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May 30, 2025

VIA ELECTRONIC FILING/HAND DELIVERY

Commission Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd., Bldg 8,
Suite 201-A (83714)
PO Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-25-16
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

Dear Commission Secretary:

Attached for electronic filing is Idaho Power Company's ("Idaho Power") Application and the Direct Testimonies and exhibits in the above matter.

Due to the collectively voluminous confidential and non-confidential information provided, the Company is posting the documents to the secure FTP site to allow parties to view the requested information remotely. Because certain documents contain confidential information, the FTP site is divided between confidential and non-confidential information. The login information for the non-confidential portion of the FTP site will be provided to all parties that intervene. The login information for the confidential portion of the FTP site will be provided to the parties that execute the attached Protective Agreement in this matter.

Five (5) copies of Idaho Power Company's Application, Direct Testimonies, and Exhibits will be hand delivered to the Commission today. The tariff schedules covering the rendering of electric service and charges to Idaho Power's customers in the state of Idaho to take effect thirty days after the filing of this Application, on and after July 1, 2025, pursuant to *Idaho Code* § 61-307 and Procedural Rule 123.01 are included as Attachment 1 to the Application. Even though the Company has filed this case on May 30, 2025, requesting implementation on July 1, 2025, as set forth in *Idaho Code* § 61-307, Idaho Power expects the Commission will suspend implementation of the Company's proposed rates for the statutory period set forth in *Idaho Code* § 61-622. With this expectation in mind, the Company has framed its requested effective date as January 1, 2026, in all discussions contained within this filing and for all related customer communication –

including the Company's press release and customer notice that accompany the Application.

In addition, a disk containing Word versions of the testimonies is enclosed for the Reporter.

If you have any questions about any of the aforementioned documents, please do not hesitate to contact me.

Very truly yours,

Donovan E. Walker

Donovan E. Walker

DEW:sg
Attachments

CERTIFICATE OF ATTORNEY

ASSERTION THAT INFORMATION CONTAINED IN AN IDAHO PUBLIC UTILITIES COMMISSION FILING IS PROTECTED FROM PUBLIC INSPECTION

Case No. IPC-E-25-16

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

The undersigned attorney, in accordance with Commission Rules of Procedure 67, believes that portions of the Direct Testimony of Adam Richins, Eric Hackett, and Brian Buckham dated May 30, 2025, contain information that Idaho Power Company and a third party claim are trade secrets, business records of a private enterprise require by law to be submitted to or inspected by a public agency, and/or public records exempt from disclosure by state or federal law (material nonpublic information under U.S. Securities and Exchange Commission Regulation FD) as described in *Idaho Code* § 74-101, *et seq*., and/or § 48-801, *et seq*. As such, it is protected from public disclosure and exempt from public inspection, examination, or copying.

DATED this 30th day of May 2025.

Donovan E. Walker

DONOVAN E. WALKER
Attorney for Idaho Power Company

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Attorneys for Idaho Power Company

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.	)	APPLICATION CASE NO. IPC-E-25-16

COMES NOW, Idaho Power Company ("Idaho Power" or "Company") and hereby applies to the Idaho Public Utilities Commission ("Commission" or "IPUC"), pursuant to Idaho Code §§ 61-307, 61-502, 61-524, and 61-622 and Commission Rules of Procedure[1] ("Rule(s)") 52, 121, and 125, for an Order approving revision to Idaho Power's schedules of rates and charges for electric service in the state of Idaho. In accordance with Rule 122.01, Idaho Power filed its Notice of Intent to File a General Rate case on March 28, 2025.

[1] Idaho Administrative Procedures Act (IDAPA) 31.01.01.

The revenue from current rates heretofore allowed Idaho Power is no longer reasonable and adequate, and Idaho Power has and will continue to experience increased costs – all of which now require immediate adjustment by way of increased revenues if Idaho Power is to maintain a stable financial condition and continue to render reliable and adequate electric service to its customers. Accordingly, in this filing the Company requests an increase in annual Idaho jurisdictional revenue of $199.1 million. This amount is net of a corresponding proposed Power Cost Adjustment ("PCA") decrease of $46.8 million. If approved, this request would result in an overall increase to adjusted base revenue of 13.09 percent. The Company's request is based on a proposed overall rate of return of 7.818 percent, with a capital structure comprised of 51 percent equity and 49 percent debt, and a 10.40 percent rate of return on equity ("ROE"). Anticipating suspension of the proposed tariff pursuant to Idaho Code § 61-622(4) and Rule 123.03, the revised tariff schedules included with this Application reflect a rate effective day of January 1, 2026.

In support of this Application, Idaho Power represents as follows:

I. BACKGROUND

1. Idaho Power is an Idaho corporation whose principal place of business is 1221 West Idaho Street, Boise, Idaho 83702.

2. Idaho Power is a public utility providing electric service to approximately 650,000 customers over a 24,000-square-mile service area in Idaho and Oregon. It is subject to the jurisdiction of this Commission, the Public Utility Commission of Oregon, and the Federal Energy Regulatory Commission. In conducting its utility business, Idaho Power operates an interconnected and vertically integrated system.

3. Idaho Power's last full Idaho general rate case ("GRC"), Case No. IPC-E-23-11, was filed on June 1, 2023, with rates becoming effective January 1, 2024. On May 31, 2024, the Company filed a Limited Scope Rate Case, Case No. IPC-E-24-07 ("2024 Limited Scope Rate Case"), involving 2024 rate base additions and incremental labor costs, which the Commission processed as a GRC with new rates becoming effective January 1, 2025.

4. Despite considerable investment and expansion in recent years, the Company's system today is fully utilized by its current customers. Continued growth in demand for electricity, aging infrastructure, and higher compliance and reliability requirements are driving the need for the Company to continue to invest large amounts of capital to expand and improve electricity supply, delivery, and reliability. The Company plans to invest approximately $1 billion in new infrastructure during 2025 with associated incremental depreciation expense.

5. At the same time, the Company has a strong track record of managing its operations and maintenance ("O&M") expenses, and as a result, excluding deferred wildfire-related costs, has achieved a compound annual O&M growth rate of only 1.5 percent between 2012 and 2024. Notwithstanding the Company's diligence and the success of its cost control measures, the historically high load growth at a time of rising costs and constrained system capacity continues to pose significant challenges for Idaho Power. Despite the relatively recent rate base increase, the Company's current rates are not sufficient to cover the cost to serve customers nor do they allow for an opportunity for Idaho Power to earn a reasonable rate of return on investment for its owners who are providing the capital to finance the investments.

6. As a result, the Company is requesting the Commission provide relief as proposed in this case so that the Company may fairly and timely recover the costs it incurs on behalf of customers, including investments in the systems and activities necessary to provide safe, reliable electric service. As more fully set forth herein and in the supporting testimonies filled contemporaneously herewith, the requested rate increase is justified, and the changes being sought by the Company in this case are fair, just, and reasonable and should therefore be approved by the Commission.

II. PROPOSED TARIFF

7. In compliance with Rule 121.01(a), the Company is including with this Application proposed changes to its tariff schedules as follows: Attachment No. 1, included herewith and made a part hereof, are the pertinent portions of Idaho Power's proposed new Electric Rate Schedules and Electric Service Regulations, IPUC No. 30, Tariff No. 101, covering the rendering of electric service and charges to Idaho Power's customers in the state of Idaho in "clean" format, and Attachment No. 2, included herewith and made a part hereof, contains those portions of Idaho Power's current IPUC No. 30, Tariff No. 101 that the Company proposes to modify as identified in "legislative" format. The proposed changes reflected in Attachment Nos. 1 and 2 were based on the tariff in effect as of May 30, 2025. Idaho Power will incorporate any other changes approved by the Commission after that date into the tariff schedules submitted in compliance with the Commission's final order in this case.

III. OVERVIEW OF REQUESTED RELIEF

8. The request in this case is largely focused on the rate base additions needed to safely and reliably serve Idaho Power's customers. As noted above, the

Company plans to invest approximately $1 billion in new infrastructure during 2025 and expects to incur depreciation/amortization and interest expense of approximately $52.5 million over 2024 levels. The associated incremental depreciation and interest expense alone will exceed the total amount of the rate increase granted by the Commission in the Company's 2024 Limited Scope Rate Case that became effective January 1, 2025, which was based on a 2024 historical test year.

9. Unfortunately, the application of a historical test year in the current environment of high growth and rising costs has resulted in unsustainable regulatory lag impacting the Company's ability to achieve reasonable rates of return and maintain sufficient credit metrics between rate cases. This dynamic was clearly demonstrated in 2024 as the Company fell well short of earning its authorized rate of return on equity, and it expects to fall well short again in 2025.

10. In short, the revenue from current rates heretofore allowed Idaho Power is no longer reasonable and adequate if Idaho Power is to maintain a stable financial condition and continue to render reliable and adequate electric service to its customers. The Company is requesting rate relief of approximately $199.1 million, or an overall increase to adjusted retail revenue of 13.09 percent. The test year is the 12 months ending December 31, 2025; the requested rate effective period begins on January 1, 2026, and if approved, the requested rates would be based on a 2025 revenue requirement.

11. Under the exceptional operational and financial realities confronting the Company, the application of a historical test year will not provide Idaho Power a reasonable opportunity to earn its authorized rate of return without other supportive rate mechanisms. As a result, in addition to the general rate relief requested in this case, Idaho

Power is proposing to implement a depreciation and interest expense tracking mechanism and to modify other earnings support mechanisms to help address some, but not all, of the harmful regulatory lag caused by using a historical test year.

IV. SUMMARY OF PROPOSED CHANGES BY CUSTOMER CLASS

12. Attachment No. 3, included herewith and made a part hereof, shows a comparison of revenues from the various rate schedules in Idaho Power's current IPUC No. 30, Tariff No. 101 from both a base revenue and billed revenue perspective. As summarized in the table below,[2] the Company's proposed base rate increase results in the following base revenue impacts to each customer segment.

General Rate Case Request *Cost of Service Percent change – Revenue Spread (Attachment 3)*						
Revenue Change	Overall % Impact	Residential	Small General Service	Large General Service [1]	Large Power [2]	Irrigation
$199,122,685	13.09	17.02	17.02	7.10	8.00	17.02

[1] Includes lighting schedules; [2] Includes special contracts

13. Residential: The annual revenue requirement to be recovered from residential service customers, which includes Schedules 1, 3, 5, and 6, is $814,155,998, representing a 17.02 percent increase in overall collection. The Company proposes to adjust each of the billing components to move closer to cost of service, including a monthly Service Charge increase to $25.00 from the existing $15.00 for all residential schedules. In addition, the Company proposes to adjust the Energy Charges within each

[2] This base rate percentage change table is net of a corresponding proposed PCA decrease of $46.8 million. Please note that the customer notice accompanying this Application uses Current Billed Revenue to Proposed Billed Revenue to inform customers of the expected bill impact rather than the percentage change in base rates.

schedule to recover the targeted revenue requirement. With respect to Schedule 1, the standard residential service, which includes seasonal inclining block Energy Charges, the Company is proposing to reduce the differentials between the current tiered prices but is not proposing to eliminate tiered pricing entirely. (Direct Testimonies of Messrs. Anderson and Maloney.)

14. In addition, the Company is proposing to implement a bill protection program for residential customers who begin taking service under Schedule 5, which is the residential time-of-use ("TOU") pricing option, effective January 1, 2026. The purpose of bill protection is to reduce financial uncertainty for customers transitioning from Schedule 1 to Schedule 5 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. (Direct Testimony of Mr. Anderson.)

15. Small General Service: The annual revenue requirement to be recovered from Schedule 7 and Schedule 8 customers is $23,641,536, which represents the capped 17.02 percent increase in overall collection from the class. The Company is proposing to increase the monthly Service Charge under Schedules 7 and 8 to $30.00, from $25.00, to move closer to the cost of service. In addition, the Company proposes to adjust Energy Charges within each schedule to recover the targeted revenue requirement. (Direct Testimonies of Messrs. Anderson and Maloney.)

16. Large General Service – Secondary: The annual revenue requirement to be recovered from large general service customers under Schedule 9 Secondary Service ("Schedule 9S") is $331,880,068, which represents a 7.19 percent increase in overall

collection from the class. For all pricing components under Schedule 9S, the Company is proposing prices that represent a uniform 20 percent movement toward the costs to serve that pricing component. For the optional TOU pricing the Energy Charge differentials are informed by the three-year average EIM prices for each TOU period. (Direct Testimonies of Messrs. Anderson and Maloney.)

17. Large General Service – Primary/Transmission: The annual revenue to be recovered from large general service customer under Schedule 9 Primary and Transmission Service is $56,288,766, representing a 6.88 percent change. For Schedule 9 Primary and Transmission Service, the Company is proposing to increase the Service Charge to align with cost of service, and for all other pricing components, 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. (Direct Testimonies of Messrs. Anderson and Maloney.)

18. Large Power Service: The annual revenue requirement for Schedule 19, Large Power Service, customers is $176,645,167, representing a 9.97 percent increase in overall collection from the class. 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. (Direct Testimonies of Messrs. Anderson and Maloney.)

19. Agricultural Irrigation Service: The annual revenue to be recovered from Schedule 24 customers is $209,823,654, which represents a 17.02 percent change. The Company is not proposing any changes to the existing pricing structure for Schedule 24

but is proposing a change to the definition of in-season and out-of-season periods that 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 is also proposing to increase the monthly Service Charge to move closer to cost-of-service-informed pricing; increasing the in-season Service Charge from $30 to $35 and the out-of-season Service Charge from $6 to $9. For the in-season Demand Charge, the Company is not proposing additional movement towards cost of service in this proceeding. (Direct Testimonies of Messrs. Anderson and Maloney.)

V. OTHER REGULATORY TREATMENT & ACCOUNTING REQUESTS

20. In addition to approval of the base revenue increase presented in this case and each of the affected tariff schedules, the Company requests the Commission issue an order that specifically authorizes regulatory treatment and/or accounting for several related matters.

21. To ensure customers do not pay twice for the same net power supply expense ("NPSE"), Idaho Power proposes a revised Schedule 55, Power Cost Adjustment reflecting the transfer of $46.8, million base level NPSE from the PCA to base rates. (Direct Testimonies of Messrs. Tatum and Larkin and Ms. Brady.)

22. In addition, to address regulatory lag that results from the use of historical test year in today's increasing cost environment, the Company requests the Commission authorize Idaho Power to: 1) establish a tracking mechanism for incremental depreciation and interest expense effective January 1, 2026; 2) continue deferring incremental wildfire mitigation and insurance costs from a base level of cost recovery established in this case; and 3) designate additional accumulated deferred investment tax credits ("ADITC") as

eligible for accelerated amortization under the terms of the currently approved ADITC/Revenue Sharing Mechanism, with the addition of a $75 million annual amortization cap. (Direct Testimonies of Messrs. Tatum, Buckham, and Larkin.)

23. The Company is also proposing to update rate recovery associated with both the Valmy and Bridger mechanisms to reflect current capital and O&M expectations, and to true-up variances between prior forecasts and actual costs. (Direct Testimony of Mr. Larkin.)

24. Finally, the Commission directed the Company in Order No. 29414 issued in Case No. IPC-E-03-11 to file accounting information related to its asset retirement obligations in its general rate cases. Attachment 4, included herewith and made a part hereof, contains journal entries made consistent with Statement of Financial Accounting Standards 143, now codified in Accounting Standards Codification section 410.

VI. TESTIMONY AND EXHIBITS

25. As required by Rule 121.01(b), a complete justification of the proposed increases in electric rates is provided in the narrative exposition set forth herein and in the form of testimony and exhibits, more fully described below. In accordance with Rule 121.01(d)-(g), the Company affirms that it stands ready for immediate consideration of this Application and is providing testimony, exhibits, workpapers, or other documentation as appropriate showing financial statements, cost of capital, and appropriate cost of service studies; how test year data were adjusted; and a jurisdictional separation of all investments, revenues, and expenses allocated or assigned, in whole or in part, to the Idaho utility business regulated by this Commission.

26. Simultaneously with the filing of this Application, Idaho Power has filed its direct case consisting of the Direct Testimonies of 15 witnesses and Exhibit Nos. 1 through 45, which more fully describe the relief requested by the Company. These witnesses and a brief summary of their testimonies are as follows:

- Ms. Lisa Grow, President and Chief Executive Officer, provides a general overview of the Company and its core business and business management practices. Ms. Grow also addresses the Company's current financial and operating situation and need for general rate relief as well as the current impacts of regulatory lag on Idaho Power.

- Mr. Tim Tatum, Vice President of Regulatory Affairs, presents the Company's case in support of the requested rate relief and also discusses regulatory policy matters related to the development of the GRC based on a 12-month test year ending December 31, 2025. He also describes several associated requests for specific regulatory and/or accounting treatment.

- Mr. Adam Richins, Senior Vice President and Chief Operating Officer, discusses the Company's recent history of reliability and performance that demonstrates a thoughtful approach to grid construction and maintenance and provides an overview of the nearly $1 billion in investments Idaho Power will be making in 2025 to ensure the continued delivery of safe, reliable electric service. He also describes the Company's safety culture and ongoing efforts to enhance customers' overall experience with Idaho Power and discusses the Company's advancements in energy efficiency as well as customer relations activities and related technology upgrades.

- Mr. Eric Hackett, Projects and Resource Development Director, discusses the Company's utility-scale battery project and the major generator interconnection facilities projects expected to be placed in service in 2025 and included in the Company's request in this case. He also discusses the prudent nature of these investments, detailing why they are needed to ensure Idaho Power's generation fleet is robust and well-positioned to provide continued safe, reliable service to customers.

- Mr. Ryan Adelman, Vice President of Power Supply, discusses the production plant-related investments the Company has made to ensure Idaho Power can continue to provide safe, reliable electric service to customers, detailing the steam production, hydroelectric production, and other production investments required since conclusion of Idaho Power's Limited Scope Rate Case in 2024.

- Mr. Mitch Colburn, Vice President of Planning, Engineering, and Construction, discusses the transmission and distribution investments necessary to ensure the provision of safe, reliable service to customers that are expected to be placed in service in 2025 and included in the Company's request in this case, demonstrating the Company's prudent investment in the electrical grid at the transmission and distribution levels. Mr. Colburn also details the Company's substantial wildfire mitigation efforts and associated capital and operation and maintenance expenditures.

- Ms. Sarah Griffin, Vice President of Human Resources, provides justification for the labor and total compensation costs included in the Company's test year. Ms. Griffin also describes the Company's overall compensation philosophy and explains why the level of compensation requested in this case is necessary to provide safe, reliable, affordable electricity to customers.

- Dr. John Thompson, who has been retained by the Company as its ROE expert, discusses risk factors relevant to Idaho Power, performs calculations of ROE appropriate for the Company using standard financial methodologies, and recommends a reasonable ROE range appropriate for Idaho Power. In this proceeding, Dr. Thompson's recommended ROE range is from 10.10 to 11.10 percent.

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

- Ms. Paula Jeppsen, Controller, Business Unit Finance and Strategy, testifies to the actual 2024 financial results with standard ratemaking adjustments. Ms. Jeppsen describes the development and application of the methodologies used to prepare the 2024 base financial information and the adjustments to those data associated with deductions to certain expenses not allowed in rates, certain adjustments to expenses and rate base, and other adjustments to revenues, expenses, and rate base related primarily to past Commission orders.

- Mr. Matthew Larkin, Revenue Requirement Senior Manager, describes how the Company utilized the 2024 financial data as presented by Ms. Jeppsen as a starting point from which he made conservative adjustments to derive similar data corresponding to the 2025 test year. Mr. Larkin prepared an exhibit that details the method and rationale for each known and measurable adjustment he utilized in developing the 2025 test year data. Once he determined the 2025 test year system-level data, Mr. Larkin supervised the preparation of the jurisdictional separation study ("JSS") utilized to determine the Idaho jurisdictional revenue requirement.

- Ms. Jessica Brady, Senior Regulatory Analyst, discusses the derivation of the Company's 2025 retail revenue forecast used for the 2025 test year and presents the quantification of the 2025 normalized or "base level" net power supply expenses ("NPSE"). Ms. Brady also addresses the requisite changes to the Company's PCA as a result of changing the normalized NPSE in the Company's base rates.

- Ms. Kelley Noe, Regulatory Consultant, summarizes the development of the system revenue requirement for purposes of forecasting the Company's rate base, revenues, and expenses for the 2025 test year. She also discusses quantification of the Idaho jurisdictional revenue requirement resulting from the Jurisdiction Separation Study ("JSS") for the twelve months ending December 31, 2025.

- Mr. Riley Maloney, Regulatory Policy and Strategy Leader, addresses derivation of the Company's 2025 class cost-of-service study ("CCOS") using the Idaho retail jurisdictional output from the JSS, as developed by Ms. Noe, and the resulting recommendations for customer pricing components. Specifically, Mr. Maloney's testimony covers the following four areas: 1) CCOS - overview, proposed modification to methodology, description, and study results, 2) allocation of CCOS-informed revenue requirement to customer classes, 3) computation of the Sales Based Adjustment Rate ("SBAR") consistent with the methodology described in the Settlement Agreement in Case No. IPC-E-15-15, and, 4) update to Fixed Cost Adjustment ("FCA") components as informed by the 2025 CCOS study.

- Mr. Grant Anderson, Pricing and Tariff Administration Leader, presents and supports the Company'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. Mr. Anderson also addresses proposed updates to select tariff schedules and rules, which are generally intended to improve consistency, transparency, and administration.

27. Portions of the Company's Application and accompanying testimonies and exhibits are based on computer models. Additional documentation and explanation are provided with testimonies and exhibits in this filing, as well as workpapers to be submitted. As envisioned by Rule of Procedure 121.02, further information can be provided upon request.

VII. EFFECTIVE DATE

28. This Application, including Attachment Nos. 1 through 4, is filed with this Commission to be kept open for public inspection as required by law, and the same fully

states the changes to be made in the schedules, regulations, and contract rates now in force.

29. While an effective date thirty days after the filing of this Application, or on or after June 30, 2025, is consistent with Idaho Code § 61-307 and Rule 123.01, Idaho Power expects the Commission will suspend implementation of the Company's proposed rates for the statutory period pursuant to Idaho Code § 61-622 and Rule 123.03. With this expectation in mind, the Company has framed its requested effective date as January 1, 2026, in all discussions contained within this filing and for all related customer communication.

VIII. PUBLIC NOTICE

30. As required by Rule 121.01(c), the Company states that this Application has been and will be brought to the attention of Idaho Power's affected customers by customer notices mailed to individual customers and by means of a press release, which will be sent to various media outlets, including the newspapers of general circulation in the area served by Idaho Power. A copy of the customer notice and press release by Rule 125 accompany this Application.

31. In addition, the affected current Electric Rate Schedules, Electric Service Regulations, including rate schedules for the special contracts, together with the proposed Electric Rate Schedules, Electric Service Regulations, including rate schedules for the special contract customers, will be kept open for public inspection at Idaho Power's offices in the state of Idaho.

32. Idaho Power believes the above-described procedures satisfy the Commission's Rules of Practice and Procedure, but Idaho Power will, in the alternative,

bring this Application to the attention of Idaho Power's affected customers through any other means directed by this Commission.

IX. COMMUNICATIONS

33. Communications with reference to this Application should be sent to the following:

Donovan E. Walker
Megan Goicoechea Allen
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caschenbrenner@idahopower.com
mlarkin@idahopower.com

X. REQUEST FOR RELIEF

34. Idaho Power respectfully requests the Commission issue its Order finding the proposed rates and charges to be fair, just, reasonable, and nondiscriminatory. Idaho Power asks the Commission to approve the new Electric Rate Schedules, Electric Service Regulations, and special contract rates set out in Attachment No. 1. If approved, Idaho Power's annual Idaho jurisdictional revenues would increase by approximately $199.1 million, and result in an overall increase to adjusted base revenue of 13.09 percent.

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

- Approval of a revised Schedule 55, Power Cost Adjustment, reflecting the transfer of certain base level NPSE from the PCA to base rates;
- Establishment of a tracking mechanism for incremental depreciation and interest expense effective January 1, 2026;

- Authorization of the continued deferral of incremental wildfire mitigation and insurance costs in 2026 and beyond as measured from new base level of costs established in this case;

- Designation of additional ADITC accumulated through 2028 as eligible for accelerated amortization under the terms of the currently approved ADITC/Revenue Sharing Mechanism, with the addition of a $75 million annual amortization cap;

- Authorization to update rate recovery associated with both the Valmy and Bridger mechanisms to reflect current capital and O&M expectations, and to true-up variances between prior forecasts and actual costs; and

- Approval of an updated per-unit wheeling revenue baseline.

DATED at Boise, Idaho, this 30th day of May 2025.

Donovan E. Walker

DONOVAN E. WALKER
Attorney for Idaho Power Company

Megan Goicoechea Allen

MEGAN GOICOECHEA ALLEN
Attorney for Idaho Power Company

APPLICANT'S STATEMENT OF READINESS FOR HEARING

DONOVAN E. WALKER, one of the attorneys of record for Idaho Power, pursuant to Rule of Procedure 121.01(d) hereby states that Idaho Power stands ready for immediate consideration of its Application.

Donovan E. Walker

Donovan E. Walker

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

ATTACHMENT NO. 1
PROPOSED TARIFF

GENERAL RULES AND REGULATIONS INDEX

SCHEDULE INDEX

SCHEDULE INDEX

SCHEDULE	TITLE	SHEET NUMBER
73	Cogeneration and Small Power Production Schedule – Idaho	73-1 – 73-10
79	Weatherization Assistance for Qualified Customers	79-1
81	Residential Air Conditioner Cycling Program (Optional)	81-1 – 81-3
82	Flex Peak Program (Optional)	82-1 – 82-7
84	Customer Energy Production Net Metering Service	84-1 – 84-9
86	Cogeneration and Small Power Production Non-Firm Energy	86-1 – 86-7
87	Intermittent Generation Integration Charges	87-1 – 87-24
89	Unit Avoided Energy Cost for Cogeneration and Small Power Production	89-1
91	Energy Efficiency Rider	91-1
95	Adjustment for Municipal Franchise Fees	95-1 – 95-2
96	Blaine County Surcharge to Fund the Undergrounding of Certain Facilities	96-1
98	Residential and Small Farm Energy Credit	98-1 – 98-2

RULE C
SERVICE AND LIMITATIONS
(Continued)

5. Point of Delivery Service Requirements (Continued)

Where separate Points of Delivery exist for supplying service to a Customer at a single Premises or separate meters are maintained for measurement of service to a Customer at a single Premises, the meter readings will not be combined or aggregated for any purpose except for determining if the Customer's total power requirements exceed 20,000 kW. Special contract arrangements will be required when a Customer's aggregate power requirement exceeds 20,000 kW.

Service delivered at low voltage (600 volts or under) will be supplied from the Company's distribution system to the outside wall of the Customer's building service pole or post unless an exception is granted by the Company and the City or State Electrical Inspector.

The Customer's facilities will be installed and maintained in accordance with the requirements of the National Electrical Code and the Company's Customer Requirements for Electric Service (found at Idahopower.com/requirements).

6. Limitation of Use. A Customer will not resell electricity received from the Company to any person except (1) where the Customer is owner, lessee, or operator of a commercial building, shopping center, apartment house, mobile home court, or other multi-family dwelling where the use has been sub-metered prior to July 1, 1980, and the use is billed to tenants at the same rates that the Company would charge for service, unless the Commission authorizes alternative procedures, or (2) where the electricity is purchased from a public utility (as defined in Idaho Code § 61-129) to charge the batteries of an electric motor vehicle as provided by order or rule of the Commission.

A Customer's wiring will not be extended or connected to furnish service to more than one building or place of use through one meter, even though such building, property, or place of use is owned by the Customer. This provision is not applicable where the Customer's residence or business consists of one or more adjacent buildings or places of use located on the same Premises or operated as an integral unit, under the same name and carrying on parts of the same residence or business.

7. Rights of Way. The Customer shall, without cost to the Company, grant the Company a right of way for the Company's lines and apparatus across and upon the property owned or controlled by the Customer, necessary or incidental to the supplying of Electric Service and shall permit access thereto by the Company's employees at all reasonable hours. The Customer shall also grant the Company access to permit the Company to trim trees and other vegetation to the extent necessary to avoid interference with the Company's lines and to protect public safety.

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

2. General Provisions

a. Cost Information. The Company will provide preliminary cost information addressing the charges contained in this rule to potential Applicants and/or Additional Applicants. This preliminary information will not be considered a formal Cost Quote and will not be binding on the Company or Applicant but rather will assist the Applicant or Additional Applicant in the decision to request a formal Cost Quote. Upon receiving a request for a formal Cost Quote, the Applicant or Additional Applicant will be required to provide all necessary information for a design and pay non-refundable engineering costs to the Company. A Cost Quote will be binding in accordance with its terms.

b. Ownership. The Company will own all distribution line facilities and retain all rights to them.

c. Rights-of-Way and Easements. The Company will construct, own, operate, and maintain lines only along public streets, roads, and highways that the Company has the legal right to occupy, and on public lands and private property across which rights-of-way or easements satisfactory to the Company will be obtained at the Applicant's or Additional Applicant's expense.

d. Removals. The Company reserves the right to remove any distribution facilities that have not been used for 1-year. Facilities shall be removed only after providing 60 days' written notice to the last customer of record and the owner of the property served.

e. Removals in High Fire Risk Zones. The Company reserves the right to remove or de-energize any electrical equipment without advance written notice if that equipment has not been used for 1-year.

f. Property Specifications. Applicants or Additional Applicants must provide the Company with final property specifications as required and approved by the appropriate governmental authorities. These specifications may include but are not limited to: recorded plat maps, utility easements, final construction grades, property pins and proof of ownership.

g. Undeveloped Subdivisions. When electric service is not provided to the individual spaces or lots within a Subdivision, the Subdivision will be classified as undeveloped.

h. Mobile Home Courts. Owners of mobile home courts with transient tenants, as defined within Idaho Code § 55-2003(19), will install, own, operate, and maintain all termination poles, pedestals, meter loops, and conductors from the Point of Delivery.

i. Conditions for Start of Construction. Construction of Line Installations and Alterations will not be scheduled until the Applicant or Additional Applicant pays the appropriate charges to the Company.

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

2. General Provisions (Continued)

j. Terms of Payment. All payments listed under this section will be paid to the Company in cash, a minimum of 30 days and no more than 120 days, prior to the start of Company construction, unless mutually agreed otherwise.

k. Interest on Payment. If the Company does not start construction on a Line Installation or Alteration within 30 days after receipt of the construction payment, the Company will compute interest on the payment amount beginning on the 31st day and ending once Company construction actually begins. Interest will be computed at the rate applicable under the Company's Rule L. If this computation results in a value of $10.00 or more, the Company will pay such interest to the Applicant, Additional Applicant, or subdivider. An Applicant, Additional Applicant, or subdivider may request to delay the start of construction beyond 30 days after receipt of payment in which case the Company will not compute or pay interest.

l. Fire Protection Facilities. The Company will provide service to Fire Protection Facilities when the Applicant pays the Work Order Cost for the Line Installation including Terminal Facilities, less Company Betterment. These costs are not subject to an Allowance, but are eligible for Vested Interest Refunds under Section 8.a.

m. Customer Provided Trench Digging and Backfill. The Company will, at its discretion, allow an Applicant, Additional Applicant or subdivider to provide trench digging and backfill. In a joint trench, backfill must be provided by the Company. Costs of customer-provided trench and backfill will be removed from or not included in the Cost Quote and will not be subject to refund.

3. Line Installation Charges

If a Line Installation is required, the Applicant or Additional Applicant will pay a partially refundable Line Installation Charge equal to the Work Order Cost less applicable Allowances identified in Section 7.

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

4. **Service Attachment Charges**

a. Overhead Service Attachment Charge. If an overhead Service Attachment is required, the Applicant or Additional Applicant will pay a non-refundable Service Attachment Charge equal to the Work Order Cost less applicable Allowances identified in Section 7.

b. Underground Service Attachment Charge. Each Applicant or Additional Applicant will pay a non-refundable Underground Service Attachment Charge for attaching new Terminal Facilities to the Company's distribution system. The Company will determine the location and maximum length of service cable.

i. Single Phase 400 Amps or Less and Single Phase Self-Contained Multiple Meter Bases 500 Amps or Less.

Underground Service Cable (Base charge plus Distance charge)

Base charge from:

underground	$ 28.00
overhead including 2" riser	$ 991.00
overhead including 3" riser	$1,247.00

Distance charge (per foot)

Company Installed Facilities with:

1/0 underground cable	$ 14.97
4/0 underground cable	$ 15.98
350 underground cable	$ 20.30

Customer Provided Trench & Conduit with:

1/0 underground cable	$ 4.11
4/0 underground cable	$ 5.12
350 underground cable	$ 7.13

ii. Three Phase 400 Amps or Less and Three Phase Self-Contained Multiple Meter Bases 500 Amps or Less. Only applicable when a single run of service cable is required.

Underground Service Cable (Base charge plus Distance charge)

Base charge from:

underground	$ 177.00
overhead including 2” riser	$ 991.00
overhead including 3” riser	$ 1,247.00
overhead including 4” riser	$ 1,644.00

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

4. Service Attachment Charges (Continued)

Distance charge (per foot)

Company installed Facilities with:

1/0 underground cable	$	15.77
4/0 underground cable	$	19.13
350 underground cable	$	24.47

Customer Provided Trench & Conduit with:

1/0 underground cable	$	5.01
4/0 underground cable	$	6.27
350 underground cable	$	10.79

iii. The Applicant or Additional Applicant will pay a non-refundable Underground Service Attachment Charge equal to the Work Order Cost for all requests for services that are not covered under 4(b)(i) or 4(b)(ii).

5. Vested Interest Charges

Additional Applicants connecting to a vested portion of a Line Installation will pay a Vested Interest Charge to be refunded to the Vested Interest Holder. Additional applicants will have two payment options:

Option One - An Additional Applicant may choose to pay an amount determined by this equation:

Vested Interest Charge = A x B x C where;

A = Load Ratio: Additional Applicant's Connected Load divided by the sum of Additional Applicant's Connected Load and Vested Interest Holder's load.
B = Distance Ratio: Additional Applicant's distance divided by original distance.
C = Vested Interest Holder's unrefunded contribution.

Option Two - An Additional Applicant may choose to pay the current Vested Interest, in which case the Additional Applicant will become the Vested Interest Holder and, as such, will become eligible to receive Vested Interest Refunds in accordance with Section 8.a.

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

5. Vested Interest Charges (Continued)

If Option One is selected, the Additional Applicant has no Vested Interest and the previous Vested Interest Holder remains the Vested Interest Holder. The Vested Interest Holder's Vested Interest will be reduced by the newest Additional Applicant's payment.

The Vested Interest Charge will not exceed the sum of the Vested Interests in the Line Installation. If an Additional Applicant connects to a portion of a vested Line Installation which was established under a prior rule or schedule, the Vested Interest Charges of the previous rule or schedule apply to the Additional Applicant.

6. Other Charges

a. Alteration Charges. If an Applicant or Additional Applicant requests a Relocation, Upgrade, Conversion or removal of Company facilities, the Applicant or Additional Applicant will pay a non-refundable charge equal to the Cost Quote.

b. Engineering Charge. Applicants or Additional Applicants will be required to prepay all engineering costs for Line Installations and/or Alterations greater than 16 estimated hours. Estimates equal to or less than 16 hours will be billed to the Applicant or Additional Applicant as part of the construction costs, or after the engineering is completed in instances where construction is not requested. Engineering charges will be calculated at $97.00 per hour.

c. Engineering Charges for Agencies and Taxing Districts of the State of Idaho. Under the authority of Idaho Code § 67-2302, an agency or taxing district of the State of Idaho may invoke its right to decline to pay engineering charges until the engineering services have been performed and billed to the agency or taxing district. Any state agency or taxing district that claims it falls within the provisions of Idaho Code § 67-2302 must notify Idaho Power of such claim at the time Idaho Power requests prepayment of the engineering charges. Idaho Power may require that the state agency or taxing district's claim be in writing. If the state agency or taxing district that has invoked the provisions of Idaho Code § 67-2302 does not pay the engineering charges within the 60-day period as provided in that statute, all the provisions of that statute will apply.

d. Joint Trench Charge. Applicants, Additional Applicants, and subdividers will pay the Company for trench and backfill costs included in the Cost Quote. In the event the Company is able to defray any of the trench and backfill costs by sharing a trench with other utilities, the cost reduction will be included in the Cost Quote.

e. Rights-of-Way and Easement Charge. Applicants or Additional Applicants will be responsible for any costs associated with the acquisition of rights-of-way or easements.

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

6. Other Charges (Continued)

f. Temporary Line Installation Charge. Applicants or Additional Applicants will pay the installation and removal costs of providing Temporary Line Installations.

g. Temporary Service Attachment Charge. Applicants or Additional Applicants will pay for Temporary Service Attachments as follows:

i. Underground - $76.00

The customer-provided meter post must be set within two linear feet of the Company's existing transformer or junction box.

ii. Overhead - $330.00

The customer-provided meter pole shall be set in a location that does not require more than 100 feet of #2 aluminum service conductor that can be readily attached to the permanent location by merely relocating it.

The electrical facilities provided by the customer on the meter pole shall be properly grounded, electrically safe, meet all clearance requirements, and ready for connection to Company facilities.

The customer shall obtain all permits required by the applicable state, county, or municipal governments and will provide copies or verification to the Company as required. The above conditions must be satisfied before the service will be attached.

h. Temporary Service (Overhead or Underground), Overhead Permanent, and Customer Provided Trench Inspection Return Trip Charge. A Return Trip Charge of $76.00 will be assessed each time Company personnel are dispatched to the job site, but are unable to connect the service. The charge will be billed after the conditions have been satisfied and the connection has been made.

i. Unusual Conditions Charge. Applicants, Additional Applicants, and subdividers will pay the Company the additional costs associated with any Unusual Conditions included in the Cost Quote. This payment, or portion thereof, will be refunded to the extent that the Unusual Conditions are not encountered.

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

6. Other Charges (Continued)

In the event that the estimate of the Unusual Conditions included in the Cost Quote is equal to or greater than $10,000, the Applicant, Additional Applicant or subdivider may either pay for the Unusual Conditions or, at the option of the Company, may furnish an Irrevocable Letter of Credit drawn on a local bank or local branch office issued in the name of Idaho Power Company for the amount of the Unusual Conditions. Upon completion of that portion of the project which included an Unusual Conditions estimate, Idaho Power Company will bill the Applicant, Additional Applicant or subdivider for the amount of Unusual Conditions encountered up to the amount established in the Irrevocable Letter of Credit. The Applicant, Additional Applicant or subdivider will have 15 days from the issuance of the Unusual Conditions billing to make payment. If the Applicant, Additional Applicant or subdivider fails to pay the Unusual Conditions bill within 15 days, Idaho Power will request payment from the bank.

j. Underground Service Return Trip Charge. When a customer agrees to supply the trench, backfill, conduit, and compaction for an underground service, an Underground Service Return Trip Charge of $126.00 will be assessed each time the Company's installation crew is dispatched to the job site at the customer's request, but is unable to complete the cable installation and energize the service due to the Company's required specifications not being met.

7. Line Installation, Shared Terminal Facilities and Service Attachment Allowances

The Company will contribute an Allowance toward the cost of Terminal Facilities associated with an additional Line Installation and/or Service Attachment. If a Customer increases their consumptive load and is responsible for upgrading Shared Terminal Facilities, such Customer will receive an Allowance toward the cost of the upgraded Shared Terminal Facilities. Allowances are based on the cost of providing and installing Standard Terminal Facilities for single phase and three phase services.

a. Allowances for Overhead and Underground Line Installations, Shared Terminal Facilities and Overhead Service Attachments

Class of Service	Maximum Allowance per Service
Residential:	
Schedules 1, 3, 5, 6	$4,233.00
Non-residence	$ 0.00
Non-residential:	
Schedules 7, 8, 9, 24	
Single Phase	$4,233.00
Three Phase	$8,707.00

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

7. Line Installation, Shared Terminal Facilities and Service Attachment Allowances (Continued)

Large Power Service Schedule 19	Case-By-Case

b. Allowances for Subdivisions and Multiple Occupancy Projects
Developers of Subdivisions and Multiple Occupancy Projects will receive a $4,233.00 Allowance for each single phase transformer installed within a development and a $8,707.00 Allowance for each three phase transformer installed within a development. Subdividers will be eligible to receive Allowances for Terminal Facilities installed inside residential and non-residential subdivisions.

8. Refunds

a. Vested Interest Refunds. Vested Interest Refunds will be paid by the Company and funded by the Additional Applicant's Vested Interest Charge as calculated in accordance with Section 5. The initial Applicant will be eligible to receive refunds up to 80 percent of their original construction cost. Additional Applicants that become Vested Interest Holders will be eligible to receive refunds up to their total contribution less 20 percent of the original construction cost.

A Vested Interest Holder and the Company may agree to waive the Vested Interest payment requirements of Additional Applicants with loads less than an agreed upon level. Waived Additional Applicants will not be considered Additional Applicants for purposes of Section 8.a.i. (1) below.

i. Vested Interest Refund Limitations

(1). Vested Interest Refunds will be funded by no more than 4 Additional Applicants during the 5-year period following the completion date of the Line Installation for the initial Applicant.

(2). In no circumstance will refunds exceed 100 percent of the refundable portion of any party's cash payment to the Company.

b. Subdivision Refunds.

i. Applicants will be eligible for Vested Interest Refunds for facilities installed inside Subdivisions if the construction was NOT part of the initial Line Installation. Customers requesting additional Line Installations within a Subdivision will be considered new Applicants and become eligible for Vested Interest Refunds.

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

8. Refunds (Continued)

ii. A subdivider will be eligible for Vested Interest Refunds for payments for Line Installations outside subdivisions.

9. Local Improvement Districts

Unless specifically provided for under this paragraph, a Local Improvement District will be provided service under the general terms of this rule.

The Company will provide a cost estimate and feasibility study for a Local Improvement District within 120 days after receiving the resolution from the requesting governing body. The Cost Quote will be based on Work Order Costs and will not be considered binding on the Company if construction is not commenced within 6 months of the submission of the estimate for reasons not within the control of the Company. The governing body issuing the resolution will pay the Company for the costs of preparing the cost estimate and feasibility study regardless of whether the Line Installation or Alteration actually takes place.

After passage of the Local Improvement District ordinance, the Company will construct the Line Installation or Alteration. Upon completion of the project, the Company will submit a bill to the Local Improvement District for the actual cost of the work performed, including the costs of preparing the cost estimate and feasibility study. If the actual cost is less than the estimated cost, the Local Improvement District will pay the actual cost. If the actual cost exceeds the estimated cost, the Local Improvement District will pay only the estimated cost. The governing body will pay the Company within 30 days after the bill has been submitted.

A Local Improvement District will be eligible for an Allowance for any new load connecting for service upon the completion of the Line Installation. A Local Improvement District will retain a Vested Interest in any Line Installation to the Local Improvement District. A Local Improvement District may waive payments for Vested Interest from Additional Applicants within the Local Improvement District.

RULE N
SPECIAL ARRANGEMENTS
FOR SUBSTATION ALLOWANCES AND
TRANSMISSION VESTED INTEREST

This rule applies to eligible customers taking service under Schedule 19, or customers taking Primary or Transmission Service under Schedule 9; when the customer's request for service requires the installation of new or upgraded transformer capacity in Substation Facilities.

Definitions

Additional Schedule 9 or 19 Applicant is a Schedule 9 or 19 Customer whose Application requires the Company to provide new or relocated service from Substation Facilities served by an existing section of Transmission Facilities with a Transmission Vested Interest.

Applicant is a Schedule 9 or 19 Customer whose Application requires the Company to provide new or relocated service from Substation Facilities served by Transmission Facilities that are free and clear of any Transmission Vested Interest.

Application is a request by an Applicant or Additional Schedule 9 or 19 Applicant for new electric service from the Company.

Connected Load is the total nameplate MW rating of the electric loads connected for Schedule 9 or 19 service.

Distribution Facilities include structures, wires, insulators, and related equipment that are operated at a 34.5 kilovolt or lower rating.

Substation Allowance is the portion of the cost of the Substation Facilities funded by the Company.

Substation Facilities include those facilities and related equipment that transform the voltage of energy from a 44 kilovolt or higher rating to a 34.5 kilovolt or lower rating.

Transmission Facilities include structures, wires, insulators, and related equipment that are operated at a 44 kilovolt or higher rating.

Transmission Line Installation is any installation of new Transmission Facilities owned by the Company.

Transmission Line Installation Charge is the partially refundable charge assessed an Applicant or Additional Schedule 9 or 19 Applicant whenever a Transmission Line Installation is built for that individual.

Transmission Vested Interest is the right to a refund that an Applicant or Additional Schedule 9 or 19 Applicant holds in a specific section of Transmission Facilities when Additional Schedule 9 or 19 Applicants attach to that section of Transmission Facilities.

Transmission Vested Interest Charge is an amount collected from an Additional Schedule 9 or 19 Applicant for refund to a Transmission Vested Interest Holder.

Transmission Vested Interest Holder is a person or entity that has paid a refundable Transmission Line Installation Charge to the Company for a Transmission Line Installation.

RULE N
SPECIAL ARRANGEMENTS
FOR SUBSTATION ALLOWANCES AND
TRANSMISSION VESTED INTEREST
(Continued)

Transmission Vested Interest Portion is that part of the Company's transmission system in which a Transmission Vested Interest is held.

Substation Allowance

If a Schedule 9 or 19 Customer's request for service requires the installation of new or upgraded transformer capacity in Substation Facilities, the following considerations will be included in the separate agreement between the Customer and the Company:

The Customer will initially pay for the cost of new or upgraded Substation Facilities required because of the Customer's request. The Customer will be eligible to receive a one-time Substation Allowance based upon subsequent sustained usage of capacity by the Customer.

a. Substation Allowance: The maximum possible allowance will be determined by multiplying the Customer's actual increase in load by $99,826 per MW but will not exceed the actual cost of the Substation Facilities.

b. Substation Allowance Refunds: The Substation Allowance will be refunded to the Customer over a five-year period, with annual payments based on the Customer's Basic Load Capacity at the time of refund. The first refund will be paid one year following the first month energy is delivered through the new Substation Facilities.

The refunds will occur based on the following adjustment, which will be added to the Substation Allowance received in the previous year. If there is no change in load from the previous year, the Substation Allowance for that year is equal to the Substation Allowance from the previous year:

$$\frac{(\text{(Change in load from the previous year as measured in MW) x (Substation Allowance per MW)})}{\text{Number of Substation Allowance Refunds remaining in five-year period}}$$

The Customer's annual refunds will be made in accordance with the Substation Allowance amount stated in the separate construction agreement between the Customer and the Company.

Transmission Vested Interest

If a Schedule 9 or 19 Customer's request for service requires the installation of new or upgraded capacity in Transmission Facilities, and those Transmission Facilities are serving the Customer by a radial feed, the following considerations will be included in the separate agreement between the Customer and the Company:

The Customer will initially pay for the cost of new or upgraded Transmission Facilities required because of the Customer's request. The Customer may be eligible to receive Transmission Vested Interest Refunds in accordance with Schedule 9 or 19.

RULE N
SPECIAL ARRANGEMENTS
FOR SUBSTATION ALLOWANCES AND
TRANSMISSION VESTED INTEREST
(Continued)

Transmission Vested Interest (Continued)

Transmission Vested Interest Refunds.

Transmission Vested Interest Refunds will be paid by the Company and funded by the Additional Schedule 9 or 19 Applicant's Transmission Vested Interest Charge as calculated in accordance with Schedule 19. The initial Applicant will be eligible to receive refunds up to 80 percent of their original construction cost.

Transmission Vested Interest Refund Limitations

a. Transmission Vested Interest Refunds will be funded by no more than 4 Additional Schedule 9 or 19 Applicants during the 5-year period following the completion date of the Transmission Line Installation.
b. In no circumstance will refunds exceed 100 percent of the refundable portion of any party's cash payment to the Company.

Transmission Vested Interest Charges:

Additional Schedule 9 or 19 Applicants with a Connected Load of greater than 1 MW who connect to a Transmission Vested Interest Portion of a Transmission Line Installation will pay a Transmission Vested Interest Charge to be refunded to the Transmission Vested Interest Holder.

An Additional Schedule 9 or 19 Applicant will pay an amount determined by this equation:

Transmission Vested Interest Charge = A x B where;

A = Load Ratio: Additional Schedule 9 or 19 Applicant’s Connected Load divided by the sum of Additional Applicant’s Connected Load and Transmission Vested Interest Holder’s load.
B = Vested Interest Holder’s un-refunded contribution

The Additional Schedule 9 or 19 Applicant has no Transmission Vested Interest and the Transmission Vested Interest Holder remains the Transmission Vested Interest Holder. The Transmission Vested Interest Holder’s Transmission Vested Interest will be reduced by the newest Additional Schedule 9 or 19 Applicant’s payment.

The Transmission Vested Interest Charge will not exceed the sum of the Transmission Vested Interests in the Transmission Line Installation. If an Additional Schedule 9 or 19 Applicant connects to a portion of a vested Transmission Line Installation which was established under a prior rule or schedule, the Transmission Vested Interest Charges of the previous rule or schedule apply to the Additional Schedule 9 or 19 Applicant.

SCHEDULE 1
RESIDENTIAL SERVICE
STANDARD PLAN
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-summer
Service Charge, per month	$25.00	$25.00
Energy Charge, per kWh		
First 800 kWh	12.5685¢	9.9581¢
801-2000 kWh	13.7920¢	10.4567¢
All Additional kWh Over 2000	15.1580¢	11.0331¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 3
MASTER-METERED MOBILE HOME PARK
RESIDENTIAL SERVICE

AVAILABILITY

Service under this schedule is available to master-metered mobile home parks included on the Company's list of "grandfathered" mobile home parks on file with the Idaho Public Utilities Commission receiving electric service under Schedule 1 as of March 20, 2009. Customers included on the Company's list of "grandfathered" mobile home parks as of March 20, 2009, will automatically be transferred to this Schedule on their next regularly scheduled cycle read date that occurs on or after March 21, 2009.

APPLICABILITY

Service under this schedule is applicable to Electric Service provided to a master-metered residential mobile home park for residential service for general domestic uses, including single phase motors of 7½ horsepower rating or less. This schedule is not applicable to standby service or shared service.

TYPE OF SERVICE

The type of service provided under this schedule is single phase, alternating current at approximately 120 or 240 volts and 60 cycles, supplied through one meter at one Point of Delivery.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit):

Service Charge, per month	$25.00
Energy Charge, per kWh	
all kWh	13.1324¢

Minimum Charge

The monthly Minimum Charge shall be the sum of the Service Charge, the Energy Charge, and the Power Cost Adjustment.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 5
RESIDENTIAL SERVICE
TIME-OF- USE PLAN
(OPTIONAL)

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Idaho to residential Customers where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served, additional investment by the Company for new transmission, substation or terminal facilities is not necessary to supply the desired service, and Advanced Meter Reading (AMR) equipment is installed.

The Residential Service Time-of-Use Plan is an optional, voluntary service that provides residential Customers the option to take electric service with seasonal time-of-use energy rates. If a Customer requests to participate in this schedule, the Customer will be placed on the schedule effective with their next billing cycle.

A Customer may terminate their participation on this schedule at any time. However, the Customer may not subsequently elect service under this schedule for one year after the effective date of cancellation. If a Customer requests to be taken off of the schedule, the Customer will be removed from the schedule as of the last meter read date.

APPLICABILITY

Service under this schedule is applicable to Electric Service required for residential service Customers for general domestic uses, including single phase motors of 7½ horsepower rating or less, subject to the following conditions:

1. When a portion of a dwelling is used regularly for business, professional or other gainful purposes, or when service is supplied in whole or in part for business, professional, or other gainful purposes, the Premises will be classified as non-residential and the appropriate general service schedule will apply. However, if the wiring is so arranged that the service for residential purposes can be metered separately, this schedule will be applied to such service.

2. Whenever the Customer's equipment does not conform to the Company's specifications for service under this schedule, service will be supplied under the appropriate General Service Schedule.

3. This schedule is not applicable to standby service, service for resale, or shared service.

TYPE OF SERVICE

The type of service provided under this schedule is single phase, alternating current at approximately 120 or 240 volts and 60 cycles, supplied through one meter at one Point of Delivery. Upon request by the owner of multi-family dwellings, the Company may provide 120/208 volt service for multi-family dwellings when all equipment is U L approved to operate at 120/208 volts.

SCHEDULE 5
RESIDENTIAL SERVICE
TIME-OF-USE PLAN
(OPTIONAL)
(Continued)

BILL PROTECTION

Customers who begin service under this schedule on or after January 1, 2026, and who have not previously received Bill Protection at the Premises, shall be eligible for Bill Protection. Bill Protection compares the total Energy Charges incurred under this schedule during the initial twelve (12) consecutive billing months of service to the Energy Charges that would have been incurred under Schedule 1 – Residential Service (Standard Plan) for the same usage and billing period. If the cumulative Energy Charges under this schedule exceed those under the Standard Plan by more than ten dollars ($10), the Customer shall receive a one-time bill credit equal to the net difference reduced by the $10 threshold for Bill Protection. Customers who do not remain continuously enrolled in this schedule for the full twelve-month period, who received service under this schedule at the Premises prior to January 1, 2026, or who have previously received Bill Protection at the Premises, are not eligible. Upon conclusion of the Bill Protection period, the Customer shall continue service under this schedule unless the Customer notifies the Company of their intent to return to the Standard Plan or another applicable rate schedule.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.

TIME PERIODS

The time periods are defined as follows. All times are stated in Mountain Time.

Summer Season

On-Peak:	7:00 p.m. to 11:00 pm. Monday through Saturday, except holidays
Mid-Peak	3:00 p.m. to 7:00 p.m. Monday through Saturday, except holidays
Off-Peak:	11:00 p.m. to 3:00 p.m. Monday through Saturday and all hours on Sunday and holidays

Non-summer Season

On-Peak:	6:00 a.m. to 9:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday through Saturday, except holidays
Off-Peak:	9:00 a.m. to 5:00 p.m. and 8:00 p.m. to 6:00 a.m. Monday through Saturday and all hours on Sunday and holidays

Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). When New Year’s Day, Independence Day, or Christmas Day falls on Sunday, the Monday immediately following that Sunday will be considered a holiday.

SCHEDULE 5
RESIDENTIAL SERVICE
TIME-OF-USE PLAN
(OPTIONAL)
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-summer
Service Charge, per month	$25.00	$25.00
Energy Charge, per kWh		
On-Peak	32.2968¢	14.3396¢
Mid-Peak	16.1484¢	n/a
Off-Peak	8.0742¢	9.5597¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

APPLICABILITY (Continued)

6. Customer meets all applicable requirements detailed in the Company's Schedule 68, Interconnections to Customer Distributed Energy Resources.

7. Legacy Status for eligible Exporting Systems will terminate December 2045.

8. The Legacy Status of the Exporting System is transferrable to a subsequent Customer at the premises for which a valid on-site generation service is in effect. Each Customer of a Legacy System taking service under Schedule 6 will be responsible for complying with the terms and conditions of the on-site generation service in effect for that premises.

9. A Legacy System that is offline for over six (6) months or that is moved to a different site shall forfeit Legacy Status of the Exporting System.

10. To remain eligible for Legacy Status, a Customer may increase the capacity of a Legacy System by no more than 10 percent of the originally installed nameplate capacity, or 1 kW, whichever is greater, to allow for the replacement of broken or degraded components. If a Customer expands a Legacy System beyond these limits and wishes to maintain Legacy Status for the original system, the new portion of the DER shall be separately metered and would not qualify for Legacy Status.

11. A Customer with a Legacy System may elect to forfeit the system's Legacy Status by submitting the request to the Company in writing.

DEFINITIONS

Designated Meter is the retail meter physically connected to the Exporting System.

Distributed Energy Resource(s) (DER(s)) is a source of electric power that is not directly connected to the bulk power system. Any combination of Generation Facilities and/or Energy Storage Devices connected in Parallel is considered DER.

Energy Storage Device is a device that captures energy produced at a point in time and stores the energy for use as electricity at a future point in time. An Energy Storage Device is a DER.

Excess Net Energy means the positive difference between the kilowatt-hours (kWh) generated by a Customer and the kWh supplied by the Company over the applicable Billing Period.

Exported Energy means the kWh generated by a Customer in excess of the Customer's on-site consumption that is exported to the Company's system.

Exporting System is a Customer-owned DER under the terms of Schedules 6, 8, or 84, which is designed to provide for the transfer of electric energy to the Company. An Exporting System is interconnected to the Company's system under the applicable terms of Schedule 68.

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

DEFINITIONS (Continued)

Financial Credit represents the amount in dollars carried forward to offset Customer's Monthly Charges in a subsequent Billing Period. A Financial Credit is generated during a Billing Period when the product of Exported Energy and the Export Credit Rate exceeds a Customer Monthly Charges.

Generation Facility means all equipment used to generate electric energy where the resulting energy is delivered to the Company via a single meter at the Point of Delivery or is consumed by the Customer. A Generation Facility is a DER.

Interconnection Facilities are all facilities reasonably required by Prudent Electrical Practices and the applicable electric and safety codes to interconnect and safely deliver energy from the DER to the Point of Delivery.

Kilowatt Hour Credit ("kWh Credit") is the accumulated Excess Net Energy that is carried forward to offset energy usage in a subsequent Billing Period.

Legacy Status refers to the ability for a system to receive Net Energy Metering, including net monthly one-for-one kWh credit compensation for Excess Net Energy.

Legacy System means any system that meets the applicable criteria as described in Order Nos. 34509 and 34546.

Net Billing is the compensation structure applicable to all systems that do not meet the criteria of a Legacy System. Net Billing will be effective with each eligible customer's first billing cycle after January 1, 2024.

Net Energy Metering is the compensation structure applicable to all Legacy Systems.

Parallel connection means generating electricity from an on-site generation system that is connected to and receives voltage from Idaho Power's system.

Point of Delivery is the retail metering point where the Company's and the Customer's electrical facilities are interconnected to allow the Customer to take retail electric service from the Company.

Prudent Electrical Practices are those practices, methods and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

Schedule 68 is the Company's service schedule which provides for interconnection to DERs or its successor schedule(s) as approved by the Commission.

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

TYPE OF SERVICE

The type of service provided under this schedule is single phase, alternating current at approximately 120 or 240 volts and 60 cycles, supplied through one meter at one Point of Delivery. Upon request by the owner of multi-family dwellings, the Company may provide 120/208 volt service for multi-family dwellings when all equipment is U L approved to operate at 120/208 volts.

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions for Net Energy Metering under this schedule.

1. Balances of generation and usage by the Customer:

a. If electricity supplied by the Company during the Billing Period exceeds the electricity generated by the Customer and delivered to the Company during the Billing Period, the Customer shall be billed for the net electricity supplied by the Company at the rates contained within this schedule, in accordance with normal metering practices.

b. If electricity generated by the Customer and delivered to the Company during the Billing Period exceeds the electricity supplied by the Company during the Billing Period, the Excess Net Energy shall be carried forward as a kWh Credit to offset energy usage in a subsequent Billing Period. kWh Credits are subject to the following provisions:

i. kWh Credits can only be used to offset billed kWh consumption. Customers shall be billed for all applicable non-energy charges for the Billing Period according to the applicable standard service schedule.

ii. kWh Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

iii. kWh Credits are non-transferrable in the event that a Customer relocates and/or discontinues service at the Point of Delivery associated with the Exporting System. Any unused kWh Credits will expire at the time the final bill is prepared.

c. Compensation for the balance of generation and usage by the Customer is subject to change upon Commission approval.

2. Aggregation of meters for the annual transfer of unused Excess Net Energy credits:

a. If a balance of kWh Credits exists at a Designated Meter the Customer may request to transfer the unused kWh Credits to offset energy consumption at eligible meters. A meter is eligible for aggregation if it meets all of the following criteria:

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE (Continued)

i. The account subject to offset is held by the Customer; and

ii. The meter is located on, or contiguous to, the property on which the Designated Meter is located. For the purposes of this tariff, contiguous property includes property that is separated from the Premises of the Designated Meter by public or railroad rights of way; and

iii. The meter is served by the same primary feeder as the Designated Meter at the time the Customer files the application for the Exporting System; and

iv. The electricity recorded by the meter is for the Customer's requirements; and

v. kWh Credits may only be transferred to meters taking service under Schedule 1, Schedule 6, Schedule 7, or Schedule 8.

b. Customers may submit requests to transfer kWh Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power, on or before January 31. If a Customer does not request to transfer kWh Credits by the January 31 submission deadline kWh Credits will carry forward to offset consumption at the Designated Meter until they become eligible the following year.

c. Requests to transfer kWh Credits must be executed by the Company no later than March 31. Transfers will be based on the balance of kWh Credits available at the time the transfer is made.

d. If multiple meters are eligible for aggregation, kWh Credits must first be applied to the Designated Meter, then to eligible meters on rate schedules in accordance with Section 2a(v) above.

e. A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

NET BILLING – CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions for Net Billing under this schedule.

1. Balances of usage and exports by the Customer.

a. The Customer shall be billed for the electricity supplied by the Company at the rates contained within this schedule, in accordance with normal metering practices.

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

NET BILLING – CONDITIONS OF PURCHASE AND SALE (Continued)

b. The Customer shall be credited for Exported Energy at the applicable Export Credit Rate contained within this schedule as a credit in dollars to only offset Monthly Charges. Financial Credits are subject to the following provisions:

i. Financial Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

ii. Financial Credits are transferrable in the event that a Customer relocates. If the establishment of service at the new Point of Delivery is not initiated at the time service at the Designated Meter is discontinued, any unused Financial Credits will be paid out following the time the final bill is prepared.

2. Aggregation of meters for the annual transfer of unused credits:

a. If a balance of Financial Credits exists at a Designated Meter, the Customer may request to transfer the unused Financial Credits to eligible meters. A meter is eligible for aggregation if it meets the following criteria:

i. The account subject to offset is held by the Customer, and

ii. The electricity recorded by the meter is for the Customer's requirements.

b. Customers may submit requests to transfer a stated percentage of available Financial Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power, on or before January 31. If a Customer does not request to transfer Financial Credits by the January 31 submission deadline Financial Credits will carry forward at the Designated Meter until they become eligible for transfer the following year.

c. Requests to transfer Financial Credits must be executed by the Company no later than March 31. Transfers will be based on the balance of Financial Credits available at the time the transfer is made.

A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

The following rate structure and charges are subject to change upon Commission approval:

STANDARD RATES (DEFAULT)

	Summer	Non-summer
Service Charge, per month	$25.00	$25.00
Energy Charge, per kWh		
First 800 kWh	12.5685¢	9.9581¢
801-2000 kWh	13.7920¢	10.4567¢
All Additional kWh Over 2000	15.1580¢	11.0331¢

TIME-OF-USE RATES (OPTIONAL)

	Summer	Non-summer
Service Charge, per month	$25.00	$25.00
Energy Charge, per kWh		
On-Peak	32.2968¢	14.3396¢
Mid-Peak	16.1484¢	n/a
Off-Peak	8.0742¢	9.5597¢

EXPORT CREDIT RATE

The following rate structure and credits are subject to change upon Commission approval:

	Summer	Non-summer
Export Credit Rate, per kWh		
On-Peak	16.9966¢	4.8365¢
Off-Peak	5.6533¢	4.8365¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 7
SMALL GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-summer
Service Charge, per month	$30.00	$30.00
Energy Charge, per kWh		
First 300 kWh	8.8802¢	8.8802¢
All Additional kWh	10.1485¢	8.8827¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

APPLICABILITY (Continued)

4. Legacy Status for eligible Exporting Systems will terminate December 2045.

5. The Legacy Status of the Exporting System is transferable to a subsequent Customer at the premises for which a valid on-site generation service is in effect. Each Customer of a Legacy System taking service under Schedule 8 will be responsible for complying with the terms and conditions of the on-site generation service in effect for that premises.

6. A Legacy System that is offline for over six (6) months or that is moved to a different site shall forfeit Legacy Status of the Exporting System.

7. To remain eligible for Legacy Status, a Customer may increase the capacity of a Legacy System by no more than 10 percent of the originally installed nameplate capacity, or 1 kW, whichever is greater, to allow for the replacement of broken or degraded components. If a Customer expands a Legacy System beyond these limits and wishes to maintain Legacy Status for the original System, the new portion of the DER shall be separately metered and would not qualify for Legacy Status.

8. A Customer with Legacy System may elect to forfeit the system's Legacy Status by submitting the request to the Company in writing.

DEFINITIONS

Designated Meter is the retail meter physically connected to the Exporting System.

Distributed Energy Resource(s) (DER(s)) is a source of electric power that is not directly connected to the bulk power system. Any combination of Generation Facilities and/or Energy Storage Devices connected in Parallel is considered a DER.

Energy Storage Device is a device that captures energy produced at a point in time and stores the energy for use as electricity at a future point in time. An Energy Storage Device is a DER.

Excess Net Energy means the positive difference between the kilowatt-hours (kWh) generated by a Customer and the kWh supplied by the Company over the applicable Billing Period.

Exported Energy means the kWh generated by a Customer in excess of the Customer's on-site consumption that is exported to the Company's system.

Exporting System is a Customer-owned DER under the terms of Schedules 6, 8, or 84, which is designed to provide for the transfer of electricity energy to the Company. An Exporting System is interconnected to the Company's system under the applicable terms of Schedule 68.

Financial Credit represents the amount in dollars carried forward to offset Monthly Charges in a subsequent Billing Period. A Financial Credit is generated during a Billing Period when the product of Exported Energy and the Export Credit Rate exceeds a Customer's Monthly Charges.

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

DEFINITIONS (Continued)

Generation Facility means all equipment used to generate electric energy where the resulting energy is either delivered to the Company via a single meter at the Point of Delivery or is consumed by the Customer. A Generation Facility is a DER.

Interconnection Facilities are all facilities reasonably required by Prudent Electrical Practices and the applicable electric and safety codes to interconnect and safely deliver energy from the DER to the Point of Delivery.

Kilowatt Hour Credit (“kWh Credit”) is the accumulated Excess Net Energy that is carried forward to offset energy usage in a subsequent Billing Period.

Legacy Status refers to the ability for a system to receive Net Energy Metering, including net monthly one-for-one kWh credit compensation for Excess Net Energy.

Legacy System means for any system that meets the applicable criteria as described in Order No. 34509 and 34546.

Net Billing is the compensation structure applicable to all systems that do not meet the criteria of a Legacy System. Net Billing will be effective with each eligible customer’s first billing cycle after January 1, 2024.

Net Energy Metering is the compensation structure applicable to all Legacy Systems.

Parallel connection means generating electricity from an on-site generation system that is connected to and receives voltage from Idaho Power’s system.

Point of Delivery is the retail metering point where the Company's and the Customer’s electrical facilities are interconnected to allow the Customer to take retail electric service from the Company.

Prudent Electrical Practices are those practices, methods, and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

Schedule 68 is the Company’s service schedule which provides for interconnection to DERs or its successor schedule(s) as approved by the Commission.

TYPE OF SERVICE

The type of service provided under this schedule is single and/or three-phase alternating current, at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions for Net Energy Metering under this schedule.

1. Balances of generation and usage by the Customer:

a. If electricity supplied by the Company during the Billing Period exceeds the electricity generated by the Customer and delivered to the Company during the Billing Period, the Customer shall be billed for the net electricity supplied by the Company at the rates contained within this schedule, in accordance with normal metering practices.

b. If electricity generated by the Customer and delivered to the Company during the Billing Period exceeds the electricity supplied by the Company during the Billing Period, the Excess Net Energy shall be carried forward as a kWh Credit to offset energy usage in a subsequent Billing Period. kWh Credits are subject to the following provisions:

i. kWh Credits can only be used to offset billed kWh consumption. Customers shall be billed for all applicable non-energy charges for the Billing Period according to the applicable standard service schedule.

ii. kWh Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

iii. kWh Credits are non-transferrable in the event that a Customer relocates and/or discontinues service at the Point of Delivery associated with the Exporting System. Any unused kWh Credits will expire at the time the final bill is prepared.

c. Compensation for the balance of generation and usage by the Customer is subject to change upon Commission approval.

2. Aggregation of meters for the annual transfer of unused kWh credits:

a. If a balance of kWh Credits exists at a Designated Meter, the Customer may request to transfer the unused kWh Credits to offset energy consumption at eligible meters. A meter is eligible for aggregation if it meets all of the following criteria:

i. The account subject to offset is held by the Customer; and

ii. The meter is located on, or contiguous to, the property on which the Designated Meter is located. For the purposes of this tariff, contiguous property includes property that is separated from the Premises of the Designated Meter by public or railroad rights of way; and

iii. The meter is served by the same primary feeder as the Designated Meter at the time the Customer files the application for the Exporting System; and

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE (Continued)

iv. The electricity recorded by the meter is for the Customer's requirements; and

v. kWh Credits may only be transferred to meters taking service under Schedule 1, Schedule 6, Schedule 7, or Schedule 8.

b. Customers may submit requests to transfer kWh Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power on or before January 31. If a Customer does not request to transfer kWh Credits by the January 31 submission deadline kWh Credits will carry forward to offset consumption at the Designated Meter until they become eligible for transfer the following year.

c. Requests to transfer kWh Credits must be executed by the Company no later than March 31. Transfers will be based on the balance of kWh Credits available at the time the transfer is made.

d. If multiple meters are eligible for aggregation, kWh Credits must first be applied to the Designated Meter, then to eligible meters on rate schedules in accordance with Section 2a(v) above.

e. A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

NET BILLING – CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions for Net Billing under the Schedule.

1. Balances of usage and exports by the Customer.

a. The Customer shall be billed for the electricity supplied by the Company at the rates contained within this schedule, in accordance with normal metering practices.

b. The Customer shall be credited for Exported Energy at the applicable Export Credit Rate contained within this schedule as a credit in dollars to only offset Monthly Charges. Financial Credits are subject to the following provisions:

i. Financial Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

ii. Financial Credits are transferrable in the event that a Customer relocates. If the establishment of service at the new Point of Delivery is not initiated at the time service at the Designated Meter is discontinued, any unused Financial Credits will be paid out following the time the final bill is prepared.

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

NET BILLING – CONDITIONS OF PURCHASE AND SALE (Continued)

2. Aggregation of meters for the annual transfer of unused Financial Credits:

a. If a balance of Financial Credits exists at a Designated Meter, the Customer may request to transfer the unused Financial Credits to eligible meters. A meter is eligible for aggregation if it meets the following criteria:

i. The account subject to offset is held by the Customer, and

ii. The electricity recorded by the meter is for the Customer's requirements.

b. Customers may submit requests to transfer a stated percentage of available Financial Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power on or before January 31. If a Customer does not request to transfer Financial Credits by the January 31 submission deadline Financial Credits will carry forward at the Designated Meter until they become eligible for transfer the following year.

c. Requests to transfer Financial Credits must be executed by the Company no later than March 31. Transfers will be based on the balance of Financial Credits available at the time the transfer is made.

d. A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

NET ENERGY METERING & NET BILLING – GENERAL CONDITIONS

1. The Customer shall never deliver or attempt to deliver energy to the Company's system when the Company's system serving the Customer's DER is de-energized for any reason.

2. The Company shall not be liable directly or indirectly for permitting or continuing to allow an attachment of an Exporting System to the Company's system, or for the acts or omissions of the Customer that cause loss or injury, including death, to any third party.

3. The Customer is responsible for all costs associated with the DER and Interconnection Facilities. The Customer is also responsible for all costs associated with any Company additions, modifications, or upgrades to any Company facilities that the Company determines are necessary as a result of the installation of the DER in order to maintain a safe, reliable electrical system.

4. The Company shall not be obligated to accept, and the Company may require the Customer to curtail, interrupt, or reduce deliveries of energy if the Company, consistent with Prudent Electrical Practices, determines that curtailment, interruption, or reduction is necessary because of line construction or maintenance requirements, emergencies, or other critical operating conditions on its system.

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION

NET ENERGY METERING & NET BILLING – GENERAL CONDITONS (Continued)

5. If the Company is required by the Commission to institute curtailment of deliveries of electricity to its customers, the Company may require the Customer to curtail its consumption of electricity in the same manner and to the same degree as other Customers on the Company's standard service schedules.

6. The Customer shall grant to the Company all access to all Company equipment and facilities including adequate and continuing access rights to the property of the Customer for the purpose of installation, operation, maintenance, replacement, or any other service required of said equipment as well as all necessary access for inspection, switching, and any other operational requirements of the Customer's Interconnections Facilities.

7. The Customer shall notify the Company immediately if an Exporting System is permanently removed or disabled. Permanent removal or disablement for the purposes of this Schedule is any removal or disablement of an Exporting System lasting longer than six (6) months. Customers with permanently removed or disabled systems will be removed from service under this schedule and placed on the appropriate standard service schedule.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.

TIME PERIODS – EXPORT CREDIT RATE

The time periods for the Export Credit Rate are defined as follows. All times are stated in Mountain Time.

Summer Season

On-Peak:	3:00 p.m. to 11:00 p.m. Monday through Saturday, except holidays
Off-Peak	11:00 p.m. to 3:00 p.m. Monday through Saturday and all hours on Sunday and holidays

Non-summer Season

Off-Peak:	All hours Monday through Sunday

Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If New Year's Day, Independence Day, or Christmas Day falls on Sunday, the following Monday will be designated a holiday.

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

The following charges are subject to change upon Commission approval:

	Summer	Non-summer
Service Charge, per month	$30.00	$30.00
Energy Charge, per kWh		
First 300 kWh	8.8802¢	8.8802¢
All Additional kWh	10.1485¢	8.8827¢

EXPORT CREDIT RATE

The following rate structure and credits are subject to change upon Commission approval:

	Summer	Non-summer
Export Credit Rate, per kWh		
On-Peak	16.9966¢	4.8365¢
Off-Peak	5.6533¢	4.8365¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE – STANDARD RATES (DEFAULT)	Summer	Non-summer
Service Charge, per month	$30.00	$30.00
Basic Charge, per kW of Basic Load Capacity		
Basic Load Capacity	$2.03	$2.03
Demand Charge, per kW of Billing Demand		
Billing Demand	$10.14	$8.16
Energy Charge, per kWh		
All kWh	5.4088¢	5.3804¢

SECONDARY SERVICE – TIME-OF-USE (OPTIONAL)	Summer	Non-summer
Service Charge, per month	$30.00	$30.00
Basic Charge, per kW of Basic Load Capacity		
Basic Load Capacity	$2.03	$2.03
Demand Charge, per kW of Billing Demand		
Billing Demand	$10.14	$8.16
Energy Charge, per kWh		
On-Peak	7.1725¢	5.9560¢
Mid-Peak	6.0348¢	5.4608¢
Off-Peak	4.8568¢	5.1083¢

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$360.00	$360.00
Basic Charge, per kW of Basic Load Capacity	$2.22	$2.22
Demand Charge, per kW of Billing Demand	$11.04	$9.91
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.10	n/a
Energy Charge, per kWh		
On-Peak	6.6710¢	5.4064¢
Mid-Peak	5.5532¢	4.9269¢
Off-Peak	4.3957¢	4.5854¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$360.00	$360.00
Basic Charge, per kW of Basic Load Capacity	$0.96	$0.96
Demand Charge, per kW of Billing Demand	$8.63	$8.44
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.10	n/a
Energy Charge, per kWh		
On-Peak	6.8460¢	5.4073¢
Mid-Peak	5.6891¢	4.9282¢
Off-Peak	4.4914¢	4.5870¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 15
DUSK TO DAWN CUSTOMER
LIGHTING
(Continued)

NEW FACILITIES

Where facilities of the Company are not presently available for a lighting fixture installation which will provide satisfactory lighting service for the Customer's Premises, the Company may install overhead or underground secondary service facilities, including secondary conductor, poles, anchors, etc., a distance not to exceed 300 feet to supply the desired service, all in accordance with the charges specified below.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

1. Monthly Per Unit Charge on existing facilities:

AREA LIGHTING

LED Fixture		
Watt (Maximum)	Lumen (Minimum)	Base Rate
40	3,600	$11.17
85	7,200	$11.89
200	18,000	$14.73

FLOOD LIGHTING

LED Fixture		
Watt (Maximum)	Lumen (Minimum)	Base Rate
85	8,100	$16.49
150	18,000	$17.43
300	32,000	$23.01

2. For New Facilities Installed Before June 1, 2004: The Monthly Charge for New Facilities installed prior to June 1, 2004, will continue to be assessed a monthly facilities charge in accordance with the changes specified in Schedule 66.

3. For New Facilities Installed On or After June 1, 2004: The non-refundable charge for New Facilities to be installed, such as underground service, overhead secondary conductor, poles, anchors, etc., shall be equal to the work order cost.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

FACILITIES BEYOND THE POINT OF DELIVERY

At the Customer's request and at the option of the Company, transformers and other facilities installed beyond the Point of Delivery to provide Primary or Transmission Service may be owned, operated, and maintained by the Company in consideration of the Customer paying a Facilities Charge to the Company. This service is provided under the provisions set forth in Rule M, Facilities Charge Service.

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.

TEMPORARY SUSPENSION

When a Customer has properly invoked Rule G, Temporary Suspension of Demand, the Basic Load Capacity, the Billing Demand, and the On-Peak Billing Demand shall be prorated based on the period of such suspension in accordance with Rule G. In the event the Customer's metered demand is less than 1,000 kW during the period of such suspension, the Basic Load Capacity and Billing Demand will be set equal to 1,000 kW for purposes of determining the Customer's Monthly Charge.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), and Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities).

SECONDARY SERVICE	Summer	Non-summer
Service Charge, per month	$125.00	$125.00
Basic Charge, per kW of Basic Load Capacity	$2.47	$2.47
Demand Charge, per kW of Billing Demand	$13.99	$12.01
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.42	n/a
Energy Charge, per kWh		
On-Peak	7.3300¢	6.0834¢
Mid-Peak	6.2088¢	5.5984¢
Off-Peak	5.0473¢	5.2530¢

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$490.00	$490.00
Basic Charge, per kW of Basic Load Capacity	$2.60	$2.60
Demand Charge, per kW of Billing Demand	$13.09	$11.93
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.07	n/a
Energy Charge, per kWh		
On-Peak	6.6358¢	5.3897¢
Mid-Peak	5.5115¢	4.9044¢
Off-Peak	4.3474¢	4.5589¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$490.00	$490.00
Basic Charge, per kW of Basic Load Capacity	$1.72	$1.72
Demand Charge, per kW of Billing Demand	$14.18	$12.42
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.07	n/a
Energy Charge, per kWh		
On-Peak	6.7062¢	5.3955¢
Mid-Peak	5.5665¢	4.9099¢
Off-Peak	4.3865¢	4.5641¢

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

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SCHEDULE 19
LARGE POWER SERVICE
(Continued)

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SCHEDULE 19
LARGE POWER SERVICE
(Continued)

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SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Large General Service Rates

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$360.00	$360.00
Basic Charge, per kW of Basic Load Capacity	$2.22	$2.22
Demand Charge, per kW of Billing Demand	$11.63	$10.50
Energy Charge, per kWh		
On-Peak	8.8053¢	7.1428¢
Mid-Peak	7.2879¢	5.9451¢
Off-Peak	4.8476¢	5.2583¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$360.00	$360.00
Basic Charge, per kW of Basic Load Capacity	$0.96	$0.96
Demand Charge, per kW of Billing Demand	$9.22	$9.03
Energy Charge, per kWh		
On-Peak	8.9803¢	7.1437¢
Mid-Peak	7.4238¢	5.9464¢
Off-Peak	4.9433¢	5.2599¢

SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD
(Continued)

MONTHLY CHARGE (Continued)

Large Power Service Rates

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$490.00	$490.00
Basic Charge, per kW of Basic Load Capacity	$2.60	$2.60
Demand Charge, per kW of Billing Demand	$13.72	$12.56
Energy Charge, per kWh		
On-Peak	8.7365¢	7.0925¢
Mid-Peak	7.2126¢	5.8890¢
Off-Peak	4.7657¢	5.1982¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$490.00	$490.00
Basic Charge, per kW of Basic Load Capacity	$1.72	$1.72
Demand Charge, per kW of Billing Demand	$14.81	$13.05
Energy Charge, per kWh		
On-Peak	8.8069¢	7.0983¢
Mid-Peak	7.2676¢	5.8945¢
Off-Peak	4.8048¢	5.2034¢

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD
(Continued)

INTERRUPTION COMPENSATION

Fixed Capacity Reduction Rate:

Large General Service Rates	**$0.0455 per kilowatt of reduction per event hour**
Large Power Service Rates	**$0.0460 per kilowatt of reduction per event hour**

DEFINITIONS

Actual kW Reduction. The kilowatt (kW) reduction during an Interruption Event, which is the difference between a Participant's hourly average kW measured at the Facility Site's meter and the corresponding hour of the Adjusted Baseline kW.

Adjusted Baseline kW. The Original Baseline kW plus or minus the "Day of" Load Adjustment amount.

"Day of" Load Adjustment. The difference between the Original Baseline kW and the actual metered kW during the hour prior to the Participant receiving notification of an event. Scalar values will be calculated by dividing the Original Baseline kW for each Interruption Event hour by the Baseline kW of the hour preceding the event notification time. The scalars are multiplied by the actual event day kW for the hour preceding the event notification time to create the Adjusted Baseline kW from which load reduction is measured. The Adjusted Baseline kW for each hour will be capped at 120% of the maximum kW amount for any hour from the Highest Energy Use Days or the hours during the event day prior to event notification.

Facility Site(s). All of a Participant's facility or equipment that is metered from a single service location that a Participant has taken service under Schedule 20.

Highest Energy Usage Days. The three days out of the immediate past 10 non-event Business Days that have the highest sum total kW as measured across the Interruption Event daily parameters.

Interruption Compensation. The Actual kW Reduction for each hour multiplied by the Fixed Capacity Reduction Rate. Participants are paid based on the average event kilowatt reduction.

Load Control Device. Refers to any technology, device, or system utilized under Schedule 20 to enable the Company to initiate the Interruption Event.

Interruption Event. Refers to an event where the Company requests or calls for interruption of specific loads with the use of one or more Load Control Devices.

Original Baseline kW. The arithmetic mean (average) kW of the Highest Energy Usage Days during the Interruption Event daily parameters, calculated for each Facility Site for each hour.

SCHEDULE 24
AGRICULTURAL IRRIGATION
SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Idaho for loads up to 20,000 kW where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served, and additional investment by the Company for new transmission, substation or terminal facilities is not necessary to supply the desired service. If the aggregate power requirement of a Customer who receives service at one or more Points of Delivery on the same Premises exceeds 20,000 kW, special contract arrangements will be required.

APPLICABILITY

Service under this schedule is applicable to power and energy supplied to agricultural use customers operating water pumping or water delivery systems used to irrigate agricultural crops or pasturage at one Point of Delivery and through one meter. Water pumping or water delivery systems include, but are not limited to, irrigation pumps, pivots, fertilizer pumps, drainage pumps, linears, and wheel lines.

TYPE OF SERVICE

The type of service provided under this schedule is single- and/or three-phase, alternating current, at approximately 60 cycles and at the standard voltage available at the Premises to be served.

DEFINITIONS

Cumulative Past Due Balance. The Cumulative Past Due Balance is calculated as the sum of all Schedule 24 past due account balances for which the Customer is financially responsible.

New Irrigation Customer. A New Irrigation Customer is a Customer who, within the previous four years, has not received Schedule 24 service in the Customer's name or has not been financially responsible for an existing Schedule 24 service, or has received Schedule 24 service in the Customer's name for less than three full billing cycles during an Irrigation Season.

Irrigation Season. The Irrigation Season begins on June 1 of each year and ends on September 30 of each year.

SERVICE CONNECTION AND DISCONNECTION

The Company will routinely keep service connected throughout the calendar year unless the Customer requests disconnection. Customer requested service disconnections will be made at no charge during the Company's normal business hours. The Company's termination practices as specified under Rule F will continue to apply with the exception that service terminations will not be made during the Irrigation Season.

SCHEDULE 24
AGRICULTURAL IRRIGATION
SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blain County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	In-Season	Out-of-Season
Service Charge, per month	$35.00	$9.00
Demand Charge, per kW of Billing Demand	$18.75	n/a
Energy Charge All kWh	7.4279¢	8.2558¢

TRANSMISSION SERVICE	In-Season	Out-of-Season
Service Charge, per month	$490.00	$9.00
Demand Charge, per kW of Billing Demand	$17.33	n/a
Energy Charge All kWh	6.9715¢	7.7172¢

SCHEDULE 24
AGRICULTURAL IRRIGATION
SERVICE
(Continued)

MONTHLY CHARGE (Continued)

Minimum Charge
The monthly Minimum Charge shall be the sum of the Service Charge, the Demand Charge, the Energy Charge, the Power Cost Adjustment, and the Facilities Charge.

PAYMENT

All monthly billings for Electric Service supplied hereunder are payable upon receipt and become past due 15 days from the date on which rendered. (For any agency or taxing district which has notified the Company in writing that it falls within the provisions of Idaho Code § 67–2302, the past due date will reflect the 60-day payment period provided by Idaho Code § 67–2302.)

Deposit. A deposit payment for Schedule 24 Customers is required under the following conditions:

1. Existing Customers.

a. Tier 1 Deposit. A Tier 1 Deposit will be required from Customers who (1) have received two or more reminder notices for nonpayment during the most recent 12-month period during which service was received, when the annual total billed amount on the Schedule 24 account(s) that received the reminder notices is greater than 15 percent of the total annual billed amount on all Schedule 24 account(s), (2) have had service terminated for nonpayment during the last four years and have not subsequently received Schedule 24 service, or (3) were required to pay a Tier 2 Deposit for the previous Irrigation Season. A Tier 1 Deposit may be satisfied by a guarantee of payment from a bank or financial institution acceptable to the Company. A reminder notice is issued approximately 45 days after the bill issue date if the balance owing for Electric Service totals $100 or more or approximately 105 days after the bill issue date for Customers meeting the provisions of Idaho Code § 67–2302. A Customer with at least one Schedule 24 account that meets the requirements for payment of a Tier 1 Deposit will be required to pay a Tier 1 Deposit on all Schedule 24 accounts for which the Customer is financially responsible and requesting Schedule 24 service. A Tier 1 Deposit does not apply to Customers who have a Cumulative Past Due Balance on December 31 equal to or greater than $1,500 (See Tier 2 Deposit). The deposit for each metered service point is computed as follows:

(1) Monthly Billing Demand is determined by multiplying 80 percent times the connected horsepower.

(2) Monthly Energy (billing kWh) is determined by multiplying 50 percent times 720 hours times the Monthly Billing Demand.

(3) The Monthly Billing Demand and the Monthly Energy are multiplied by the current In-Season rates and added to the Irrigation In-Season Service Charge to determine the estimated monthly bill.

(4) The estimated monthly bill is multiplied by a factor of one and one-half (1.5).

SCHEDULE 24
AGRICULTURAL IRRIGATION
SERVICE
(Continued)

PAYMENT (Continued)

b. Tier 2 Deposit. Customers with a Cumulative Past Due Balance equal to or greater than $1,500 when the average of the Cumulative Past Due Balance is equal to or greater than $750 per service point, or when the Cumulative Past Due Balance is equal to or greater than $10,000 on December 31 will be required to pay a Tier 2 Deposit on all Schedule 24 accounts for which the Customer is financially responsible and requesting Schedule 24 service. A Tier 2 Deposit will also be required from Customers who have had a Tier 2 Deposit during any of the previous four years and who have not subsequently had active Schedule 24 service. The Company will allow payments for past due balances to be received up to five (5) days after December 31, without requiring a Tier 2 Deposit. A Tier 2 Deposit may be satisfied by a guarantee of payment from a bank or financial institution acceptable to the Company. The deposit for each metered service point is computed as follows:

(1) Monthly Billing Demand is determined by multiplying 80 percent times the connected horsepower.

(2) Monthly Energy (billing kWh) is determined by multiplying 50 percent times 720 hours times the Monthly Billing Demand.

(3) The Monthly Billing Demand and the Monthly Energy are multiplied by the current In-Season rates and added to the Irrigation In-Season Service Charge to determine the estimated monthly bill.

(4) The estimated monthly bill is multiplied by a factor of four (4).

2. New Irrigation Customers. A Tier 1 Deposit will be required from a New Irrigation Customer unless the New Irrigation Customer had a Cumulative Past Due Balance equal to or greater than $1,500 on December 31 during any of the previous four years and has not subsequently had Schedule 24 service, in which case a Tier 2 Deposit will be required. The deposit for each metered service point will be computed using the same methodology as outlined for existing Customers requiring a Tier 1 or Tier 2 Deposit. A Tier 1 or Tier 2 Deposit for New Irrigation Customers may be satisfied by a guarantee of payment from a bank or financial institution acceptable to the Company.

3. Bankruptcy or Receivership. An adequate assurance of payment as agreed to by the Company or as ordered by a court of competent jurisdiction or the Commission shall be required from any Customer for whom an order for relief has been entered under the federal bankruptcy laws, or for whom a receiver has been appointed in a court proceeding. As a condition of service, an adequate assurance of payment equal to a Tier 2 Deposit shall be required. This requirement shall continue from the date of the order for relief in bankruptcy, or the court appointing a receiver, until the dismissal of the bankruptcy, or the dismissal of the court proceeding, or until the bankruptcy plan has been completed.

A Customer who has been discharged from bankruptcy, a Customer whose receivership proceeding has been terminated, or a Customer whose bankruptcy proceedings have been dismissed will be required to pay an amount equal to a Tier 2 Deposit at the start of the Irrigation Season.

SCHEDULE 26
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
MICRON TECHNOLOGY, INC.
BOISE, IDAHO

SPECIAL CONTRACT DATED MARCH 9, 2022, AMENDED APRIL 11, 2024

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees). Terms used below have the meanings given to them in the Special Contract referenced above.

Monthly Contract Demand Charge
$3.12 per kW of Contract Demand.

Monthly Billing Demand Charge
$23.35 per kW of Billing Demand but not less than Minimum Monthly Billing Demand.

Minimum Monthly Billing Demand
The Minimum Monthly Billing Demand will be 25,000 kilowatts.

Daily Excess Demand Charge
$1.248 per each kW over the Contract Demand.

Monthly Energy Charge
2.7585¢ per kWh.

Embedded Energy Fixed Cost Charge
0.0000¢ per kWh of Renewable Resource On-Site Usage

Monthly Adjusted Renewable Capacity Credit(s)
See Table Nos.1, 2, 3, and Second Revised Exhibit 1 of Micron's Special Contract, dated March 9, 2022, as amended.

Renewable Resource Cost
As defined in Second Revised Exhibit 1 of Micron's Special Contract, dated March 9, 2022, as amended.

Excess Generation Credit
As defined in Second Revised Exhibit 1 of Micron's Special Contract, dated March 9, 2022, as amended.

Administrative Charge
As defined in Second Revised Exhibit 1 of Micron's Special Contract, dated March 9, 2022, as amended.

Pricing elements that rely on the most recently filed IRP are effective December 1, 2024, pursuant to Order No. 36383 issued on November 8, 2024.

SCHEDULE 29
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
J. R. SIMPLOT COMPANY
POCATELLO, IDAHO

SPECIAL CONTRACT DATED JUNE 29, 2004

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Contract Demand Charge
$3.12 per kW of Contract Demand

Demand Charge,
$18.55 per kW of Billing Demand but no less than the Contract Demand less 5,000 kW

Daily Excess Demand Charge
$1.248 per each kW over the Contract Demand

Energy Charge
3.0782¢ per kWh

Monthly Facilities Charge
Facilities installed beyond the Point of Delivery will be subject to the provisions of Rule M, Facilities Charge Service.

SCHEDULE 30
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
UNITED STATES DEPARTMENT OF ENERGY
IDAHO OPERATIONS OFFICE

SPECIAL CONTRACT DATED SEPTEMBER 15, 2021
CONTRACT NO. 47PA0420D0011

AVAILABILITY

This schedule is available for firm retail service of electric power and energy delivered for the operations of the Department of Energy's facilities located at the Idaho National Engineering Laboratory site, as provided in the Contract for Electric Service between the parties.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

1. Demand Charge, per kW of Billing Demand	$19.80
2. Energy Charge, per kWh	3.0664¢

SPECIAL CONDITIONS

1. Billing Demand. The Billing Demand shall be the average kW supplied during the 30-minute period of maximum use during the month.

2. Power Factor Adjustment. When the Power Factor is less than 95 percent during the 30-minute period of maximum load for the month, Company may adjust the measured Demand to determine the Billing Demand by multiplying the measured kW of Demand by 0.95 and dividing by the actual Power Factor.

MONTHLY ANTELOPE ASSET CHARGE (“AAC”)

The AAC will be paid for the Company’s investment in, and operation and maintenance expenses associated with, specified transmission facilities required to provide service under the contract.

The Monthly AAC consists of two components:

1. PacifiCorp Pass-Through Charge (PPTC):

PPTC = (O&M x GAV) + (CEC)

SCHEDULE 31
IDAHO POWER COMPANY
AGREEMENT FOR SUPPLY OF
STANDBY ELECTRIC SERVICE
FOR
THE AMALGAMATED SUGAR COMPANY

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Standby Contract Demand Charge, per kW of	
Standby Contract Demand	$3.12
Standby Facilities Contract Demand Charge	
Per kW of Standby Facilities Contract Demand:	
Paul Facility:	$3.25
Nampa Facility:	$3.28
Twin Falls Facility:	$2.93
Standby Billing Demand Charge, per kW of	
Standby Billing Demand	$5.63

Excess Demand Charge
$1.248 per day for each kW taken in excess of the Total Contract Demand.

Energy Charge Energy taken with Standby Demand will be priced at the applicable Schedule 19 Energy Charge.

SCHEDULE 32
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
J. R. SIMPLOT COMPANY
CALDWELL, IDAHO

SPECIAL CONTRACT DATED APRIL 8, 2015

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

	Summer	Non-Summer
Contract Demand Charge		
per kW of Contract Demand	$3.12	$3.12
Demand Charge		
per kW of Billing Demand but no less than the Contract Demand less 10,000 kW	$23.99	$20.39
Daily Excess Demand Charge		
per each kW over the Contract Demand	$1.248	$1.248
Energy Charge		
per kWh	3.1464¢	3.1073¢

Monthly Facilities Charge

Facilities installed beyond the Point of Delivery will be subject to the provisions of Rule M, Facilities Charge Service.

SCHEDULE 33
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
BRISBIE, LLC.
(Continued)

TIME PERIODS (Continued)

The holidays observed by the Company are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day, Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). When New Year's Day, Independence Day, or Christmas Day falls on a Sunday, the Monday immediately following that Sunday will be considered a holiday.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

	Summer	Non-summer
Service Charge, per month	$490.00	$490.00
Basic Charge, per kW of Basic Load Capacity	$1.72	$1.72
Demand Charge, per kW of Billing Demand	$14.18	$12.42
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.07	n/a
Energy Charge, per kWh		
On-Peak	6.7062¢	5.3955¢
Mid-Peak	5.5665¢	4.9099¢
Off-Peak	4.3865¢	4.5641¢
Embedded Energy Fixed Cost Rate, per kWh		
On-Peak	1.7022¢	1.6774¢
Mid-Peak	1.7022¢	1.6744¢
Off-Peak	1.7022¢	1.6774¢

SCHEDULE 33
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
BRISBIE, LLC.
(Continued)

BLOCK 2

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees). Terms used below have the meanings given to them in the Special Contract referenced above.

Daily Excess Demand Charge
$1.248 per each kW over the Contract Demand.

Excess Generation Credit
As defined in Second Revised Exhibit 3.1 of Brisbie, LLC's Special Contract, December 22, 2021 as amended.

Monthly Contract Demand Charge
$3.12 per kW of Contract Demand.

Monthly Billing Demand Charge
$22.29 per kW of Billing Demand but not less than Minimum Monthly Billing Demand.

Minimum Monthly Billing Demand
The Minimum Monthly Billing Demand will be 20,000 kilowatts.

Monthly Adjusted Renewable Capacity Credit(s)
See Table Nos. 1, 2, 3, and Second Revised Exhibit 3.1 of Brisbie, LLC's Special Contract, dated December 22, 2021, as amended.

Renewable Resource Cost
As included in the Monthly Contract Payment listed in Second Revised Exhibit 3.1 of Brisbie, LLC's Special Contract, December 22, 2021, as amended.

Supplemental Energy Cost
As defined in Second Revised Exhibit 3.1 of Brisbie, LLC's Special Contract, December 22, 2021, as amended.

Administrative Charge
As defined in Second Revised Exhibit 3.1 of Brisbie, LLC's Special Contract, December 22, 2021, as amended.

Pricing elements that rely on the most recently filed IRP are effective December 1, 2024, pursuant to Order No. 36383 issued on November 8, 2024.

SCHEDULE 34
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
LAMB WESTON, INC.
(Continued)

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

	Summer	Non-summer
Service Charge, per month	$490.00	$490.00
Basic Charge, per kW of Basic Load Capacity	$2.60	$2.60
Demand Charge, per kW of Billing Demand	$13.09	$11.93
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.07	n/a
Energy Charge, per kWh		
On-Peak	6.6358¢	5.3897¢
Mid-Peak	5.5115¢	4.9044¢
Off-Peak	4.3474¢	4.5589¢

SCHEDULE 34
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
LAMB WESTON, INC.
(Continued)

BLOCK 2

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Daily Excess Demand Charge
$1.248 per each kW over the Contract Demand.

Monthly Contract Demand Charge
$3.12 per kW of Contract Demand.

Monthly Billing Demand Charge
$9.00 per kW of Billing Demand but not less than Minimum Monthly Billing Demand.

Energy Charge
4.689¢ per kWh of Block 2 Energy.

Minimum Monthly Billing Demand
The Minimum Monthly Billing Demand will be 20,000 kilowatts.

SCHEDULE 40
NON-METERED GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The average monthly kWh of energy usage shall be estimated by the Company, based on the Customer's electric equipment and one-twelfth of the annual hours of operation thereof. Since the service provided is non-metered, failure of the Customer's equipment will not be reason for a reduction in the Monthly Charge. The Monthly Charge shall be computed at the following rate, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Energy Charge, per kWh	11.1557¢
Minimum Charge, per month	$2.00

ADDITIONAL CHARGES

Applicable only to municipalities or agencies of federal, state, or county governments with an authorized Point of Delivery having the potential of intermittent variations in energy usage.

Intermittent Usage Charge, per unit, per month	$2.50

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

SERVICE OPTIONS (Continued)

"A" - Idaho Power-Owned, Idaho Power-Maintained System (Continued)

Monthly Charges

The monthly charges are as follows, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Charges, per fixture (41A)

LED Fixture		
Watt (Maximum)	Lumen (Minimum)	Base Rate
40	3,600	$15.98
85	7,200	$17.29
140	10,800	$18.82
200	18,000	$21.93

Non-Metered Service – Variable Energy

Energy Charge, per kWh 11.1557¢

Pole Charges

For Company-owned poles installed after October 5,1964 required to be used for street lighting only:

	Charge
Wood pole, per pole	$1.81
Steel pole, per pole	$7.18

Facilities Charges

Customers assessed a monthly facilities charge prior to June 1, 2004 will continue to be assessed a monthly facilities charge in accordance with the charges specified in Schedule 66.

Payment

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

"B" – Customer-Owned, Idaho Power-Maintained System – Discontinued

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

SERVICE OPTIONS (Continued)

"C" - Customer-Owned, Customer-Maintained System

The Customer's lighting system, including posts or standards, fixtures, initial installation of fixtures and underground cables with suitable terminals for connection to the Company's distribution system, is installed, owned, and maintained by the Customer. The Customer is responsible for notifying the Company of any changes or additions to the lighting equipment or loads being served under Option C – Non-Metered Service. Failure to notify the Company of such changes or additions will result in the termination of non-metered service under Option C and the requirement that service be provided under Option C - Metered Service.

All new Customer-owned lighting systems installed outside of Subdivisions on or after January 1, 2012 are required to be metered in order to record actual energy usage.

Customer-owned systems installed prior to June 1, 2004 that are constructed, operated, or modified in such a way as to allow for the potential or actual variation in energy usage may have the estimated annual variations in energy usage charged the Non-Metered Service - Energy Charge until the street lighting system is converted to Metered Service, or until the potential for variations in energy usage has been eliminated, whichever is sooner.

Monthly Charges

The monthly charges are as follows, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees). For non-metered service, the average monthly kWh of energy usage shall be estimated by the Company based on the total wattage of the Customer’s lighting system and 4,059 hours of operation.

Non-Metered Service (41C)

Energy Charge, per kWh	4.3291¢

Metered Service (41CM)

Service Charge, per meter	$1.84
Energy Charge, per kWh	4.3291¢

SCHEDULE 42
TRAFFIC CONTROL SIGNAL
LIGHTING SERVICE

APPLICABILITY

Service under this schedule is applicable to Electric Service required for the operation of traffic control signal lights within the State of Idaho. Traffic control signal lamps are mounted on posts or standards by means of brackets, mast arms, or cable.

CHARACTER OF SERVICE

The traffic control signal fixtures, including posts or standards, brackets, mast arm, cable, lamps, control mechanisms, fixtures, service cable, and conduit to the point of, and with suitable terminals for, connection to the Company's underground or overhead distribution system, are installed, owned, maintained and operated by the Customer. Service is limited to the supply of energy only for the operation of traffic control signal lights.

The installation of a meter to record actual energy consumption is required for all new traffic control signal lighting systems installed on or after June 1, 2004. For traffic control signal lighting systems installed prior to June 1, 2004 a meter may be installed to record actual usage upon the mutual consent of the Customer and the Company.

MONTHLY CHARGE

The monthly kWh of energy usage shall be either the amount estimated by the Company based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated, or the actual meter reading as applicable. The Monthly Charge shall be computed at the following rate, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Energy Charge, per kWh	9.5358¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 45
STANDBY SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge for Standby Service is the sum of the Standby Reservation Charge, the Standby Demand Charge, and the Excess Demand Charge, if any, at the following rates:

Customers taking service under Schedule 9

	Summer	Non-summer
Standby Reservation Charge, per kW of Available Standby Capacity		
Secondary Service	$6.19	$6.19
Primary Service	$6.39	$6.39
Transmission Service	$3.12	$3.12
Standby Demand Charge, per kW of Standby Billing Demand		
Secondary Service	$12.32	$10.22
Primary Service	$12.78	$12.23
Transmission Service	$8.63	$8.44

Customers taking service under Schedule 19

	Summer	Non-summer
Standby Reservation Charge, per kW of Available Standby Capacity		
Primary Service	$6.52	$6.52
Transmission Service	$3.12	$3.12
Standby Demand Charge, per kW of Standby Billing Demand		
Primary Service	$15.16	$14.01
Transmission Service	$14.18	$12.42

Customers taking service under Schedule 9 or Schedule 19

Excess Demand Charge
$1.248 per day for each kW taken in excess of the Total Contract Demand.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Standby Reservation Charge, the Standby Demand Charge, and the Excess Demand Charge.

CONTRIBUTION TOWARD MINIMUM CHARGES ON OTHER SCHEDULES

Any Standby Service Charges paid under this schedule shall not be considered in determining the Minimum Charge under any other Company schedule.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 46
ALTERNATE DISTRIBUTION SERVICE

AVAILABILITY

Alternate Distribution Service under this schedule is available at points on the Company's interconnected system within the State of Idaho where existing facilities of adequate capacity and desired phase and voltage are adjacent to the location where Alternate Distribution Service is desired, and where additional investment by the Company for new distribution facilities is not necessary to supply the requested service. When additional transmission or substation facilities are required, separate arrangements will be made between the Customer and the Company.

Alternate Distribution Service is available only to Customers taking Primary Service under Schedule 9 or 19.

AGREEMENT

Service shall be provided only after the Uniform Alternate Distribution Service Agreement is executed by the Customer and the Company. The term of the initial agreement shall be dependent upon the investment required by the Company to provide the Alternate Distribution Service, but shall in no event be less than one year. The Uniform Alternate Distribution Service Agreement shall automatically renew and extend each year, unless terminated under the provisions of the Agreement.

TYPE OF SERVICE

Alternate Distribution Service consists of a second distribution circuit to the Customer which backs up the Customer's regular distribution circuit through an automatic switching device. Alternate Distribution Service facilities include, but are not limited to, the automatic switching device and that portion of the distribution substation and the distribution line required to provide the service. The kW of Alternate Distribution Service capacity shall be specified in the Uniform Alternate Distribution Service Agreement.

STANDARD OF SERVICE

The Alternate Distribution Service provided under this schedule is not an uninterruptible supply and is subject to the same standard of service as provided under Rule J.

MONTHLY CHARGES

The Monthly Charge is the sum of the Capacity Charge and the Mileage Charge at the following rates:

Capacity Charge
$3.40 per contracted kW of capacity

Mileage Charge
$0.005 per kW per tenth of a mile in excess of 1.8 miles.

SCHEDULE 54
FIXED COST ADJUSTMENT

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Idaho retail Customers receiving service under Schedules 1, 3, 5, or 6 (Residential Service) or under Schedules 7 and 8 (Small General Service).

Customers added to Idaho Power's system starting January 1, 2026, will be considered new customers, all other customers are considered existing customers.

FIXED COST PER CUSTOMER RATE

The Fixed Cost per Customer rate (FCC) is determined by dividing the Company's fixed cost components for Residential and Small General Service Customers by the average number of Residential and Small General Service customers, respectively.

The Fixed Cost per Customer Distribution rate (FCC-Dist) is determined by dividing the Company's distribution and customer fixed cost components for Residential and Small General Service Customers by the average number of Residential and Small General Service Customers, respectively.

Residential	FCC	FCC-Dist
Schedules 1 and 3	$862.88	$205.61
Schedule 5	$862.88	$205.61
Schedule 6	$857.24	$331.94

Small General Service	FCC	FCC-Dist
Schedule 7	$272.14	$52.50
Schedule 8	$476.31	$276.26

FIXED COST PER ENERGY RATE

The Fixed Cost per Energy rate (FCE) is determined by dividing the Company's fixed cost components for Residential and Small General Service customers by the weather-normalized energy load for Residential and Small General Service customers, respectively.

The Fixed Cost per Energy Distribution rate (FCE-Dist) is determined by dividing the Company's distribution and customer fixed cost components for Residential and Small General Service customers by the weather-normalized energy load for Residential and Small General Service customers, respectively.

SCHEDULE 54
FIXED COST ADJUSTMENT
(Continued)

FIXED COST PER ENERGY RATE (Continued)

Residential	FCE	FCE-Dist
Schedules 1 and 3	7.8969¢ per kWh	1.8817¢ per kWh
Schedule 5 – Summer On-Peak	23.1762¢ per kWh	8.7922¢ per kWh
Schedule 5 – Mid-Peak	11.5881¢ per kWh	4.3961¢ per kWh
Schedule 5 – Summer Off-Peak	5.7940¢ per kWh	2.1981¢ per kWh
Schedule 5 – Non-Summer On-Peak	9.2909¢ per kWh	1.3286¢ per kWh
Schedule 5 – Non-Summer Off-Peak	6.1939¢ per kWh	0.8857¢ per kWh
Schedule 6	8.6079¢ per kWh	3.3332¢ per kWh

Small General Service	FCE	FCE-Dist
Schedule 7	5.8413¢ per kWh	1.1270¢ per kWh
Schedule 8	7.4432¢ per kWh	4.3171¢ per kWh

ALLOWED FIXED COST RECOVERY AMOUNT

The Allowed Fixed Cost Recovery amount is computed by summing 1) the product of the average number of existing Residential and Small General Service customers multiplied by the appropriate Residential and Small General Service FCC rate and 2) the product of the average number of new Residential and Small General Service customers multiplied by the appropriate Residential and Small General Service FCC-Dist rate.

ACTUAL FIXED COSTS RECOVERED AMOUNT

The Actual Fixed Costs Recovered amount is computed by summing 1) the product of the actual energy load for existing Residential and Small General Service customers multiplied by the appropriate Residential and Small General Service FCE rate and 2) the product of the actual energy load for new Residential and Small General Service customers multiplied by the appropriate Residential and Small General Service FCE-Dist rate.

FIXED COST ADJUSTMENT

The Fixed Cost Adjustment (FCA) is the difference between the Allowed Fixed Cost Recovery Amount and the Actual Fixed Costs Recovered Amount divided by the estimated weather-normalized energy load for the following year for Residential and Small General Service Customers.

The monthly Fixed Cost Adjustment for Residential Service (Schedules 1, 3, 5, and 6) is 0.6182 cents per kWh. The monthly Fixed Cost Adjustment for Small General Service (Schedules 7 and 8) is 0.7638 cents per kWh.

EXPIRATION

The Fixed Cost Adjustment included on this schedule will expire May 31, 2025.

SCHEDULE 55
POWER COST ADJUSTMENT
(Continued)

POWER COST ADJUSTMENT

The Power Cost Adjustment (PCA) is the sum of: 1) 95 percent of the difference between the Projected Power Costs in Category 1 and the Base Power Costs in Category 1; 2) 100 percent of the difference between the Projected Power Costs in Category 2 and the Base Power Costs in Category 2; 3) 100 percent of the difference between the Projected Power Costs in Category 3 and the Base Power Costs in Category 3; 4) 100 percent of the difference between the Projected Power Costs in Category 4 and the Base Power Costs; 5) the Balancing Adjustment; and 6) Earnings Sharing. The following table calculates the rates for Categories 1, 2, 3, and 4.

The following table shows the determination of PCA rates for Categories 1, 2, 3, and 4:

Category	Description	Base Power Cost	Projected Power Cost	Difference	Sharing %	Rate
		(¢ per kWh)				
1	The sum of fuel expense and purchased power expense (excluding purchases from cogeneration and small power producers), less the sum of off-system surplus sales revenue and revenue from market-based special contract pricing.	1.75445	1.77069	0.01624	95%	0.01543
2	Purchased power expense from cogeneration and small power producers.	1.43605	1.39092	(0.04513)	100%	(0.04513)
3	Demand response incentive payments.	0.06174	0.06881	0.00706	100%	0.00706
4	Payments for battery energy storage system leases.	0.13647	0.00000	(0.13647)	100%	(0.13647)
Total		**3.38872**	**3.23041**	**(0.15830)**		**(0.15912)**

SCHEDULE 55
POWER COST ADJUSTMENT
(Continued)

The monthly Power Cost Adjustment rates applied to the Energy rate of all metered schedules and Special Contracts are shown below. The monthly Power Cost Adjustment applied to the per unit charges of the nonmetered schedules is the monthly estimated usage times the cents per kWh rates shown below. Totals may not tie due to rounding.

Schedule	Category				Balancing Adjustment	Earnings Sharing	Total PCA
	1	2	3	4			
1	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
3	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
5	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
6	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
7	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
8	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
9S	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
9P	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
9T	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
15	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
19S	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
19P	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
19T	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
24	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
40	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
41	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
42	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	(0.0000)	0.4355
26	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	*	0.4355
29	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	*	0.4355
30	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	*	0.4355
32	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	*	0.4355
34	0.0154	(0.0451)	0.0071	(0.1365)	0.5946	*	0.4355

* Earnings Sharing Credits are applied as monthly amounts per the table below.

Schedule	Special Contract	Monthly Credit
26	Micron	($0.00)
29	Simplot	($0.00)
30	DOE	($0.00)
32	Simplot-Caldwell	($0.00)
34	Lamb Weston	($0.00)

EXPIRATION

The Power Cost Adjustment included on this schedule will expire May 31, 2025.

SCHEDULE 62
CLEAN ENERGY YOUR WAY PROGRAM
(OPTIONAL)
(Continued)

SECTION 2: CLEAN ENERGY YOUR WAY – CONSTRUCTION (Continued)

CUSTOMER AGREEMENT AND BILLING STRUCTURE

For each billing period, Customer(s) shall incur or receive the following charges/credits:

1. A participating Customer(s)' Service Charge, Billing Demand, On-Peak Billing Demand, Basic Load Capacity, and other monthly charges will be charged at the standard rates, charges, and fees associated with the Customer's applicable service schedule;

2. Net Consumption shall be charged at the standard rates, charges, and fees associated with the Customer's applicable service schedule;

3. The REF On-Site Usage for Special Contract customers shall be charged at a rate in their respective service schedule and the REF On-Site Usage for Schedule 19 Customers shall be charged as follows:

	Fixed Cost Component of the Retail Energy Charge, per kWh		
Time Period	Secondary Service	Primary Service	Transmission Service
Summer On-Peak	2.4049 ¢	1.6993 ¢	1.7022 ¢
Summer Mid-Peak	2.4049 ¢	1.6993 ¢	1.7022 ¢
Summer Off-Peak	2.4049 ¢	1.6993 ¢	1.7022 ¢
Non-Summer On-Peak	2.3699 ¢	1.6745 ¢	1.6774 ¢
Non-Summer Mid-Peak	2.3699 ¢	1.6745 ¢	1.6774 ¢
Non-Summer Off-Peak	2.3699 ¢	1.6745 ¢	1.6774 ¢

4. Excess Generation shall be credited to the Customer at a rate contained in the Renewable Construction Agreement;

5. REF Cost as contained in the Renewable Construction Agreement; and,

6. REF Credit as contained in the Renewable Construction Agreement (if applicable).

REC OWNERSHIP AND ADDITIONAL REC PROCUREMENT

REC ownership will be negotiated on an individual Customer basis. A Customer may elect to take ownership of the REF's RECs or elect for Idaho Power to retain ownership and retire the RECs on the Customer's behalf.

If the REF generation does not meet 100 percent of the Customer(s)' consumption on a yearly basis, the Customer(s) may elect to enter into a separate REC purchase contract to cover the difference between REF generation and the Customer(s)' consumption. Any separate REC purchase agreement will be negotiated on a case-by-case basis.

SCHEDULE 66
MISCELLANEOUS CHARGES
(Continued)

CHARGES (Continued)

RULE M

1. Monthly Facilities Charge Rate

	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%

The monthly Facilities Charge is determined by multiplying the Monthly Facilities Charge Rate by the Company's total investment in distribution facilities installed beyond the Point of Delivery.

SCHEDULE 68

Monthly Maintenance Charge 0.65%

The monthly Maintenance Charge is determined by multiplying the Monthly Maintenance Charge by the Company's investment in the System Protection, DER metering, and DER communication equipment.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Idaho to all Customer Generators owning or operating DERs, in Parallel with the Company's system, that qualify for Schedule 6, Schedule 8, Schedule 84, or Non-Export as defined in this schedule. DERs with Total Nameplate Capacity of 3 MVA or greater are required to sign a Uniform Customer Generator Interconnection Agreement.

APPLICABILITY

Service under this schedule applies to construction, operation, and maintenance of a Customer Generator System interconnected in Parallel with the Company's system. In limited circumstances, certain interconnection requirements included in this schedule may not be applicable when the Company determines the DER relies on a technology, such as regenerative drives, that does not jeopardize grid stability or reliability. In making its determination, the Company will evaluate criteria such as the magnitude and duration of exports.

DEFINITIONS

Company is the Idaho Power Company.

Company-Furnished Facilities are those portions of the Interconnection Facilities funded by the Customer Generator and provided by the Company.

Customer Generator is a Customer or prospective Customer applying to operate or operating a DER in Parallel with the Company's system.

Customer Generator-Furnished Facilities are those portions of the Interconnection Facilities provided by the Customer Generator.

Customer Generator Interconnection Process is the Company's DER interconnection application, engineering review, construction, and inspection process for Customer Generator Systems. The Customer Generator Interconnection Process intends to ensure a safe and reliable generation interconnection in compliance with all applicable regulatory requirements, good utility practices, and national safety standards.

Customer Generator System is an Exporting System or a Non-Exporting System.

Customer Representative is a person or entity identified by the Customer Generator who is authorized to communicate with the Company on the Customer Generator's behalf.

Disconnection Equipment is any device or combination of devices by which the Company can manually and/or automatically interrupt the flow of energy from the Customer Generator to the Company's system, including enclosures or other equipment as may be required to ensure that only the Company will have access to the devices.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

DEFINITIONS (Continued)

Distributed Energy Resource(s) (DER(s)) is a source of electric power that is not directly connected to the bulk power system. Any combination of Generation Facilities and/or Energy Storage Devices connected in Parallel is considered a DER.

Energy Storage Device is a device that captures energy produced at a point in time and stores the energy for use as electricity at a future point in time. An Energy Storage Device is a DER.

Exporting System is a Customer-owned DER under the terms of Schedules 6, 8, or 84, which is designed to provide for the transfer of electric energy to the Company.

Feasibility Review is the Company's standard engineering review of a proposed Customer Generator System and is intended to ensure the Company's system is equipped to incorporate the proposed Customer Generator-Furnished Facilities in a manner that conforms with good utility practices and the National Electric Safety Code.

Feasibility Study is the Company's more detailed engineering assessment for DERs as determined by the Feasibility Review. This study is intended to ensure that the Company's system is sufficiently equipped to incorporate proposed DERs in a manner that conforms with good utility practices and the National Electric Safety Code, including protection coordination and system voltage management.

Generation Facility means equipment used to produce electric energy at a specific physical location and service point that qualifies for Schedules 6, 8, 84, or Non-Export. A Generation Facility is a DER.

Inadvertent Export is the unplanned, unscheduled, and uncompensated transfer of electrical energy from a Customer's Non-Exporting System to the Company's system across the Interconnection Point.

Incomplete Application is an application missing any information needed to satisfy the requirements of the Customer Interconnection Process; including but not limited to, Customer Generator signature, the application fee, and details about the Generation Facility.

Interconnection Facilities are all facilities which are reasonably required by good utility practices and the National Electric Safety Code to interconnect and to allow for Parallel operations of the DER with the Company's system, including, but not limited to, Special Facilities, Disconnection Equipment, and Metering Equipment.

Interconnection Point is the point where the Customer Generator's conductors connect to the facilities owned by the Company.

Metering Equipment is the Company owned equipment required to measure, record or telemeter power flows between the Customer Generator and the Company's system.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 1: GENERAL INTERCONNECTION REQUIREMENTS

The following provisions apply to all Customer Generators requesting interconnection to the Company's system.

CONSTRUCTION AND OPERATION OF INTERCONNECTION FACILITIES

All Customer Generator-Furnished Interconnection Facilities will be constructed and maintained in a manner as determined by the Company to be in full compliance with all good utility practices, including the Company's Customer Requirements for Electric Service (found at idahopower.com/requirements), National Electric Safety Code, conforms to the IEEE 1547 standards, and all other applicable federal, state, and local safety and electrical codes and standards at all times.

The Customer Generator shall:

1. Upon request, submit proof to the Company that all licenses, permits, inspections, and approvals necessary for the construction and operation of the Customer's DER and Interconnection Facilities under this schedule have been obtained from applicable federal, state, or local authorities.

2. Upon request, submit the designs, plans, specifications, settings, and performance data for the DER and Customer Generator-Furnished Facilities to the Company for review. The Company's acceptance shall not be construed as confirming or endorsing the design, or as a warranty of safety, durability, or reliability of the DER or Customer Generator-Furnished Facilities. The Company will retain the right to inspect this equipment at its discretion.

3. Demonstrate to the Company's satisfaction that the Customer's DER and Customer Generator-Furnished Facilities have been completed, and that all features and equipment of the Customer's DER and Customer Generator-Furnished Facilities are capable of operating safely to commence deliveries of energy into the Company's system.

4. Provide and maintain adequate Protection Equipment sufficient to prevent damage to the DER, Customer Generator-Furnished Facilities, and any other Customer Generator-owned facilities in conformance with all applicable electrical and safety codes and requirements.

5. Provide and maintain Disconnection Equipment in accordance with all applicable electrical and safety codes and requirements as described within this Schedule.

6. Upon request, provide a 24-hour telephone contact(s). This contact will be used by the Company to arrange for repairs and inspections or in case of an emergency. The Company will make its best effort to arrange repairs and inspections during normal business hours and to notify the Customer Generator of such arrangements in advance. The Company will provide a telephone number to the Customer Generator so that the Customer Generator can obtain information about Company activity impacting the Customer's DER.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 1: GENERAL INTERCONNECTION REQUIREMENTS (Continued)

ENERGY STORAGE DEVICE (Continued)

2. AC Coupled:

i. AC Coupled with an Exporting System: For an Energy Storage Device coupled with an Exporting System taking service under Schedules 6, 8, or 84, the Total Nameplate Capacity is the aggregate Total Nameplate Capacity of all DERs on the Customer's side of the Interconnection Point.

ii. AC Coupled with a Non-Exporting System: An Energy Storage Device coupled with a Non-Exporting System is subject to the provisions of Section 3 of this Schedule. The Total Nameplate Capacity of the Energy Storage Device shall be considered 0 kVA.

APPLICATION EXPIRATION

Applications from a Customer Generator with existing retail service that are not completed within one year of the initial Feasibility Review are considered expired. Applications from a Customer Generator without existing retail service that has not completed the Customer Generator Interconnection Process requirements by the requested project in-service date identitifed on the completed application will be considered expired.

Customer Generators requesting connection or approval of expired applications are required to resubmit a completed application form and a $100 non-refundable application fee and are subject to the full application process described in Section 2.

RECERTIFICATION

1. The Company may perform full recertification inspections of Customer Generator Systems at the Company's discretion and at no charge to the Customer Generator. The Company will provide the Customer Generator with written notice at least fourteen (14) calendar days prior to performing a recertification inspection. Recertification inspections will be performed in the same manner as new Customer Generator System inspections described in Section 2. Customers may choose to verify the results of the Company's inspection through an independent inspection performed by a certified third-party at the Customer Generator's expense.

2. If in the reasonable opinion of the Company, the Customer Generator's operation or maintenance of the DER or Interconnection Facilities is unsafe, not in compliance with this schedule, or may otherwise adversely affect the Company's equipment, personnel, or service to its customers, the Company reserves the right to inspect any Customer Generator System at any time, and without prior notice.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 1: GENERAL INTERCONNECTION REQUIREMENTS (Continued)

SYSTEM MODIFICATIONS

1. Any modifications to Customer Generator Systems that increase the Total Nameplate Capacity of the system or modify the system in any way (including inverter replacements) that may impact the safety or reliability of the Company's electrical system are considered system modifications for the purposes of this schedule.

2. Customer Generators planning to make system modifications must submit an application, a $100 non-refundable fee, and complete the application process according to the procedures required for new interconnection.

3. System modifications without gaining prior Company approval are considered unauthorized installations subject to the provisions of this schedule as described in Unauthorized Installations and Expansions.

UNAUTHORIZED INSTALLATIONS AND EXPANSIONS

1. Customer Generator Systems that have been interconnected to the Company's system without Company approval are considered unauthorized installations that jeopardize the reliability of Idaho Power's system and the safety of its employees. This includes, but is not limited to, newly installed systems and unapproved expansions or other modifications of approved systems. The process described herein provides the Company with the ability to offer Customer Generation in an efficient, safe, and reliable manner.

2. Unauthorized installations are subject to immediate Company inspection and disconnection without notice. The Company will provide the reason for the disconnection of the Customer's DER. The Customer will be called and written, or electronic notification will be sent. The Customer will have twelve (12) months from the notification date to notify the Company and complete one of the options listed under 5(a) and 5(b).

3. If proper disconnection equipment is present, the Company will open the disconnect or notify the Customer to open the disconnect immediately.

4. If proper disconnection equipment is not present, the Customer Generator must disconnect the DER from operating in Parallel with the Company's system immediately by turning off the breaker or by other means necessary.

5. The Customer must complete and notify the Company of one of the below options within twelve (12) months from the notification date:

   a. Option 1: Complete the full Customer Generator Interconnection Process described in Section 2, and the system will be re-energized.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 1: GENERAL INTERCONNECTION REQUIREMENTS (Continued)

UNAUTHORIZED INSTALLATIONS AND EXPANSIONS (Continued)

b. Option 2: Permanently disable the DER from Parallel operations with the Company system. Permanent disablement of the DER requires an inspection to be scheduled with the Company within twelve (12) months from the postmarked notification date. Customers that do not schedule within this time period will be subject to termination of service.

6. If it is determined, at the sole discretion of the Company, that an unauthorized Customer Generation System, expansion, or other system modification results in damage to equipment on the Company's system, the Customer will be responsible for all costs associated with replacing the Company's damaged equipment and defend, indemnify, and reimburse the Company for liabilities or damages incurred by the Company for third-party claims arising out of the Customer Generator's unauthorized connection.

PERMANENTLY REMOVED OR DISABLED SYSTEMS

The Customer shall notify the Company immediately if a DER is permanently removed or disabled. Permanent removal or disablement for the purposes of this Schedule is any removal or disablement of a DER lasting longer than six (6) months. If the Customer wishes to interconnect the DER after six (6) months, the Customer Generator must reapply and meet the interconnection requirements in place at the time of application.

SECTION 2: INTERCONNECTION PROCESS REQUIREMENTS FOR DISTRIBUTED ENERGY RESOURCES LESS THAN 3 MVA

The following section is applicable to all DERs with Total Nameplate Capacity less than 3 MVA.

APPLICATION PROCESS

Customer Generators requesting to interconnect a DER less than 3 MVA are required to complete the following application process prior to interconnection:

1. Customer Generators must submit a completed application form and a $100 non-refundable application fee to the Company. Applications are available on the Company's website or will be provided to the Customer upon request. Incomplete Applications are considered withdrawn after sixty (60) days from the date the application was received.

2. Upon receipt of a completed application and a $100 non-refundable fee, the Company will either (1) provide the Customer with a written or electronic notification that the application has been received and all necessary information has been provided, or (2) request the Customer provide forms of documentation outlined in Section 1.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 2: INTERCONNECTION PROCESS REQUIREMENTS FOR DISTRIBUTED ENERGY RESOURCES LESS THAN 3 MVA (Continued)

APPLICATION PROCESS (Continued)

If the DER system components, capacity, or configuration changes from the original application, the Customer Generator will be subject to a new Feasibility Review.

If the Customer Generator changes its Customer Representative, a new application and a $100 non-refundable application fee is required.

3. The Company will perform within seven (7) business days, unless it is determined that additional studies are necessary, the Feasibility Review based on Total Nameplate Capacity and other project information provided in the application. The Feasibility Review determines the capability of the Company's electrical system to incorporate the proposed Customer Generator System and determines if Upgrades are necessary. For a Customer Generator who does not yet have established service, the Feasibility Review will occur as part of the Company's evaluation for Upgrades for new customers conducted in compliance with Rule H – New Service Attachments and Distribution Line Installations or Alterations.

a. If the results of the Feasibility Review indicate satisfactory system capability, the Company will provide the Customer with an official "Approval to Proceed" notification.

b. If the results of the Feasibility Review indicate that Upgrades are necessary to accommodate the proposed project, the Company will notify the Customer through written or electronic notification of such Upgrades. Funding, construction, installation, and maintenance of required Upgrades will be subject to the Company's standard Rule H regarding New Service Attachments and Distribution Line Installations or Alterations.

c. If the Company determines that additional time is necessary to determine satisfactory system capability or that Upgrades are necessary to accommodate the proposed project, the Company will notify the Customer. The Company will perform within fifteen (15) business days the additional studies to complete the Feasibility Review.

4. If the results of the Feasibility Review require the need for a Feasibility Study, the Company will provide the Customer with a Feasiblity Study Agreement which requires a deposit of $1,000 and must be signed and returned within fifteen 15 business days. Upon receipt of the signed Feasibility Study Agreement and deposit, the Company will perform the Feasiblity Study within thirty (30) business days. If the results of the Feasibility Study indicate that Upgrades or Protection Equipment are necessary to accommodate the proposed project, the Company will notify the Customer of such Upgrades or Protection Equipment. At the Company's discretion, additional studies referenced in Section 4 may be applicable.

a. Installation and funding of the construction, installation, and maintenance of required Protection Equipment will be subject to the following provisions:

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 2: INTERCONNECTION PROCESS REQUIREMENTS FOR DISTRIBUTED ENERGY RESOURCES LESS THAN 3 MVA (Continued)

APPLICATION PROCESS (Continued)

i. Protection Equipment Requirements (Rotating Machines): Generation Facilities up to 500 kVA Total Nameplate Capacity may not require additional Protection Equipment but will be evaluated on a case-by-case basis. Generation Facilities greater than 500 kVA Total Nameplate Capacity will require additional Company-Furnished Protection Equipment.

ii. Protection Equipment Requirements (Other DER): DER up to 3 MVA Total Nameplate Capacity may not require additional Protection Equipment but will be evaluated on a case-by-case basis.

iii. When it is determined Company-owned Protection Equipment is required, the Customer shall pay the actual costs of all required Protection Equipment prior to the start of Parallel operations. The Customer will also pay a Maintenance Charge specified in Schedule 66, per month times the investment in the Protection Equipment.

5. Following receipt of “Approval to Proceed,” the Customer is responsible for completing the installation of the Customer Generator System and fulfilling all applicable federal, state, and local inspection requirements. Customers must also provide the Company with a completed System Verification Form detailing the specifications of all installed components of the completed Customer Generator System. System Verification Forms can be found on the Company’s website or will be provided upon request. Upon completion, the Company reserves the right to request the Customer to provide forms of documentation outlined in Section 1, verifying that all federal, state, and local requirements have been met.

6. Once all required documentation has been submitted and the Company has verified that all applicable federal, state, local, and Customer Generation Interconnection Process requirements have been met, the Company will complete, barring conditions beyond the Company’s control, an on-site inspection within ten (10) business days for DER with Total Nameplate Capacity of 100 kVA or less and within twenty (20) business days for DER with Total Nameplate Capacity of greater than 100 kVA. Company on-site inspections will not be performed until the system has passed all applicable federal, state, and local inspection requirements. The Company on-site inspection may include the following:

a. Verification that actual installed components correspond to the information provided on the initial application and the System Verification Form.
b. Verification that the disconnect is functional and reconnection time complies with IEEE 1547.
c. Verification of the proximity and visibility of the disconnect or a sign indicating the location of the disconnect.
d. Photographic documentation of the installation.
e. Posting of appropriate Company signage.
f. Documentation of the meter number and system configuration.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 2: INTERCONNECTION PROCESS REQUIREMENTS FOR DISTRIBUTED ENERGY RESOURCES LESS THAN 3 MVA (Continued)

APPLICATION PROCESS (Continued)

g. Verification of Smart Inverters, including the settings for all inverter-based DERs 100 kVA and greater.
h. Verification of Total Nameplate Capacity.
i. Verification of plant controller for all DERs 500 kVA and greater.

7. A return trip charge of $52.00 will be billed to the Customer each time Company personnel are dispatched to the job site but are unable to conduct the on-site inspection due to one or more of the conditions not being met that had been certified as complete by the Customer or Customer's Representative, as identified on the System Verification Form.

8. Successful completion of the Company on-site inspection constitutes the conclusion of the application process. The Company must make a reasonable effort to move an Exporting Customer Generator to the appropriate rate schedule within five (5) business days. The rate change will be no later than the Customer's next Billing Period following their successfully completed inspection. Upon completion of this process, the Customer will receive confirmation that the application process has been successfully completed.

9. It is within Idaho Power's sole discretion to disconnect, or refuse to connect, any Customer Generator System that does not pass inspection, poses a threat to public safety, or has unanticipated impacts to Idaho Power's system. In these situations, a Company representative will send a written communication to the Customer Generator regarding Idaho Power's inability to connect/reconnect the Customer Generator System until the issue(s) is resolved. Idaho Power will continue working with the Customer to resolve the issue(s) required to connect the Customer's System. Idaho Power will re-inspect the System upon receiving notice from the Customer indicating Customer's Generation System meets all applicable federal, state, and local requirements and is suitable for connection.

SECTION 3: ADDITIONAL INTERCONNECTION REQUIREMENTS OF NON-EXPORTING SYSTEMS

In addition to the requirements of Section 1, the following section is applicable to all Customer Generators electing to establish their system as Non-Export.

NON-EXPORT TOTAL NAMEPLATE CAPACITY LIMIT

For customers taking service under Schedule 1 or Schedule 7 that own and/or operate a Generation Facility, service is subject to an aggregate DER Total Nameplate Capacity of 25 kVA or less, that is operated in Parallel with the Idaho Power System.The capacity of an Energy Storage Device shall not be used to calculate the 25 kVA capacity limit but will be used to calculate Total Nameplate Capacity for the Feasbility Review.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 3: ADDITIONAL INTERCONNECTION REQUIREMENTS OF NON-EXPORTING SYSTEMS (Continued)

NON-EXPORT CONTROL SYSTEM

1. Non-Export Systems must incorporate one of the following three options:

a. Option 1: (“Advanced Functionality”): The use of an internal transfer relay, energy management system, or other customer facility hardware or software system(s) may be used to ensure power is never exported across the Interconnection Point. To ensure that Inadvertent Export of power is limited to acceptable levels, all of the following conditions must be met: (a) inverter-based DERs must utilize a Smart Inverter; (b) the DER must monitor the total Inadvertent Export; (c) the DER must disconnect from the Company’s distribution system or halt energy production within two seconds after the period of continuous Inadvertent Export exceeds 30 seconds; (d) the DER must enter a safe operating mode where Inadvertent Export will not occur as a result of a failure of the control or Smart Inverter system for more than 30 seconds, which results in loss of control signal, loss of control power or single component failure or related control sensing of the control circuitry.

b. Option 2: (“Reverse Power Protection”): To ensure power is never exported, a reverse power relay protective function must be implemented at the Interconnection Point. The default setting for this Protection Equipment, when used, shall be 0.1% (export) of the DERs Total Nameplate Capacity, with a maximum 2.0 second time delay.

c. Option 3: (“Minimum Power Protection”): To ensure at least a minimum amount of power is imported at all times (and, therefore, that power is not exported), an under-power protective function may be implemented at the Interconnection Point. The default setting for this non-export control system, when used, shall be 5% (import) of the DERs Total Nameplate Capacity, with a maximum two (2) second time delay.

2. Control System Failure: Where applicable, any failure of the Customer’s DER control system for 30 seconds or more, which includes, but is not limited to; the internal transfer relay, energy management system, or other Customer facility hardware or software system(s) intended to prevent the reverse power flow, shall cause the Customer’s DER to enter a safe operating mode whereby the production of energy from the Non-Export DER is autonomously limited to an amount that shall not cause Inadvertent Export to occur until such time that the Customer has reestablished real power output control of the non-export control system.

UNAUTHORIZED INADVERTENT EXPORT

Inadvertent Export exceeding three hours of the DER Total Nameplate Capacity in any 30-day period will be defined as unauthorized Inadvertent Export, and the following steps will be followed for Customers with Non-Exporting Systems:

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 3: ADDITIONAL INTERCONNECTION REQUIREMENTS OF NON-EXPORTING SYSTEMS (Continued)

UNAUTHORIZED INADVERTENT EXPORT (Continued)

1. The Company will notify the Non-Export Customer Generator that their Customer Generator System has exceeded the Inadvertent Export limit.

2. After notification of Inadvertent Export, the following will occur:

a. For Schedule 1, Residential and Schedule 7, Small General Non-Exporting Systems, the Customer Generator must rectify Inadvertent Export within 30 days after receipt of the notification by Idaho Power that the Non-Exporting System has exceeded the Inadvertent Export limit. If the Customer Generator has not rectified Inadvertent Export after 30 days, at the Customer's election, one of the following actions will occur:

i. The Customer Generator System disconnect will be placed in the open (off) position until the issue that caused the export is remedied. A Company inspection will be required before the Non-Exporting System can interconnect to the Company's system; or,

ii. If the Customer does not elect to open the disconnect, the Customer Generator will be placed on Schedule 6 or Schedule 8, as appropriate, and subject to applicable provisions of Section 2. If the Customer elects to be placed on Schedule 6 or Schedule 8, the Customer will be given the option to submit an additional application and be moved back to Schedule 1 or Schedule 7, as appropriate, after 180 days.

b. For Schedules other than Schedule 1 or Schedule 7:

i. Upon receipt of the notification by Idaho Power that the Customer Generator's Non-Exporting System has exceeded the Inadvertent Export limit, the Customer Generator System disconnect will be placed in the open position until the issue that caused the export is remedied. A Company inspection will be required before the Non-Exporting System can interconnect to the Company's system.

3. If it is determined, at the sole discretion of the Company, that unauthorized Inadvertent Export results in damage to equipment on the Company's system, the Customer Generator will be responsible for all costs associated with replacing the Company's damaged equipment and defend, indemnify, and reimburse the Company for liabilities or damages incurred by the Company for third-party claims arising out of the Customer Generator's unauthorized Inadvertent Export.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 4: ADDITIONAL INTERCONNECTION REQUIREMENTS OF DISTRIBUTED ENERGY RESOURCES 3 MVA OR GREATER (Continued)

SYSTEM PROTECTION, DER METERING, AND DER COMMUNICATION MAINTENANCE CHARGE

The Customer shall pay the actual costs of System Protection, DER metering, and DER communication equipment, as identified in the study process, prior to the start of Parallel operations. The Customer will pay a Maintenance Charge as specified in Schedule 66 per month times the investment in the System Protection, DER metering, and DER communication equipment. The Customer Generator will also be responsible for any applicable monthly charges as outlined in Attachment 1 of the CGIA.

IDAHO POWER COMPANY
UNIFORM CUSTOMER GENERATOR
INTERCONNECTION AGREEMENT

This Uniform Customer Generator Interconnection Agreement (“Agreement”) is entered to be effective as of the ____ day of __________, 20___ (“Effective Date”), between ____________________________, (“Customer Generator”) and Idaho Power Company (the “Company”). Customer Generator and the Company may also be referred to individually as a “Party” or collectively as the “Parties.” Unless explicitly noted otherwise, the term “days” refers to calendar days.

RECITALS

A. Customer Generator owns or operates a Customer Generator System that qualifies for service under Idaho Power’s Commission-approved Schedule 68 which is subject to change from time to time pursuant to Commission order.

B. The Customer Generator System to be interconnected and operate in Parallel with the Company’s system pursuant to this Agreement is more particularly described in Attachment 1.

AGREEMENT

For and in consideration of the mutual covenants and provisions set forth in this Agreement, and other good and valuable consideration, the receipt of which is hereby acknowledged, the Parties intending to be legally bound agree as follows:

1. **Recitals.** The Parties acknowledge and agree as to the accuracy of the Recitals set forth above, and such Recitals are incorporated herein by this reference.

2. **Defined Terms.** Capitalized terms not defined in this Agreement shall have the meaning given to them in Schedule 68.

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

APPLICABILITY (Continued)

ii. Single-Meter Interconnection (applicable to new applicants effective December 2, 2020): Owns and/or operates a Generation Facility interconnected to the Customer's individual electric system on the Customer's side of the Point of Delivery, thus all energy received and delivered by the Company is through a single meter.

6. The Generation Facility must have a total nameplate rating equal to or less than the greater of: (a) the greatest monthly Billing Demand established during the most recent 12-month period at the time of applying for interconnection, which includes and ends with the most recent Billing Period, or (b) 100 kW. The capacity of an Energy Storage Device shall not be used to calculate the capacity limits in this schedule.

a. Subject to the Company's discretion and approval, for a Customer applying to interconnect a Generation Facility (1) where 12-months of Billing Demand is not available, or (2) where the Billing Demand is not reflective of future operations, the customer may provide evidence that the proposed Generation Facility meets the applicability of this schedule in accordance with one of the following:

i. Schedules 9 and 19:

a. If previous billing data is available for the premises and the Customer's electrical needs are similar to the previous customer, the Company may rely on available historical Billing Demand at the premises not to exceed the previous 12 months.

b. If the Customer has another account in the Company's service area with similar electrical needs, the Company may rely on available historical Billing Demand from that account not to exceed the previous 12 months.

c. The Customer can have a third-party currently licensed or registered professional engineer provide analysis and documentation detailing the electrical load requirements for the Customer which support the requested load or an increase in demand expected to occur.

ii. Schedule 24:

a. If historical Billing Demand is available for the Premises and is still reflective of expected operations, the Company will rely on the maximum of the most recently available 12-months of Billing Demand.

b. For newly installed equipment, the Customer may submit documentation of the horsepower ("HP") of the irrigation equipment (motors and/or pumps). Based on the submitted documentation, the Company will determine the maximum continuous HP using a conversion factor of 1 HP to 0.8kW to define the demand for the Point of Delivery.

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

APPLICABILITY (Continued)

7. Legacy Status for eligible Exporting Systems will terminate on December 1, 2045.

8. The Legacy Status of the Exporting System is transferable to a subsequent Customer at the premises for which a valid on-site generation service is in effect. Each Customer of a Legacy System taking service under Schedule 84 will be responsible for complying with the terms and conditions of the on-site generation service in effect for that premises.

9. A Legacy System that is offline for over six (6) months or that is moved to a different site shall forfeit Legacy Status of the Exporting System.

10. To remain eligible for Legacy Status, a Customer may increase the capacity of a Legacy System by no more than 10 percent of the originally installed nameplate capacity, or 1 kW, whichever is greater, to allow for the replacement of broken or degraded components. If a Customer expands a Legacy System beyond these limits and wishes to maintain Legacy Status for the original system, the new portion of the DER shall be separately metered and would not qualify for Legacy Status.

11. A Customer that modifies a two-meter Generation Facility to a single-meter forfeits the Legacy Status of the Generation Facility.

12. A Customer with a Legacy System may elect to forfeit the system's Legacy Status by submitting the request to the Company in writing. A Customer forfeiting Legacy Status will be required to reconfigure to a single-meter system.

DEFINITIONS

Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor.

Designated Meter is the retail meter physically connected to the Exporting System.

Distributed Energy Resource(s) (DER(s)) is a source of electric power that is not directly connected to the bulk power system. Any combination of Generation Facilities and/or Energy Storage Devices connected in Parallel is considered a DER.

Energy Storage Device is a device that captures energy produced at a point in time and stores the energy for use as electricity at a future point in time. An Energy Storage Device is a DER.

Excess Net Energy means the positive difference between the kilowatt-hours (kWh) generated by a Customer and the kWh supplied by the Company over the applicable Billing Period.

Exported Energy means all kWh generated by a Customer in excess of the Customer's on-site consumption that is exported to the Company's system.

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

DEFINITIONS (Continued)

Exporting System is a Customer-owned DER under the terms of Schedules 6, 8, or 84, which is designed to provide for the transfer of electric energy to the Company. An Exporting System is interconnected to the Company's system under the applicable terms of Schedule 68.

Financial Credit represents the amount in dollars carried forward to offset Monthly Charges in a subsequent Billing Period. A Financial Credit is generated during a Billing Period when the product of Exported Energy and the Export Credit Rate exceeds a Customer's Monthly Charges.

Generation Facility means all equipment used to generate electric energy where the resulting energy is either delivered to the Company via a single meter at the Point of Delivery or Generation Interconnection Point, or is consumed by the Customer.

Generation Interconnection Point is the point where the conductors installed to allow receipt of the Customer's generation connect to the Company's facilities adjacent to the Customer's Point of Delivery.

Interconnection Facilities are all facilities reasonably required by Prudent Electrical Practices and the applicable electric and safety codes to interconnect and safely deliver energy from the DER to the Point of Delivery or Generation Interconnection Point.

Kilowatt Hour Credit ("kWh Credit") is the accumulated Excess Net Energy that is carried forward to offset energy usage in a subsequent Billing Period.

Legacy Status refers to the ability for a system to receive Net Energy Metering, including net monthly one-for-one kWh credit compensation for Excess Net Energy.

Legacy Systems means any system that meets the applicable criteria as described in Order Nos. 34509, 34546, 34854 and 34892.

Net Billing is the compensation structure applicable to all systems that do not meet the criteria of a Legacy System. Net Billing will be effective with each eligible customer's first billing cycle after January 1, 2024.

Net Energy Metering is the compensation structure applicable to all Legacy Systems.

Parallel connection means generating electricity from an on-site generation system that is connected to and receives voltage from Idaho Power's system.

Point of Delivery is the retail metering point where the Company's and the Customer's electrical facilities are interconnected to allow the Customer to take retail electric service from the Company.

Prudent Electrical Practices are those practices, methods and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

DEFINITIONS (Continued)

Schedule 68 is the Company's service schedule which provides for interconnection to DERs or its successor schedule(s) as approved by the Commission.

MONTHLY BILLING

The Customer shall be billed in accordance with the Customer's applicable standard service schedule, including appropriate monthly charges, and the Export Credit Rate under this schedule.

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions for Net Energy Metering under this schedule.

1. Balances of generation and usage by the Customer:

a. If electricity supplied by the Company during the Billing Period exceeds the electricity generated by the Customer and delivered to the Company during the Billing Period, the Customer shall be billed for the net electricity supplied by the Company at the Customer's standard schedule retail rate, in accordance with normal metering practices.

b. If electricity generated by the Customer and delivered to the Company during the Billing Period exceeds the electricity supplied by the Company during the Billing Period, the Excess Net Energy shall be carried forward as a kWh Credit to offset energy usage in a subsequent Billing Period. kWh Credits are subject to the following provisions:

i. kWh Credits can only be used to offset billed kWh consumption. Customers shall be billed for all applicable non-energy charges for the Billing Period according to the applicable standard service schedule.

ii. kWh Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

iii. kWh Credits are non-transferrable in the event that a Customer relocates and/or discontinues service at the Point of Delivery associated with the Exporting System. Any unused kWh Credits will expire at the time the final bill is prepared.

2. Aggregation of meters for the annual transfer of unused kWh Credits:

a. If a balance of kWh Credits exists at a Designated Meter, the Customer may request to transfer the unused kWh Credits to offset energy consumption at eligible meters. A meter is eligible for aggregation if it meets all of the following criteria:

i. The account subject to offset is held by the Customer; and

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE (Continued)

ii. The meter is located on, or contiguous to, the property on which the Designated Meter is located. For the purposes of this tariff, contiguous property includes property that is separated from the Premises of the Designated Meter by public or railroad rights of way; and

iii. The meter is served by the same primary feeder as the Designated Meter at the time the Customer files the application for the Exporting System; and

iv. The electricity recorded by the meter is for the Customer's requirements; and

v. For Customers taking service under Schedule 1 or Schedule 7, kWh Credits may only be transferred to meters taking service under Schedule 1 or Schedule 7. For Customers taking service under Schedule 9, Schedule 19, or Schedule 24, kWh Credits may only be transferred to meters taking service under Schedule 9, Schedule 19, or Schedule 24.

b. Customers may submit requests to transfer kWh Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power on or before January 31. If a Customer does not request to transfer kWh Credits by the January 31 submission deadline kWh Credits will carry forward to offset consumption at the Designated Meter until they become eligible the following year.

c. Requests to transfer kWh Credits must be executed by the Company no later than March 31. Transfers will be based on the balance of kWh Credits available at the time the transfer is made.

d. If multiple meters are eligible for aggregation, kWh Credits must first be applied to the Designated Meter, then to eligible meters on rate schedules in accordance with Section 2a(v) above.

e. A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

NET BILLING – CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to transactions for Net Billing under this schedule.

1. Balances of usage and exports by the Customer.

a. The Customer shall be billed for the electricity supplied by the Company at the rates contained within the Customer's applicable standard service schedule, in accordance with normal metering practices.

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

NET BILLING – CONDITIONS OF PURCHASE AND SALE (Continued)

b. The Customer shall be credited for Exported Energy at the applicable Export Credit Rate contained within this schedule as a credit in dollars to only offset Monthly Charges. Financial Credits are subject to the following provisions:

i. Financial Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

ii. Financial Credits are transferrable in the event that a Customer relocates. If the establishment of service at the new Point of Delivery is not initiated at the time service at the Designated Meter is discontinued, any unused Financial Credits will be paid out following the time the final bill is prepared.

2. Aggregation of meters for the annual transfer of unused Financial Credits:

a. If a balance of Financial Credits exists at a Designated Meter, the Customer may request to transfer the unused Financial Credits to eligible meters. A meter is eligible for aggregation if it meets the following criteria:

i. The account subject to offset is held by the Customer; and

ii. The electricity recorded by the meter is for the Customer's requirements.

b. Customers may submit requests to transfer a stated percentage of available Financial Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power on or before January 31. If a Customer does not request to transfer Financial Credits by the January 31 submission deadline Financial Credits will carry forward at the Designated Meter until they become eligible for transfer the following year.

c. Requests to transfer Financial Credits must be executed by the Company no later than March 31. Transfers will be based on the balance of Financial Credits available at the time the transfer is made.

d. A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

NET ENERGY METERING & NET BILLING – GENERAL CONDITIONS

1. The Customer shall never deliver or attempt to deliver energy to the Company's system when the Company's system serving the Customer's DER is de-energized for any reason.

2. The Company shall not be liable directly or indirectly for permitting or continuing to allow an attachment of a Exporting System to the Company's system, or for the acts or omissions of the Customer that cause loss or injury, including death, to any third party.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

ATTACHMENT NO. 2
TARIFF IN LEGISLATIVE FORMAT

GENERAL RULES AND REGULATIONS INDEX

SCHEDULE INDEX

SCHEDULE INDEX

RULE C
SERVICE AND LIMITATIONS
(Continued)

5. Point of Delivery Service Requirements (Continued)

Where separate Points of Delivery exist for supplying service to a Customer at a single Premises or separate meters are maintained for measurement of service to a Customer at a single Premises, the meter readings will not be combined or aggregated for any purpose except for determining if the Customer's total power requirements exceed 20,000 kW. Special contract arrangements will be required when a Customer's aggregate power requirement exceeds 20,000 kW.

Service delivered at low voltage (600 volts or under) will be supplied from the Company's distribution system to the outside wall of the Customer's building service pole or post unless an exception is granted by the Company and the City or State Electrical Inspector.

The Customer's facilities will be installed and maintained in accordance with the requirements of the National Electrical Code and the Company's Customer Requirements for Electric Service (found at Idahopower.com/requirements).

6. Limitation of Use. A Customer will not resell electricity received from the Company to any person except (1) where the Customer is owner, lessee, or operator of a commercial building, shopping center, apartment house, mobile home court, or other multi-family dwelling where the use has been sub-metered prior to July 1, 1980, and the use is billed to tenants at the same rates that the Company would charge for service, unless the Commission authorizes alternative procedures, or (2) where the electricity is purchased from a public utility (as defined in Idaho Code § 61-129) to charge the batteries of an electric motor vehicle as provided by order or rule of the Commission.

A Customer's wiring will not be extended or connected to furnish service to more than one building or place of use through one meter, even though such building, property, or place of use is owned by the Customer. This provision is not applicable where the Customer's residence or business consists of one or more adjacent buildings or places of use located on the same Premises or operated as an integral unit, under the same name and carrying on parts of the same residence or business.

7. Rights of Way. The Customer shall, without cost to the Company, grant the Company a right of way for the Company's lines and apparatus across and upon the property owned or controlled by the Customer, necessary or incidental to the supplying of Electric Service and shall permit access thereto by the Company's employees at all reasonable hours. The Customer shall also grant the Company access to permit the Company to trim trees and other vegetation to the extent necessary to avoid interference with the Company's lines and to protect public safety.

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

2. General Provisions

a. Cost Information. The Company will provide preliminary cost information addressing the charges contained in this rule to potential Applicants and/or Additional Applicants. This preliminary information will not be considered a formal Cost Quote and will not be binding on the Company or Applicant but rather will assist the Applicant or Additional Applicant in the decision to request a formal Cost Quote. Upon receiving a request for a formal Cost Quote, the Applicant or Additional Applicant will be required to provide all necessary information for a design and pay non-refundable engineering costs to the Company. A Cost Quote will be binding in accordance with its terms.

b. Ownership. The Company will own all distribution line facilities and retain all rights to them.

c. Rights-of-Way and Easements. The Company will construct, own, operate, and maintain lines only along public streets, roads, and highways that the Company has the legal right to occupy, and on public lands and private property across which rights-of-way or easements satisfactory to the Company will be obtained at the Applicant's or Additional Applicant's expense.

d. Removals. The Company reserves the right to remove any distribution facilities that have not been used for 1-year. Facilities shall be removed only after providing 60 days' written notice to the last customer of record and the owner of the property served.

e. Removals in High Fire Risk Zones. The Company reserves the right to remove or de-energize any electrical equipment without advance written notice if that equipment has not been used for 1-year.

~~e~~f. Property Specifications. Applicants or Additional Applicants must provide the Company with final property specifications as required and approved by the appropriate governmental authorities. These specifications may include but are not limited to: recorded plat maps, utility easements, final construction grades, property pins and proof of ownership.

~~f~~g. Undeveloped Subdivisions. When electric service is not provided to the individual spaces or lots within a Subdivision, the Subdivision will be classified as undeveloped.

~~g~~h. Mobile Home Courts. Owners of mobile home courts with transient tenants, as defined within Idaho Code § 55-2003(19), will install, own, operate, and maintain all termination poles, pedestals, meter loops, and conductors from the Point of Delivery.

~~h~~i. Conditions for Start of Construction. Construction of Line Installations and Alterations will not be scheduled until the Applicant or Additional Applicant pays the appropriate charges to the Company.

~~i. Terms of Payment. All payments listed under this section will be paid to the Company in cash, a minimum of 30 days and no more than 120 days, prior to the start of Company construction, unless mutually agreed otherwise.~~

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

2. General Provisions (Continued)

j. ~~i.~~ Terms of Payment. All payments listed under this section will be paid to the Company in cash, a minimum of 30 days and no more than 120 days, prior to the start of Company construction, unless mutually agreed otherwise.

~~j~~k. Interest on Payment. If the Company does not start construction on a Line Installation or Alteration within 30 days after receipt of the construction payment, the Company will compute interest on the payment amount beginning on the 31st day and ending once Company construction actually begins. Interest will be computed at the rate applicable under the Company's Rule L. If this computation results in a value of $10.00 or more, the Company will pay such interest to the Applicant, Additional Applicant, or subdivider. An Applicant, Additional Applicant, or subdivider may request to delay the start of construction beyond 30 days after receipt of payment in which case the Company will not compute or pay interest.

~~k~~l. Fire Protection Facilities. The Company will provide service to Fire Protection Facilities when the Applicant pays the Work Order Cost for the Line Installation including Terminal Facilities, less Company Betterment. These costs are not subject to an Allowance, but are eligible for Vested Interest Refunds under Section 8.a.

~~l~~m. Customer Provided Trench Digging and Backfill. The Company will, at its discretion, allow an Applicant, Additional Applicant or subdivider to provide trench digging and backfill. In a joint trench, backfill must be provided by the Company. Costs of customer-provided trench and backfill will be removed from or not included in the Cost Quote and will not be subject to refund.

3. Line Installation Charges

If a Line Installation is required, the Applicant or Additional Applicant will pay a partially refundable Line Installation Charge equal to the Work Order Cost less applicable Allowances identified in Section 7.

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

4. Service Attachment Charges

a. Overhead Service Attachment Charge. If an overhead Service Attachment is required, the Applicant or Additional Applicant will pay a non-refundable Service Attachment Charge equal to the Work Order Cost less applicable Allowances identified in Section 7.

b. Underground Service Attachment Charge. Each Applicant or Additional Applicant will pay a non-refundable Underground Service Attachment Charge for attaching new Terminal Facilities to the Company's distribution system. The Company will determine the location and maximum length of service cable.

i. Single Phase 400 Amps or Less and Single Phase Self-Contained Multiple Meter Bases 500 Amps or Less.

Underground Service Cable (Base charge plus Distance charge)

Base charge from:	
underground	$ 28.00
overhead including 2" riser	$ 991.00
overhead including 3" riser	$1,247.00
Distance charge (per foot)	
Company Installed Facilities with:	
1/0 underground cable	$ 14.97
4/0 underground cable	$ 15.98
350 underground cable	$ 20.30
Customer Provided Trench & Conduit with:	
1/0 underground cable	$ 4.11
4/0 underground cable	$ 5.12
350 underground cable	$ 7.13

ii. Three Phase 400 Amps or Less and Three Phase Self-Contained Multiple Meter Bases 500 Amps or Less. Only applicable when a single run of service cable is required.

Underground Service Cable (Base charge plus Distance charge)

Base charge from:	
underground	$ 177.00
overhead including 2" riser	$ 991.00
overhead including 3" riser	$ 1,247.00
overhead including 4" riser	$ 1,644.00

~~All Three Phase, Single Phase Greater than 400 Amps, and Single Phase Self-Contained Multiple Meter Bases Greater Than 500 Amps.~~

~~If a three phase, single phase greater than 400 amp, or single phase self-contained multiple meter base greater than 500 amp underground Service Attachment is required, the Applicant or Additional Applicant will pay a non-refundable Underground Service Attachment Charge equal to the Work Order Cost.~~

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

4. Service Attachment Charges (Continued)

Distance charge (per foot)

Company installed Facilities with:		
	1/0 underground cable	$ 15.77
	4/0 underground cable	$ 19.13
	350 underground cable	$ 24.47
Customer Provided Trench & Conduit with:		
	1/0 underground cable	$ 5.01
	4/0 underground cable	$ 6.27
	350 underground cable	$ 10.79

iii. ~~All Three Phase, Single Phase Greater than 400 Amps, and Single Phase Self-Contained Multiple Meter Bases Greater Tthan 500.~~

~~If a three phase, single phase greater than 400 amp, or single phase self-contained multiple meter base greater than 500 amp underground Service Attachment is required, t~~The Applicant or Additional Applicant will pay a non-refundable Underground Service Attachment Charge equal to the Work Order Cost for all requests for services that are not covered under 4(b)(i) or 4(b)(ii).

5. Vested Interest Charges

Additional Applicants connecting to a vested portion of a Line Installation will pay a Vested Interest Charge to be refunded to the Vested Interest Holder. Additional applicants will have two payment options:

Option One - An Additional Applicant may choose to pay an amount determined by this equation:

Vested Interest Charge = A x B x C where;

A = Load Ratio: Additional Applicant's Connected Load divided by the sum of Additional Applicant's Connected Load and Vested Interest Holder's load.
B = Distance Ratio: Additional Applicant's distance divided by original distance.
C = Vested Interest Holder's unrefunded contribution.

Option Two - An Additional Applicant may choose to pay the current Vested Interest, in which case the Additional Applicant will become the Vested Interest Holder and, as such, will become eligible to receive Vested Interest Refunds in accordance with Section 8.a.

~~If Option One is selected, the Additional Applicant has no Vested Interest and the previous Vested Interest Holder remains the Vested Interest Holder. The Vested Interest Holder's Vested Interest will be reduced by the newest Additional Applicant's payment.~~

~~The Vested Interest Charge will not exceed the sum of the Vested Interests in the Line Installation. If an Additional Applicant connects to a portion of a vested Line Installation which was established under a prior rule or schedule, the Vested Interest Charges of the previous rule or schedule apply to the Additional Applicant.~~

~~6. Other Charges~~

~~a. Alteration Charges. If an Applicant or Additional Applicant requests a Relocation, Upgrade, Conversion or removal of Company facilities, the Applicant or Additional Applicant will pay a non-refundable charge equal to the Cost Quote.~~

~~b. Engineering Charge. Applicants or Additional Applicants will be required to prepay all engineering costs for Line Installations and/or Alterations greater than 16 estimated hours. Estimates equal to or less than 16 hours will be billed to the Applicant or Additional Applicant as part of the construction costs, or after the engineering is completed in instances where construction is not requested. Engineering charges will be calculated at $97.00 per hour.~~

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

5. Vested Interest Charges (Continued)

If Option One is selected, the Additional Applicant has no Vested Interest and the previous Vested Interest Holder remains the Vested Interest Holder. The Vested Interest Holder's Vested Interest will be reduced by the newest Additional Applicant's payment.

The Vested Interest Charge will not exceed the sum of the Vested Interests in the Line Installation. If an Additional Applicant connects to a portion of a vested Line Installation which was established under a prior rule or schedule, the Vested Interest Charges of the previous rule or schedule apply to the Additional Applicant.

6. Other Charges

a. Alteration Charges. If an Applicant or Additional Applicant requests a Relocation, Upgrade, Conversion or removal of Company facilities, the Applicant or Additional Applicant will pay a non-refundable charge equal to the Cost Quote.

b. Engineering Charge. Applicants or Additional Applicants will be required to prepay all engineering costs for Line Installations and/or Alterations greater than 16 estimated hours. Estimates equal to or less than 16 hours will be billed to the Applicant or Additional Applicant as part of the construction costs, or after the engineering is completed in instances where construction is not requested. Engineering charges will be calculated at $97.00 per hour.

~~**6. Other Charges (Continued)**~~

c. Engineering Charges for Agencies and Taxing Districts of the State of Idaho. Under the authority of Idaho Code § 67-2302, an agency or taxing district of the State of Idaho may invoke its right to decline to pay engineering charges until the engineering services have been performed and billed to the agency or taxing district. Any state agency or taxing district that claims it falls within the provisions of Idaho Code § 67-2302 must notify Idaho Power of such claim at the time Idaho Power requests prepayment of the engineering charges. Idaho Power may require that the state agency or taxing district's claim be in writing. If the state agency or taxing district that has invoked the provisions of Idaho Code § 67-2302 does not pay the engineering charges within the 60-day period as provided in that statute, all the provisions of that statute will apply.

d. Joint Trench Charge. Applicants, Additional Applicants, and subdividers will pay the Company for trench and backfill costs included in the Cost Quote. In the event the Company is able to defray any of the trench and backfill costs by sharing a trench with other utilities, the cost reduction will be included in the Cost Quote.

e. Rights-of-Way and Easement Charge. Applicants or Additional Applicants will be responsible for any costs associated with the acquisition of rights-of-way or easements.

~~f. Temporary Line Installation Charge. Applicants or Additional Applicants will pay the installation and removal costs of providing Temporary Line Installations.~~

~~g. Temporary Service Attachment Charge. Applicants or Additional Applicants will pay for Temporary Service Attachments as follows:~~

~~i. Underground - $76.00~~

~~The customer-provided meter post must be set within two linear feet of the Company's existing transformer or junction box.~~

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

6. Other Charges (Continued)

f. Temporary Line Installation Charge. Applicants or Additional Applicants will pay the installation and removal costs of providing Temporary Line Installations.

g. Temporary Service Attachment Charge. Applicants or Additional Applicants will pay for Temporary Service Attachments as follows:

i. Underground - $76.00

The customer-provided meter post must be set within two linear feet of the Company's existing transformer or junction box.

~~g. Temporary Service Attachment Charge (Continued)~~

ii. Overhead - $330.00

The customer-provided meter pole shall be set in a location that does not require more than 100 feet of #2 aluminum service conductor that can be readily attached to the permanent location by merely relocating it.

The electrical facilities provided by the customer on the meter pole shall be properly grounded, electrically safe, meet all clearance requirements, and ready for connection to Company facilities.

The customer shall obtain all permits required by the applicable state, county, or municipal governments and will provide copies or verification to the Company as required. The above conditions must be satisfied before the service will be attached.

h. Temporary Service (Overhead or Underground), Overhead Permanent, and Customer Provided Trench Inspection Return Trip Charge. A Return Trip Charge of $76.00 will be assessed each time Company personnel are dispatched to the job site, but are unable to connect the service. The charge will be billed after the conditions have been satisfied and the connection has been made.

i. Unusual Conditions Charge. Applicants, Additional Applicants, and subdividers will pay the Company the additional costs associated with any Unusual Conditions included in the Cost Quote. This payment, or portion thereof, will be refunded to the extent that the Unusual Conditions are not encountered.

~~In the event that the estimate of the Unusual Conditions included in the Cost Quote is equal to or greater than $10,000, the Applicant, Additional Applicant or subdivider may either pay for the Unusual Conditions~~

~~or, at the option of the Company, may furnish an Irrevocable Letter of Credit drawn on a local bank or local branch office issued in the name of Idaho Power Company for the amount of the Unusual Conditions. Upon completion of that portion of the project which included an Unusual Conditions estimate, Idaho Power Company will bill the Applicant, Additional Applicant or subdivider for the amount of Unusual Conditions encountered up to the amount established in the Irrevocable Letter of Credit. The Applicant, Additional Applicant or subdivider will have 15 days from the issuance of the Unusual Conditions billing to make payment. If the Applicant, Additional Applicant or subdivider fails to pay the Unusual Conditions bill within 15 days, Idaho Power will request payment from the bank.~~

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

6. Other Charges (Continued)

In the event that the estimate of the Unusual Conditions included in the Cost Quote is equal to or greater than $10,000, the Applicant, Additional Applicant or subdivider may either pay for the Unusual Conditions or, at the option of the Company, may furnish an Irrevocable Letter of Credit drawn on a local bank or local branch office issued in the name of Idaho Power Company for the amount of the Unusual Conditions. Upon completion of that portion of the project which included an Unusual Conditions estimate, Idaho Power Company will bill the Applicant, Additional Applicant or subdivider for the amount of Unusual Conditions encountered up to the amount established in the Irrevocable Letter of Credit. The Applicant, Additional Applicant or subdivider will have 15 days from the issuance of the Unusual Conditions billing to make payment. If the Applicant, Additional Applicant or subdivider fails to pay the Unusual Conditions bill within 15 days, Idaho Power will request payment from the bank.

j. Underground Service Return Trip Charge. When a customer agrees to supply the trench, backfill, conduit, and compaction for an underground service, an Underground Service Return Trip Charge of $126.00 will be assessed each time the Company's installation crew is dispatched to the job site at the customer's request, but is unable to complete the cable installation and energize the service due to the Company's required specifications not being met.

7. Line Installation, Shared Terminal Facilities and Service Attachment Allowances

The Company will contribute an Allowance toward the cost of Terminal Facilities associated with an additional Line Installation and/or Service Attachment. If a Customer increases their consumptive load and is responsible for upgrading Shared Terminal Facilities, such Customer will receive an Allowance toward the cost of the upgraded Shared Terminal Facilities. Allowances are based on the cost of providing and installing Standard Terminal Facilities for single phase and three phase services.

a. Allowances for Overhead and Underground Line Installations, Shared Terminal Facilities and Overhead Service Attachments

Class of Service	Maximum Allowance per Service
Residential:	
Schedules 1, 3, 5, 6	$4,233.00
Non-residence	$ 0.00
Non-residential:	
Schedules 7, 8, 9, 24	
Single Phase	$4,233.00

Three Phase	$8,707.00
~~Large Power Service~~	
~~Schedule 19~~	~~Case-By-Case~~

~~b. Allowances for Subdivisions and Multiple Occupancy Projects~~

~~Developers of Subdivisions and Multiple Occupancy Projects will receive a $4,233.00 Allowance for each single phase transformer installed within a development and a $8,707.00 Allowance for each three phase transformer installed within a development. Subdividers will be eligible to receive Allowances for Terminal Facilities installed inside residential and non-residential subdivisions.~~

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

7. Line Installation, Shared Terminal Facilities and Service Attachment Allowances (Continued)

Large Power Service Schedule 19	Case-By-Case

b. Allowances for Subdivisions and Multiple Occupancy Projects
Developers of Subdivisions and Multiple Occupancy Projects will receive a $4,233.00 Allowance for each single phase transformer installed within a development and a $8,707.00 Allowance for each three phase transformer installed within a development. Subdividers will be eligible to receive Allowances for Terminal Facilities installed inside residential and non-residential subdivisions.

8. Refunds

a. Vested Interest Refunds. Vested Interest Refunds will be paid by the Company and funded by the Additional Applicant's Vested Interest Charge as calculated in accordance with Section 5. The initial Applicant will be eligible to receive refunds up to 80 percent of their original construction cost. Additional Applicants that become Vested Interest Holders will be eligible to receive refunds up to their total contribution less 20 percent of the original construction cost.

A Vested Interest Holder and the Company may agree to waive the Vested Interest payment requirements of Additional Applicants with loads less than an agreed upon level. Waived Additional Applicants will not be considered Additional Applicants for purposes of Section 8.a.i. (1) below.

i. Vested Interest Refund Limitations

(1). Vested Interest Refunds will be funded by no more than 4 Additional Applicants during the 5-year period following the completion date of the Line Installation for the initial Applicant.

(2). In no circumstance will refunds exceed 100 percent of the refundable portion of any party's cash payment to the Company.

b. Subdivision Refunds.

i. Applicants will be eligible for Vested Interest Refunds for facilities installed inside Subdivisions if the construction was NOT part of the initial Line Installation. Customers requesting additional Line Installations within a Subdivision will be considered new Applicants and become eligible for Vested Interest Refunds.

~~ii. A subdivider will be eligible for Vested Interest Refunds for payments for Line Installations outside subdivisions.~~

RULE H
NEW SERVICE ATTACHMENTS
AND DISTRIBUTION LINE
INSTALLATIONS OR
ALTERATIONS
(Continued)

8. Refunds (Continued)

ii. ~~ii.~~ A subdivider will be eligible for Vested Interest Refunds for payments for Line Installations outside subdivisions.

9. Local Improvement Districts

Unless specifically provided for under this paragraph, a Local Improvement District will be provided service under the general terms of this rule.

The Company will provide a cost estimate and feasibility study for a Local Improvement District within 120 days after receiving the resolution from the requesting governing body. The Cost Quote will be based on Work Order Costs and will not be considered binding on the Company if construction is not commenced within 6 months of the submission of the estimate for reasons not within the control of the Company. The governing body issuing the resolution will pay the Company for the costs of preparing the cost estimate and feasibility study regardless of whether the Line Installation or Alteration actually takes place.

After passage of the Local Improvement District ordinance, the Company will construct the Line Installation or Alteration. Upon completion of the project, the Company will submit a bill to the Local Improvement District for the actual cost of the work performed, including the costs of preparing the cost estimate and feasibility study. If the actual cost is less than the estimated cost, the Local Improvement District will pay the actual cost. If the actual cost exceeds the estimated cost, the Local Improvement District will pay only the estimated cost. The governing body will pay the Company within 30 days after the bill has been submitted.

A Local Improvement District will be eligible for an Allowance for any new load connecting for service upon the completion of the Line Installation. A Local Improvement District will retain a Vested Interest in any Line Installation to the Local Improvement District. A Local Improvement District may waive payments for Vested Interest from Additional Applicants within the Local Improvement District.

SCHEDULE 1
RESIDENTIAL SERVICE
STANDARD PLAN
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-summer
Service Charge, per month	$~~15.00~~25.00	$~~15.00~~25.00
Energy Charge, per kWh		
First 800 kWh	~~9~~12.~~9398~~5685¢	~~8~~9.~~7476~~9581¢
801-2000 kWh	~~11~~13.~~9518~~7920¢	~~9~~10.~~6439~~4567¢
All Additional kWh Over 2000	~~14~~15.~~1985~~1580¢	~~10~~11.~~6805~~0331¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 3
MASTER-METERED MOBILE HOME PARK
RESIDENTIAL SERVICE

AVAILABILITY

Service under this schedule is available to master-metered mobile home parks included on the Company's list of "grandfathered" mobile home parks on file with the Idaho Public Utilities Commission receiving electric service under Schedule 1 as of March 20, 2009. Customers included on the Company's list of "grandfathered" mobile home parks as of March 20, 2009, will automatically be transferred to this Schedule on their next regularly scheduled cycle read date that occurs on or after March 21, 2009.

APPLICABILITY

Service under this schedule is applicable to Electric Service provided to a master-metered residential mobile home park for residential service for general domestic uses, including single phase motors of 7½ horsepower rating or less. This schedule is not applicable to standby service or shared service.

TYPE OF SERVICE

The type of service provided under this schedule is single phase, alternating current at approximately 120 or 240 volts and 60 cycles, supplied through one meter at one Point of Delivery.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit):

Service Charge, per month	$~~15.00~~25.00
Energy Charge, per kWh	
all kWh	1~~0~~3.~~7277~~1324¢

Minimum Charge

The monthly Minimum Charge shall be the sum of the Service Charge, the Energy Charge, and the Power Cost Adjustment.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 5
RESIDENTIAL SERVICE
TIME-OF- USE PLAN
(OPTIONAL)

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Idaho to residential Customers where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served, additional investment by the Company for new transmission, substation or terminal facilities is not necessary to supply the desired service, and Advanced Meter Reading (AMR) equipment is installed.

The Residential Service Time-of-Use Plan is an optional, voluntary service that provides residential Customers the option to take electric service with seasonal time-of-use energy rates. If a Customer requests to participate in this schedule, the Customer will be placed on the schedule effective with their next billing cycle.

A Customer may terminate their participation on this schedule at any time. However, the Customer may not subsequently elect service under this schedule for one year after the effective date of cancellation. If a Customer requests to be taken off of the schedule, the Customer will be removed from the schedule as of the last meter read date.

APPLICABILITY

Service under this schedule is applicable to Electric Service required for residential service Customers for general domestic uses, including single phase motors of 7½ horsepower rating or less, subject to the following conditions:

1. When a portion of a dwelling is used regularly for business, professional or other gainful purposes, or when service is supplied in whole or in part for business, professional, or other gainful purposes, the Premises will be classified as non-residential and the appropriate general service schedule will apply. However, if the wiring is so arranged that the service for residential purposes can be metered separately, this schedule will be applied to such service.

2. Whenever the Customer's equipment does not conform to the Company's specifications for service under this schedule, service will be supplied under the appropriate General Service Schedule.

3. This schedule is not applicable to standby service, service for resale, or shared service.

TYPE OF SERVICE

The type of service provided under this schedule is single phase, alternating current at approximately 120 or 240 volts and 60 cycles, supplied through one meter at one Point of Delivery. Upon request by the owner of multi-family dwellings, the Company may provide 120/208 volt service for multi-family dwellings when all equipment is U L approved to operate at 120/208 volts.

~~SUMMER AND NON-SUMMER SEASONS~~

~~The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.~~

SCHEDULE 5
RESIDENTIAL SERVICE
TIME-OF-USE PLAN
(OPTIONAL)
(Continued)

BILL PROTECTION

Customers who begin service under this schedule on or after January 1, 2026, and who have not previously received Bill Protection at the Premises, shall be eligible for Bill Protection. Bill Protection compares the total Energy Charges incurred under this schedule during the initial twelve (12) consecutive billing months of service to the Energy Charges that would have been incurred under Schedule 1 – Residential Service (Standard Plan) for the same usage and billing period. If the cumulative Energy Charges under this schedule exceed those under the Standard Plan by more than ten dollars ($10), the Customer shall receive a one-time bill credit equal to the net difference reduced by the $10 threshold for Bill Protection. Customers who do not remain continuously enrolled in this schedule for the full twelve-month period, who received service under this schedule at the Premises prior to January 1, 2026, or who have previously received Bill Protection at the Premises, are not eligible. Upon conclusion of the Bill Protection period, the Customer shall continue service under this schedule unless the Customer notifies the Company of their intent to return to the Standard Plan or another applicable rate schedule.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.

TIME PERIODS

The time periods are defined as follows. All times are stated in Mountain Time.

Summer Season

On-Peak:	7:00 p.m. to 11:00 pm. Monday through Saturday, except holidays
Mid-Peak	3:00 p.m. to 7:00 p.m. Monday through Saturday, except holidays
Off-Peak:	11:00 p.m. to 3:00 p.m. Monday through Saturday and all hours on Sunday and holidays

Non-summer Season

On-Peak:	6:00 a.m. to 9:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday through Saturday, except holidays
Off-Peak:	9:00 a.m. to 5:00 p.m. and 8:00 p.m. to 6:00 a.m. Monday through Saturday and all hours on Sunday and holidays

Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). When New Year's Day, Independence Day, or Christmas Day falls on Sunday, the Monday immediately following that Sunday will be considered a holiday.

~~MONTHLY CHARGE~~

~~The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).~~

	~~Summer~~	~~Non-summer~~
~~Service Charge, per month~~	~~$15.00~~	~~$15.00~~
~~Energy Charge, per kWh~~		
~~On-Peak~~	~~24.7398¢~~	~~12.8267¢~~
~~Mid-Peak~~	~~12.3701¢~~	~~n/a~~
~~Off-Peak~~	~~6.1850¢~~	~~8.5511¢~~

~~PAYMENT~~

~~The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.~~

SCHEDULE 5
RESIDENTIAL SERVICE
TIME-OF-USE PLAN
(OPTIONAL)
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-summer
Service Charge, per month	$~~15.00~~25.00	$~~15.00~~25.00
Energy Charge, per kWh		
On-Peak	~~24.7398~~32.2968¢	~~12.8267~~14.3396¢
Mid-Peak	~~12.3701~~16.1484¢	n/a
Off-Peak	~~6.1850~~8.0742¢	~~8.5511~~9.5597¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

APPLICABILITY (Continued)

6. Customer meets all applicable requirements detailed in the Company's Schedule 68, Interconnections to Customer Distributed Energy Resources.

7. Legacy Status for eligible Exporting Systems will terminate December 2045.

8. The Legacy Status of the Exporting System is transferrable to a subsequent Customer at the premises for which a valid on-site generation service is in effect. Each Customer of a Legacy System taking service under Schedule 6 will be responsible for complying with the terms and conditions of the on-site generation service in effect for that premises.

9. A Legacy System that is offline for over six (6) months or that is moved to a different site shall forfeit Legacy Status of the Exporting System.

10. To remain eligible for Legacy Status, a Customer may increase the capacity of a Legacy System by no more than 10 percent of the originally installed nameplate capacity, or 1 kW, whichever is greater, to allow for the replacement of broken or degraded components. If a Customer expands a Legacy System beyond these limits and wishes to maintain Legacy Status for the original system, the new portion of the DER shall be separately metered and would not qualify for Legacy Status.

11. A Customer with a Legacy System may elect to forfeit the system's Legacy Status by submitting the request to the Company in writing.

DEFINITIONS

Designated Meter is the retail meter physically connected to the Exporting System.

Distributed Energy Resource(s) (DER(s)) is a source of electric power that is not directly connected to the bulk power system. Any combination of Generation Facilities and/or Energy Storage Devices connected in Parallel is considered DER.

Energy Storage Device is a device that captures energy produced at a point in time and stores the energy for use as electricity at a future point in time. An Energy Storage Device is a DER.

Excess Net Energy means the positive difference between the kilowatt-hours (kWh) generated by a Customer and the kWh supplied by the Company over the applicable Billing Period.

Exported Energy means the kWh generated by a Customer in excess of the Customer's on-site consumption that is exported to the Company's system.

Exporting System is a Customer-owned DER under the terms of Schedules 6, 8, or 84, which is designed to provide for the transfer of electric energy to the Company. An Exporting System is interconnected to the Company's system under the applicable terms of Schedule 68.

~~Generation Facility means all equipment used to generate electric energy where the resulting energy is delivered to the Company via a single meter at the Point of Delivery or is consumed by the Customer. A Generation Facility is a DER.~~

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

DEFINITIONS (Continued)

Financial Credit represents the amount in dollars carried forward to offset Customer's Monthly Charges in a subsequent Billing Period. A Financial Credit is generated during a Billing Period when the product of Exported Energy and the Export Credit Rate exceeds a Customer Monthly Charges.

Generation Facility means all equipment used to generate electric energy where the resulting energy is delivered to the Company via a single meter at the Point of Delivery or is consumed by the Customer. A Generation Facility is a DER.

Interconnection Facilities are all facilities reasonably required by Prudent Electrical Practices and the applicable electric and safety codes to interconnect and safely deliver energy from the DER to the Point of Delivery.

Kilowatt Hour Credit ("kWh Credit") is the accumulated Excess Net Energy that is carried forward to offset energy usage in a subsequent Billing Period.

Legacy Status refers to the ability for a system to receive Net Energy Metering, including net monthly one-for-one kWh credit compensation for Excess Net Energy.

Legacy System means any system that meets the applicable criteria as described in Order Nos. 34509 and 34546.

Net Billing is the compensation structure applicable to all systems that do not meet the criteria of a Legacy System. Net Billing will be effective with each eligible customer's first billing cycle after January 1, 2024.

Net Energy Metering is the compensation structure applicable to all Legacy Systems.

Parallel connection means generating electricity from an on-site generation system that is connected to and receives voltage from Idaho Power's system.

Point of Delivery is the retail metering point where the Company's and the Customer's electrical facilities are interconnected to allow the Customer to take retail electric service from the Company.

Prudent Electrical Practices are those practices, methods and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

Schedule 68 is the Company's service schedule which provides for interconnection to DERs or its successor schedule(s) as approved by the Commission.

~~TYPE OF SERVICE~~

~~The type of service provided under this schedule is single phase, alternating current at approximately 120 or 240 volts and 60 cycles, supplied through one meter at one Point of Delivery. Upon~~

~~request by the owner of multi-family dwellings, the Company may provide 120/208 volt service for multi-family dwellings when all equipment is U L approved to operate at 120/208 volts.~~

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

TYPE OF SERVICE

The type of service provided under this schedule is single phase, alternating current at approximately 120 or 240 volts and 60 cycles, supplied through one meter at one Point of Delivery. Upon request by the owner of multi-family dwellings, the Company may provide 120/208 volt service for multi-family dwellings when all equipment is U L approved to operate at 120/208 volts.

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions for Net Energy Metering under this schedule.

1. Balances of generation and usage by the Customer:

a. If electricity supplied by the Company during the Billing Period exceeds the electricity generated by the Customer and delivered to the Company during the Billing Period, the Customer shall be billed for the net electricity supplied by the Company at the rates contained within this schedule, in accordance with normal metering practices.

b. If electricity generated by the Customer and delivered to the Company during the Billing Period exceeds the electricity supplied by the Company during the Billing Period, the Excess Net Energy shall be carried forward as a kWh ~~c~~Credit to offset energy usage in a subsequent Billing Period. ~~Excess Net Energy credits~~kWh Credits are subject to the following provisions:

i. kWh Credits can only be used to offset billed kWh consumption. Customers shall be billed for all applicable non-energy charges for the Billing Period according to the applicable standard service schedule.

ii. kWh Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

iii. kWh Credits are non-transferrable in the event that a Customer relocates and/or discontinues service at the Point of Delivery associated with the Exporting System. Any unused kWh ~~c~~Credits will expire at the time the final bill is prepared.

c. Compensation for the balance of generation and usage by the Customer is subject to change upon Commission approval.

2. Aggregation of meters for the annual transfer of unused Excess Net Energy credits:

a. If a balance of ~~Excess Net Energy~~kWh ~~c~~ Credits exists at a Designated Meter the Customer may request to transfer the unused kWh ~~c~~Credits to offset energy consumption at eligible meters. A meter is eligible for aggregation if it meets all of the following criteria:

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE (Continued)

i. The account subject to offset is held by the Customer; and

ii. The meter is located on, or contiguous to, the property on which the Designated Meter is located. For the purposes of this tariff, contiguous property includes property that is separated from the Premises of the Designated Meter by public or railroad rights of way; and

iii. The meter is served by the same primary feeder as the Designated Meter at the time the Customer files the application for the Exporting System; and

iv. The electricity recorded by the meter is for the Customer's requirements; and

v. kWh Credits may only be transferred to meters taking service under Schedule 1, Schedule 6, Schedule 7, or Schedule 8.

b. Customers may submit requests to transfer ~~Excess Net Energy~~kWh ~~c~~Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power ~~by midnight, Mountain Standard Time~~, on or before January 31. If a Customer does not request to transfer ~~Excess Net Energy~~kWh C~~c~~redits by the January 31 submission deadline ~~Excess Net Energy~~kWh ~~c~~Credits will carry forward to offset consumption at the Designated Meter until they become eligible the following year.

c. Requests to transfer ~~Excess Net Energy~~kWh C~~c~~redits must be executed by the Company no later than March 31. Transfers will be based on the balance of ~~Excess Net Energy~~kWh C~~c~~redits available at the time the transfer is made.

d. If multiple meters are eligible for aggregation, ~~Excess Net Energy~~kWh ~~c~~Credits must first be applied to the Designated Meter, then to eligible meters on rate schedules in accordance with Section 2a(v) above.

e. A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

NET BILLING – CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions for Net Billing under this schedule.

1. Balances of usage and exports by the Customer.

a. The Customer shall be billed for the electricity supplied by the Company at the rates contained within this schedule, in accordance with normal metering practices.

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

NET BILLING – CONDITIONS OF PURCHASE AND SALE (Continued)

b. The Customer shall be credited for Exported Energy at the applicable Export Credit Rate contained within this schedule as a credit in dollars to only offset Monthly Charges. ~~Exported Energy~~ Financial ~~c~~Credits are subject to the following provisions:

i. Financial Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

ii. Financial Credits are transferrable in the event that a Customer relocates. If the establishment of service at the new Point of Delivery is not initiated at the time service at the Designated Meter is discontinued, ~~it is the Customer's responsibility to request the credit transfer when service is established at the new location in Idaho Power's service are~~ any unused Financial Credits will be paid out following the time the final bill is prepared~~a~~.

~~iii. If a Customer discontinues services at the Point of Delivery associated with the Exporting System and does not intend to establish service at another location in Idaho Power's service area any unused credits will be paid out following the time the final bill is prepared.~~

2. Aggregation of meters for the annual transfer of unused credits:

a. If a balance of Financial ~~c~~Credits exists at a Designated Meter, the Customer may request to transfer the unused Financial ~~c~~Credits to eligible meters. A meter is eligible for aggregation if it meets the following criteria:

i. The account subject to offset is held by the Customer, and

ii. The electricity recorded by the meter is for the Customer's requirements.

b. Customers may submit requests to transfer a stated percentage of available Financial ~~c~~Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power ~~by midnight, Mountain Standard Time~~, on or before January 31. If a Customer does not request to transfer Financial ~~c~~Credits by the January 31 submission deadline Financial ~~c~~Credits will carry forward at the Designated Meter until they become eligible for transfer the following year.

~~c.~~ Requests to transfer Financial ~~c~~Credits must be executed by the Company no later than

c. March 31. Transfers will be based on the balance of Financial ~~c~~Credits available at the time the transfer is made.

~~d.~~ A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

SCHEDULE 6
RESIDENTIAL SERVICE
ON-SITE GENERATION
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

The following rate structure and charges are subject to change upon Commission approval:

STANDARD RATES (DEFAULT)

	Summer	Non-summer
Service Charge, per month	$~~15.00~~25.00	$~~15.00~~25.00
Energy Charge, per kWh		
First 800 kWh	~~9~~12.~~9398~~5685¢	~~8~~9.~~7476~~9581¢
801-2000 kWh	~~11~~13.~~9518~~7920¢	~~9~~10.~~6439~~4567¢
All Additional kWh Over 2000	~~14~~15.~~1985~~1580¢	1~~0~~1.~~6805~~0331¢

TIME-OF-USE RATES (OPTIONAL)

	Summer	Non-summer
Service Charge, per month	$~~15.00~~25.00	$~~15.00~~25.00
Energy Charge, per kWh		
On-Peak	~~24~~32.~~7398~~2968¢	1~~2~~4.~~8267~~3396¢
Mid-Peak	~~12~~16.~~3701~~1484¢	n/a
Off-Peak	~~6~~8.~~1850~~0742¢	~~8~~9.~~5511~~5597¢

EXPORT CREDIT RATE

The following rate structure and credits are subject to change upon Commission approval:

	Summer	Non-summer
Export Credit Rate, per kWh		
On-Peak	16.9966¢	4.8365¢
Off-Peak	5.6533¢	4.8365¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 7
SMALL GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-summer
Service Charge, per month	$~~25.00~~30.00	$~~25.00~~30.00
Energy Charge, per kWh		
First 300 kWh	~~7~~8.~~1782~~8802¢	~~7~~8.~~1782~~8802¢
All Additional kWh	~~8~~10.~~2032~~1485¢	~~7~~8.~~1800~~8827¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

APPLICABILITY (Continued)

4. Legacy Status for eligible Exporting Systems will terminate December 2045.

5. The Legacy Status of the Exporting System is transferable to a subsequent Customer at the premises for which a valid on-site generation service is in effect. Each Customer of a Legacy System taking service under Schedule 8 will be responsible for complying with the terms and conditions of the on-site generation service in effect for that premises.

6. A Legacy System that is offline for over six (6) months or that is moved to a different site shall forfeit Legacy Status of the Exporting System.

7. To remain eligible for Legacy Status, a Customer may increase the capacity of a Legacy System by no more than 10 percent of the originally installed nameplate capacity, or 1 kW, whichever is greater, to allow for the replacement of broken or degraded components. If a Customer expands a Legacy System beyond these limits and wishes to maintain Legacy Status for the original System, the new portion of the DER shall be separately metered and would not qualify for Legacy Status.

8. A Customer with Legacy System may elect to forfeit the system's Legacy Status by submitting the request to the Company in writing.

DEFINITIONS

Designated Meter is the retail meter physically connected to the Exporting System.

Distributed Energy Resource(s) (DER(s)) is a source of electric power that is not directly connected to the bulk power system. Any combination of Generation Facilities and/or Energy Storage Devices connected in Parallel is considered a DER.

Energy Storage Device is a device that captures energy produced at a point in time and stores the energy for use as electricity at a future point in time. An Energy Storage Device is a DER.

Excess Net Energy means the positive difference between the kilowatt-hours (kWh) generated by a Customer and the kWh supplied by the Company over the applicable Billing Period.

Exported Energy means the kWh generated by a Customer in excess of the Customer's on-site consumption that is exported to the Company's system.

Exporting System is a Customer-owned DER under the terms of Schedules 6, 8, or 84, which is designed to provide for the transfer of electricity energy to the Company. An Exporting System is interconnected to the Company's system under the applicable terms of Schedule 68.

Financial Credit represents the amount in dollars carried forward to offset Monthly Charges in a subsequent Billing Period. A Financial Credit is generated during a Billing Period when the product of Exported Energy and the Export Credit Rate exceeds a Customer's Monthly Charges.

~~Generation Facility means all equipment used to generate electric energy where the resulting energy is either delivered to the Company via a single meter at the Point of Delivery or is consumed by the Customer. A Generation Facility is a DER.~~

~~Interconnection Facilities are all facilities reasonably required by Prudent Electrical Practices and the applicable electric and safety codes to interconnect and safely deliver energy from the DER to the Point of Delivery.~~

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

DEFINITIONS (Continued)

Generation Facility means all equipment used to generate electric energy where the resulting energy is either delivered to the Company via a single meter at the Point of Delivery or is consumed by the Customer. A Generation Facility is a DER.

Interconnection Facilities are all facilities reasonably required by Prudent Electrical Practices and the applicable electric and safety codes to interconnect and safely deliver energy from the DER to the Point of Delivery.~~.~~

Kilowatt Hour Credit ("kWh Credit") is the accumulated Excess Net Energy that is carried forward to offset energy usage in a subsequent Billing Period.

Legacy Status refers to the ability for a system to receive Net Energy Metering, including net monthly one-for-one kWh credit compensation for Excess Net Energy.

Legacy System means for any system that meets the applicable criteria as described in Order No. 34509 and 34546.

Net Billing is the compensation structure applicable to all systems that do not meet the criteria of a Legacy System. Net Billing will be effective with each eligible customer's first billing cycle after January 1, 2024.

Net Energy Metering is the compensation structure applicable to all Legacy Systems.

Parallel connection means generating electricity from an on-site generation system that is connected to and receives voltage from Idaho Power's system.

Point of Delivery is the retail metering point where the Company's and the Customer's electrical facilities are interconnected to allow the Customer to take retail electric service from the Company.

Prudent Electrical Practices are those practices, methods, and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

Schedule 68 is the Company's service schedule which provides for interconnection to DERs or its successor schedule(s) as approved by the Commission.

TYPE OF SERVICE

The type of service provided under this schedule is single and/or three-phase alternating current, at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

~~NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE~~

~~The conditions listed below shall apply to all transactions for Net Energy Metering under this schedule.~~

~~1. Balances of generation and usage by the Customer:~~

~~a. If electricity supplied by the Company during the Billing Period exceeds the electricity generated by the Customer and delivered to the Company during the Billing Period, the Customer shall be billed for the net electricity supplied by the Company at the rates contained within this schedule, in accordance with normal metering practices.~~

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions for Net Energy Metering under this schedule.

1. Balances of generation and usage by the Customer:

a. If electricity supplied by the Company during the Billing Period exceeds the electricity generated by the Customer and delivered to the Company during the Billing Period, the Customer shall be billed for the net electricity supplied by the Company at the rates contained within this schedule, in accordance with normal metering practices.
~~NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE (Continued)~~

b. If electricity generated by the Customer and delivered to the Company during the Billing Period exceeds the electricity supplied by the Company during the Billing Period, the Excess Net Energy shall be carried forward as a kWh ~~c~~Credit to offset energy usage in a subsequent Billing Period. ~~Excess Net Energy~~kWh C~~c~~redits are subject to the following provisions:

i. kWh Credits can only be used to offset billed kWh consumption. Customers shall be billed for all applicable non-energy charges for the Billing Period according to the applicable standard service schedule.

ii. kWh Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

iii. kWh Credits are non-transferrable in the event that a Customer relocates and/or discontinues service at the Point of Delivery associated with the Exporting System. Any unused kWh ~~c~~Credits will expire at the time the final bill is prepared.

c. Compensation for the balance of generation and usage by the Customer is subject to change upon Commission approval.

2. Aggregation of meters for the annual transfer of unused ~~Excess Net Energy~~kWh credits:

a. If a balance of ~~Excess Net Energy~~kWh ~~c~~Credits exists at a Designated Meter, the Customer may request to transfer the unused kWh ~~c~~Credits to offset energy consumption at eligible meters. A meter is eligible for aggregation if it meets all of the following criteria:

i. The account subject to offset is held by the Customer; and

ii. The meter is located on, or contiguous to, the property on which the Designated Meter is located. For the purposes of this tariff, contiguous property includes property that is separated from the Premises of the Designated Meter by public or railroad rights of way; and

iii. The meter is served by the same primary feeder as the Designated Meter at the time the Customer files the application for the Exporting System; and

~~iv. The electricity recorded by the meter is for the Customer's requirements; and~~

~~v. Credits may only be transferred to meters taking service under Schedule 1, Schedule 6, Schedule 7, or Schedule 8.~~

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE (Continued)

iv. The electricity recorded by the meter is for the Customer's requirements; and

v. kWh Credits may only be transferred to meters taking service under Schedule 1, Schedule 6, Schedule 7, or Schedule 8.

b. Customers may submit requests to transfer ~~Excess Net Energy~~kWh ~~c~~Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power ~~by midnight, Mountain Standard Time,~~ on or before January 31. If a Customer does not request to transfer ~~Excess Net Energy~~kWh ~~c~~Credits by the January 31 submission deadline ~~Excess Net Energy~~kWh ~~c~~Credits will ~~C~~carry forward to offset consumption at the Designated Meter until they become eligible for transfer the following year.

c. Requests to transfer ~~Excess Net Energy~~kWh ~~c~~Credits must be executed by the Company no later than March 31. Transfers will be based on the balance of ~~Excess Net Energy~~kWh ~~c~~Credits available at the time the transfer is made.

d. If multiple meters are eligible for aggregation, ~~Excess Net Energy~~kWh ~~c~~Credits must first be applied to the Designated Meter, then to eligible meters on rate schedules in accordance with Section 2a(v) above.

e. A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

NET BILLING – CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions for Net Billing under the Schedule.

1. Balances of usage and exports by the Customer.

a. The Customer shall be billed for the electricity supplied by the Company at the rates contained within this schedule, in accordance with normal metering practices.

b. The Customer shall be credited for Exported Energy at the applicable Export Credit Rate contained within this schedule as a credit in dollars to only offset Monthly Charges. ~~Exported Energy~~Financial ~~c~~Credits are subject to the following provisions:

i. Financial Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

~~ii.~~ Financial Credits are transferrable in the event that a Customer relocates. If the establishment of service at the new Point of Delivery is not initiated at the time service at the Designated Meter is discontinued, any unused Financial Credits will be paid out following the time the final bill is prepared.~~, it is the Customer's responsibility to request the credit transfer when service is established at the new location in Idaho Power's service area.~~

~~iii.~~i. ~~If a Customer discontinues service at the Point of Delivery associated with the Exporting System and does not intend to establish service at another location in Idaho Power's service area any unused credits will be paid out following the time the final bill is prepared.~~

ii.

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

NET BILLING – CONDITIONS OF PURCHASE AND SALE (Continued)

~~If a Customer discontinues service at the Point of Delivery associated with the Exporting System and does not intend to establish service at another location in Idaho Power's service area any unused credits will be paid out following the time the final bill is prepared.~~

2. Aggregation of meters for the annual transfer of unused Financial ~~c~~Credits:

a. If a balance of Financial~~c~~ Credits exists at a Designated Meter, the Customer may request to transfer the unused Financial ~~c~~Credits to eligible meters. A meter is eligible for aggregation if it meets the following criteria:

i. The account subject to offset is held by the Customer, and

ii. The electricity recorded by the meter is for the Customer's requirements.

b. Customers may submit requests to transfer a stated percentage of available Financial ~~c~~Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power ~~by midnight, Mountain Standard Time,~~ on or before January 31. If a Customer does not request to transfer Financial ~~c~~Credits by the January 31 submission deadline Financial ~~c~~Credits will carry forward at the Designated Meter until they become eligible for transfer the following year.

c. Requests to transfer Financial ~~c~~Credits must be executed by the Company no later than March 31. Transfers will be based on the balance of Financial~~c~~ Credits available at the time the transfer is made.

d. A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

NET ENERGY METERING & NET BILLING – GENERAL CONDITIONS

1. The Customer shall never deliver or attempt to deliver energy to the Company's system when the Company's system serving the Customer's DER is de-energized for any reason.

2. The Company shall not be liable directly or indirectly for permitting or continuing to allow an attachment of an Exporting System to the Company's system, or for the acts or omissions of the Customer that cause loss or injury, including death, to any third party.

3. The Customer is responsible for all costs associated with the DER and Interconnection Facilities. The Customer is also responsible for all costs associated with any Company additions, modifications, or upgrades to any Company facilities that the Company determines are necessary as a result of the installation of the DER in order to maintain a safe, reliable electrical system.

4. The Company shall not be obligated to accept, and the Company may require the Customer to curtail, interrupt, or reduce deliveries of energy if the Company, consistent with Prudent Electrical Practices, determines that curtailment, interruption, or reduction is necessary because of line

construction or maintenance requirements, emergencies, or other critical operating conditions on its system.

~~5. If the Company is required by the Commission to institute curtailment of deliveries of electricity to its customers, the Company may require the Customer to curtail its consumption of electricity in the same manner and to the same degree as other Customers on the Company's standard service schedules.~~

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION

NET ENERGY METERING & NET BILLING – GENERAL CONDITONS (Continued)

5. If the Company is required by the Commission to institute curtailment of deliveries of electricity to its customers, the Company may require the Customer to curtail its consumption of electricity in the same manner and to the same degree as other Customers on the Company's standard service schedules.

6. The Customer shall grant to the Company all access to all Company equipment and facilities including adequate and continuing access rights to the property of the Customer for the purpose of installation, operation, maintenance, replacement, or any other service required of said equipment as well as all necessary access for inspection, switching, and any other operational requirements of the Customer's Interconnections Facilities.

7. The Customer shall notify the Company immediately if an Exporting System is permanently removed or disabled. Permanent removal or disablement for the purposes of this Schedule is any removal or disablement of an Exporting System lasting longer than six (6) months. Customers with permanently removed or disabled systems will be removed from service under this schedule and placed on the appropriate standard service schedule.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.

TIME PERIODS – EXPORT CREDIT RATE

The time periods for the Export Credit Rate are defined as follows. All times are stated in Mountain Time.

Summer Season

On-Peak:	3:00 p.m. to 11:00 p.m. Monday through Saturday, except holidays
Off-Peak	11:00 p.m. to 3:00 p.m. Monday through Saturday and all hours on Sunday and holidays

Non-summer Season

Off-Peak:	All hours Monday through Sunday

Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If New Year's Day, Independence Day, or Christmas Day falls on Sunday, the following Monday will be designated a holiday.

~~MONTHLY CHARGE~~

~~The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).~~

SCHEDULE 8
SMALL GENERAL SERVICE
ON-SITE GENERATION
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 54 (Fixed Cost Adjustment), Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

~~MONTHLY CHARGE (Continued)~~

The following charges are subject to change upon Commission approval:

	Summer	Non-summer
Service Charge, per month	$~~25.00~~30.00	$~~25.00~~30.00
Energy Charge, per kWh		
First 300 kWh	~~7~~8.~~1782~~8802¢	~~7~~8.~~1782~~8802¢
All Additional kWh	~~8~~10.~~2032~~1485¢	~~7~~8.~~1800~~8827¢

EXPORT CREDIT RATE

The following rate structure and credits are subject to change upon Commission approval:

	Summer	Non-summer
Export Credit Rate, per kWh		
On-Peak	16.9966¢	4.8365¢
Off-Peak	5.6533¢	4.8365¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE – STANDARD RATES (DEFAULT)	Summer	Non-summer
Service Charge, per month	$~~25.00~~30.00	
$~~25.00~~30.00		
Basic Charge, per kW of Basic Load Capacity Basic Load Capacity	$~~1~~2.~~54~~03	
$~~1~~2.~~54~~03		
Demand Charge, per kW of Billing Demand Billing Demand	$~~7~~10.~~95~~14	
$~~6~~8.~~27~~16		
Energy Charge, per kWh All kWh	5.~~3524~~4088¢	5.~~1627~~3804¢

SECONDARY SERVICE – TIME-OF-USE (OPTIONAL)	Summer	Non-summer
Service Charge, per month	$~~25.00~~30.00	
$~~25.00~~30.00		
Basic Charge, per kW of Basic Load Capacity Basic Load Capacity	$~~1.54~~2.03	
$~~1.54~~2.03		
Demand Charge, per kW of Billing Demand Billing Demand	$~~7.95~~10.14	
$~~6.27~~8.16		
Energy Charge, per kWh		
On-Peak	~~5~~7.~~7270~~1725¢	~~5~~5.~~4593~~9560¢
Mid-Peak	~~5~~6.~~7270~~0348¢	~~5~~5.~~2149~~4608¢
Off-Peak	~~5~~4.~~1611~~8568¢	~~5~~5.~~0204~~1083¢

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month $~~340.00~~360.00	$~~340.00~~360.00	
Basic Charge, per kW of Basic Load Capacity	$~~1.79~~2.22	$~~1.79~~2.22
Demand Charge, per kW of Billing Demand	$~~8.18~~11.04	$~~7.75~~9.91
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.56~~2.10	n/a
Energy Charge, per kWh		
On-Peak	~~5~~6.~~2834~~6710¢	~~4~~5.~~7992~~4064¢
Mid-Peak	~~5~~5.~~2834~~5532¢	4.~~5625~~9269¢
Off-Peak	4.~~7357~~3957¢	4.~~3735~~5854¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month $~~340.00~~360.00	$~~340.00~~360.00	
Basic Charge, per kW of Basic Load Capacity	$~~1.07~~0.96	$~~1.07~~0.96
Demand Charge, per kW of Billing Demand	$~~7~~8.~~22~~63	$~~6.32~~8.44
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.56~~2.10	n/a
Energy Charge, per kWh		
On-Peak	~~5~~6.~~2156~~8460¢	~~4~~5.~~7042~~4073¢
Mid-Peak	~~5~~5.~~2156~~6891¢	4.~~4678~~9282¢
Off-Peak	4.~~6621~~4914¢	4.~~2782~~5870¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 15
DUSK TO DAWN CUSTOMER
LIGHTING
(Continued)

NEW FACILITIES

Where facilities of the Company are not presently available for a lighting fixture installation which will provide satisfactory lighting service for the Customer's Premises, the Company may install overhead or underground secondary service facilities, including secondary conductor, poles, anchors, etc., a distance not to exceed 300 feet to supply the desired service, all in accordance with the charges specified below.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

1. Monthly Per Unit Charge on existing facilities:

AREA LIGHTING

LED Fixture

Watt (Maximum)	Lumen (Minimum)	Base Rate
40	3,600	$~~9~~11.~~62~~17
85	7,200	$11.~~72~~89
200	18,000	$~~16~~14.~~94~~73

FLOOD LIGHTING

LED Fixture

Watt (Maximum)	Lumen (Minimum)	Base Rate
85	8,100	$1~~9~~6.~~12~~49
150	18,000	$~~21~~17.~~06~~43
300	32,000	$2~~4~~3.~~79~~01

2. For New Facilities Installed Before June 1, 2004: The Monthly Charge for New Facilities installed prior to June 1, 2004, will continue to be assessed a monthly facilities charge in accordance with the changes specified in Schedule 66.

3. For New Facilities Installed On or After June 1, 2004: The non-refundable charge for New Facilities to be installed, such as underground service, overhead secondary conductor, poles, anchors, etc., shall be equal to the work order cost.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

FACILITIES BEYOND THE POINT OF DELIVERY

At the Customer's request and at the option of the Company, transformers and other facilities installed beyond the Point of Delivery to provide Primary or Transmission Service may be owned, operated, and maintained by the Company in consideration of the Customer paying a Facilities Charge to the Company. This service is provided under the provisions set forth in Rule M, Facilities Charge Service.

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.

TEMPORARY SUSPENSION

When a Customer has properly invoked Rule G, Temporary Suspension of Demand, the Basic Load Capacity, the Billing Demand, and the On-Peak Billing Demand shall be prorated based on the period of such suspension in accordance with Rule G. In the event the Customer's metered demand is less than 1,000 kW during the period of such suspension, the Basic Load Capacity and Billing Demand will be set equal to 1,000 kW for purposes of determining the Customer's Monthly Charge.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), and Schedule 96 (Blaine County Surcharge to Fund the Undergrounding of Certain Facilities).

SECONDARY SERVICE	Summer	Non-summer
Service Charge, per month	$~~85.00~~125.00	$~~85.00~~125.00
Basic Charge, per kW of Basic Load Capacity	$~~1.97~~2.47	$~~1.97~~2.47
Demand Charge, per kW of Billing Demand	$~~10.29~~13.99	$~~8~~12.~~28~~01
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1~~2.~~78~~42	n/a
Energy Charge, per kWh		
On-Peak	~~5~~7.~~8739~~3300¢	~~5~~6.~~3117~~0834¢
Mid-Peak	~~5~~6.~~8739~~2088¢	5.~~0747~~5984¢
Off-Peak	5.~~3201~~0473¢	~~4~~5.~~8846~~2530¢

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month $~~415.00~~490.00	$~~415.00~~490.00	
Basic Charge, per kW of Basic Load Capacity	$~~2.17~~2.60	$~~2.17~~2.60
Demand Charge, per kW of Billing Demand	$~~9.84~~13.09	$~~8~~11.~~46~~93
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.56~~2.07	n/a
Energy Charge, per kWh		
On-Peak	~~5~~6.~~1263~~6358¢	~~4~~5.~~6278~~3897¢
Mid-Peak	~~5~~5.~~1263~~5115¢	4.~~3907~~9044¢
Off-Peak	4.~~5720~~3474¢	4.~~2005~~5589¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month $~~415.00~~490.00	$~~415.00~~490.00	
Basic Charge, per kW of Basic Load Capacity	$~~1.83~~1.72	$~~1.83~~1.72
Demand Charge, per kW of Billing Demand	$~~9.99~~14.18	$~~8.60~~12.42
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.56~~2.07	n/a
Energy Charge, per kWh		
On-Peak	~~5~~6.~~1093~~7062¢	~~4~~5.~~5983~~3955¢
Mid-Peak	5.~~1093~~5665¢	4.~~3610~~9099¢
Off-Peak	4.~~5519~~3865¢	4.~~1707~~5641¢

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

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~~SPECIAL ARRANGEMENTS FOR SUBSTATION ALLOWANCES AND/OR TRANSMISSION VESTED INTEREST~~

~~**Definitions**~~

~~Additional Schedule 19 Applicant is a Schedule 19 Customer whose Application requires the Company to provide new or relocated service from Substation Facilities served by an existing section of Transmission Facilities with a Transmission Vested Interest.~~

~~Applicant is a Schedule 19 Customer whose Application requires the Company to provide new or relocated service from Substation Facilities served by Transmission Facilities that are free and clear of any Transmission Vested Interest.~~

~~Application is a request by an Applicant or Additional Schedule 19 Applicant for new electric service from the Company.~~

~~Connected Load is the total nameplate MW rating of the electric loads connected for Schedule 19 service.~~

~~Distribution Facilities include structures, wires, insulators, and related equipment that are operated at a 34.5 kilovolt or lower rating.~~

~~Substation Allowance is the portion of the cost of the Substation Facilities funded by the Company.~~

~~Substation Facilities include those facilities and related equipment that transform the voltage of energy from a 44 kilovolt or higher rating to a 34.5 kilovolt or lower rating.~~

~~Transmission Facilities include structures, wires, insulators, and related equipment that are operated at a 44 kilovolt or higher rating.~~

~~Transmission Line Installation is any installation of new Transmission Facilities owned by the Company.~~

~~Transmission Line Installation Charge is the partially refundable charge assessed an Applicant or Additional Schedule 19 Applicant whenever a Transmission Line Installation is built for that individual.~~

~~Transmission Vested Interest is the right to a refund that an Applicant or Additional Schedule 19 Applicant holds in a specific section of Transmission Facilities when Additional Schedule 19 Applicants attach to that section of Transmission Facilities.~~

~~Transmission Vested Interest Charge is an amount collected from an Additional Schedule 19 Applicant for refund to a Transmission Vested Interest Holder.~~

~~Transmission Vested Interest Holder is a person or entity that has paid a refundable Transmission Line Installation Charge to the Company for a Transmission Line Installation.~~

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

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~~SPECIAL ARRANGEMENTS FOR SUBSTATION ALLOWANCES AND/OR TRANSMISSION VESTED INTEREST (Continued)~~

~~**Definitions** (Continued)~~

~~Transmission Vested Interest Portion is that part of the Company's transmission system in which a Transmission Vested Interest is held.~~

~~**Substation Allowance**~~

~~If a Schedule 19 Customer's request for service requires the installation of new or upgraded transformer capacity in Substation Facilities, the following considerations will be included in the separate agreement between the Customer and the Company:~~

~~The Customer will initially pay for the cost of new or upgraded Substation Facilities required because of the Customer's request. The Customer will be eligible to receive a one-time Substation Allowance based upon subsequent sustained usage of capacity by the Customer.~~

~~a. Substation Allowance: The maximum possible allowance will be determined by multiplying the Customer's actual increase in load by $99,826 per MW, but will not exceed the actual cost of the Substation Facilities.~~

~~b. Substation Allowance Refunds: The Substation Allowance will be refunded to the Customer over a five-year period, with annual payments based on the Customer's Basic Load Capacity at the time of refund. The first refund will be paid one year following the first month energy is delivered through the new Substation Facilities.~~

~~The refunds will occur based on the following adjustment, which will be added to the Substation Allowance received in the previous year. If there is no change in load from the previous year, the Substation Allowance for that year is equal to the Substation Allowance from the previous year:~~

$$\frac{\text{((Change in load from the previous year as measured in MW) x (Substation Allowance per MW))}}{\text{Number of Substation Allowance Refunds remaining in five-year period}}$$

~~The Customer's annual refunds will be made in accordance with the Substation Allowance amount stated in the separate construction agreement between the Customer and the Company.~~

~~**Transmission Vested Interest**~~

~~If a Schedule 19 Customer's request for service requires the installation of new or upgraded capacity in Transmission Facilities, and those Transmission Facilities are serving the Customer by a radial feed, the following considerations will be included in the separate agreement between the Customer and the Company:~~

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

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~~SPECIAL ARRANGEMENTS FOR SUBSTATION ALLOWANCES AND/OR TRANSMISSION VESTED INTEREST (Continued)~~

~~**Transmission Vested Interest** (Continued)~~

~~The Customer will initially pay for the cost of new or upgraded Transmission Facilities required because of the Customer's request. The Customer may be eligible to receive Transmission Vested Interest Refunds in accordance with Schedule 19.~~

~~**Transmission Vested Interest Refunds.**~~

~~Transmission Vested Interest Refunds will be paid by the Company and funded by the Additional Schedule 19 Applicant's Transmission Vested Interest Charge as calculated in accordance with Schedule 19. The initial Applicant will be eligible to receive refunds up to 80 percent of their original construction cost.~~

~~Transmission Vested Interest Refund Limitations~~

~~a. Transmission Vested Interest Refunds will be funded by no more than 4 Additional Schedule 19 Applicants during the 5-year period following the completion date of the Transmission Line Installation.~~

~~b. In no circumstance will refunds exceed 100 percent of the refundable portion of any party's cash payment to the Company.~~

~~**Transmission Vested Interest Charges:**~~

~~Additional Schedule 19 Applicants with a Connected Load of greater than 1 MW who connect to a Transmission Vested Interest Portion of a Transmission Line Installation will pay a Transmission Vested Interest Charge to be refunded to the Transmission Vested Interest Holder.~~

~~An Additional Schedule 19 Applicant will pay an amount determined by this equation:~~

~~Transmission Vested Interest Charge = A x B where;~~

~~A = Load Ratio: Additional Schedule 19 Applicant's Connected Load divided by the sum of Additional Applicant's Connected Load and Transmission Vested Interest Holder's load.~~

~~B = Vested Interest Holder's un-refunded contribution~~

~~The Additional Schedule 19 Applicant has no Transmission Vested Interest and the Transmission Vested Interest Holder remains the Transmission Vested Interest Holder. The Transmission Vested Interest Holder's Transmission Vested Interest will be reduced by the newest Additional Schedule 19 Applicant's payment.~~

~~The Transmission Vested Interest Charge will not exceed the sum of the Transmission Vested Interests in the Transmission Line Installation. If an Additional Schedule 19 Applicant connects to a portion of a vested Transmission Line Installation which was established under a prior rule or schedule, the Transmission Vested Interest Charges of the previous rule or schedule apply to the Additional Schedule 19 Applicant.~~

SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Large General Service Rates

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$3~~4~~60.00	$3~~4~~60.00
Basic Charge, per kW of Basic Load Capacity	$~~1~~2.~~79~~22	$~~1~~2.~~79~~22
Demand Charge, per kW of Billing Demand	$~~8~~11.~~71~~63	$~~8~~10.~~28~~50
Energy Charge, per kWh		
On-Peak	~~5~~8.~~2129~~8053¢	~~6~~7.~~2851~~1428¢
Mid-Peak	~~4~~7.~~4927~~2879¢	~~7~~5.~~4056~~9451¢
Off-Peak	~~5~~4.~~6151~~8476¢	~~6~~5.~~7148~~2583¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$3~~4~~60.00	$3~~4~~60.00
Basic Charge, per kW of Basic Load Capacity	$~~1~~0.~~07~~96	$~~1~~0.~~07~~96
Demand Charge, per kW of Billing Demand	$~~7.75~~9.22	$~~6.85~~9.03
Energy Charge, per kWh		
On-Peak	~~5~~8.~~1451~~9803¢	~~6~~7.~~1901~~1437¢
Mid-Peak	~~4~~7.~~4249~~4238¢	~~7~~5.~~3109~~9464¢
Off-Peak	~~5~~4.~~5415~~9433¢	~~6~~5.~~6195~~2599¢

SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD
(Continued)

MONTHLY CHARGE (Continued)

Large Power Service Rates

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$~~415~~490.00	$~~415~~490.00
Basic Charge, per kW of Basic Load Capacity	$2.~~17~~60	$2.~~17~~60
Demand Charge, per kW of Billing Demand	$1~~0~~3.~~35~~72	$~~8.97~~12.56
Energy Charge, per kWh		
On-Peak	~~5~~8.7365~~0506~~¢	7~~6~~.0925~~1085~~¢
Mid-Peak	7~~4~~.2126~~3304~~¢	5~~7~~.8890~~2286~~¢
Off-Peak	~~-~~4~~5~~.7657~~4462~~¢	5~~6~~.1982~~5366~~¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$4~~15~~90.00	$~~415~~490.00
Basic Charge, per kW of Basic Load Capacity	$1.~~83~~72	$1.~~83~~72
Demand Charge, per kW of Billing Demand	$1~~0~~4.~~50~~81	$~~9~~13.~~11~~05
Energy Charge, per kWh		
On-Peak	~~5~~8.~~0336~~8069¢	~~6~~7.~~0790~~0983¢
Mid-Peak	~~4~~7.~~3134~~2676¢	~~7~~5.~~1989~~8945¢
Off-Peak	~~5~~4.~~4261~~8048¢	~~6~~5.~~5068~~2034¢

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD
(Continued)

INTERRUPTION COMPENSATION

Fixed Capacity Reduction Rate:

Large General Service Rates **$0.~~0333~~ 0455 per kilowatt of reduction per event hour**

Large Power Service Rates **$0.~~0382~~ 0460 per kilowatt of reduction per event hour**

DEFINITIONS

Actual kW Reduction. The kilowatt (kW) reduction during an Interruption Event, which is the difference between a Participant's hourly average kW measured at the Facility Site's meter and the corresponding hour of the Adjusted Baseline kW.

Adjusted Baseline kW. The Original Baseline kW plus or minus the "Day of" Load Adjustment amount.

"Day of" Load Adjustment. The difference between the Original Baseline kW and the actual metered kW during the hour prior to the Participant receiving notification of an event. Scalar values will be calculated by dividing the Original Baseline kW for each Interruption Event hour by the Baseline kW of the hour preceding the event notification time. The scalars are multiplied by the actual event day kW for the hour preceding the event notification time to create the Adjusted Baseline kW from which load reduction is measured. The Adjusted Baseline kW for each hour will be capped at 120% of the maximum kW amount for any hour from the Highest Energy Use Days or the hours during the event day prior to event notification.

Facility Site(s). All of a Participant's facility or equipment that is metered from a single service location that a Participant has taken service under Schedule 20.

Highest Energy Usage Days. The three days out of the immediate past 10 non-event Business Days that have the highest sum total kW as measured across the Interruption Event daily parameters.

Interruption Compensation. The Actual kW Reduction for each hour multiplied by the Fixed Capacity Reduction Rate. Participants are paid based on the average event kilowatt reduction.

Load Control Device. Refers to any technology, device, or system utilized under Schedule 20 to enable the Company to initiate the Interruption Event.

Interruption Event. Refers to an event where the Company requests or calls for interruption of specific loads with the use of one or more Load Control Devices.

Original Baseline kW. The arithmetic mean (average) kW of the Highest Energy Usage Days during the Interruption Event daily parameters, calculated for each Facility Site for each hour.

SCHEDULE 24
AGRICULTURAL IRRIGATION
SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Idaho for loads up to 20,000 kW where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served, and additional investment by the Company for new transmission, substation or terminal facilities is not necessary to supply the desired service. If the aggregate power requirement of a Customer who receives service at one or more Points of Delivery on the same Premises exceeds 20,000 kW, special contract arrangements will be required.

APPLICABILITY

Service under this schedule is applicable to power and energy supplied to agricultural use customers operating water pumping or water delivery systems used to irrigate agricultural crops or pasturage at one Point of Delivery and through one meter. Water pumping or water delivery systems include, but are not limited to, irrigation pumps, pivots, fertilizer pumps, drainage pumps, linears, and wheel lines.

TYPE OF SERVICE

The type of service provided under this schedule is single- and/or three-phase, alternating current, at approximately 60 cycles and at the standard voltage available at the Premises to be served.

DEFINITIONS

Cumulative Past Due Balance. The Cumulative Past Due Balance is calculated as the sum of all Schedule 24 past due account balances for which the Customer is financially responsible.

New Irrigation Customer. A New Irrigation Customer is a Customer who, within the previous four years, has not received Schedule 24 service in the Customer's name or has not been financially responsible for an existing Schedule 24 service, or has received Schedule 24 service in the Customer's name for less than three full billing cycles during an Irrigation Season.

Irrigation Season. The Irrigation Season ~~will~~ begins on June 1 of each year and ends on September 30 of each year. ~~with the Customer's meter reading for the May Billing Period and end with the Customer's meter reading for the September Billing Period. The beginning cycles of a Billing Period may actually be based on meter readings taken not more than seven days prior to the start of the corresponding calendar month.~~

SERVICE CONNECTION AND DISCONNECTION

The Company will routinely keep service connected throughout the calendar year unless the Customer requests disconnection. Customer requested service disconnections will be made at no charge during the Company's normal business hours. The Company's termination practices as specified under Rule F will continue to apply with the exception that service terminations will not be made during the Irrigation Season.

SCHEDULE 24
AGRICULTURAL IRRIGATION
SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Franchise Fees), Schedule 96 (Blain County Surcharge to Fund the Undergrounding of Certain Facilities), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	In-Season	Out-of-Season
Service Charge, per month	$~~30.00~~35.00	$~~6.00~~9.00
Demand Charge, per kW of Billing Demand	$~~14.75~~18.75	n/a
Energy Charge All kWh	~~6~~7.~~0051~~4279¢	~~7~~8.~~0589~~2558¢

TRANSMISSION SERVICE	In-Season	Out-of-Season
Service Charge, per month	$~~415.00~~490.00	$~~6.00~~9.00
Demand Charge, per kW of Billing Demand	$~~13.92~~17.33	n/a
Energy Charge All kWh	~~5~~6.~~7529~~9715¢	~~6~~7.~~7352~~7172¢

SCHEDULE 24
AGRICULTURAL IRRIGATION
SERVICE
(Continued)

MONTHLY CHARGE (Continued)

Minimum Charge
The monthly Minimum Charge shall be the sum of the Service Charge, the Demand Charge, the Energy Charge, the Power Cost Adjustment, and the Facilities Charge.

PAYMENT

All monthly billings for Electric Service supplied hereunder are payable upon receipt and become past due 15 days from the date on which rendered. (For any agency or taxing district which has notified the Company in writing that it falls within the provisions of Idaho Code § 67–2302, the past due date will reflect the 60-day payment period provided by Idaho Code § 67–2302.)

Deposit. A deposit payment for Schedule 24 Customers is required under the following conditions:

1. Existing Customers.

a. Tier 1 Deposit. A Tier 1 Deposit will be required from Customers who (1) have received two or more reminder notices for nonpayment during the most recent 12-month period during which service was received, when the annual total billed amount on the Schedule 24 account(s) that received the reminder notices is greater than 15 percent of the total annual billed amount on all Schedule 24 account(s), (2) have had service terminated for nonpayment during the last four years and have not subsequently received Schedule 24 service, or (3) were required to pay a Tier 2 Deposit for the previous Irrigation Season. A Tier 1 Deposit may be satisfied by a guarantee of payment from a bank or financial institution acceptable to the Company. A reminder notice is issued approximately 45 days after the bill issue date if the balance owing for Electric Service totals $100 or more or approximately 105 days after the bill issue date for Customers meeting the provisions of Idaho Code § 67–2302. A Customer with at least one Schedule 24 account that meets the requirements for payment of a Tier 1 Deposit will be required to pay a Tier 1 Deposit on all Schedule 24 accounts for which the Customer is financially responsible and requesting Schedule 24 service. A Tier 1 Deposit does not apply to Customers who have a Cumulative Past Due Balance on December 31 equal to or greater than $1,500 (See Tier 2 Deposit). The deposit for each metered service point is computed as follows:

(1) Monthly Billing Demand is determined by multiplying 80 percent times the connected horsepower.

(2) Monthly Energy (billing kWh) is determined by multiplying 50 percent times 720 hours times the Monthly Billing Demand.

(3) The Monthly Billing Demand and the Monthly Energy are multiplied by the current In-Season rates and added to the Irrigation In-Season Service Charge to determine the estimated monthly bill.

(4) The estimated monthly bill is multiplied by a factor of one and one-half (1.5).

SCHEDULE 24
AGRICULTURAL IRRIGATION
SERVICE
(Continued)

PAYMENT (Continued)

b. Tier 2 Deposit. Customers with a Cumulative Past Due Balance equal to or greater than $1,500 when the average of the Cumulative Past Due Balance is equal to or greater than $750 per service point, or when the Cumulative Past Due Balance is equal to or greater than $10,000 on December 31 will be required to pay a Tier 2 Deposit on all Schedule 24 accounts for which the Customer is financially responsible and requesting Schedule 24 service. A Tier 2 Deposit will also be required from Customers who have had a ~~Cumulative Past Due Balance equal to or greater than $1,500 on December 31~~ Tier 2 Deposit during any of the previous four years and who have not subsequently had active Schedule 24 service. The Company will allow payments for past due balances to be received up to five (5) days after December 31, without requiring a Tier 2 Deposit. A Tier 2 Deposit may be satisfied by a guarantee of payment from a bank or financial institution acceptable to the Company. The deposit for each metered service point is computed as follows:

(1) Monthly Billing Demand is determined by multiplying 80 percent times the connected horsepower.

(2) Monthly Energy (billing kWh) is determined by multiplying 50 percent times 720 hours times the Monthly Billing Demand.

(3) The Monthly Billing Demand and the Monthly Energy are multiplied by the current In-Season rates and added to the Irrigation In-Season Service Charge to determine the estimated monthly bill.

(4) The estimated monthly bill is multiplied by a factor of four (4).

2. New Irrigation Customers. A Tier 1 Deposit will be required from a New Irrigation Customer unless the New Irrigation Customer had a Cumulative Past Due Balance equal to or greater than $1,500 on December 31 during any of the previous four years and has not subsequently had Schedule 24 service, in which case a Tier 2 Deposit will be required. The deposit for each metered service point will be computed using the same methodology as outlined for existing Customers requiring a Tier 1 or Tier 2 Deposit. A Tier 1 or Tier 2 Deposit for New Irrigation Customers may be satisfied by a guarantee of payment from a bank or financial institution acceptable to the Company.

3. Bankruptcy or Receivership. An adequate assurance of payment as agreed to by the Company or as ordered by a court of competent jurisdiction or the Commission shall be required from any Customer for whom an order for relief has been entered under the federal bankruptcy laws, or for whom a receiver has been appointed in a court proceeding. As a condition of service, an adequate assurance of payment equal to a Tier 2 Deposit shall be required. This requirement shall continue from the date of the order for relief in bankruptcy, or the court appointing a receiver, until the dismissal of the bankruptcy, or the dismissal of the court proceeding, or until the bankruptcy plan has been completed.

A Customer who has been discharged from bankruptcy, a Customer whose receivership proceeding has been terminated, or a Customer whose bankruptcy proceedings have been dismissed will be required to pay an amount equal to a Tier 2 Deposit at the start of the Irrigation Season.

SCHEDULE 26
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
MICRON TECHNOLOGY, INC.
BOISE, IDAHO

SPECIAL CONTRACT DATED MARCH 9, 2022, AMENDED APRIL 11, 2024

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees). Terms used below have the meanings given to them in the Special Contract referenced above.

Monthly Contract Demand Charge
$~~3.24~~3.12 per kW of Contract Demand.

Monthly Billing Demand Charge
$~~17.16~~23.35 per kW of Billing Demand but not less than Minimum Monthly Billing Demand.

Minimum Monthly Billing Demand
The Minimum Monthly Billing Demand will be 25,000 kilowatts.

Daily Excess Demand Charge
$~~1.288~~1.248 per each kW over the Contract Demand.

Monthly Energy Charge
~~3~~2.~~0394~~7585¢ per kWh.

Embedded Energy Fixed Cost Charge
0.0000¢ per kWh of Renewable Resource On-Site Usage

Monthly Adjusted Renewable Capacity Credit(s)
See Table Nos.1, 2, 3, and Second Revised Exhibit 1 of Micron's Special Contract, dated March 9, 2022, as amended.

Renewable Resource Cost
As defined in Second Revised Exhibit 1 of Micron's Special Contract, dated March 9, 2022, as amended.

Excess Generation Credit
As defined in Second Revised Exhibit 1 of Micron's Special Contract, dated March 9, 2022, as amended.

Administrative Charge
As defined in Second Revised Exhibit 1 of Micron's Special Contract, dated March 9, 2022, as amended.

Pricing elements that rely on the most recently filed IRP are effective December 1, 2024, pursuant to Order No. 36383 issued on November 8, 2024.

SCHEDULE 29
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
J. R. SIMPLOT COMPANY
POCATELLO, IDAHO

SPECIAL CONTRACT DATED JUNE 29, 2004

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Contract Demand Charge
$~~3.19~~3.12 per kW of Contract Demand

Demand Charge,
$~~14.50~~18.55 per kW of Billing Demand but no less than the Contract Demand less 5,000 kW

Daily Excess Demand Charge
$~~1.267~~1.248 per each kW over the Contract Demand

Energy Charge
~~3.0385~~3.0782¢ per kWh

Monthly Facilities Charge
Facilities installed beyond the Point of Delivery will be subject to the provisions of Rule M, Facilities Charge Service.

SCHEDULE 30
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
UNITED STATES DEPARTMENT OF ENERGY
IDAHO OPERATIONS OFFICE

SPECIAL CONTRACT DATED SEPTEMBER 15, 2021
CONTRACT NO. 47PA0420D0011

AVAILABILITY

This schedule is available for firm retail service of electric power and energy delivered for the operations of the Department of Energy's facilities located at the Idaho National Engineering Laboratory site, as provided in the Contract for Electric Service between the parties.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

1.	Demand Charge, per kW of Billing Demand	$~~9.96~~19.80
2.	Energy Charge, per kWh	~~4~~3.~~16500~~0664¢

SPECIAL CONDITIONS

1. Billing Demand. The Billing Demand shall be the average kW supplied during the 30-minute period of maximum use during the month.

2. Power Factor Adjustment. When the Power Factor is less than 95 percent during the 30-minute period of maximum load for the month, Company may adjust the measured Demand to determine the Billing Demand by multiplying the measured kW of Demand by 0.95 and dividing by the actual Power Factor.

MONTHLY ANTELOPE ASSET CHARGE (“AAC”)

The AAC will be paid for the Company’s investment in, and operation and maintenance expenses associated with, specified transmission facilities required to provide service under the contract.

The Monthly AAC consists of two components:

1. PacifiCorp Pass-Through Charge (PPTC):

PPTC = (O&M x GAV) + (CEC)

SCHEDULE 31
IDAHO POWER COMPANY
AGREEMENT FOR SUPPLY OF
STANDBY ELECTRIC SERVICE
FOR
THE AMALGAMATED SUGAR COMPANY

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Standby Contract Demand Charge, per kW of
Standby Contract Demand $3.1~~1~~2

Standby Facilities Contract Demand Charge
Per kW of Standby Facilities Contract Demand:
Paul Facility: $3.~~4~~25
Nampa Facility: $3.~~4~~2~~7~~8
Twin Falls Facility: $~~3~~2.~~1~~93~~5~~

Standby Billing Demand Charge, per kW of
Standby Billing Demand $~~1~~5.~~67~~63

Excess Demand Charge
$1.248 per day for each kW taken in excess of the Total Contract Demand.

Energy Charge Energy taken with Standby Demand will be priced at the applicable Schedule 19 Energy Charge.

SCHEDULE 32
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
J. R. SIMPLOT COMPANY
CALDWELL, IDAHO

SPECIAL CONTRACT DATED APRIL 8, 2015

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

	Summer	Non-Summer
Contract Demand Charge		
per kW of Contract Demand	$~~3.23~~3.12	$~~3.23~~3.12
Demand Charge		
per kW of Billing Demand but no less than the Contract Demand less 10,000 kW	$~~19.21~~23.99	$~~15.88~~20.39
Daily Excess Demand Charge		
per each kW over the Contract Demand	$~~1.293~~1.248	$~~1.293~~1.248
Energy Charge		
per kWh	~~2~~3.~~9799~~1464¢	3.~~2189~~1073¢

Monthly Facilities Charge

Facilities installed beyond the Point of Delivery will be subject to the provisions of Rule M, Facilities Charge Service.

SCHEDULE 33
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
BRISBIE, LLC.
(Continued)

TIME PERIODS (Continued)

The holidays observed by the Company are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day, Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). When New Year's Day, Independence Day, or Christmas Day falls on a Sunday, the Monday immediately following that Sunday will be considered a holiday.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

	Summer	Non-summer
Service Charge, per month	$~~415.00~~490.00	$~~415.00~~490.00
Basic Charge, per kW of Basic Load Capacity	$~~1.83~~1.72	$~~1.83~~1.72
Demand Charge, per kW of Billing Demand	$~~9.99~~14.18	$~~8.60~~12.42
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.56~~2.07	n/a
Energy Charge, per kWh		
On-Peak	~~5~~6.~~10937~~062¢	~~4~~5.~~59833~~955¢
Mid-Peak	5.~~10935~~665¢	4.~~36109~~099¢
Off-Peak	4.~~55193~~865¢	4.~~17075~~641¢
Embedded Energy Fixed Cost Rate, per kWh		
On-Peak	~~0~~1.~~89587~~022¢	1.~~73136~~774¢
Mid-Peak	~~0~~1.~~89587~~022¢	1.~~72236~~744¢
Off-Peak	~~0~~1.~~86717~~022¢	1.~~71516~~774¢

SCHEDULE 33
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
BRISBIE, LLC.
(Continued)

BLOCK 2

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees). Terms used below have the meanings given to them in the Special Contract referenced above.

Daily Excess Demand Charge
$~~1.293~~1.248 per each kW over the Contract Demand.

Excess Generation Credit
As defined in Second Revised Exhibit 3.1 of Brisbie, LLC's Special Contract, December 22, 2021 as amended.

Monthly Contract Demand Charge
$~~3.23~~3.12 per kW of Contract Demand.

Monthly Billing Demand Charge
$~~21.84~~22.29 per kW of Billing Demand but not less than Minimum Monthly Billing Demand.

Minimum Monthly Billing Demand
The Minimum Monthly Billing Demand will be 20,000 kilowatts.

Monthly Adjusted Renewable Capacity Credit(s)
See Table Nos. 1, 2, 3, and Second Revised Exhibit 3.1 of Brisbie, LLC's Special Contract, dated December 22, 2021, as amended.

Renewable Resource Cost
As included in the Monthly Contract Payment listed in Second Revised Exhibit 3.1 of Brisbie, LLC's Special Contract, December 22, 2021, as amended.

Supplemental Energy Cost
As defined in Second Revised Exhibit 3.1 of Brisbie, LLC's Special Contract, December 22, 2021, as amended.

Administrative Charge
As defined in Second Revised Exhibit 3.1 of Brisbie, LLC's Special Contract, December 22, 2021, as amended.

Pricing elements that rely on the most recently filed IRP are effective December 1, 2024, pursuant to Order No. 36383 issued on November 8, 2024.

SCHEDULE 34
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
LAMB WESTON, INC.
(Continued)

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on September 30 of each year. The non-summer season begins on October 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

	Summer	Non-summer
Service Charge, per month	$~~415.00~~490.00	$~~415.00~~490.00
Basic Charge, per kW of Basic Load Capacity	$~~2.17~~2.60	$~~2.17~~2.60
Demand Charge, per kW of Billing Demand	$~~9.84~~13.09	$~~8~~11.~~46~~93
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.56~~ 2.07	n/a
Energy Charge, per kWh		
On-Peak	~~5~~6.~~1263~~6358¢	~~4~~5.~~6278~~3897¢
Mid-Peak	~~5~~5.~~1263~~5115¢	4.~~3907~~9044¢
Off-Peak	4.~~5720~~3474¢	4.~~2005~~5589¢

SCHEDULE 34
IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
FOR
LAMB WESTON, INC.
(Continued)

BLOCK 2

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Daily Excess Demand Charge
$~~1.293~~1.248 per each kW over the Contract Demand.

Monthly Contract Demand Charge
$~~3.23~~3.12 per kW of Contract Demand.

Monthly Billing Demand Charge
$~~23~~9.~~75~~ 00 per kW of Billing Demand but not less than Minimum Monthly Billing Demand.

Energy Charge
4.689¢ per kWh of Block 2 Energy.

Minimum Monthly Billing Demand
The Minimum Monthly Billing Demand will be 20,000 kilowatts.

SCHEDULE 40
NON-METERED GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The average monthly kWh of energy usage shall be estimated by the Company, based on the Customer's electric equipment and one-twelfth of the annual hours of operation thereof. Since the service provided is non-metered, failure of the Customer's equipment will not be reason for a reduction in the Monthly Charge. The Monthly Charge shall be computed at the following rate, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Energy Charge, per kWh	~~9~~11.~~805~~1557¢
Minimum Charge, per month	$2.00

ADDITIONAL CHARGES

Applicable only to municipalities or agencies of federal, state, or county governments with an authorized Point of Delivery having the potential of intermittent variations in energy usage.

Intermittent Usage Charge, per unit, per month	$~~2.00~~2.50

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

SERVICE OPTIONS (Continued)

"A" - Idaho Power-Owned, Idaho Power-Maintained System (Continued)

Monthly Charges

The monthly charges are as follows, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Charges, per fixture (41A)

LED Fixture		
Watt (Maximum)	Lumen (Minimum)	Base Rate
40	3,600	$~~12.05~~15.98
85	7,200	$~~14.00~~17.29
140	10,800	$~~16.06~~18.82
200	18,000	$~~19.99~~21.93

Non-Metered Service – Variable Energy

Energy Charge, per kWh ~~9~~11.~~805~~1557¢

Pole Charges

For Company-owned poles installed after October 5,1964 required to be used for street lighting only:

	Charge
Wood pole, per pole	$1.81
Steel pole, per pole	$7.18

Facilities Charges

Customers assessed a monthly facilities charge prior to June 1, 2004 will continue to be assessed a monthly facilities charge in accordance with the charges specified in Schedule 66.

Payment

The monthly bill rendered for service supplied hereunder is payable upon receipt and becomes past due 15 days from the date on which rendered.

"B" – Customer-Owned, Idaho Power-Maintained System – Discontinued

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

SERVICE OPTIONS (Continued)

"C" - Customer-Owned, Customer-Maintained System

The Customer's lighting system, including posts or standards, fixtures, initial installation of fixtures and underground cables with suitable terminals for connection to the Company's distribution system, is installed, owned, and maintained by the Customer. The Customer is responsible for notifying the Company of any changes or additions to the lighting equipment or loads being served under Option C – Non-Metered Service. Failure to notify the Company of such changes or additions will result in the termination of non-metered service under Option C and the requirement that service be provided under Option C - Metered Service.

All new Customer-owned lighting systems installed outside of Subdivisions on or after January 1, 2012 are required to be metered in order to record actual energy usage.

Customer-owned systems installed prior to June 1, 2004 that are constructed, operated, or modified in such a way as to allow for the potential or actual variation in energy usage may have the estimated annual variations in energy usage charged the Non-Metered Service - Energy Charge until the street lighting system is converted to Metered Service, or until the potential for variations in energy usage has been eliminated, whichever is sooner.

Monthly Charges

The monthly charges are as follows, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees). For non-metered service, the average monthly kWh of energy usage shall be estimated by the Company based on the total wattage of the Customer’s lighting system and 4,059 hours of operation.

Non-Metered Service (41C)

Energy Charge, per kWh	~~6~~4.~~651~~3291¢

Metered Service (41CM)

Service Charge, per meter	$~~5~~1.~~59~~84
Energy Charge, per kWh	~~6~~4.~~651~~3291¢

SCHEDULE 42
TRAFFIC CONTROL SIGNAL
LIGHTING SERVICE

APPLICABILITY

Service under this schedule is applicable to Electric Service required for the operation of traffic control signal lights within the State of Idaho. Traffic control signal lamps are mounted on posts or standards by means of brackets, mast arms, or cable.

CHARACTER OF SERVICE

The traffic control signal fixtures, including posts or standards, brackets, mast arm, cable, lamps, control mechanisms, fixtures, service cable, and conduit to the point of, and with suitable terminals for, connection to the Company's underground or overhead distribution system, are installed, owned, maintained and operated by the Customer. Service is limited to the supply of energy only for the operation of traffic control signal lights.

The installation of a meter to record actual energy consumption is required for all new traffic control signal lighting systems installed on or after June 1, 2004. For traffic control signal lighting systems installed prior to June 1, 2004 a meter may be installed to record actual usage upon the mutual consent of the Customer and the Company.

MONTHLY CHARGE

The monthly kWh of energy usage shall be either the amount estimated by the Company based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated, or the actual meter reading as applicable. The Monthly Charge shall be computed at the following rate, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees).

Energy Charge, per kWh ~~7~~9.~~689~~5358¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 45
STANDBY SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge for Standby Service is the sum of the Standby Reservation Charge, the Standby Demand Charge, and the Excess Demand Charge, if any, at the following rates:

Customers taking service under Schedule 9

	Summer	Non-summer
Standby Reservation Charge, per kW of Available Standby Capacity		
Secondary Service	$~~5.45~~6.19	$~~5.45~~6.19
Primary Service	$~~5.43~~6.39	$~~5.43~~6.39
Transmission Service	$3.1~~1~~2	$3.1~~1~~2
Standby Demand Charge, per kW of Standby Billing Demand		
Secondary Service	$~~9.35~~12.32	$~~7.61~~10.22
Primary Service	$~~9.37~~12.78	$~~9.08~~12.23
Transmission Service	$~~6.95~~8.63	$~~6.09~~8.44

Customers taking service under Schedule 19

	Summer	Non-summer
Standby Reservation Charge, per kW of Available Standby Capacity		
Primary Service	$6.~~70~~52	$6.~~70~~52
Transmission Service	$3.1~~1~~2	$3.1~~1~~2
Standby Demand Charge, per kW of Standby Billing Demand		
Primary Service	$~~11~~15.~~69~~16	$~~10.31~~14.01
Transmission Service	$~~9.6~~14.18	$~~8.27~~12.42

Customers taking service under Schedule 9 or Schedule 19

Excess Demand Charge
$1.248 per day for each kW taken in excess of the Total Contract Demand.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Standby Reservation Charge, the Standby Demand Charge, and the Excess Demand Charge.

CONTRIBUTION TOWARD MINIMUM CHARGES ON OTHER SCHEDULES

Any Standby Service Charges paid under this schedule shall not be considered in determining the Minimum Charge under any other Company schedule.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 46
ALTERNATE DISTRIBUTION
SERVICE

AVAILABILITY

Alternate Distribution Service under this schedule is available at points on the Company's inter-connected system within the State of Idaho where existing facilities of adequate capacity and desired phase and voltage are adjacent to the location where Alternate Distribution Service is desired, and where additional investment by the Company for new distribution facilities is not necessary to supply the requested service. When additional transmission or substation facilities are required, separate arrangements will be made between the Customer and the Company.

Alternate Distribution Service is available only to Customers taking Primary Service under Schedule 9 or 19.

AGREEMENT

Service shall be provided only after the Uniform Alternate Distribution Service Agreement is executed by the Customer and the Company. The term of the initial agreement shall be dependent upon the investment required by the Company to provide the Alternate Distribution Service, but shall in no event be less than one year. The Uniform Alternate Distribution Service Agreement shall automatically renew and extend each year, unless terminated under the provisions of the Agreement.

TYPE OF SERVICE

Alternate Distribution Service consists of a second distribution circuit to the Customer which backs up the Customer's regular distribution circuit through an automatic switching device. Alternate Distribution Service facilities include, but are not limited to, the automatic switching device and that portion of the distribution substation and the distribution line required to provide the service. The kW of Alternate Distribution Service capacity shall be specified in the Uniform Alternate Distribution Service Agreement.

STANDARD OF SERVICE

The Alternate Distribution Service provided under this schedule is not an uninterruptible supply and is subject to the same standard of service as provided under Rule J.

MONTHLY CHARGES

The Monthly Charge is the sum of the Capacity Charge and the Mileage Charge at the following rates:

Capacity Charge
$3.~~59~~ 40 per contracted kW of capacity

Mileage Charge
$0.00~~3~~5 per kW per tenth of a mile in excess of 1.8 miles.

SCHEDULE 54
FIXED COST ADJUSTMENT

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Idaho retail Customers receiving service under Schedules 1, 3, 5, or 6 (Residential Service) or under Schedules 7 and 8 (Small General Service).

Customers added to Idaho Power's system starting January 1, 202~~4~~6, will be considered new customers, all other customers are considered existing customers.

FIXED COST PER CUSTOMER RATE

The Fixed Cost per Customer rate (FCC) is determined by dividing the Company's fixed cost components for Residential and Small General Service Customers by the average number of Residential and Small General Service customers, respectively.

The Fixed Cost per Customer Distribution rate (FCC-Dist) is determined by dividing the Company's distribution and customer fixed cost components for Residential and Small General Service Customers by the average number of Residential and Small General Service Customers, respectively.

Residential	FCC	FCC-Dist
Schedules 1 and 3	$~~679~~862.~~20~~88	$2~~27~~05.61~~96~~
Schedule 5	$~~679~~862.~~20~~88	$~~227~~205.61~~96~~
Schedule 6	$~~594~~857.~~72~~24	$~~244~~331.~~20~~94

Small General Service	FCC	FCC-Dist
Schedule 7	$~~174~~272.~~96~~14	$~~24~~52.~~02~~50
Schedule 8	$~~221~~476.~~61~~31	$~~63~~276.~~33~~26

FIXED COST PER ENERGY RATE

The Fixed Cost per Energy rate (FCE) is determined by dividing the Company's fixed cost components for Residential and Small General Service customers by the weather-normalized energy load for Residential and Small General Service customers, respectively.

The Fixed Cost per Energy Distribution rate (FCE-Dist) is determined by dividing the Company's distribution and customer fixed cost components for Residential and Small General Service customers by the weather-normalized energy load for Residential and Small General Service customers, respectively.

SCHEDULE 54
FIXED COST ADJUSTMENT
(Continued)

FIXED COST PER ENERGY RATE (Continued)

Residential	FCE	FCE-Dist
Schedules 1 and 3	~~6~~7.~~1651~~8969¢ per kWh	~~2~~1.~~0692~~8817¢ per kWh
Schedule 5 – Summer On-Peak	~~16~~23.~~2698~~1762¢ per kWh	~~6~~8.~~9989~~7922¢ per kWh
Schedule 5 – Mid-Peak	~~8~~11.~~1345~~5881¢ per kWh	~~3~~4.~~4990~~3961¢ per kWh
Schedule 5 – Summer Off-Peak	~~4~~5.~~0675~~7940¢ per kWh	~~1~~2.~~7497~~1981¢ per kWh
Schedule 5 – Non-Summer On-Peak	~~7~~9.~~7990~~2909¢ per kWh	~~2~~1.~~2059~~3286¢ per kWh
Schedule 5 – Non-Summer Off-Peak	~~5~~6.~~1993~~1939¢ per kWh	~~1~~0.~~4705~~8857¢ per kWh
Schedule 6	~~6~~8.~~4294~~6079¢ per kWh	~~2~~3.~~6400~~3332¢ per kWh

Small General Service	FCE	FCE-Dist
Schedule 7	~~3~~5.~~8463~~8413¢ per kWh	~~0~~1.~~5282~~1270¢ per kWh
Schedule 8	~~5~~7.~~2308~~4432¢ per kWh	~~1~~4.~~4949~~3171¢ per kWh

ALLOWED FIXED COST RECOVERY AMOUNT

The Allowed Fixed Cost Recovery amount is computed by summing 1) the product of the average number of existing Residential and Small General Service customers multiplied by the appropriate Residential and Small General Service FCC rate and 2) the product of the average number of new Residential and Small General Service customers multiplied by the appropriate Residential and Small General Service FCC-Dist rate.

ACTUAL FIXED COSTS RECOVERED AMOUNT

The Actual Fixed Costs Recovered amount is computed by summing 1) the product of the actual energy load for existing Residential and Small General Service customers multiplied by the appropriate Residential and Small General Service FCE rate and 2) the product of the actual energy load for new Residential and Small General Service customers multiplied by the appropriate Residential and Small General Service FCE-Dist rate.

FIXED COST ADJUSTMENT

The Fixed Cost Adjustment (FCA) is the difference between the Allowed Fixed Cost Recovery Amount and the Actual Fixed Costs Recovered Amount divided by the estimated weather-normalized energy load for the following year for Residential and Small General Service Customers.

The monthly Fixed Cost Adjustment for Residential Service (Schedules 1, 3, 5, and 6) is 0.6182 cents per kWh. The monthly Fixed Cost Adjustment for Small General Service (Schedules 7 and 8) is 0.7638 cents per kWh.

EXPIRATION

The Fixed Cost Adjustment included on this schedule will expire May 31, 2025.

SCHEDULE 55
POWER COST ADJUSTMENT
(Continued)

POWER COST ADJUSTMENT

The Power Cost Adjustment (PCA) is the sum of: 1) 95 percent of the difference between the Projected Power Costs in Category 1 and the Base Power Costs in Category 1; 2) 100 percent of the difference between the Projected Power Costs in Category 2 and the Base Power Costs in Category 2; 3) 100 percent of the difference between the Projected Power Costs in Category 3 and the Base Power Costs in Category 3; 4) 100 percent of the difference between the Projected Power Costs in Category 4 and the Base Power Costs; 5) the Balancing Adjustment; and 6~~5~~) Earnings Sharing. The following table calculates the rates for Categories 1, 2, ~~and~~ 3, and 4.

The following table shows the determination of PCA rates for Categories 1, 2, 3, and ~~3~~4:

Category	Description	Base Power Cost	Projected Power Cost	Difference	Sharing %	Rate
		(¢ per kWh)				
1	The sum of fuel expense and purchased power expense (excluding purchases from cogeneration and small power producers), less the sum of off-system surplus sales revenue and revenue from market-based special contract pricing.	~~1.64824~~1.75445	1.77069	~~0.12245~~0.01624	95%	~~0.11633~~0.01543
2	Purchased power expense from cogeneration and small power producers.	~~1.35833~~1.43605	1.39092	~~0.03259~~(0.04513)	100%	~~0.03259~~(0.04513)
3	Demand response incentive payments.	~~0.06767~~0.06174	0.06881	~~0.00113~~0.00706	100%	~~0.00113~~0.00706
4	Payments for battery energy storage system leases.	0.13647	0.00000	(0.13647)	100%	(0.13647)
Total		**~~3.07424~~3.38872**	**3.23041**	**~~0.15617~~(0.15830)**		**~~0.15005~~(0.15912)**

SCHEDULE 55
POWER COST ADJUSTMENT
(Continued)

The monthly Power Cost Adjustment rates applied to the Energy rate of all metered schedules and Special Contracts are shown below. The monthly Power Cost Adjustment applied to the per unit charges of the nonmetered schedules is the monthly estimated usage times the cents per kWh rates shown below. Totals may not tie due to rounding.

Schedule	Category				Balancing Adjustment	Earnings Sharing	Total PCA
	1	2	3	4			
1	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
3	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
5	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
6	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
7	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
8	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
9S	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
9P	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
9T	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
15	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
19S	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
19P	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
19T	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
24	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
40	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
41	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
42	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	(0.0000)	~~0.7447~~0.4355
26	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	*	~~0.7447~~0.4355

29	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	*	~~0.7447~~0.4355
30	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	*	~~0.7447~~0.4355
32	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	*	~~0.7447~~0.4355
34	~~0.1163~~0.0154	~~0.0326~~(0.0451)	~~0.0011~~0.0071	(0.1365)	0.5946	*	~~0.7447~~0.4355

* Earnings Sharing Credits are applied as monthly amounts per the table below.

Schedule	Special Contract	Monthly Credit
26	Micron	($0.00)
29	Simplot	($0.00)
30	DOE	($0.00)
32	Simplot-Caldwell	($0.00)
34	Lamb Weston	($0.00)

EXPIRATION

The Power Cost Adjustment included on this schedule will expire May 31, 2025.

SCHEDULE 62
CLEAN ENERGY YOUR WAY PROGRAM
(OPTIONAL)
(Continued)

SECTION 2: CLEAN ENERGY YOUR WAY – CONSTRUCTION (Continued)

CUSTOMER AGREEMENT AND BILLING STRUCTURE

For each billing period, Customer(s) shall incur or receive the following charges/credits:

1. A participating Customer(s)' Service Charge, Billing Demand, On-Peak Billing Demand, Basic Load Capacity, and other monthly charges will be charged at the standard rates, charges, and fees associated with the Customer's applicable service schedule;

2. Net Consumption shall be charged at the standard rates, charges, and fees associated with the Customer's applicable service schedule;

3. The REF On-Site Usage for Special Contract customers shall be charged at a rate in their respective service schedule and the REF On-Site Usage for Schedule 19 Customers shall be charged as follows:

	Fixed Cost Component of the Retail Energy Charge, per kWh		
Time Period	Secondary Service	Primary Service	Transmission Service
Summer On-Peak	~~0~~2.~~9240~~ 4049 ¢	~~0~~1.~~8961~~ 6993 ¢	~~0~~1.~~8958~~ 7022 ¢
Summer Mid-Peak	~~0~~2.4049~~9240~~ ¢	~~0~~1.~~8961~~ 6993 ¢	~~0~~1.~~8958~~ 7022 ¢
Summer Off-Peak	~~0~~2.~~8955~~ 4049 ¢	~~0~~1.~~8676~~ 6993 ¢	~~0~~1.~~8671~~ 7022 ¢
Non-Summer On-Peak	~~1~~2.~~7576~~3699 ¢	1.~~7321~~ 6745 ¢	1.~~7313~~6774 ¢
Non-Summer Mid-Peak	~~1~~2.~~7487~~ 3699 ¢	1.~~7232~~ 6745 ¢	1.~~7223~~ 6774 ¢
Non-Summer Off-Peak	~~1~~2.~~7415~~ 3699 ¢	1.~~7160~~ 6745 ¢	1.~~7151~~ 6774 ¢

4. Excess Generation shall be credited to the Customer at a rate contained in the Renewable Construction Agreement;

5. REF Cost as contained in the Renewable Construction Agreement; and,

6. REF Credit as contained in the Renewable Construction Agreement (if applicable).

REC OWNERSHIP AND ADDITIONAL REC PROCUREMENT

REC ownership will be negotiated on an individual Customer basis. A Customer may elect to take ownership of the REF's RECs or elect for Idaho Power to retain ownership and retire the RECs on the Customer's behalf.

If the REF generation does not meet 100 percent of the Customer(s)' consumption on a yearly basis, the Customer(s) may elect to enter into a separate REC purchase contract to cover the difference between REF generation and the Customer(s)' consumption. Any separate REC purchase agreement will be negotiated on a case-by-case basis.

SCHEDULE 66
MISCELLANEOUS CHARGES
(Continued)

CHARGES (Continued)

RULE M

1. Monthly Facilities Charge Rate

	Facilities Installed 31 Years or Less	Facilities Installed More Than 31 Years
Schedule 9	~~1.34~~1.42%	~~0.61~~0.65%
Schedule 15	~~1.62~~1.77%	~~1.62~~1.77%
Schedule 19	~~1.34~~1.42%	~~0.61~~0.65%
Schedule 24	~~1.34~~1.42%	~~0.61~~0.65%
Schedule 29	~~1.34~~1.42%	~~0.61~~0.65%
Schedule 32	~~1.34~~1.42%	~~0.61~~0.65%
Schedule 41	~~1.13~~1.21%	~~1.13~~1.21%
Schedule 45	~~1.34~~1.42%	~~0.61~~0.65%
Schedule 46	~~1.34~~1.42%	~~0.61~~0.65%

The monthly Facilities Charge is determined by multiplying the Monthly Facilities Charge Rate by the Company's total investment in distribution facilities installed beyond the Point of Delivery.

SCHEDULE 68

Monthly Maintenance Charge 0.65%

The monthly Maintenance Charge is determined by multiplying the Monthly Maintenance Charge by the Company's investment in the System Protection, DER metering, and DER communication equipment.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Idaho to all Customer Generators owning or operating DERs, in Parallel with the Company's system, that qualify for Schedule 6, Schedule 8, Schedule 84, or Non-Export as defined in this schedule. DERs with Total Nameplate Capacity of 3 MVA or greater are required to sign a Uniform Customer Generator Interconnection Agreement.

APPLICABILITY

Service under this schedule applies to construction, operation, and maintenance of a Customer Generator System interconnected in Parallel with the Company's system. In limited circumstances, certain interconnection requirements included in this schedule may not be applicable when the Company determines the DER relies on a technology, such as regenerative drives, that does not jeopardize grid stability or reliability. In making its determination, the Company will evaluate criteria such as the magnitude and duration of exports.

DEFINITIONS

Company is the Idaho Power Company.

Company-Furnished Facilities are those portions of the Interconnection Facilities funded by the Customer Generator and provided by the Company.

Customer Generator is a Customer or prospective Customer applying to operate or operating a DER in Parallel with the Company's system.

Customer Generator-Furnished Facilities are those portions of the Interconnection Facilities provided by the Customer Generator.

Customer Generator Interconnection Process is the Company's DER interconnection application, engineering review, construction, and inspection process for Customer Generator Systems. The Customer Generator Interconnection Process intends to ensure a safe and reliable generation interconnection in compliance with all applicable regulatory requirements, good utility practices, and national safety standards.

Customer Generator System is an Exporting System or a Non-Exporting System.

Customer Representative is a person or entity identified by the Customer Generator who is authorized to communicate with the Company on the Customer Generator's behalf.

Disconnection Equipment is any device or combination of devices by which the Company can manually and/or automatically interrupt the flow of energy from the Customer Generator to the Company's system, including enclosures or other equipment as may be required to ensure that only the Company will have access to the devices.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

DEFINITIONS (Continued)

Distributed Energy Resource(s) (DER(s)) is a source of electric power that is not directly connected to the bulk power system. Any combination of Generation Facilities and/or Energy Storage Devices connected in Parallel is considered a DER.

Energy Storage Device is a device that captures energy produced at a point in time and stores the energy for use as electricity at a future point in time. An Energy Storage Device is a DER.

Exporting System is a Customer-owned DER under the terms of Schedules 6, 8, or 84, which is designed to provide for the transfer of electric energy to the Company.

Feasibility Review is the Company's standard engineering review of a proposed Customer Generator System and is intended to ensure the Company's system is equipped to incorporate the proposed Customer Generator-Furnished Facilities in a manner that conforms with good utility practices and the National Electric Safety Code.

Feasibility Study is the Company's more detailed engineering assessment for DERs as determined by the Feasibility Review. This study is intended to ensure that the Company's system is sufficiently equipped to incorporate proposed DERs in a manner that conforms with good utility practices and the National Electric Safety Code, including protection coordination and system voltage management.

Generation Facility means equipment used to produce electric energy at a specific physical location and service point that qualifies for Schedules 6, 8, 84, or Non-Export. A Generation Facility is a DER.

Inadvertent Export is the unplanned, unscheduled, and uncompensated transfer of electrical energy from a Customer's Non-Exporting System to the Company's system across the Interconnection Point.

Incomplete Application is an application missing any information needed to satisfy the requirements of the Customer Interconnection Process; including but not limited to, Customer Generator signature, the application fee, and details about the Generation Facility.

Interconnection Facilities are all facilities which are reasonably required by good utility practices and the National Electric Safety Code to interconnect and to allow for Parallel operations of the DER with the Company's system, including, but not limited to, Special Facilities, Disconnection Equipment, and Metering Equipment.

Interconnection Point is the point where the Customer Generator's conductors connect to the facilities owned by the Company.

Metering Equipment is the Company owned equipment required to measure, record or telemeter power flows between the Customer Generator and the Company's system.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 1: GENERAL INTERCONNECTION REQUIREMENTS

The following provisions apply to all Customer Generators requesting interconnection to the Company's system.

CONSTRUCTION AND OPERATION OF INTERCONNECTION FACILITIES

All Customer Generator-Furnished Interconnection Facilities will be constructed and maintained in a manner as determined by the Company to be in full compliance with all good utility practices, including the Company's Customer Requirements for Electric Service (found at idahopower.com/requirements), National Electric Safety Code, conforms to the IEEE 1547 standards, and all other applicable federal, state, and local safety and electrical codes and standards at all times.

The Customer Generator shall:

1. Upon request, submit proof to the Company that all licenses, permits, inspections, and approvals necessary for the construction and operation of the Customer's DER and Interconnection Facilities under this schedule have been obtained from applicable federal, state, or local authorities.

2. Upon request, submit the designs, plans, specifications, settings, and performance data for the DER and Customer Generator-Furnished Facilities to the Company for review. The Company's acceptance shall not be construed as confirming or endorsing the design, or as a warranty of safety, durability, or reliability of the DER or Customer Generator-Furnished Facilities. The Company will retain the right to inspect this equipment at its discretion.

3. Demonstrate to the Company's satisfaction that the Customer's DER and Customer Generator-Furnished Facilities have been completed, and that all features and equipment of the Customer's DER and Customer Generator-Furnished Facilities are capable of operating safely to commence deliveries of energy into the Company's system.

4. Provide and maintain adequate Protection Equipment sufficient to prevent damage to the DER, Customer Generator-Furnished Facilities, and any other Customer Generator-owned facilities in conformance with all applicable electrical and safety codes and requirements.

5. Provide and maintain Disconnection Equipment in accordance with all applicable electrical and safety codes and requirements as described within this Schedule.

6. Upon request, provide a 24-hour telephone contact(s). This contact will be used by the Company to arrange for repairs and inspections or in case of an emergency. The Company will make its best effort to arrange repairs and inspections during normal business hours and to notify the Customer Generator of such arrangements in advance. The Company will provide a telephone number to the Customer Generator so that the Customer Generator can obtain information about Company activity impacting the Customer's DER.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 1: GENERAL INTERCONNECTION REQUIREMENTS (Continued)

ENERGY STORAGE DEVICE (Continued)

2. AC Coupled:

i. AC Coupled with an Exporting System: For an Energy Storage Device coupled with an Exporting System taking service under Schedules 6, 8, or 84, the Total Nameplate Capacity is the aggregate Total Nameplate Capacity of all DERs on the Customer's side of the Interconnection Point.

ii. AC Coupled with a Non-Exporting System: An Energy Storage Device coupled with a Non-Exporting System is subject to the provisions of Section 3 of this Schedule. The Total Nameplate Capacity of the Energy Storage Device shall be considered 0 kVA.

APPLICATION EXPIRATION

Applications from a Customer Generator with existing retail service that are not completed within one year of the initial Feasibility Review are considered expired. Applications from a Customer~~s~~ Generator without existing retail service that has not completed the Customer Generator Interconnection Process requirements by the requested project in-service date identitifed on the completed application will be considered expired.

Customer Generators requesting connection or approval of expired applications are required to resubmit a completed application form and a $100 non-refundable application fee and are subject to the full application process described in Section 2.

RECERTIFICATION

1. The Company may perform full recertification inspections of Customer Generator Systems at the Company's discretion and at no charge to the Customer Generator. The Company will provide the Customer Generator with written notice at least fourteen (14) calendar days prior to performing a recertification inspection. Recertification inspections will be performed in the same manner as new Customer Generator System inspections described in Section 2. Customers may choose to verify the results of the Company's inspection through an independent inspection performed by a certified third-party at the Customer Generator's expense.

2. If in the reasonable opinion of the Company, the Customer Generator's operation or maintenance of the DER or Interconnection Facilities is unsafe, not in compliance with this schedule, or may otherwise adversely affect the Company's equipment, personnel, or service to its customers, the Company reserves the right to inspect any Customer Generator System at any time, and without prior notice.

~~SYSTEM MODIFICATIONS~~

~~1. Any modifications to Customer Generator Systems that increase the Total Nameplate Capacity of the system or modify the system in any way (including inverter replacements) that may impact the safety or reliability of the Company's electrical system are considered system modifications for the purposes of this schedule.~~

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 1: GENERAL INTERCONNECTION REQUIREMENTS (Continued)

SYSTEM MODIFICATIONS

1. Any modifications to Customer Generator Systems that increase the Total Nameplate Capacity of the system or modify the system in any way (including inverter replacements) that may impact the safety or reliability of the Company's electrical system are considered system modifications for the purposes of this schedule.

~~SYSTEM MODIFICATIONS (Continued)~~

2. Customer Generators planning to make system modifications must submit an application, a $100 non-refundable fee, and complete the application process according to the procedures required for new interconnection.

3. System modifications without gaining prior Company approval are considered unauthorized installations subject to the provisions of this schedule as described in Unauthorized Installations and Expansions.

UNAUTHORIZED INSTALLATIONS AND EXPANSIONS

1. Customer Generator Systems that have been interconnected to the Company's system without Company approval are considered unauthorized installations that jeopardize the reliability of Idaho Power's system and the safety of its employees. This includes, but is not limited to, newly installed systems and unapproved expansions or other modifications of approved systems. The process described herein provides the Company with the ability to offer Customer Generation in an efficient, safe, and reliable manner.

2. Unauthorized installations are subject to immediate Company inspection and disconnection without notice. The Company will provide the reason for the disconnection of the Customer's DER. The Customer will be called and written, or electronic notification will be sent. The Customer will have twelve (12) months from the notification date to notify the Company and complete one of the options listed under 5(a) and 5(b).

3. If proper disconnection equipment is present, the Company will open the disconnect or notify the Customer to open the disconnect immediately.

4. If proper disconnection equipment is not present, the Customer Generator must disconnect the DER from operating in Parallel with the Company's system immediately by turning off the breaker or by other means necessary.

5. The Customer must complete and notify the Company of one of the below options within twelve (12) months from the notification date:

a. Option 1: Complete the full Customer Generator Interconnection Process described in Section 2, and the system will be re-energized.

~~b. Option 2: Permanently disable the DER from Parallel operations with the Company system. Permanent disablement of the DER requires an inspection to be scheduled with the Company within twelve (12) months from the postmarked notification date. Customers that do not schedule within this time period will be subject to termination of service.~~

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 1: GENERAL INTERCONNECTION REQUIREMENTS (Continued)

UNAUTHORIZED INSTALLATIONS AND EXPANSIONS (Continued)

b. Option 2: Permanently disable the DER from Parallel operations with the Company system. Permanent disablement of the DER requires an inspection to be scheduled with the Company within twelve (12) months from the postmarked notification date. Customers that do not schedule within this time period will be subject to termination of service.

6. If it is determined, at the sole discretion of the Company, that an unauthorized Customer Generation System, expansion, or other system modification results in damage to equipment on the Company's system, the Customer will be responsible for all costs associated with replacing the Company's damaged equipment and defend, indemnify, and reimburse the Company for liabilities or damages incurred by the Company for third-party claims arising out of the Customer Generator's unauthorized connection.

PERMANENTLY REMOVED OR DISABLED SYSTEMS

The Customer shall notify the Company immediately if a DER is permanently removed or disabled. Permanent removal or disablement for the purposes of this Schedule is any removal or disablement of a DER lasting longer than six (6) months. If the Customer wishes to interconnect the DER after six (6) months, the Customer Generator must reapply and meet the interconnection requirements in place at the time of application.

SECTION 2: INTERCONNECTION PROCESS REQUIREMENTS FOR DISTRIBUTED ENERGY RESOURCES LESS THAN 3 MVA

The following section is applicable to all DERs with Total Nameplate Capacity less than 3 MVA.

APPLICATION PROCESS

Customer~~s~~ Generators requesting to interconnect a DER less than 3 MVA are required to complete the following application process prior to interconnection:

1. Customer~~s~~ Generators must submit a completed application form and a $100 non-refundable application fee to the Company. Applications are available on the Company's website or will be provided to the Customer upon request. Incomplete Applications are considered withdrawn after sixty (60) days from the date the application was received.

2. Upon receipt of a completed application and a $100 non-refundable fee, the Company will either (1) provide the Customer with a written or electronic notification that the application has been received and all necessary information has been provided, or (2) request the Customer provide forms of documentation outlined in Section 1.

~~3. The Company will perform within seven (7) business days, unless it is determined that additional studies are necessary, the Feasibility Review based on Total Nameplate Capacity and other project information provided in the application. The Feasibility Review determines the capability of the Company's electrical system to incorporate the proposed Customer Generator System and determines if Upgrades are necessary.~~

~~a. If the results of the Feasibility Review indicate satisfactory system capability, the Company will provide the Customer with an official "Approval to Proceed" notification.~~

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 2: INTERCONNECTION PROCESS REQUIREMENTS FOR DISTRIBUTED ENERGY RESOURCES LESS THAN 3 MVA (Continued)

APPLICATION PROCESS (Continued)

If the DER system components, capacity, or configuration changes from the original application, the Customer Generator will be subject to a new Feasibility Review.

If the Customer Generator changes its Customer Representative, a new application and a $100 non-refundable application fee is required.

3. The Company will perform within seven (7) business days, unless it is determined that additional studies are necessary, the Feasibility Review based on Total Nameplate Capacity and other project information provided in the application. The Feasibility Review determines the capability of the Company's electrical system to incorporate the proposed Customer Generator System and determines if Upgrades are necessary. For a Customer Generator who does not yet have established service, the Feasibility Review will occur as part of the Company's evaluation for Upgrades for new customers conducted in compliance with Rule H – New Service Attachments and Distribution Line Installations or Alterations.

a. If the results of the Feasibility Review indicate satisfactory system capability, the Company will provide the Customer with an official "Approval to Proceed" notification.

b. If the results of the Feasibility Review indicate that Upgrades are necessary to accommodate the proposed project, the Company will notify the Customer through written or electronic notification of such Upgrades. Funding, construction, installation, and maintenance of required Upgrades will be subject to the Company's standard Rule H regarding New Service Attachments and Distribution Line Installations or Alterations.

c. If the Company determines that additional time is necessary to determine satisfactory system capability or that Upgrades are necessary to accommodate the proposed project, the Company will notify the Customer. The Company will perform within fifteen (15) business days the additional studies to complete the Feasibility Review.

4. If the results of the Feasibility Review require the need for a Feasibility Study, the Company will provide the Customer with a Feasiblity Study Agreement which requires a deposit of $1,000 and must be signed and returned~~perform the Feasibility Study~~ within fifteen 15 business days. Upon receipt of the signed Feasibility Study Agreement and deposit, the Company will perform the Feasiblity Study within thirty (30) business days. If the results of the Feasibility Study indicate that Upgrades or Protection Equipment are necessary to accommodate the proposed project, the Company will notify the Customer of such Upgrades or Protection Equipment. ~~The Feasibilty Study Agreement includes a deposit of $1,000.~~At the Company's discretion, additional studies referenced in Section 4 may be applicable.

a. Installation and funding of the construction, installation, and maintenance of required Protection Equipment will be subject to the following provisions:

~~i. Protection Equipment Requirements (Rotating Machines): Generation Facilities up to 500 kVA Total Nameplate Capacity may not require additional Protection Equipment but will be evaluated on a case-by-case basis. Generation Facilities greater than 500 kVA Total Nameplate Capacity will require additional Company-Furnished Protection Equipment.~~

~~ii. Protection Equipment Requirements (Other DER): DER up to 3 MVA Total Nameplate Capacity may not require additional Protection Equipment but will be evaluated on a case-by-case basis.~~

~~iii. When it is determined Company-owned Protection Equipment is required, the Customer shall pay the actual costs of all required Protection Equipment prior to the start of Parallel operations. The Customer will also pay a Maintenance Charge of 0.59 percent per month times the investment in the Protection Equipment.~~

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 2: INTERCONNECTION PROCESS REQUIREMENTS FOR DISTRIBUTED ENERGY RESOURCES LESS THAN 3 MVA (Continued)

APPLICATION PROCESS (Continued)

i. Protection Equipment Requirements (Rotating Machines): Generation Facilities up to 500 kVA Total Nameplate Capacity may not require additional Protection Equipment but will be evaluated on a case-by-case basis. Generation Facilities greater than 500 kVA Total Nameplate Capacity will require additional Company-Furnished Protection Equipment.

ii. Protection Equipment Requirements (Other DER): DER up to 3 MVA Total Nameplate Capacity may not require additional Protection Equipment but will be evaluated on a case-by-case basis.

iii. When it is determined Company-owned Protection Equipment is required, the Customer shall pay the actual costs of all required Protection Equipment prior to the start of Parallel operations. The Customer will also pay a Maintenance Charge ~~of 0.59 percent~~ specified in Schedule 66, per month times the investment in the Protection Equipment.

5. Following receipt of "Approval to Proceed," the Customer is responsible for completing the installation of the Customer Generator System and fulfilling all applicable federal, state, and local inspection requirements. Customers must also provide the Company with a completed System Verification Form detailing the specifications of all installed components of the completed Customer Generator System. System Verification Forms can be found on the Company's website or will be provided upon request. Upon completion, the Company reserves the right to request the Customer to provide forms of documentation outlined in Section 1, verifying that all federal, state, and local requirements have been met.

6. Once all required documentation has been submitted and the Company has verified that all applicable federal, state, local, and Customer Generation Interconnection Process requirements have been met, the Company will complete, barring conditions beyond the Company's control, an on-site inspection within ten (10) business days for DER with Total Nameplate Capacity of 100 kVA or less and within twenty (20) business days for DER with Total Nameplate Capacity of greater than 100 kVA. Company on-site inspections will not be performed until the system has passed all applicable federal, state, and local inspection requirements. The Company on-site inspection may include the following:

a. Verification that actual installed components correspond to the information provided on the initial application and the System Verification Form.
b. Verification that the disconnect is functional and reconnection time complies with IEEE 1547.
c. Verification of the proximity and visibility of the disconnect or a sign indicating the location of the disconnect.
d. Photographic documentation of the installation.
e. Posting of appropriate Company signage.

f. Documentation of the meter number and system configuration.

~~g. Verification of Smart Inverters, including the settings for all inverter-based DERs 100 kVA and greater.~~

~~h. Verification of Total Nameplate Capacity.~~

~~i. Verification of plant controller for all DERs 500 kVA and greater.~~

~~7. A return trip charge of $52.00 will be billed to the Customer each time Company personnel are dispatched to the job site but are unable to conduct the on-site inspection due to one or more of the conditions not being met that had been certified as complete by the Customer or installer on the System Verification Form.~~

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 2: INTERCONNECTION PROCESS REQUIREMENTS FOR DISTRIBUTED ENERGY RESOURCES LESS THAN 3 MVA (Continued)

APPLICATION PROCESS (Continued)

g. Verification of Smart Inverters, including the settings for all inverter-based DERs 100 kVA and greater.
h. Verification of Total Nameplate Capacity.
i. Verification of plant controller for all DERs 500 kVA and greater.

7. A return trip charge of $52.00 will be billed to the Customer each time Company personnel are dispatched to the job site but are unable to conduct the on-site inspection due to one or more of the conditions not being met that had been certified as complete by the Customer or ~~installer~~Customer's Representative, as identified on the System Verification Form.

8. Successful completion of the Company on-site inspection constitutes the conclusion of the application process. The Company must make a reasonable effort to move an Exporting Customer Generator to the appropriate rate schedule within five (5) business days. The rate change ~~. Under no circumstances will the rate change occur more than fifteen (15) business days from the date of the successfully completed inspection.~~will be no later than the Customer's next Billing Period following their successfully completed inspection. Upon completion of this process, the Customer will receive confirmation that the application process has been successfully completed.

9. It is within Idaho Power's sole discretion to disconnect, or refuse to connect, any Customer Generator System that does not pass inspection, poses a threat to public safety, or has unanticipated impacts to Idaho Power's system. In these situations, a Company representative will send a written communication to the Customer Generator regarding Idaho Power's inability to connect/reconnect the Customer Generator System until the issue(s) is resolved. Idaho Power will continue working with the Customer to resolve the issue(s) required to connect the Customer's System. Idaho Power will re-inspect the System upon receiving notice from the Customer indicating Customer's Generation System meets all applicable federal, state, and local requirements and is suitable for connection.

SECTION 3: ADDITIONAL INTERCONNECTION REQUIREMENTS OF NON-EXPORTING SYSTEMS

In addition to the requirements of Section 1, the following section is applicable to all Customer Generators electing to establish their system as Non-Export.

NON-EXPORT TOTAL NAMEPLATE CAPACITY LIMIT

For customers taking service under Schedule 1 or Schedule 7 that own and/or operate a Generation Facility, service is subject to an aggregate DER Total Nameplate Capacity of 25 kVA or less, that is operated in Parallel with the Idaho Power System.The capacity of an Energy Storage Device shall not be used to calculate the 25 kVA capacity limit but will be used to calculate Total Nameplate Capacity for the Feasbility Review.

~~NON-EXPORT CONTROL SYSTEM~~

~~1. Non-Export Systems must incorporate one of the following three options:~~

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 3: ADDITIONAL INTERCONNECTION REQUIREMENTS OF NON-EXPORTING SYSTEMS (Continued)

~~NON-EXPORT CONTROL SYSTEM (Continued)~~NON-EXPORT CONTROL SYSTEM

1. Non-Export Systems must incorporate one of the following three options:

a. Option 1: ("Advanced Functionality"): The use of an internal transfer relay, ~~E~~energy ~~M~~management ~~S~~system, or other customer facility hardware or software system(s) may be used to ensure power is never exported across the Interconnection Point. To ensure that Inadvertent Export of power is limited to acceptable levels, all of the following conditions must be met: (a) inverter-based DERs must utilize a Smart Inverter; (b) the DER must monitor the total Inadvertent Export; (c) the DER must disconnect from the Company's distribution system or halt energy production within two seconds after the period of continuous Inadvertent Export exceeds 30 seconds; (d) the DER must enter a safe operating mode where Inadvertent Export will not occur as a result of a failure of the control or Smart Inverter system for more than 30 seconds, which results in loss of control signal, loss of control power or single component failure or related control sensing of the control circuitry.

b. Option 2: ("Reverse Power Protection"): To ensure power is never exported, a reverse power relay protective function must be implemented at the Interconnection Point. The default setting for this Protection Equipment, when used, shall be 0.1% (export) of the DERs Total Nameplate Capacity, with a maximum 2.0 second time delay.

c. Option 3: ("Minimum Power Protection"): To ensure at least a minimum amount of power is imported at all times (and, therefore, that power is not exported), an under-power protective function may be implemented at the Interconnection Point. The default setting for this non-export control system, when used, shall be 5% (import) of the DERs Total Nameplate Capacity, with a maximum two (2) second time delay.

2. Control System Failure: Where applicable, any failure of the Customer's DER control system for 30 seconds or more, which includes, but is not limited to; the internal transfer relay, energy management system, or other Customer facility hardware or software system(s) intended to prevent the reverse power flow, shall cause the Customer's DER to enter a safe operating mode whereby the production of energy from the Non-Export DER is autonomously limited to an amount that shall not cause Inadvertent Export to occur until such time that the Customer has reestablished real power output control of the non-export control system.

UNAUTHORIZED INADVERTENT EXPORT

Inadvertent Export exceeding three hours of the DER Total Nameplate Capacity in any 30-day period will be defined as unauthorized Inadvertent Export, and the following steps will be followed for Customers with Non-Exporting Systems:

~~1. The Company will notify the Non-Export Customer Generator that their Customer Generator System has exceeded the Inadvertent Export limit.~~

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 3: ADDITIONAL INTERCONNECTION REQUIREMENTS OF NON-EXPORTING SYSTEMS (Continued)

UNAUTHORIZED INADVERTENT EXPORT (Continued)

1. The Company will notify the Non-Export Customer Generator that their Customer Generator System has exceeded the Inadvertent Export limit.

2. After notification of Inadvertent Export, the following will occur:

a. For Schedule 1, Residential and Schedule 7, Small General Non-Exporting Systems, the Customer Generator must rectify Inadvertent Export within 30 days after receipt of the notification by Idaho Power that the Non-Exporting System has exceeded the Inadvertent Export limit. If the Customer Generator has not rectified Inadvertent Export after 30 days, at the Customer's election, one of the following actions will occur:

i. The Customer Generator System disconnect will be placed in the open (off) position until the issue that caused the export is remedied. A Company inspection will be required before the Non-Exporting System can interconnect to the Company's system; or,

ii. If the Customer does not elect to open the disconnect, the Customer Generator will be placed on Schedule 6 or Schedule 8, as appropriate, and subject to applicable provisions of Section 2. If the Customer elects to be placed on Schedule 6 or Schedule 8, the Customer will be given the option to submit an additional application and be moved back to Schedule 1 or Schedule 7, as appropriate, after 180 days.

b. For Schedules other than Schedule 1 or Schedule 7:

i. Upon receipt of the notification by Idaho Power that the Customer Generator's Non-Exporting System has exceeded the Inadvertent Export limit, the Customer Generator System disconnect will be placed in the open position until the issue that caused the export is remedied. A Company inspection will be required before the Non-Exporting System can interconnect to the Company's system.

3. If it is determined, at the sole discretion of the Company, that unauthorized Inadvertent Export results in damage to equipment on the Company's system, the Customer Generator will be responsible for all costs associated with replacing the Company's damaged equipment and defend, indemnify, and reimburse the Company for liabilities or damages incurred by the Company for third-party claims arising out of the Customer Generator's unauthorized Inadvertent Export.

SCHEDULE 68
INTERCONNECTIONS TO CUSTOMER
DISTRIBUTED ENERGY RESOURCES
(Continued)

SECTION 4: ADDITIONAL INTERCONNECTION REQUIREMENTS OF DISTRIBUTED ENERGY RESOURCES 3 MVA OR GREATER (Continued)

SYSTEM PROTECTION, DER METERING, AND DER COMMUNICATION MAINTENANCE CHARGE

The Customer shall pay the actual costs of System Protection, DER metering, and DER communication equipment, as identified in the study process, prior to the start of Parallel operations. The Customer will pay a Maintenance Charge ~~of 0.59 percent~~as specified in Schedule 66 per month times the investment in the System Protection, DER metering, and DER communication equipment. The Customer Generator will also be responsible for any applicable monthly charges as outlined in Attachment 1 of the CGIA.

IDAHO POWER COMPANY
UNIFORM CUSTOMER GENERATOR
INTERCONNECTION AGREEMENT

This Uniform Customer Generator Interconnection Agreement ("Agreement") is entered to be effective as of the ____ day of __________, 20___ ("Effective Date"), between ____________________________, ("Customer Generator") and Idaho Power Company (the "Company"). Customer Generator and the Company may also be referred to individually as a "Party" or collectively as the "Parties." Unless explicitly noted otherwise, the term "days" refers to calendar days.

RECITALS

A. Customer Generator owns or operates a Customer Generator System that qualifies for service under Idaho Power's Commission-approved Schedule 68 which is subject to change from time to time pursuant to Commission order.

B. The Customer Generator System to be interconnected and operate in Parallel with the Company's system pursuant to this Agreement is more particularly described in Attachment 1.

AGREEMENT

For and in consideration of the mutual covenants and provisions set forth in this Agreement, and other good and valuable consideration, the receipt of which is hereby acknowledged, the Parties intending to be legally bound agree as follows:

1. **Recitals.** The Parties acknowledge and agree as to the accuracy of the Recitals set forth above, and such Recitals are incorporated herein by this reference.

2. **Defined Terms.** Capitalized terms not defined in this Agreement shall have the meaning given to them in Schedule 68.

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

APPLICABILITY (Continued)

ii. Single-Meter Interconnection (applicable to new applicants effective December 2, 2020): Owns and/or operates a Generation Facility interconnected to the Customer's individual electric system on the Customer's side of the Point of Delivery, thus all energy received and delivered by the Company is through a single meter.

6. The Generation Facility must have a total nameplate rating equal to or less than the greater of: (a) the greatest monthly Billing Demand established during the most recent 12-month period at the time of applying for interconnection, which includes and ends with the most recent Billing Period, or (b) 100 kW. The capacity of an Energy Storage Device shall not be used to calculate the capacity limits in this schedule.

a. Subject to the Company's discretion and approval, for a Customer applying to interconnect a Generation Facility (1) where 12-months of Billing Demand is not available, or (2) where the Billing Demand is not reflective of future operations, the customer may provide evidence that the proposed Generation Facility meets the applicability of this schedule in accordance with one of the following:

i. ~~i.~~ Schedules 9 and 19:

a. If previous billing data is available for the premises and the Customer's electrical needs are similar to the previous customer, the Company may rely on available historical Billing Demand at the premises not to exceed the previous 12 months.

b. ~~ii.~~ If the Customer has another account in the Company's service area with similar electrical needs, the Company may rely on available historical Billing Demand from that account not to exceed the previous 12 months.

c. ~~iii.~~ The Customer can have a third-party currently licensed or registered professional engineer provide analysis and documentation detailing the electrical load requirements for the Customer which support the requested load or an increase in demand expected to occur ~~within the next 12 months~~.

ii. Schedule 24:

a. ~~iv.~~ If historical Billing Demand is available for the Premises and is still reflective of expected operations, the Company will rely on the maximum of the most recently available 12-months of Billing Demand.

For newly installed equipment~~a Customer taking retail service under Schedule 24~~, the Customer may submit documentation of the horsepower ("HP") of the irrigation equipment (motors and/or pumps). Based on the submitted documentation, the Company will determine the maximum continuous

HP using a conversion factor of 1 HP to 0.8kW to define the demand for the Point of Delivery.

b.

~~7. Legacy Status for eligible Exporting Systems will terminate on December 1, 2045.~~

~~8. The Legacy Status of the Exporting System is transferable to a subsequent Customer at the premises for which a valid on-site generation service is in effect. Each Customer of a Legacy System taking service under Schedule 84 will be responsible for complying with the terms and conditions of the on-site generation service in effect for that premises.~~

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

APPLICABILITY (Continued)

7. Legacy Status for eligible Exporting Systems will terminate on December 1, 2045.

8. The Legacy Status of the Exporting System is transferable to a subsequent Customer at the premises for which a valid on-site generation service is in effect. Each Customer of a Legacy System taking service under Schedule 84 will be responsible for complying with the terms and conditions of the on-site generation service in effect for that premises.

9. A Legacy System that is offline for over six (6) months or that is moved to a different site shall forfeit Legacy Status of the Exporting System.

10. To remain eligible for Legacy Status, a Customer may increase the capacity of a Legacy System by no more than 10 percent of the originally installed nameplate capacity, or 1 kW, whichever is greater, to allow for the replacement of broken or degraded components. If a Customer expands a Legacy System beyond these limits and wishes to maintain Legacy Status for the original system, the new portion of the DER shall be separately metered and would not qualify for Legacy Status.

11. A Customer that modifies a two-meter Generation Facility to a single-meter forfeits the Legacy Status of the Generation Facility.

12. A Customer with a Legacy System may elect to forfeit the system's Legacy Status by submitting the request to the Company in writing. A Customer forfeiting Legacy Status will be required to reconfigure to a single-meter system.

DEFINITIONS

Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor.

Designated Meter is the retail meter physically connected to the Exporting System.

Distributed Energy Resource(s) (DER(s)) is a source of electric power that is not directly connected to the bulk power system. Any combination of Generation Facilities and/or Energy Storage Devices connected in Parallel is considered a DER.

Energy Storage Device is a device that captures energy produced at a point in time and stores the energy for use as electricity at a future point in time. An Energy Storage Device is a DER.

Excess Net Energy means the positive difference between the kilowatt-hours (kWh) generated by a Customer and the kWh supplied by the Company over the applicable Billing Period.

Exported Energy means all kWh generated by a Customer in excess of the Customer's on-site consumption that is exported to the Company's system.

~~Exporting System is a Customer-owned DER under the terms of Schedules 6, 8, or 84, which is designed to provide for the transfer of electric energy to the Company. An Exporting System is interconnected to the Company's system under the applicable terms of Schedule 68.~~

~~Generation Facility means all equipment used to generate electric energy where the resulting energy is either delivered to the Company via a single meter at the Point of Delivery or Generation Interconnection Point, or is consumed by the Customer.~~

~~Generation Interconnection Point is the point where the conductors installed to allow receipt of the Customer's generation connect to the Company's facilities adjacent to the Customer's Point of Delivery.~~

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

DEFINITIONS (Continued)

Exporting System is a Customer-owned DER under the terms of Schedules 6, 8, or 84, which is designed to provide for the transfer of electric energy to the Company. An Exporting System is interconnected to the Company's system under the applicable terms of Schedule 68.

Financial Credit represents the amount in dollars carried forward to offset Monthly Charges in a subsequent Billing Period. A Financial Credit is generated during a Billing Period when the product of Exported Energy and the Export Credit Rate exceeds a Customer's Monthly Charges.

Generation Facility means all equipment used to generate electric energy where the resulting energy is either delivered to the Company via a single meter at the Point of Delivery or Generation Interconnection Point, or is consumed by the Customer.

Generation Interconnection Point is the point where the conductors installed to allow receipt of the Customer's generation connect to the Company's facilities adjacent to the Customer's Point of Delivery.

Interconnection Facilities are all facilities reasonably required by Prudent Electrical Practices and the applicable electric and safety codes to interconnect and safely deliver energy from the DER to the Point of Delivery or Generation Interconnection Point.

Kilowatt Hour Credit ("kWh Credit") is the accumulated Excess Net Energy that is carried forward to offset energy usage in a subsequent Billing Period.

Legacy Status refers to the ability for a system to receive Net Energy Metering, including net monthly one-for-one kWh credit compensation for Excess Net Energy.

Legacy Systems means any system that meets the applicable criteria as described in Order Nos. 34509, 34546, 34854 and 34892.

Net Billing is the compensation structure applicable to all systems that do not meet the criteria of a Legacy System. Net Billing will be effective with each eligible customer's first billing cycle after January 1, 2024.

Net Energy Metering is the compensation structure applicable to all Legacy Systems.

Parallel connection means generating electricity from an on-site generation system that is connected to and receives voltage from Idaho Power's system.

Point of Delivery is the retail metering point where the Company's and the Customer's electrical facilities are interconnected to allow the Customer to take retail electric service from the Company.

Prudent Electrical Practices are those practices, methods and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

~~Schedule 68 is the Company's service schedule which provides for interconnection to DERs or its successor schedule(s) as approved by the Commission.~~

~~MONTHLY BILLING~~

~~The Customer shall be billed in accordance with the Customer's applicable standard service schedule, including appropriate monthly charges, and the Export Credit Rate under this schedule.~~

~~NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE~~

~~The conditions listed below shall apply to all transactions for Net Energy Metering under this schedule.~~

~~1. Balances of generation and usage by the Customer:~~

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

DEFINITIONS (Continued)
~~NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE (Continued)~~

Schedule 68 is the Company's service schedule which provides for interconnection to DERs or its successor schedule(s) as approved by the Commission.

MONTHLY BILLING

The Customer shall be billed in accordance with the Customer's applicable standard service schedule, including appropriate monthly charges, and the Export Credit Rate under this schedule.

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions for Net Energy Metering under this schedule.

1. Balances of generation and usage by the Customer:

a. If electricity supplied by the Company during the Billing Period exceeds the electricity generated by the Customer and delivered to the Company during the Billing Period, the Customer shall be billed for the net electricity supplied by the Company at the Customer's standard schedule retail rate, in accordance with normal metering practices.

b. If electricity generated by the Customer and delivered to the Company during the Billing Period exceeds the electricity supplied by the Company during the Billing Period, the Excess Net Energy shall be carried forward as a kWh ~~c~~Credit to offset energy usage in a subsequent Billing Period. ~~Excess Net Energy~~kWh ~~c~~Credits are subject to the following provisions:

i. kWh Credits can only be used to offset billed kWh consumption. Customers shall be billed for all applicable non-energy charges for the Billing Period according to the applicable standard service schedule.

ii. kWh Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

iii. kWh Credits are non-transferrable in the event that a Customer relocates and/or discontinues service at the Point of Delivery associated with the Exporting System. Any unused kWh ~~c~~Credits will expire at the time the final bill is prepared.

2. Aggregation of meters for the annual transfer of unused ~~Excess Net Energy~~ kWh C~~c~~redits:

a. If a balance of ~~Excess Net Energy~~kWh ~~c~~ Credits exists at a Designated Meter, the Customer may request to transfer the unused kWh ~~c~~Credits to offset energy consumption at eligible meters. A meter is eligible for aggregation if it meets all of the following criteria:

i. The account subject to offset is held by the Customer; and

~~ii. The meter is located on, or contiguous to, the property on which the Designated Meter is located. For the purposes of this tariff, contiguous property includes property that is separated from the Premises of the Designated Meter by public or railroad rights of way; and~~

~~iii. The meter is served by the same primary feeder as the Designated Meter at the time the Customer files the application for the Exporting System; and~~

~~iv. The electricity recorded by the meter is for the Customer's requirements; and~~

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

NET ENERGY METERING - CONDITIONS OF PURCHASE AND SALE (Continued)

ii. The meter is located on, or contiguous to, the property on which the Designated Meter is located. For the purposes of this tariff, contiguous property includes property that is separated from the Premises of the Designated Meter by public or railroad rights of way; and

iii. The meter is served by the same primary feeder as the Designated Meter at the time the Customer files the application for the Exporting System; and

iv. The electricity recorded by the meter is for the Customer's requirements; and

v. For Customers taking service under Schedule 1 or Schedule 7, kWh ~~c~~Credits may only be transferred to meters taking service under Schedule 1 or Schedule 7. For Customers taking service under Schedule 9, Schedule 19, or Schedule 24, kWh~~c~~ Credits may only be transferred to meters taking service under Schedule 9, Schedule 19, or Schedule 24.

b. Customers may submit requests to transfer ~~Excess Net Energy~~kWh ~~c~~Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power ~~by midnight, Mountain Standard Time,~~ on or before January 31. If a Customer does not request to transfer ~~Excess Net Energy~~kWh ~~c~~Credits by the January 31 submission deadline ~~Excess Net Energy~~kWh ~~c~~ Credits will carry forward to offset consumption at the Designated Meter until they become eligible the following year.

c. Requests to transfer ~~Excess Net Energy~~kWh ~~c~~Credits must be executed by the Company no later than March 31. Transfers will be based on the balance of ~~Excess Net Energy~~kWh ~~c~~Credits available at the time the transfer is made.

d. If multiple meters are eligible for aggregation, ~~Excess Net Energy~~kWh ~~c~~Credits must first be applied to the Designated Meter, then to eligible meters on rate schedules in accordance with Section 2a(v) above.

e. A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

NET BILLING – CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to transactions for Net Billing under this schedule.

1. Balances of usage and exports by the Customer.

a. The Customer shall be billed for the electricity supplied by the Company at the rates contained within the Customer's applicable standard service schedule, in accordance with normal metering practices.

~~b. The Customer shall be credited for Exported Energy at the applicable Export Credit Rate contained within this schedule as a credit in dollars to only offset Monthly Charges. Exported Energy credits are subject to the following provisions:~~

~~i. Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.~~

SCHEDULE 84
LARGE GENERAL, LARGE POWER, AND IRRIGATION
ON-SITE GENERATION SERVICE
(Continued)

NET BILLING – CONDITIONS OF PURCHASE AND SALE (Continued)

b. The Customer shall be credited for Exported Energy at the applicable Export Credit Rate contained within this schedule as a credit in dollars to only offset Monthly Charges. ~~Exported Energy~~Financial ~~c~~Credits are subject to the following provisions:

i. Financial Credits shall carry forward provided the Customer maintains electric service at the same Point of Delivery.

ii. Financial Credits are transferrable in the event that a Customer relocates. If the establishment of service at the new Point of Delivery is not initiated at the time service at the Designated Meter is discontinued, ~~it is the Customer's responsibility to request the credit transfer when service is established at the new location in Idaho Power's service area~~any unused Financial Credits will be paid out following the time the final bill is prepared.

~~iii. If a Customer discontinues service at the Point of Delivery associated with the Exporting System and does not intend to establish service at another location in Idaho Power's service area any unused credits will be paid out following the time the final bill is prepared.~~

2. Aggregation of meters for the annual transfer of unused Financial ~~c~~Credits:

a. If a balance of Financial ~~c~~Credits exists at a Designated Meter, the Customer may request to transfer the unused Financial ~~c~~Credits to eligible meters. A meter is eligible for aggregation if it meets the following criteria:

i. The account subject to offset is held by the Customer; and

ii. The electricity recorded by the meter is for the Customer's requirements.

b. Customers may submit requests to transfer a stated percentage of available Financial~~c~~ Credits between December 1 and January 31 of each year. All requests must be received by Idaho Power ~~by midnight, Mountain Standard Time,~~ on or before January 31. If a Customer does not request to transfer Financial~~c~~ Credits by the January 31 submission deadline Financial ~~c~~Credits will carry forward at the Designated Meter until they become eligible for transfer the following year.

c. Requests to transfer Financial~~c~~ Credits must be executed by the Company no later than March 31. Transfers will be based on the balance of Financial ~~c~~ Credits available at the time the transfer is made.

d. A meter aggregation fee of $10.00 will be assessed per aggregated meter per annual transfer transaction.

NET ENERGY METERING & NET BILLING – GENERAL CONDITIONS

1. The Customer shall never deliver or attempt to deliver energy to the Company's system when the Company's system serving the Customer's DER is de-energized for any reason.

2. The Company shall not be liable directly or indirectly for permitting or continuing to allow an attachment of a Exporting System to the Company's system, or for the acts or omissions of the Customer that cause loss or injury, including death, to any third party.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

ATTACHMENT NO. 3
SUMMARY OF REVENUE IMPACT

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

Summary of Revenue Impact
Current Adjusted Base Revenue to Proposed Base Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers*	Normalized Energy (kWh)*	Current Base Revenue	Transfer Adjustment	Adjusted Base Revenue	Mills Per kWh	Total Adjustments to Base Revenue	Proposed Base Revenue	Mills Per kWh	Percent Change Base to Base Revenue**
	Uniform Tariff Schedules:											
(1)	Residential Service	1	518,639	5,655,021,943	$ 653,615,731	$ 16,932,843	$ 670,548,573	115.58	$ 114,229,099	$ 784,777,672	138.78	17.04%
(2)	Master Metered Mobile Home Park	3	19	5,073,613	558,876	15,205	574,081	110.15	97,883	671,964	132.44	17.05%
(3)	Residential Service Time-of-Day	5	990	18,023,075	2,005,813	53,981	2,059,794	111.29	350,994	2,410,788	133.76	17.04%
(4)	Residential Service On-Site Generation	6	18,862	187,836,945	21,806,213	757,973	22,564,186	116.09	3,731,346	26,295,532	139.99	16.54%
(5)	Small General Service	7	30,034	139,928,074	19,712,436	423,404	20,135,840	140.88	3,427,461	23,563,301	168.40	17.02%
(6)	Small General Service On-Site Generation	8	83	530,076	65,461	2,116	67,578	123.49	10,629	78,207	147.54	15.73%
(7)	Large General Service	9	39,866	4,063,330,315	349,992,394	12,302,038	362,294,433	86.13	25,872,815	388,167,247	95.53	7.14%
(8)	Dusk to Dawn Lighting	15	-	1,937,298	1,370,823	5,865	1,376,688	707.60	53,976	1,430,664	738.48	3.92%
(9)	Large Power Service	19	134	2,196,091,802	153,975,159	6,648,976	160,624,135	70.11	16,020,926	176,645,061	80.44	9.97%
(10)	Agricultural Irrigation Service	24	19,754	1,770,164,055	173,947,865	5,359,420	179,307,284	98.27	30,516,128	209,823,412	118.53	17.02%
(11)	Unmetered General Service	40	1,857	14,484,473	1,452,369	43,854	1,496,223	100.27	122,781	1,619,004	111.78	8.21%
(12)	Street Lighting	41	1,687	20,419,614	3,941,761	61,823	4,003,584	193.04	157,223	4,160,807	203.77	3.93%
(13)	Traffic Control Lighting	42	859	3,056,155	239,792	9,253	249,045	78.46	42,384	291,429	95.36	17.02%
(14)	Total Uniform Tariffs		632,784	14,075,897,437	$ 1,382,684,693	$ 42,616,751	$ 1,425,301,444	98.23	$ 194,633,644	$ 1,619,935,089	115.09	13.66%
(15)	Total Special Contracts		6	1,375,512,497	$ 91,533,813	$ 4,164,557	$ 95,698,370	66.55	$ 4,483,634	$ 100,182,004	72.83	4.69%
(16)	**Idaho Power Supplied Retail Sales** [(2)]		**632,790**	**15,451,409,934**	**$ 1,474,218,506**	**$ 46,781,308**	**$ 1,520,999,814**	**95.41**	**$ 199,117,278**	**$ 1,720,117,093**	**111.32**	**13.09%**

* Test Year Revenue Forecast Jan 2025 - Dec 2025
** Impacts do not include Clean Energy Your Way

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

Summary of Revenue Impact - Schedule 9, 19, and 24 Distribution Level Detail
Current Adjusted Base Revenue to Proposed Base Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers*	Normalized Energy (kWh)*	Current Base Revenue	Transfer Adjustment	Adjusted Base Revenue	Mills Per kWh	Adjustments to Base Revenue	Proposed Base Revenue	Mills Per kWh	Percent Change Base to Base Revenue**
	Uniform Tariff Schedules:											
(1)	Large General Secondary	9S	39,568	3,404,848,961	$ 299,319,222	$ 10,309,544	$ 309,628,766	87.91	$ 22,249,731	$ 331,878,498	97.47	7.19%
(2)	Large General Primary	9P	292	654,889,792	50,358,109	1,981,620	52,339,730	76.90	3,600,668	55,940,398	85.42	6.88%
(3)	Large General Transmission	9T	6	3,591,562	315,063	10,874	325,937	87.72	22,415	348,352	96.99	6.88%
(4)	Total Schedule 9		39,866	4,063,330,315	$ 349,992,394	$ 12,302,038	$ 362,294,433	86.13	$ 25,872,815	$ 388,167,247	95.53	7.14%
(5)	Large Power Secondary	19S	1	6,446,801	$ 493,115	$ 19,519	$ 512,634	76.49	$ 51,130	$ 563,764	87.45	9.97%
(6)	Large Power Primary	19P	130	2,150,590,270	150,860,865	6,511,213	157,372,078	70.15	15,696,560	173,068,639	80.47	9.97%
(7)	Large Power Transmission	19T	3	39,054,731	2,621,179	118,244	2,739,423	67.12	273,235	3,012,658	77.14	9.97%
(8)	Total Schedule 19		134	2,196,091,802	$ 153,975,159	$ 6,648,976	$ 160,624,135	70.11	$ 16,020,926	$ 176,645,061	80.44	9.97%
(9)	Irrigation Secondary	24S	19,754	1,770,164,055	$ 173,947,865	$ 5,359,420	$ 179,307,284	98.27	$ 30,516,128	$ 209,823,412	118.53	17.02%
(10)	Irrigation Transmission	24T	-	-	-	-	-	0.00	-	-	0.00	0.00%
(11)	Total Schedule 24		19,754	1,770,164,055	$ 173,947,865	$ 5,359,420	$ 179,307,284	98.27	$ 30,516,128	$ 209,823,412	118.53	17.02%

* Test Year Revenue Forecast Jan 2025 - Dec 2025
** Impacts do not include Clean Energy Your Way

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

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers*	Normalized Energy (kWh)*	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue**
	Uniform Tariff Schedules:									
(1)	Residential Service	1	518,639	5,655,021,943	$ 658,399,879	116.43	$ 114,151,636	$ 772,551,515	136.61	17.34%
(2)	Master Metered Mobile Home Park	3	19	5,073,613	563,168	111.00	97,827	660,995	130.28	17.37%
(3)	Residential Service Time-of-Day	5	990	18,023,075	2,021,060	112.14	350,761	2,371,822	131.60	17.36%
(4)	Residential Service On-Site Generation	6	18,862	187,836,945	21,965,311	116.94	3,924,306	25,889,617	137.83	17.87%
(5)	Small General Service	7	30,034	139,928,074	19,815,003	141.61	3,429,961	23,244,964	166.12	17.31%
(6)	Small General Service On-Site Generation	8	83	530,076	65,849	124.23	11,151	77,000	145.26	16.93%
(7)	Large General Service	9	39,866	4,063,330,315	355,491,513	87.49	25,952,355	381,443,869	93.87	7.30%
(8)	Dusk to Dawn Lighting	15	-	1,937,298	1,373,424	708.94	54,014	1,427,438	736.82	3.93%
(9)	Large Power Service	19	134	2,196,091,802	156,944,262	71.47	16,064,057	173,008,320	78.78	10.24%
(10)	Agricultural Irrigation Service	24	19,754	1,770,164,055	176,355,288	99.63	30,550,816	206,906,104	116.89	17.32%
(11)	Unmetered General Service	40	1,857	14,484,473	1,471,938	101.62	123,066	1,595,004	110.12	8.36%
(12)	Street Lighting	41	1,687	20,419,614	3,969,246	194.38	157,624	4,126,870	202.10	3.97%
(13)	Traffic Control Lighting	42	859	3,056,155	243,912	79.81	42,444	286,356	93.70	17.40%
(14)	Total Uniform Tariffs		632,784	14,075,897,437	$ 1,398,679,854	99.37	$ 194,910,018	$ 1,593,589,872	113.21	13.94%
(15)	Total Special Contracts		6	1,375,512,497	$ 93,394,142	67.90	$ 4,510,649	$ 97,904,791	71.18	4.83%
(16)	**Idaho Power Supplied Retail Sales** [2]		**632,790**	**15,451,409,934**	**$ 1,492,073,996**	**96.57**	**$ 199,420,668**	**$ 1,691,494,663**	**109.47**	**13.37%**

* Test Year Revenue Forecast Jan 2025 - Dec 2025
** Impacts do not include Clean Energy Your Way

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

Summary of Revenue Impact - Schedule 9, 19, and 24 Distribution Level Detail
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers*	Normalized Energy (kWh)*		Current Billed Revenue	Mills Per kWh		Adjustments to Base Revenue		Proposed Base Revenue	Mills Per kWh	Percent Change Base to Base Revenue**
	Uniform Tariff Schedules:												
(1)	Large General Secondary	9S	39,568	3,404,848,961	$	303,929,388	89.26	$	22,317,490	$	326,246,878	95.82	7.34%
(2)	Large General Primary	9P	292	654,889,792		51,242,211	78.25		3,612,380		54,854,591	83.76	7.05%
(3)	Large General Transmission	9T	6	3,591,562		319,915	89.07		22,485		342,400	95.33	7.03%
(4)	Total Schedule 9		39,866	4,063,330,315	$	355,491,513	87.49	$	25,952,355	$	381,443,869	93.87	7.30%
(5)	Large Power Secondary	19S	1	6,446,801	$	501,818	77.84	$	51,257	$	553,075	85.79	10.21%
(6)	Large Power Primary	19P	130	2,150,590,270		153,768,463	71.50		15,738,798		169,507,261	78.82	10.24%
(7)	Large Power Transmission	19T	3	39,054,731		2,673,981	68.47		274,002		2,947,983	75.48	10.25%
(8)	Total Schedule 19		134	2,196,091,802	$	156,944,262	71.47	$	16,064,057	$	173,008,320	78.78	10.24%
(9)	Irrigation Secondary	24S	19,754	1,770,164,055	$	176,355,288	99.63	$	30,550,816	$	206,906,104	116.89	17.32%
(10)	Irrigation Transmission	24T	-	-		-	0.00		-		-	0.00	0.00%
(11)	Total Schedule 24		19,754	1,770,164,055	$	176,355,288	99.63	$	30,550,816	$	206,906,104	116.89	17.32%

* Test Year Revenue Forecast Jan 2025 - Dec 2025
** Impacts do not include Clean Energy Your Way

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

ATTACHMENT NO. 4
ASSET RETIREMENT OBLIGATION ENTRIES

MATT LARKIN
Revenue Requirement Senior Manager
mlarkin@idahopower.com

VIA ELECTRONIC FILING

May 6, 2025

Commission Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd., Bldg 8,
Suite 201-A (83714)
PO Box 83720
Boise, Idaho 83720-0074

RE: Case No. IPC-E-03-11
Annual Compliance Filing of Asset Retirement Obligations ("ARO") Accounting Standards Codification ("ASC") 410

Dear Commission Secretary:

In Order No. 29414, the Idaho Public Utilities Commission directed Idaho Power Company ("Company") to record regulatory assets or liabilities associated with implementation of Statement of Financial Accounting Standards 143 (now codified as Accounting Standards Codification ("ASC") 410). As a result of the Order, the Company is required to file annually, and as part of any rate case filing, all journal entries made under the requirements of ASC 410.

On May 17, 2012, Order No. 32549 was issued authorizing the Company to begin recovery of incremental costs related to the early closure of the Boardman power plant ("Boardman") and established the Boardman balancing account which tracks the difference between cost and revenues, including Boardman-related ARO balances. In addition, Order No. 32549 exempted Boardman-related ARO balances from the deferral treatment required under Order No. 29414.

Pursuant to Order No. 29414, attached please find all journal entries made under the requirements of ASC 410. If you have any questions regarding this filing, please contact Regulatory Projects Coordinator Courtney Waites at (208) 388-5612 or cwaites@idahopower.com.

Very truly yours,

Matt Larkin

MTL/sg

Enclosures
cc: Chris McEwan

1221 W. Idaho St (83702)
P.O. Box 70
Boise, ID 83707

Idaho Power Company

Accounting Standards Codification 410 (previously FAS 143) Accounting

Year Ended December 31, 2024

Recorded journal entries

		FERC Account	Dr.	Cr.
December 31, 2023 balances				
	ARO Assets	101/107	39,919,736	-
	Accumulated depreciation - ARO assets	108	-	27,071,494
	Accumulated depreciation - removal costs	108	175,369,216	-
	Cash	131	-	3,927,132
	Regulatory assets	182.3/4/5/6	33,755,829	-
	ARO Liabilities	230	-	48,848,874
	Regulatory liabilities	254	-	175,369,216
	Accretion expense (Boardman only), cumulative	411	2,235,411	-
	Depreciation expense (Boardman only), cumulative	403	3,936,524	-
Calendar year 2024 Accretion, Depreciation, Regulatory Asset Amortization, and Removal Cost Entries				
1	Regulatory asset (accretion expense)	182.3	**1,886,461**	
	Accretion expense (Boardman only)	411	**8,600**	
	ARO liabilities	230		**1,895,061**
	To record accretion expense on the asset retirement obligations			
2	Regulatory asset (depreciation expense)	182.3	**527,347**	
	Accumulated depreciation - ARO assets	108		**527,347**
	To record depreciation on the ARO assets			
3	Accumulated depreciation - removal costs	108		**9,188,010**
	Regulatory liabilities	254	**9,188,010**	
	To record adjustments to the ARO regulatory liability for the difference between regulatory-approved removal costs and the ASC 410 accruals			
Calendar year 2024 changes in estimates				
4	ARO Assets	107	**171,615**	
	Regulatory asset	182.3/182.4	**670,530**	
	ARO Liabilities	230		**842,145**
	To record revision of estimated AROs at Valmy, Bridger, and Boardman.			
Calendar year 2024 retirements				
5	Regulatory asset	182.3		**512,959**
	Cash	131		**96,276**
	ARO Liabilities	230	**609,235**	
	To primarily record retirements at Bridger and retirement spend at Boardman.			
6	ARO Assets	107		**348,229**
	Accumulated depreciation - ARO assets	108	**348,229**	
	To record removal of Evap Pond and Irrigation Pivot at Bridger as both were closed and fully depreciated.			
December 31, 2024 balances				
	ARO Assets	101/107	**39,743,122**	**-**
	Accumulated depreciation - ARO assets	108	**-**	**27,250,611**
	Accumulated depreciation - removal costs	108	**166,181,206**	**-**
	Cash	131	**-**	**4,023,407**
	Regulatory assets	182.3/4/5/6	**36,327,207**	**-**
	ARO Liabilities	230	**-**	**50,976,845**
	Regulatory liabilities	254	**-**	**166,181,206**