.45	8,058.80	7,442.93	516.20	568.48	6.8%	8.3%	551.06	7.8%
23		50%	110,000	9,446.22	8,714.15	9,843.70	9,218.46	397.48	504.31	4.2%	5.8%	468.70	5.2%
24		65%	143,000	11,349.85	10,553.86	11,628.61	10,994.00	278.76	440.14	2.5%	4.2%	386.35	3.6%
25		80%	176,000	13,253.48	12,393.56	13,413.51	12,769.53	160.04	375.97	1.2%	3.0%	303.99	2.4%
26	500	20%	73,000	$ 9,362.39	$ 8,355.99	$ 10,418.47	$ 9,407.73	$ 1,056.08	$ 1,051.74	11.3%	12.6%	$ 1,053.19	12.1%
27		35%	128,000	12,535.10	11,422.16	13,393.31	12,366.95	858.21	944.79	6.8%	8.3%	915.93	7.8%
28		50%	183,000	15,707.81	14,488.34	16,368.15	15,326.17	660.34	837.83	4.2%	5.8%	778.67	5.2%
29		65%	238,000	18,880.52	17,554.51	19,342.99	18,285.39	462.47	730.88	2.4%	4.2%	641.41	3.6%
30		80%	293,000	22,053.23	20,620.69	22,317.83	21,244.61	264.60	623.92	1.2%	3.0%	504.15	2.4%

Bills are based on class average energy consumption by time period and season.

Exhibit No. 45
Case No. IPC-E-25-16
G. Anderson, IPC

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison
Filed May 30, 2025
IPC-E-25-16

Large General - Primary Service
Schedule 9

Column	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
				Monthly Billing				Change				Weighted	
Line	Load Size	Load		Current		Proposed		$		%		Average Change	
No.	kW	Factor	kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
1	300	40%	88,000	$ 8,678.33	$ 7,715.78	$ 9,455.03	$ 8,425.03	$ 776.70	$ 709.25	8.9%	9.2%	$ 731.73	9.1%
2		50%	110,000	9,848.83	8,796.05	10,538.98	9,491.29	690.15	695.24	7.0%	7.9%	693.54	7.6%
3		60%	132,000	11,019.33	9,876.32	11,622.92	10,557.56	603.59	681.24	5.5%	6.9%	655.36	6.4%
4		70%	154,000	12,189.83	10,956.59	12,706.87	11,623.82	517.04	667.23	4.2%	6.1%	617.17	5.4%
5		80%	176,000	13,360.33	12,036.86	13,790.82	12,690.09	430.48	653.22	3.2%	5.4%	578.98	4.6%
6	400	40%	117,000	$ 11,440.04	$ 10,158.00	$ 12,470.28	$ 11,097.21	$ 1,030.25	$ 939.21	9.0%	9.2%	$ 969.56	9.2%
7		50%	146,000	12,982.97	11,581.99	13,899.12	12,502.74	916.15	920.75	7.1%	7.9%	919.22	7.6%
8		60%	176,000	14,579.11	13,055.09	15,377.23	13,956.74	798.12	901.65	5.5%	6.9%	867.14	6.4%
9		70%	205,000	16,122.04	14,479.09	16,806.07	15,362.27	684.03	883.19	4.2%	6.1%	816.80	5.4%
10		80%	234,000	17,664.97	15,903.08	18,234.91	16,767.80	569.94	864.72	3.2%	5.4%	766.46	4.6%
11	500	40%	146,000	$ 14,201.75	$ 12,600.22	$ 15,485.54	$ 13,769.40	$ 1,283.79	$ 1,169.18	9.0%	9.3%	$ 1,207.38	9.2%
12		50%	183,000	16,170.32	14,417.05	17,308.54	15,562.66	1,138.22	1,145.62	7.0%	7.9%	1,143.15	7.6%
13		60%	220,000	18,138.89	16,233.87	19,131.54	17,355.93	992.65	1,122.06	5.5%	6.9%	1,078.93	6.4%
14		70%	256,000	20,054.25	18,001.58	20,905.27	19,100.72	851.02	1,099.14	4.2%	6.1%	1,016.43	5.4%
15		80%	293,000	22,022.82	19,818.40	22,728.27	20,893.99	705.45	1,075.58	3.2%	5.4%	952.21	4.6%
16	600	40%	176,000	$ 17,016.66	$ 15,091.55	$ 18,550.06	$ 16,490.05	$ 1,533.40	$ 1,398.50	9.0%	9.3%	$ 1,443.47	9.2%
17		50%	220,000	19,357.66	17,252.10	20,717.95	18,622.58	1,360.29	1,370.49	7.0%	7.9%	1,367.09	7.6%
18		60%	264,000	21,698.66	19,412.64	22,885.85	20,755.11	1,187.18	1,342.47	5.5%	6.9%	1,290.71	6.4%
19		70%	307,000	23,986.46	21,524.08	25,004.47	22,839.18	1,018.01	1,315.10	4.2%	6.1%	1,216.07	5.4%
20		80%	351,000	26,327.46	23,684.62	27,172.36	24,971.71	844.90	1,287.08	3.2%	5.4%	1,139.69	4.6%
21	700	40%	205,000	$ 19,778.37	$ 17,533.78	$ 21,565.31	$ 19,162.24	$ 1,786.95	$ 1,628.46	9.0%	9.3%	$ 1,681.29	9.2%
22		50%	256,000	22,491.80	20,038.04	24,078.10	21,634.04	1,586.30	1,595.99	7.1%	8.0%	1,592.76	7.6%
23		60%	307,000	25,205.24	22,542.31	26,590.89	24,105.83	1,385.65	1,563.52	5.5%	6.9%	1,504.23	6.4%
24		70%	359,000	27,971.87	25,095.68	29,152.94	26,626.09	1,181.07	1,530.42	4.2%	6.1%	1,413.97	5.4%
25		80%	410,000	30,685.31	27,599.94	31,665.73	29,097.89	980.42	1,497.94	3.2%	5.4%	1,325.44	4.6%
26	800	40%	234,000	$ 22,540.08	$ 19,976.00	$ 24,580.57	$ 21,834.43	$ 2,040.49	$ 1,858.43	9.1%	9.3%	$ 1,919.11	9.2%
27		50%	293,000	25,679.15	22,873.09	27,487.52	24,693.95	1,808.37	1,820.86	7.0%	8.0%	1,816.70	7.6%
28		60%	351,000	28,765.01	25,721.08	30,345.19	27,505.02	1,580.18	1,783.93	5.5%	6.9%	1,716.02	6.4%
29		70%	410,000	31,904.08	28,618.17	33,252.14	30,364.55	1,348.06	1,746.37	4.2%	6.1%	1,613.60	5.4%
30		80%	468,000	34,989.95	31,466.16	36,109.82	33,175.61	1,119.87	1,709.44	3.2%	5.4%	1,512.92	4.6%

Bills are based on class average energy consumption by time period and season.

Exhibit No. 45
Case No. IPC-E-25-16
G. Anderson, IPC

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison
Filed May 30, 2025
IPC-E-25-16

Large Power Service - Primary
Schedule 19

Column	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
				Monthly Billing				Change				Weighted	
Line	Load Size	Load		Current		Proposed		$		%		Average Change	
No.	kW	Factor	kWh	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	$	%
1	1,000	40%	295,000	$ 29,553.27	$ 25,491.22	$ 32,758.60	$ 29,558.69	$ 3,205.33	$ 4,067.47	10.8%	16.0%	$ 3,780.09	14.1%
2		50%	365,000	33,160.31	28,800.09	36,179.69	32,929.91	3,019.38	4,129.82	9.1%	14.3%	3,759.67	12.4%
3		60%	440,000	37,025.00	32,345.31	39,845.14	36,541.93	2,820.14	4,196.63	7.6%	13.0%	3,737.80	11.0%
4		70%	510,000	40,632.05	35,654.18	43,266.23	39,913.15	2,634.18	4,258.98	6.5%	11.9%	3,717.38	10.0%
5		80%	585,000	44,496.73	39,199.39	46,931.68	43,525.18	2,434.94	4,325.78	5.5%	11.0%	3,695.50	9.0%
6	2,500	40%	730,000	$ 72,874.21	$ 62,751.03	$ 80,794.96	$ 72,800.53	$ 7,920.75	$ 10,049.50	10.9%	16.0%	$ 9,339.92	14.1%
7		50%	915,000	82,407.11	71,495.90	89,836.41	81,710.18	7,429.30	10,214.29	9.0%	14.3%	9,285.96	12.4%
8		60%	1,100,000	91,940.01	80,240.76	98,877.85	90,619.84	6,937.84	10,379.07	7.5%	12.9%	9,232.00	11.0%
9		70%	1,280,000	101,215.26	88,749.29	107,674.93	99,288.69	6,459.67	10,539.40	6.4%	11.9%	9,179.49	9.9%
10		80%	1,465,000	110,748.16	97,494.16	116,716.37	108,198.34	5,968.22	10,704.18	5.4%	11.0%	9,125.53	9.0%
11	3,500	40%	1,025,000	$ 102,012.48	$ 87,827.24	$ 113,063.57	$ 101,869.22	$ 11,051.08	$ 14,041.98	10.8%	16.0%	$ 13,045.01	14.1%
12		50%	1,280,000	115,152.42	99,880.98	125,526.10	114,150.10	10,373.67	14,269.11	9.0%	14.3%	12,970.63	12.4%
13		60%	1,535,000	128,292.36	111,934.72	137,988.63	126,430.97	9,696.26	14,496.25	7.6%	13.0%	12,896.25	11.0%
14		70%	1,795,000	141,689.95	124,224.81	150,695.52	138,952.64	9,005.57	14,727.83	6.4%	11.9%	12,820.41	9.9%
15		80%	2,050,000	154,829.89	136,278.55	163,158.05	151,233.52	8,328.16	14,954.97	5.4%	11.0%	12,746.03	8.9%
16	5,000	40%	1,465,000	$ 145,591.07	$ 125,323.40	$ 161,344.29	$ 145,351.86	$ 15,753.22	$ 20,028.46	10.8%	16.0%	$ 18,603.38	14.1%
17		50%	1,830,000	164,399.22	142,576.79	179,182.81	162,930.37	14,783.60	20,353.58	9.0%	14.3%	18,496.92	12.3%
18		60%	2,195,000	183,207.37	159,830.18	197,021.34	180,508.87	13,813.97	20,678.69	7.5%	12.9%	18,390.45	11.0%
19		70%	2,560,000	202,015.52	177,083.57	214,859.86	198,087.38	12,844.34	21,003.80	6.4%	11.9%	18,283.98	9.9%
20		80%	2,930,000	221,081.32	194,573.31	232,942.75	215,906.68	11,861.43	21,333.37	5.4%	11.0%	18,176.06	8.9%
21	7,000	40%	2,050,000	$ 203,609.96	$ 175,239.49	$ 225,637.13	$ 203,248.45	$ 22,027.17	$ 28,008.96	10.8%	16.0%	$ 26,015.03	14.1%
22		50%	2,560,000	229,889.84	199,346.97	250,562.19	227,810.19	20,672.35	28,463.22	9.0%	14.3%	25,866.27	12.3%
23		60%	3,075,000	256,427.37	223,690.79	275,731.62	252,612.74	19,304.24	28,921.95	7.5%	12.9%	25,716.04	11.0%
24		70%	3,585,000	282,707.26	247,798.27	300,656.68	277,174.49	17,949.42	29,376.21	6.3%	11.9%	25,567.28	9.9%
25		80%	4,100,000	309,244.79	272,142.10	325,826.10	301,977.03	16,581.32	29,834.93	5.4%	11.0%	25,417.06	8.9%
26	8,500	40%	2,490,000	$ 247,188.55	$ 212,735.64	$ 273,917.85	$ 246,731.08	$ 26,729.31	$ 33,995.44	10.8%	16.0%	$ 31,573.40	14.1%
27		50%	3,110,000	279,136.64	242,042.77	304,218.91	276,590.46	25,082.27	34,547.69	9.0%	14.3%	31,392.55	12.3%
28		60%	3,735,000	311,342.38	271,586.25	334,764.33	306,690.64	23,421.95	35,104.39	7.5%	12.9%	31,210.24	11.0%
29		70%	4,355,000	343,290.47	300,893.38	365,065.38	336,550.02	21,774.91	35,656.64	6.3%	11.9%	31,029.39	9.8%
30		80%	4,980,000	375,496.21	330,436.86	395,610.80	366,650.20	20,114.59	36,213.34	5.4%	11.0%	30,847.09	8.9%

Bills are based on class average energy consumption by time period and season.

Exhibit No. 45
Case No. IPC-E-25-16
G. Anderson, IPC

Idaho Power Company
State of Idaho
Monthly Adjusted Base Revenue Comparison
Filed May 30, 2025
IPC-E-25-16

Agricultural Irrigation Service - Secondary
Schedule 24

Column	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
				Monthly Billing				Change				Weighted	
Line	Load Size	Load		Current		Proposed		$		%		Average Change	
No.	kW	Factor	kWh	In-Season	Out-Season	In-Season	Out-Season	In-Season	Out-Season	In-Season	Out-Season	$	%
1	10	20%	1,440	$ 273.22	$ 114.12	$ 329.46	$ 127.88	$ 56.24	$ 13.77	20.6%	12.1%	$ 24.33	18.6%
2		35%	2,520	342.69	195.20	409.68	217.05	66.99	21.84	19.5%	11.2%	30.61	16.9%
3		50%	3,600	412.16	276.29	489.90	306.21	77.74	29.92	18.9%	10.8%	36.89	15.9%
4		65%	4,680	481.63	357.38	570.13	395.37	88.50	37.99	18.4%	10.6%	43.16	15.3%
5		80%	5,760	551.10	438.46	650.35	484.53	99.25	46.07	18.0%	10.5%	49.44	14.9%
6	50	20%	7,200	$ 1,246.12	$ 546.58	$ 1,507.31	$ 603.42	$ 261.19	$ 56.84	21.0%	10.4%	$ 107.01	17.8%
7		35%	12,600	1,593.47	952.02	1,908.42	1,049.23	314.95	97.21	19.8%	10.2%	138.39	16.3%
8		50%	18,000	1,940.81	1,357.45	2,309.52	1,495.04	368.71	137.59	19.0%	10.1%	169.77	15.4%
9		65%	23,400	2,288.15	1,762.89	2,710.63	1,940.86	422.48	177.97	18.5%	10.1%	201.15	14.9%
10		80%	28,800	2,635.49	2,168.32	3,111.74	2,386.67	476.24	218.35	18.1%	10.1%	232.53	14.5%
11	100	20%	14,400	$ 2,462.25	$ 1,087.16	$ 2,979.62	$ 1,197.84	$ 517.37	$ 110.67	21.0%	10.2%	$ 210.35	17.7%
12		35%	25,200	3,156.93	1,898.03	3,781.83	2,089.46	624.90	191.43	19.8%	10.1%	273.11	16.2%
13		50%	36,000	3,851.62	2,708.90	4,584.04	2,981.09	732.43	272.18	19.0%	10.0%	335.87	15.3%
14		65%	46,800	4,546.30	3,519.77	5,386.26	3,872.71	839.96	352.94	18.5%	10.0%	398.63	14.8%
15		80%	57,600	5,240.98	4,330.64	6,188.47	4,764.34	947.49	433.70	18.1%	10.0%	461.39	14.5%
16	300	20%	43,200	$ 7,326.74	$ 3,249.48	$ 8,868.85	$ 3,575.51	$ 1,542.11	$ 326.02	21.0%	10.0%	$ 623.71	17.7%
17		35%	75,600	9,410.79	5,682.10	11,275.49	6,250.38	1,864.70	568.29	19.8%	10.0%	812.00	16.1%
18		50%	108,000	11,494.85	8,114.71	13,682.13	8,925.26	2,187.29	810.55	19.0%	10.0%	1,000.28	15.3%
19		65%	140,400	13,578.90	10,547.32	16,088.77	11,600.14	2,509.87	1,052.82	18.5%	10.0%	1,188.56	14.8%
20		80%	172,800	15,662.95	12,979.93	18,495.41	14,275.02	2,832.46	1,295.09	18.1%	10.0%	1,376.85	14.4%
21	500	20%	72,000	$ 12,191.23	$ 5,411.81	$ 14,758.09	$ 5,953.18	$ 2,566.86	$ 541.37	21.1%	10.0%	$ 1,037.08	17.7%
22		35%	126,000	15,664.65	9,466.16	18,769.15	10,411.31	3,104.50	945.15	19.8%	10.0%	1,350.88	16.1%
23		50%	180,000	19,138.08	13,520.52	22,780.22	14,869.44	3,642.14	1,348.92	19.0%	10.0%	1,664.69	15.3%
24		65%	234,000	22,611.50	17,574.87	26,791.29	19,327.57	4,179.79	1,752.70	18.5%	10.0%	1,978.50	14.8%
25		80%	288,000	26,084.92	21,629.22	30,802.35	23,785.70	4,717.43	2,156.48	18.1%	10.0%	2,292.30	14.4%
26	750	20%	108,000	$ 18,271.85	$ 8,114.71	$ 22,119.63	$ 8,925.26	$ 3,847.79	$ 810.55	21.1%	10.0%	$ 1,553.78	17.7%
27		35%	189,000	23,481.98	14,196.24	28,136.23	15,612.46	4,654.25	1,416.22	19.8%	10.0%	2,024.49	16.1%
28		50%	270,000	28,692.11	20,277.77	34,152.83	22,299.66	5,460.72	2,021.89	19.0%	10.0%	2,495.20	15.3%
29		65%	351,000	33,902.25	26,359.30	40,169.43	28,986.86	6,267.18	2,627.55	18.5%	10.0%	2,965.91	14.8%
30		80%	432,000	39,112.38	32,440.84	46,186.03	35,674.06	7,073.65	3,233.22	18.1%	10.0%	3,436.62	14.4%

Weighted Average Bills are based on four months of in-season, fours month of out-season, and four months of zero usage.

Exhibit No. 45
Case No. IPC-E-25-16
G. Anderson, IPC