DONOVAN E. WALKER
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October 24, 2025

VIA ELECTRONIC FILING

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 the Motion for Approval of Stipulation and Settlement and Request for Accounting Order and the Direct Testimony of Timothy E. Tatum in Support of Settlement Stipulation in the above-referenced matter.

If you have any questions, please do not hesitate to contact me.

Very truly yours,

Donovan E. Walker

DEW:cd
Attachments

1221 W. Idaho St (83702)
P.O. Box 70
Boise, ID 83707

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MEGAN GOICOECHEA ALLEN (ISB No. 7623)
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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.	)	CASE NO. IPC-E-25-16 MOTION FOR APPROVAL OF STIPULATION AND SETTLEMENT AND REQUEST FOR ACCOUNTING ORDER

COMES NOW, Idaho Power Company ("Idaho Power" or "Company"), and hereby moves the Commission pursuant to Commission Rules of Procedure[1] 56 and 274, 275, and 276 for an Order accepting the Stipulation and Settlement ("Stipulation") entered into by and among Idaho Power, the Staff of the Idaho Public Utilities Commission ("Staff"), and the following intervenors in this docket: City of Boise, Clean Energy Opportunities for Idaho ("CEO"), Federal Executive Agencies ("FEA"), Idaho Irrigation Pumpers Association, Inc. ("IIPA"), Industrial Customers of Idaho Power ("ICIP"), Kroger Co. ("Kroger"), Micron Technology, Inc. ("Micron"), and NW Energy Coalition ("NWEC")

[1] Hereinafter cited as RP or "Procedural Rule".

(collectively referred to as the "Stipulating Parties"). Additionally, in order to facilitate implementation of one of the terms of the Stipulation related to adjustments to plant in service as described in Section II, below, the Company respectfully requests Commission authorization to retain in Construction Work in Progress ("CWIP") the costs associated with the distribution undergrounding portion of the Wood River Valley ("WRV") project until such time that the entire project is completed and placed into service.

This Motion is based on the Direct Testimony of Timothy E. Tatum in Support of Settlement Stipulation filed contemporaneously herewith; the signed Stipulation and accompanying Exhibit Nos. 1 through 5 memorializing the Stipulating Parties' agreement included as Attachment No. 1; the revised tariff sheets provided in Attachment No. 2; and the following:

I. STIPULATION AND SETTLEMENT

1. On May 30, 2025, Idaho Power filed an Application with the Commission requesting an increase in annual Idaho jurisdictional revenue of $199.1 million, which if approved would have resulted in an overall increase to adjusted base revenue of 13.09 percent. Idaho Power proposed spreading the rate increase to varying degrees among all customer classes and special contract customers. On June 13, 2025, the Commission issued Order No. 36638, which, in pertinent part, designated the proceeding as a general rate case pursuant to Procedural Rule 124 and suspended the effective date of the proposed rates for a period of thirty (30) days plus five (5) months from July 1, 2025, to effectuate review of the Company's request in accordance with Idaho Code § 61-622(4) and Procedural Rule 123.03.

2. Petitions to intervene in this proceeding were filed by the City of Boise, CEO, FEA, IIPA, IdaHydro, ICIP, Kroger, Micron, NWEC, and John Gannon, Deborah Fease, Amy Lorrance, and Randy Morris ("Gannon, et al., *pro se*"). These entities are collectively referred to as the "Parties." By various orders, the Commission granted these interventions. IPUC Order Nos. 36557, 36635, 36665, 36666, 36685, 36690, and 36691.

3. The Parties consulted informally in July to devise a proposed schedule for completing discovery, filing testimony, and holding hearings in this proceeding. The Parties also agreed to engage in settlement discussions in accordance with Procedural Rule 272 with a view toward resolving the issues in this case, and Commission Staff provided notice of settlement negotiations to all parties of record on September 2, 2025. All Parties were given an opportunity, whether in person or virtually, to participate in or be apprised of the course of settlement negotiations, which were held on September 9, September 29, and October 6, 2025.

4. Based on the settlement discussions, the following Parties whose signatures appear on the Stipulation have agreed to resolve and settle all the issues in the case: Idaho Power, Staff, City of Boise, CEO, FEA, IIPA, ICIP, Kroger, Micron, and NWEC. Gannon, et al., *pro se* and IdaHydro did not join in the Stipulation; the former has indicated it will not object to the settlement while the latter has not indicated a position.

5. If the Stipulation is approved, the Company's overall Idaho jurisdictional retail revenue will increase by approximately $110 million, or 7.48 percent.

6. For settlement purposes and subject to Commission approval, the Stipulating Parties agree that the revenue requirement increase contemplated by the Stipulation should be recovered by implementing tariffs in conformance with those in

Attachment No. 2, which are intended to effectuate the settlement and incorporate other changes that have been approved by the Commission as of the date of this filing.

7. The Stipulating Parties recommend that the Commission grant this Motion and accept and approve the Stipulation in its entirety, without material change or condition, pursuant to RP 274 and 276.

8. A technical hearing is scheduled to take place in Boise starting on December 2 and continuing as needed through December 5, 2025. Idaho Power and the Commission Staff each intend to present live testimony supporting this Motion and recommending approval of the Stipulation. Other Parties may choose to present live supporting testimony as well. As noted in page 17 of the Stipulation, all the Stipulating Parties agree that the Stipulation is in the public interest and represents a fair, just, and reasonable compromise of the issues in this proceeding.

II. ACCOUNTING ORDER AND TREATMENT

9. As set forth in Section A(2)(b) and paragraph 16 of the Stipulation, the Stipulating Parties have agreed that the costs associated with the distribution undergrounding portion of the WRV project should be removed from the revenue requirement in this case and retained in CWIP until the entire project (both distribution and transmission) is completed and placed in service. To implement the Stipulating Parties' agreement in this regard, the Company respectfully requests that the Commission issue an accounting order authorizing this treatment, which is consistent with the accounting order granted by the Commission in Order No. 36687 authorizing the delay in placing the incremental distribution costs attributable to Blaine County – recorded in

CWIP – into service until the transmission line is complete and operational, allowing for a single surcharge for the incremental WRV project costs attributable to Blaine County.

III. REQUEST FOR RELIEF

NOW, THEREFORE, Idaho Power respectfully requests that the Commission issue a final order:

1. Granting this Motion and accepting the Stipulation and Settlement agreed to by the Stipulating Parties and provided as Attachment No. 1 hereto, in its entirety without material change or condition;

2. Authorizing the Company to implement revised tariff schedules designed to recover $110 million in additional annual revenue from its Idaho jurisdiction consistent with the terms of the Stipulation, provided as Attachment No. 2 hereto, effective January 1, 2026; and

3. Authorizing Idaho Power to retain costs associated with the distribution undergrounding portion of the WRV project in CWIP until the entire project (distribution and transmission) is completed and placed in service.

Respectfully submitted this 24th day of October 2025.

Donovan E. Walker

DONOVAN E. WALKER
Attorney for Idaho Power Company

Megan Goicoechea Allen

MEGAN GOICOECHEA ALLEN
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 24th day of October 2025, I served a true and correct copy of the Motion for Approval of Stipulation and Settlement and Request for Accounting Order upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Erika Melanson Deputy Attorney General Idaho Public Utilities Commission 11331 W. Chinden Blvd., Bldg No. 8 Suite 201-A (83714) PO Box 83720 Boise, ID 83720-0074	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__Email erika.malanson@puc.idaho.gov
Idaho Irrigation Pumpers Association, Inc. Eric L. Olsen Echo Hawk & Olsen, PLLC 505 Pershing Ave., Ste. 100 P.O. Box 6119 Pocatello, Idaho 83205	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__Email elo@echohawk.com
Lance Kaufman, Ph.D. 2623 NW Bluebell Place Corvallis, OR 97330	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email lance@aegisinsight.com
Clean Energy Opportunities for Idaho Kelsey Jae Law for Conscious Leadership 920 N. Clover Dr. Boise, ID 83703	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email Kelsey@kelseyjae.com

Courtney White Mike Heckler 3778 Plantation River Drive, Suite 102 Boise, Idaho 83703	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email courtney@cleanenergyopportunities.com mike@cleanenergyopportunites.com
City of Boise City Ed Jewell Deputy City Attorney Boise City Attorney's Office 150 N. Capital Blvd., P.O. Box 500 Boise, Idaho 83701	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email edjewell@cityofboise.org BoiseCityAttorney@cityofboise.org
Katie O'Neil Energy Program Manager Boise City Dept. of Public Works 150 N. Capitol Blvd. P.O. Box 500 Boise, Idaho 83701-0500	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email koneil@cityofboise.org
Federal Executive Agencies Emily W. Medlyn Jelani A. Freeman U.S. Department of Energy 1000 Independence Ave., S.W. Washington, D.C. 20585	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email emily.medlyn@hg.doe.gov Jelani.freemen@hq.doe.gov
Dwight Etheridge Exeter Associates, Inc. 10480 Little Patuxent Parkway, Suite 300 Columbia, MD 21044	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email detheridge@exeterassociates.com

IdaHydro C. Tom Arkoosh Nicholas J. Erekson Arkoosh Law Offices 913 W. River Street, Suite 450 P.O. Box 2900 Boise, ID 83701	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email tom.arkoosh@arkoosh.com nick.erekson@arkoosh.com Erin.cecil@arkoosh.com
The Kroger Co. Kurt J. Boehm Jody Kyler Cohn Boehm, Kurtz & Lowry 425 Walnut Street, Suite 2400 Cincinnati, OH 45202	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email kboehm@bkllawfirm.com jkylercohn@bkllawfirm.com
Micron Technology, Inc. Austin Rueschhoff Thorvald A. Nelson Kristine A.K. Roach Holland & Hart, LLP 555 17th Street, Suite 3200 Denver, CO 80202	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email darueschhoff@hollandhart.com tnelson@hollandhart.com awjensen@hollandhart.com karoach@hollandhart.com aclee@hollandhart.com tlfriel@hollandhart.com
Industrial Customers of Idaho Power Peter Richardson Richardson Adams, PLLC 515 N. 27th Street Boise, Idaho 83702	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X__ Email peter@richardsonadams.com

Northwest Energy Coalition Benjamin J. Otto Lauren McCloy Derek Goldman Northwest Energy Coalition 1407 W. Cottonwood Court Boise, Idaho 83702	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site __X_Email ben@nwenergy.org lauren@nwenergy.org derek@nwenergy.org
John Gannon 1104 Johnson Street Boise, Idaho 83705	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FTP Site _X__ Email Johngannon200@gmail.com Occidentalpacific@hotmail.com Feased854@gmail.com



Christy Davenport
Legal Administrative Assistant

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

ATTACHMENT NO. 1

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DONOVAN E. WALKER (ISB No. 5921)
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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.	)	CASE NO. IPC-E-25-16 STIPULATION AND SETTLEMENT

This Stipulation and Settlement ("Stipulation") is entered into by and among Idaho Power Company ("Idaho Power" or "Company"), the Staff of the Idaho Public Utilities Commission ("Staff"), and the following intervenors in this docket: City of Boise, Clean Energy Opportunities for Idaho ("CEO"), Federal Executive Agencies ("FEA"), Idaho Irrigation Pumpers Association, Inc. ("IIPA"), Industrial Customers of Idaho Power ("ICIP"), Kroger Co. ("Kroger"), Micron Technology, Inc. ("Micron"), and NW Energy Coalition ("NWEC"). These entities are referred to individually as a "Stipulating Party" or collectively referred to as the "Stipulating Parties."

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I. INTRODUCTION

The terms and conditions of this Stipulation are set forth herein. If the Stipulation is approved, the Company's overall retail revenue will increase by approximately $110 million, or 7.48 percent. The Stipulating Parties agree that this Stipulation represents a fair, just, and reasonable compromise of the issues in this proceeding and that this Stipulation is in the public interest. The Stipulating Parties maintain that the Stipulation and its acceptance by the Idaho Public Utilities Commission ("IPUC" or "Commission") represent a reasonable resolution of all issues identified in this matter. Therefore, the Stipulating Parties recommend that the Commission, in accordance with Commission Rule of Procedure[1] 274, approve the Stipulation and all of its terms and conditions without material change or condition.

II. BACKGROUND

On May 30, 2025, Idaho Power filed an Application with the Commission requesting an increase in annual Idaho jurisdictional revenue of $199.1 million, which if approved would have resulted in an overall increase to adjusted base revenue of 13.09 percent. Idaho Power proposed spreading the rate increase to varying degrees among all customer classes and special contract customers. Anticipating suspension of the proposed tariff pursuant to Idaho Code § 61-622(4) and Procedural Rule 123.03, the Company requested that new rates become effective on January 1, 2026. Idaho Power notified customers of the requested rate increase via press release and customer notices mailed to individual customers in accordance with the requirements of Procedural Rule 125.

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[1] Hereinafter cited as "Procedural Rule".

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To facilitate review of the Company's request, on June 13, 2025, the Commission designated the proceeding as a general rate case pursuant to Procedural Rule 124 and notified the public in Order No. 36638 that the Commission may make decisions addressing the Company's revenue requirement, rates, charges, and service to its Idaho retail customers. It also suspended the effective date of the proposed rates for a period of thirty (30) days plus five (5) months or until the Commission enters an order accepting, rejecting, or modifying the proposed rate increases.

Petitions to intervene in this proceeding were filed by the City of Boise, CEO, FEA, IIPA, IdaHydro, ICIP, Kroger, Micron, NWEC, and John Gannon, Deborah Fease, Amy Lorrance, and Randy Morris ("Gannon, et al., *pro se*). These entities are collectively referred to as the "Parties." By various orders, the Commission granted these interventions. IPUC Order Nos. 36557, 36635, 36665, 36666, 36685, 36690, and 36691.

The Parties consulted informally in July to devise a proposed schedule for completing discovery, filing testimony, and holding hearings in this proceeding. The Parties also agreed to engage in settlement discussions in accordance with Procedural Rule 272 with a view toward resolving the issues in this case. All Parties attended, whether in person or virtually, settlement discussions held on September 9, September 29, and October 6, 2025.

Based upon the settlement discussions among the Parties, as a compromise of the positions in this case, and for other consideration as set forth below, the Stipulating Parties agree to the following terms:

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III. TERMS OF THE STIPULATION AND SETTLEMENT

A. Revenue Requirement

The Stipulating Parties agree that Idaho Power shall be allowed to increase annual Idaho jurisdictional retail revenues by approximately $110 million, or 7.48 percent, effective January 1, 2026. The Stipulating Parties further agree that the $110 million increase represents a compromise of the revenue requirement positions in the case for the purpose of settlement and that the agreed upon amount should be approved by the Commission in its entirety without further adjustment. In determining the approximately $110 million additional revenue requirement, the Stipulating Parties agree on certain revenue requirement adjustments to the Company's filed case as summarized in the table below and further described in the paragraphs that follow. It should be noted that the adjustments detailed in this Stipulation do not reflect any Party's endorsement of the underlying methodology and will not be construed as precedent in any subsequent proceeding before the Commission.

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Summary of Stipulated Revenue Requirement Adjustments (Figures reflect Idaho Jurisdictional Amounts)		
Filed Net Revenue Increase: $199,122,685		
Stipulated Adjustments	**Adjustment Impact**	**Net Rate Change**
1. Cost of Capital		
a. Return on Equity	($27,687,577)	$171,435,108
2. Rate Base		
b. Adjustments to Plant in Service	($21,605,673)	$149,829,436
c. Customer Advances – Update to Actuals	($1,411,447)	$148,417,989
d. Customer Advances – BPA	($986,816)	$147,431,173
3. Revenue		
e. Revenue Forecast – Update to Actuals	($9,054,540	$138,376,633
4. Expenses		
f. Executive Comp, Training, and Travel	($3,919,804)	$134,456,829
g. Board of Directors Comp and Expenses	($1,313,083)	$133,143,746
h. Miscellaneous Adjustments	($1,223,909)	$131,919,837
5. Deferrals and Mechanisms		
i. Wildfire O&M Base Update	($10,722,564)	$121,197,273
j. Insurance Base	($5,328,358)	$115,868,915
k. Wildfire Deferral Amortization	($2,646,864)	$113,222,051
l. Net Power Cost Update – Gas Prices	($2,186,414)	$111,035,637
m. Net Power Cost Update – EIM Benefits	($995,491)	$110,040,145

1. Cost of Capital

(a) Cost of Capital. The Stipulating Parties agree to a 9.6 percent return on equity ("ROE") and a 7.410 percent overall rate of return ("ROR") based on the filed cost of debt and capital structure, applied to an authorized Idaho jurisdictional rate base of $4,881,563,721.

2. Rate Base

(b) Adjustments to Plant in Service. The Stipulating Parties agree to reduce the test year revenue requirement by $21,605,673 to account for the following: (1) modification to the plant forecast from a 13-month average to a December 2025 average of monthly averages ("AMA") utilizing actual plant additions for January through July 2025, (2) removal of the annualizing adjustments associated with projects over $2 million, (3) updating

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the forecast for projects under $2 million based on actual plant additions for January through July 2025, (4) removal of the C.J. Strike Boat Barrier project, which is not expected to close to plant in 2025, and (5) removal of the Wood River Valley ("WRV") distribution line.

(c) Customer Advances – Update to Actuals. The Stipulating Parties agree to reduce the filed request by $1,411,447 to reflect higher actual customer advance balances as of July 2025 compared to the forecasted balances included in the original filing.

(d) Customer Advances – BPA. The Stipulating Parties agree to reduce the filed request by $986,816 to include the Boardman to Hemingway seller's security deposit received from the Bonneville Power Administration ("BPA").

3. Revenues

(e) Revenue Forecast. The Stipulating Parties agree to reduce the filed request by $9,054,540 to reflect an update to the revenue forecast based on actual revenue through July 2025.

4. Expenses

(f) Executive Compensation, Training, and Travel. The Stipulating Parties agree to reduce revenue requirement by $3,919,804 to reflect the removal of certain executive compensation, training, and travel expenses.

(g) Board of Directors Comp and Expenses. The Stipulating Parties agree to reduce revenue requirement by $1,313,083 to reflect the removal of one-half of the Board of Director's compensation and certain Board of Director's expenses.

(h) Miscellaneous Administrative and General Expense Adjustments. The Stipulating Parties agree to adjust a portion of the test year operating expenses related to the following cost categories: (1) company airplane flights & maintenance ($355,195), (2)

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advertising ($297,372), (3) legal fees ($321,813), (4) credit card expenses ($100,000), and (5) injuries and damages ($149,528). The net effect of these adjustments decreases the overall revenue requirement by $1,223,909. The adjustments described in this paragraph serve to reduce the level of allowed recovery for each respective cost category, but do not entirely eliminate cost recovery for any individual cost category nor do they establish precedent for any future proceedings.

5. Deferrals / Mechanism-Related Adjustments

(i) Wildfire Operations & Maintenance (O&M) Adjustment. The Stipulating Parties agree various wildfire-related costs that constituted one-time expenditures that will not continue in the future were removed from the Company's revenue requirement, reducing the revenue requirement by $211,884. The Stipulating Parties also agree to remove the revenue requirement of $736,780 associated with the Standby Helicopter Service and the Aerial Drone Inspection Pilot. The Stipulating Parties agree to reduce revenue requirement by $9,773,901 to reduce Transition to/Maintain 3-year Vegetation Management Cycle to actuals for 2024. The net effect of these adjustments decreases the overall revenue requirement by $10,722,564.

Wildfire O&M Base Update. The following activities are eligible for deferral through the earlier of Idaho Power's next general rate case ("GRC") or 2027: (1) incremental vegetation management, including Transition to/Maintain 3-year Cycle, above 2024 levels of $31,932,421, (2) incremental Enhanced Practices for Red and Yellow Risk Zones above 2025 Test Year amount of $1,486,000, (3) incremental internal Vegetation Management Crew Pilot, and (4) the Standby Helicopter Service and the Aerial Drone Inspection Pilot.

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The costs associated with these activities above the base amount of $33,418,421[2] are eligible for deferral. The Stipulating Parties agree that Wildfire O&M and Insurance deferred amounts will be recorded in separate regulatory asset accounts.

(j) Insurance Base. The Stipulating Parties agree to reduce the revenue requirement by $5,328,358 to reflect insurance actuals for 2024 compared to the test year balance included in the original filing. Incremental insurance above the 2024 actual amount of $20,164,472[3] will continue to be deferred through the earlier of the Company's next GRC or 2027. The Stipulating Parties agree that Wildfire O&M and Insurance deferred amounts will be recorded in separate regulatory asset accounts.

(k) Wildfire Deferral Amortization. The Stipulating Parties agree to reduce revenue requirement by $2,646,864 to reflect the updated amortization of the actual wildfire deferral balance of $54,819,901 as of June 30, 2025, over a 7-year period. The wildfire deferral balance of $54,819,901 consists of incremental wildfire O&M and insurance expenses deferred for 2023, 2024, and year-to-date June 2025.

(l) Net Power Cost Update – Gas Prices. An adjustment was made to update the modeling assumption related to natural gas prices that reduces filed system Net Power Supply Expense ("NPSE") by $45.2 million. Net of the Power Cost Adjustment ("PCA") transfer adjustment, this results in a net reduction to the Company's revenue requirement of $2,186,414.

(m) Net Power Cost Update – Energy Imbalance Market ("EIM"). An adjustment was made to update base NPSE to incorporate an estimate of EIM benefits

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[2] Total system.
[3] *Id.*

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which reduces filed system NPSE by $20.6 million. Net of the PCA transfer adjustment, this results in a net reduction to the Company's revenue requirement of $995,491.

B. Cost-of-Service, Revenue Allocation, and Rate Design

6. Cost-of-Service. The Stipulating Parties do not agree on any particular class cost-of-service ("CCOS") methodology and this Stipulation does not request that the Commission approve a particular CCOS methodology. The Company's filed CCOS methodology, updated to reflect customer, energy, and demand allocators based on January through July normalized actuals (consistent with the "Revenue Forecast – Update to Actuals" adjustment described in Section A(3)(e)) and the settled revenue requirement ("Settlement CCOS Study"), has been utilized on a limited basis to inform a starting point for revenue allocation, Schedule 9, Schedule 19, and Schedule 30 rate design (as further explained below), Fixed Cost Adjustment ("FCA") rates, the Sales Based Adjustment Rate ("SBAR") used in the PCA, special contract pricing, and optional service offerings including Schedules 31, 45, 46, and 62.

7. Revenue Allocation. The Stipulating Parties agree that the above-described $110 million net revenue increase should be recovered by implementing tariffs in conformance with the attached Exhibit No. 1. The revenue allocation was generally developed using a method to increase the prices for each customer class ranging between approximately 0.3 times (2.38 percent) to 1.3 times (9.89 percent) of the overall 7.48 percent increase.

8. Rate Design. For settlement purposes, the Stipulating Parties agree to the rate design and related tariff provisions proposed by the Company in Mr. Grant

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Anderson's direct testimony, updated to reflect the Settlement CCOS Study, with the following exceptions:

a. Service Charges: The existing $15 Service Charge will be retained for Schedule 1 (Residential Service Standard Plan), Schedule 3 (Master-Metered Mobile Home Park Residential Service), Schedule 5 (Residential Service – Time-of-Use Plan), and Schedule 6 (Residential Service On-Site Generation). The existing $25 Service Charge will be retained for Schedule 7 (Small General Service), Schedule 8 (Small General Service On-Site Generation), and Schedule 9 (Large General Service - Secondary). For Schedule 9 (Large General Service - Primary and Transmission), a Service Charge of $345 will be implemented, for Schedule 19 (Large Power Secondary Service), a Service Charge of $110 will be implemented, and for Schedule 19 (Large Power – Primary and Transmission Service), a Service Charge of $450 will be implemented.

b. Demand-Related Charges: For Schedule 9 (Large General Service – Primary and Transmission), Schedule 19 (Large Power Service), and Schedule 30 (Electric Service Rate for United States Department of Energy Idaho Operations Office), the collection of demand-classified costs through the Demand and/or Basic Load Capacity charges will reflect an approximate 40 percent movement toward cost of service for that pricing component, as informed by the Settlement CCOS Study.

c. Non-Residential Time-of-Use ("TOU"): For Schedule 9 (Large General Service) and 19 (Large Power Service), the TOU periods will be adjusted

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as follows: On-Peak hours will remain consistent with the Company's filed position, Off-Peak hours will be defined as 10 a.m. to 2 p.m., Monday through Saturday and all hours on Sundays and Holidays; and Mid-Peak hours will include all hours not designated as On-Peak or Off-Peak. The method for establishing the differentials between On-Peak, Mid-Peak, and Off-Peak will remain consistent with the Company's filed position.

The attached Exhibit No. 2 details the specific pricing for each schedule.

9. Rate Effective Date. The Stipulating Parties request that the Commission issue an Order approving the agreed-upon rates contained in this Stipulation to become effective on January 1, 2026.

C. Non-Revenue Stipulated Agreements

10. Single Issue CCOS Case. The Stipulating Parties agree that it would be appropriate for the Commission to address the CCOS methodology and associated policy issues in a separate proceeding in which alternatives to the Company's filed CCOS methodology in this case, including a CCOS study with an hourly-informed class allocation of Production and Transmission revenue requirement, will be presented for the Commission's consideration. To this end, Idaho Power agrees to initiate a single-issue case related to CCOS methodology for the Commission's consideration ("Single Issue CCOS Case") in advance of filing a Notice of Intent for its next GRC but in no event later than the end of the first quarter of 2026. Prior to filing that case, Idaho Power will meet with Staff and other interested Parties to identify alternative CCOS studies that will be presented by the Company for Commission consideration. Should Idaho Power file a GRC prior to the issuance of a final order in the Single Issue CCOS Case, Idaho Power

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will include a CCOS study with an hourly-informed class allocation of Production and Transmission revenue requirement in addition to its proposed CCOS study as part of its GRC filing. After receipt of the final order in the Single Issue CCOS Case, Idaho Power will supplement its GRC filing to incorporate any directives stemming from the final Commission decision. However, the results of the Single Issue CCOS Case do not prevent any Party from proposing any alternative CCOS methodology in a GRC.

11. Test Year Methodology Workshop. In advance of the Company's next GRC, Staff will initiate a workshop with Idaho Power and interested parties to discuss test-year methodologies.

12. Irrigation TOU. Idaho Power commits to immediately initiate collaborative discussions with the Idaho Irrigation Pumpers Association ("IIPA"), and other interested parties, with the intent of developing an optional Agricultural Irrigation Service (Schedule 24) TOU offering that could be filed for IPUC approval as early as January 1, 2026, with the newly established rate structure becoming effective on or after June 1, 2026. Issues within scope for this collaborative effort include, but are not limited to, (1) appropriate TOU rate periods, (2) the extent to which generation and transmission costs are to be collected through on-peak energy charges, (3) interplay between the potential TOU offering and the Irrigation Peak Rewards demand response program and (4) mitigation of fixed cost revenue erosion.

13. Capital Investments. At the time of this Stipulation, Staff had completed its prudence review of capital projects included in the test year rate base through July 2025. Except as otherwise noted in this Stipulation, all capital projects included in the Company's test year are presumed to be prudently incurred. To the extent Staff identifies

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

potential prudence concerns with capital investments after July 2025, it will address those in the Company's next GRC.

14. Revenue Sharing/Accumulated Deferred Investment Tax Credit ("ADITC") Mechanism Background. Since 2009, the Company has been subject to an ADITC / Revenue Sharing Mechanism, which was established by Order No. 30978 in Case No. IPC-E-09-30 and modified and extended by Order No. 32424 in Case No. IPC-E-11-22, Order No. 33149 in Case No. IPC-E-14-14, Order No. 34071 in Case No. GNR-U-18-01, and Order No. 36042 in Case No. IPC-E-23-11, that includes provisions for the accelerated amortization of ADITC to help achieve a minimum specified percent Idaho-jurisdiction return on year-end equity ("Idaho ROE"), currently set at 9.12 percent. The mechanism also provides for the potential sharing between Idaho Power and Idaho customers of Idaho jurisdictional earnings in excess of a 9.6 percent Idaho ROE. Under the current mechanism, the ADITC and sharing thresholds are to be reset at a GRC to align the sharing threshold with the newly authorized ROE and the threshold for use of accelerated amortization of ADITC if the Company's Idaho ROE falls below 95 percent of the authorized ROE.

15. Revenue Sharing / ADITC Mechanism Modifications. Under this Stipulation, the ADITC Revenue Sharing Mechanism is modified to include an additional amount of ADITC equal to the total of existing ADITC not currently eligible for accelerated amortization under the mechanism and all available investment tax credits generated through the end of calendar-year 2028. Further, the Stipulating Parties agree that the maximum allowed annual accelerated amortization of ADITC will be $55 million for calendar year 2026 and thereafter. Effective January 1, 2026, revenue sharing between

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Idaho Power and Idaho customers of Idaho-jurisdictional earnings will occur if earnings are in excess of a 9.6 percent Idaho ROE and all revenue sharing will continue to be implemented through the PCA. The new minimum-specified Idaho ROE is set at 95 percent of the stipulated 9.6 percent, or 9.12 percent.

16. WRV Distribution Line. Pursuant to Section A(2)(b), the Stipulating Parties agree to remove the costs associated with the distribution undergrounding portion of the WRV project from the revenue requirement. In consideration of this removal, the Stipulating Parties agree that the Company shall retain the distribution undergrounding portion of the WRV project in Construction Work in Progress ("CWIP") until the entire project (distribution and transmission) is completed and placed in service.

17. NPSE Base and PCA. For purposes of calculating the PCA, the new system-level base NPSE is $468,840,624. The decrease to base NPSE from current levels results in the transfer of $13.1 million from base rates to the PCA. Exhibit No. 3 attached hereto details the individual PCA component amounts by Federal Energy Regulatory Commission account that have been agreed upon by the Stipulating Parties. Schedule 55, Power Cost Adjustment, will be modified effective January 1, 2026, to reflect this transfer of NPSE recovery.

18. Fixed Cost Adjustment ("FCA"). In determining the fixed cost per customer ("FCC") and fixed costs per energy ("FCE") to be tracked through the Company's FCA, the Stipulating Parties agree to use the Settlement CCOS Study. The FCC and fixed costs per energy FCE effective January 1, 2026, are included in Exhibit No. 4 for the respective FCA-applicable customer classes.

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

19. Sales Based Adjustment Rate ("SBAR"). In determining the agreed-upon SBAR to be applied in the Company's PCA, the Stipulating Parties agree to use the Settlement CCOS Study to determine the generation-related Idaho jurisdictional revenue requirement that has been classified as energy-related. The resulting SBAR of $27.82 per megawatt-hour ("MWh") was developed using 2025 normalized Idaho test year retail sales in the amount of 15,497,724 MWh as proposed by the Company in this case. Exhibit No. 5 to the Stipulation details the derivation of the agreed upon SBAR that is to become effective on January 1, 2026.

20. Wheeling Revenue. The Stipulating Parties agree to a baseline wheeling tracker level of collection of $3.38 per MWh. This reflects Idaho jurisdictional point-to-point wheeling revenues of $52,329,358 divided by Idaho jurisdictional retail sales of 15,497,724 MWh.

21. Valmy and Bridger. The Stipulating Parties agree that the stipulated revenue requirement includes updated recovery associated with both the Valmy and Bridger mechanisms and reflects updated capital and O&M forecasted spend, as well as the true-up of variances between prior forecasts and actual costs through 2024. Also, the Stipulating Parties acknowledge that in addition to the rate recovery update, the discussion related to the Valmy coal-related investments provided in Mr. Ryan Adelman's direct filed testimony satisfies the 2024 annual reporting required by Order No. 34349.

22. Rule H Three Phase Base Charge. The Stipulating Parties agree to implement the following three phase base charges: $80 (underground), $1,072 (overhead including 2" riser), and $1,352 (overhead including 3" riser), effective January 1, 2026.

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power will update charges annually when it submits its annual Rule H compliance filing on or before December 31 of each year.

D. Other General Provisions

The Stipulating Parties agree that this Stipulation represents a compromise of the positions of the Stipulating Parties in this case. As provided in Procedural Rule 272, other than any testimony filed in support of the approval of this Stipulation, and except to the extent necessary for a Party to explain before the Commission its own statements and positions with respect to the Stipulation, all statements made and positions taken in negotiations relating to this Stipulation shall be confidential and will not be admissible in evidence in this or any other proceeding, unless all Parties to the negotiation agree to the contrary in writing.

The Stipulating Parties submit this Stipulation to the Commission and recommend approval in its entirety pursuant to Procedural Rule 274. The Stipulating Parties shall support this Stipulation before the Commission, and no Stipulating Party shall appeal a Commission Order approving the Stipulation or an issue resolved by the Stipulation. If this Stipulation is challenged by any person not a party to the Stipulation, the Stipulating Parties to this Stipulation reserve the right to file testimony, cross-examine witnesses, and put on such case as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

If the Commission rejects any part or all of this Stipulation or imposes any additional material conditions on approval of this Stipulation, each Stipulating Party reserves the right, upon written notice to the Commission and the other Parties to this proceeding, within fourteen (14) days of the date of such action by the Commission, to withdraw from this Stipulation. In such case, no Party shall be bound or prejudiced by the terms of this Stipulation, and each Party shall be entitled to seek reconsideration of the Commission's Order, file testimony as it chooses, cross-examine witnesses, and do all other things necessary to put on such case as it deems appropriate. In such case, the Parties immediately will request the prompt reconvening of a prehearing conference for purposes of establishing a procedural schedule for the completion of the case. The Parties agree to cooperate in development of a schedule that concludes the proceeding on the earliest possible date, taking into account the needs of the Parties in participating in hearings and preparing briefs.

The Stipulating Parties agree that this Stipulation is in the public interest and that all of its terms and conditions are fair, just, and reasonable.

No Party shall be bound, benefited, or prejudiced by any position asserted in the negotiation of this Stipulation, except to the extent expressly stated herein, nor shall this Stipulation be construed as a waiver of the rights of any Party unless such rights are expressly waived herein. Except as otherwise expressly provided for herein, execution of this Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory, or principle of regulation or cost recovery. No Party shall be deemed to have agreed that any method, theory or principle of regulation or cost recovery employed in arriving at this Stipulation is appropriate for

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

resolving any issues in any other proceeding in the future. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

The obligations of the Stipulating Parties under this Stipulation are subject to the Commission's approval of this Stipulation in accordance with its terms and conditions and upon such approval being upheld on appeal, if any, by a court of competent jurisdiction.

This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

DATED this 24th day of October 2025.

Idaho Power Company

By Donovan E. Walker
Donovan Walker
Attorney for Idaho Power Company

Idaho Public Utilities Commission Staff

By Erika K. Melanson
Erika Melanson
Deputy Attorney General
Attorney for Commission Staff

City of Boise

By Ed Jewell
Ed Jewell
Attorney for City of Boise

Clean Energy Opportunities for Idaho

By Kelsey Jae
Kelsey Jae
Attorney for Clean Energy Opportunities for Idaho

Federal Executive Agencies

By Emily Medlyn
Emily Medlyn
Attorney for Federal Executive Agencies

Idaho Irrigation Pumpers Association, Inc.

By Eric L Olsen
Eric L. Olsen
Attorney for Idaho Irrigation Pumpers Association, Inc.

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Industrial Customers of Idaho Power

By_____
Peter J. Richardson
Attorney for Industrial Customers
of Idaho Power

Kroger Co.

By Kurt Boehm
Kurt Boehm
Attorney for Kroger Inc.

Micron Technology, Inc.

By Austin Rueschhoff
Austin Rueschhoff
Attorney for Micron Technology, Inc.

NW Energy Coalition

By Benjamin J. Otto
Benjamin J. Otto
Attorney for NW Energy Coalition

Industrial Customers of Idaho Power

By Peter J Richardson
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Attorney for Industrial Customers
of Idaho Power

Kroger Co.

By_____
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Attorney for Kroger Inc.

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By_____
Austin Rueschhoff
Attorney for Micron Technology, Inc.

NW Energy Coalition

By_____
Benjamin J. Otto
Attorney for NW Energy Coalition

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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

EXHIBIT NO. 1
RATE SPREAD

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Exhibit No. 1 - Rate Spread

Tariff Description	Rate Schedule No.	Test Year Revenue	Settlement Revenue Allocation	Total Revenue Change	Total Percent Change
Residential Service	1,3,5	$ 660,757,196	$ 726,106,082	$ 65,348,887	
Residential Service On-Site Gen	6	19,602,279	21,540,944	1,938,665	
Total Residential Service		680,359,474	747,647,026	67,287,552	9.89%
Small General Service	7	19,586,437	21,523,536	1,937,099	
Small General Service On-Site Gen	8	50,589	55,592	5,003	
Combined Small General Service		19,637,026	21,579,128	1,942,102	9.89%
Large General Service	9S	297,525,775	309,512,661	11,986,886	4.03%
Large General Service	9P, 9T	49,438,136	51,014,122	1,575,985	3.19%
Area Lighting	15	1,365,685	1,398,188	32,503	2.38%
Large Power Service	19S, 19P, 19T	155,075,886	162,905,833	7,829,947	5.05%
Irrigation Service	24	178,025,213	193,490,955	15,465,742	8.69%
Non-Metered General Service	40	1,445,727	1,511,219	65,491	4.53%
Municipal Street Lighting	41	3,979,343	4,074,051	94,708	2.38%
Traffic Control Lighting	42	242,590	266,582	23,992	9.89%
Micron	26	38,600,849	40,025,129	1,424,280	3.69%
Simplot - Donn	29	10,402,134	10,649,705	247,571	2.38%
DOE/INL	30	12,869,059	13,695,104	826,045	6.42%
Simplot - Caldwell	32	9,950,378	10,187,197	236,819	2.38%
Brisbie	33	2,686,924	3,483,200	796,276	29.64%
Lamb Weston	34	8,581,731	8,785,977	204,245	2.38%
Total Idaho Retail Sales (Excluding CEYW)		**$ 1,470,185,932**	**$ 1,580,226,077**	**$ 110,040,145**	**7.48%**

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

EXHIBIT NO. 2
PRICING

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Residential Service
Schedule 1 and Schedule 6

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	6,457,447	$ 15.00	$ 96,861,700	$ 15.00	$ 96,861,700
(2)	Minimum Charge	37,059	3.00	111,178	3.00	111,178
(3)	Summer Energy (Jun-Sep)					
(4)	First 800 kWh	1,290,839,001	$ 0.101779	$ 131,380,303	$ 0.121195	$ 156,443,233
(5)	801-2,000 kWh	551,835,102	0.122380	67,533,580	0.132995	73,391,309
(6)	All Additional kWh	96,264,914	0.145385	13,995,475	0.146185	14,072,486
(7)	Subtotal - Summer Energy	1,938,939,017	$ 0.109807	$ 212,909,357	$ 0.125794	$ 243,907,029
(8)	Non-Summer Energy (Oct-May)					
(9)	First 800 kWh	2,563,878,153	$ 0.089569	$ 229,644,002	$ 0.099332	$ 254,675,145
(10)	801-2,000 kWh	1,035,332,377	0.098750	102,239,072	0.104305	107,990,344
(11)	All Additional kWh	375,114,121	0.109361	41,022,855	0.110052	41,282,059
(12)	Subtotal - Non-Summer Energy	3,974,324,652	$ 0.093829	$ 372,905,930	$ 0.101640	$ 403,947,548
(13)	Subtotal - Total Energy	5,913,263,669		$ 585,815,287		$ 647,854,576
(14)	Transfer Adjustment Revenue			(4,994,462)		
(15)	Total Adjusted Base Revenue			$ 677,793,704		$ 744,827,454

▪ END END ▪

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Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Residential Service Standard Plan
Schedule 1

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	6,231,558	$ 15.00	$ 93,473,372	$ 15.00	$ 93,473,372
(2)	Minimum Charge	36,602	3.00	109,807	3.00	109,807
(3)	Summer Energy (Jun-Sep)					
(4)	First 800 kWh	1,252,168,857	$ 0.101779	$ 127,444,494	$ 0.121195	$ 151,756,605
(5)	801-2,000 kWh	541,234,863	0.122380	66,236,323	0.132995	71,981,531
(6)	All Additional kWh	94,033,756	0.145385	13,671,098	0.146185	13,746,325
(7)	Subtotal - Summer Energy	1,887,437,477	$ 0.109859	$ 207,351,914	$ 0.125824	$ 237,484,460
(8)	Non-Summer Energy (Oct-May)					
(9)	First 800 kWh	2,492,142,872	$ 0.089569	$ 223,218,745	$ 0.099332	$ 247,549,536
(10)	801-2,000 kWh	1,006,802,014	0.098750	99,421,699	0.104305	105,014,484
(11)	All Additional kWh	361,303,302	0.109361	39,512,490	0.110052	39,762,151
(12)	Subtotal - Non-Summer Energy	3,860,248,188	$ 0.093816	$ 362,152,934	$ 0.101632	$ 392,326,171
(13)	Subtotal - Total Energy	5,747,685,665		$ 569,504,849		$ 629,810,631
(14)	Transfer Adjustment Revenue			(4,854,611)		
(15)	Total Adjusted Base Revenue			$ 658,233,416		$ 723,393,810

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Residential Service On-Site Generation
Schedule 6

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	225,889	$ 15.00	$ 3,388,329	$ 15.00	$ 3,388,329
(2)	Minimum Charge	457	3.00	1,371	3.00	1,371
(3)	Summer Energy (Jun-Sep)					
(4)	First 800 kWh	38,670,144	$ 0.101779	$ 3,935,809	$ 0.121195	$ 4,686,628
(5)	801-2,000 kWh	10,600,238	0.122380	1,297,257	0.132995	1,409,779
(6)	All Additional kWh	2,231,158	0.145385	324,377	0.146185	326,162
(7)	Subtotal - Summer Energy	51,501,540	$ 0.107908	$ 5,557,443	$ 0.124706	$ 6,422,569
(8)	Non-Summer Energy (Oct-May)					
(9)	First 800 kWh	71,735,281	$ 0.089569	$ 6,425,257	$ 0.099332	$ 7,125,609
(10)	801-2,000 kWh	28,530,364	0.098750	2,817,373	0.104305	2,975,860
(11)	All Additional kWh	13,810,819	0.109361	1,510,365	0.110052	1,519,908
(12)	Subtotal - Non-Summer Energy	114,076,464	$ 0.094261	$ 10,752,996	$ 0.101874	$ 11,621,377
(13)	Subtotal - Total Energy	165,578,004		$ 16,310,438		$ 18,043,945
(14)	Transfer Adjustment Revenue			(139,851)		
(15)	Total Adjusted Base Revenue			$ 19,560,287		$ 21,433,645

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Master-Metered Mobile Home Park Residential Service
Schedule 3

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	225	$ 15.00	$ 3,374	$ 15.00	$ 3,374
(2)	Total Energy	4,821,221	0.109482	527,837	0.119450	575,895
(3)	Transfer Adjustment Revenue			(4,072)		
(4)	Total Adjusted Base Revenue			$ 527,138		$ 579,268

▪ END **END ▪**

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Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

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

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	12,364	$ 15.00	$ 185,465	$ 15.00	$ 185,465
(2)	Minimum Charge	7	3.00	21	3.00	21
(3)	Summer Energy (Jun-Sep)					
(4)	On-Peak	1,047,143	$ 0.252957	$ 264,882	$ 0.299185	$ 313,289
(5)	Mid-Peak	1,103,536	0.126480	139,575	0.149594	165,082
(6)	Off-Peak	3,916,751	0.063241	247,699	0.074797	292,961
(7)	Subtotal - Summer Energy	6,067,430	$ 0.107485	$ 652,157	$ 0.127128	$ 771,333
(8)	Non-Summer Energy (Oct-May)					
(9)	On-Peak	2,841,379	$ 0.131150	$ 372,647	$ 0.138347	$ 393,096
(10)	Off-Peak	9,653,346	0.087433	844,021	0.092231	890,338
(11)	Subtotal - Non-Summer Energy	12,494,725	$ 0.097375	$ 1,216,668	$ 0.102718	$ 1,283,434
(12)	Subtotal - Total Energy	18,562,155		$ 1,868,825		$ 2,054,767
(13)	Transfer Adjustment Revenue			(15,678)		
(14)	Total Adjusted Base Revenue			$ 2,038,632		$ 2,240,253

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Residential Service - Time-of-Use Plan
Schedule 5

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	12,000	$ 15.00	$ 179,999	$ 15.00	$ 179,999
(2)	Minimum Charge	6	3.00	18	3.00	18
(3)	Summer Energy (Jun-Sep)					
(4)	On-Peak	1,033,452	$ 0.252957	$ 261,419	$ 0.299185	$ 309,193
(5)	Mid-Peak	1,098,575	0.126480	138,948	0.149594	164,340
(6)	Off-Peak	3,828,823	0.063241	242,139	0.074797	286,384
(7)	Subtotal - Summer Energy	5,960,850	$ 0.107788	$ 642,505	$ 0.127485	$ 759,918
(8)	Non-Summer Energy (Oct-May)					
(9)	On-Peak	2,788,557	$ 0.131150	$ 365,719	$ 0.138347	$ 385,789
(10)	Off-Peak	9,421,467	0.087433	823,747	0.092231	868,951
(11)	Subtotal - Non-Summer Energy	12,210,024	$ 0.097417	$ 1,189,466	$ 0.102763	$ 1,254,740
(12)	Subtotal - Total Energy	18,170,875		$ 1,831,972		$ 2,014,658
(13)	Transfer Adjustment Revenue			(15,347)		
(14)	Total Adjusted Base Revenue			$ 1,996,641		$ 2,194,675

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Residential Service - Time-of-Use
Schedule 6 TOU

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	364	$ 15.00	$ 5,466	$ 15.00	$ 5,466
(2)	Minimum Charge	1	3.00	3	3.00	3
(3)	Summer Energy (Jun-Sep)					
(4)	On-Peak	13,691	$ 0.252957	$ 3,463	$ 0.299185	$ 4,096
(5)	Mid-Peak	4,961	0.126480	627	0.149594	742
(6)	Off-Peak	87,928	0.063241	5,561	0.074797	6,577
(7)	Subtotal - Summer Energy	106,580	$ 0.090555	$ 9,651	$ 0.107103	$ 11,415
(8)	Non-Summer Energy (Oct-May)					
(9)	On-Peak	52,822	$ 0.131150	$ 6,928	$ 0.138347	$ 7,308
(10)	Off-Peak	231,879	0.087433	20,274	0.092231	21,386
(11)	Subtotal - Non-Summer Energy	284,700	$ 0.095544	$ 27,201	$ 0.100787	$ 28,694
(12)	Subtotal - Total Energy	391,280		$ 36,853		$ 40,109
(13)	Transfer Adjustment Revenue			(330)		
(14)	Total Adjusted Base Revenue			$ 41,991		$ 45,578

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Small General Service
Schedule 7 and Schedule 8

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	360,123	$ 25.00	$ 9,003,064	$ 25.00	$ 9,003,064
(2)	Minimum Charge	217	3.00	651	3.00	651
(3)	Summer Energy (Jun-Sep)					
(4)	First 300 kWh	21,542,878	$ 0.074534	$ 1,605,677	$ 0.087174	$ 1,877,979
(5)	All Additional kWh	25,321,142	0.085176	2,156,754	0.099619	2,522,467
(6)	Subtotal - Summer Energy	46,864,020	$ 0.080284	$ 3,762,430	$ 0.093898	$ 4,400,446
(7)	Non-Summer Energy (Oct-May)					
(8)	First 300 kWh	44,450,246	$ 0.074534	$ 3,313,055	$ 0.087174	$ 3,874,906
(9)	All Additional kWh	49,315,986	0.074552	3,676,605	0.087194	4,300,058
(10)	Subtotal - Non-Summer Energy	93,766,231	$ 0.074543	$ 6,989,660	$ 0.087184	$ 8,174,964
(11)	Subtotal - Total Energy	140,630,251		$ 10,752,090		$ 12,575,409
(12)	Transfer Adjustment Revenue			(118,779)		
(13)	Total Adjusted Base Revenue			$ 19,637,026		$ 21,579,124

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Small General Service
Schedule 7

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	359,171	$ 25.00	$ 8,979,275	$ 25.00	$ 8,979,275
(2)	Minimum Charge	217	3.00	651	3.00	651
(3)	Summer Energy (Jun-Sep)					
(4)	First 300 kWh	21,488,093	$ 0.074534	$ 1,601,594	$ 0.087174	$ 1,873,203
(5)	All Additional kWh	25,239,553	0.085176	2,149,804	0.099619	2,514,339
(6)	Subtotal - Summer Energy	46,727,646	$ 0.080282	$ 3,751,398	$ 0.093896	$ 4,387,542
(7)	Non-Summer Energy (Oct-May)					
(8)	First 300 kWh	44,361,036	$ 0.074534	$ 3,306,405	$ 0.087174	$ 3,867,129
(9)	All Additional kWh	49,189,701	0.074552	3,667,191	0.087194	4,289,047
(10)	Subtotal - Non-Summer Energy	93,550,738	$ 0.074543	$ 6,973,596	$ 0.087185	$ 8,156,176
(11)	Subtotal - Total Energy	140,278,384		$ 10,724,994		$ 12,543,718
(12)	Transfer Adjustment Revenue			(118,482)		
(13)	Total Adjusted Base Revenue			$ 19,586,437		$ 21,523,643

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Small General Service On-Site Generation
Schedule 8

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	952	$ 25.00	$ 23,789	$ 25.00	$ 23,789
(2)	Minimum Charge	-	3.00	-	3.00	-
(3)	Summer Energy (Jun-Sep)					
(4)	First 300 kWh	54,785	$ 0.074534	$ 4,083	$ 0.087174	$ 4,776
(5)	All Additional kWh	81,589	0.085176	6,949	0.099619	8,128
(6)	Subtotal - Summer Energy	136,374	$ 0.080901	$ 11,033	$ 0.094620	$ 12,904
(7)	Non-Summer Energy (Oct-May)					
(8)	First 300 kWh	89,209	$ 0.074534	$ 6,649	$ 0.087174	$ 7,777
(9)	All Additional kWh	126,284	0.074552	9,415	0.087194	11,011
(10)	Subtotal - Non-Summer Energy	215,494	$ 0.074545	$ 16,064	$ 0.087186	$ 18,788
(11)	Subtotal - Total Energy	351,868		$ 27,097		$ 31,692
(12)	Transfer Adjustment Revenue			(297)		
(13)	Total Adjusted Base Revenue			$ 50,589		$ 55,481

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

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

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	476,162	$ 25.00	$ 11,904,058	$ 25.00	$ 11,904,058
(2)	Minimum Charge	267	3.00	800	3.00	800
(3)	Basic Charge					
(4)	Total Basic Charge	15,707,257	$ 1.58	$ 24,817,466	$ 1.84	$ 28,901,353
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	4,157,240	$ 8.12	$ 33,756,793	$ 9.49	$ 39,452,212
(7)	Non-Summer (Oct-May)	7,447,672	6.39	47,590,625	7.75	57,719,459
(8)	Total Demand	11,604,913		$ 81,347,418		$ 97,171,671
(9)	Energy Charge					
(10)	Summer (Jun-Sep)	1,204,197,234	$ 0.054658	$ 65,819,012	$ 0.050908	$ 61,303,273
(11)	Non-Summer (Oct-May)	2,210,140,832	0.052721	116,520,835	0.049875	110,230,774
(12)	Subtotal - Total Energy	3,414,338,066		$ 182,339,847		$ 171,534,047
(13)	Transfer Adjustment Revenue			(2,883,819)		
(14)	Total Adjusted Base Revenue			$ 297,525,770		$ 309,511,929

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

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

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	476,162	$ 25.00	$ 11,904,058	$ 25.00	$ 11,904,058
(2)	Minimum Charge	267	3.00	800	3.00	800
(3)	Basic Charge					
(4)	Total Basic Charge	15,707,257	$ 1.58	$ 24,817,466	$ 1.84	$ 28,901,353
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	4,157,240	$ 8.12	$ 33,756,793	$ 9.49	$ 39,452,212
(7)	Non-Summer (Oct-May)	7,447,672	$ 6.39	47,590,625	7.75	57,719,459
(8)	Total Demand	11,604,913		$ 81,347,418		$ 97,171,671
(9)	Summer Energy (Jun-Sep) - Current					
(10)	On-Peak	165,592,662	$ 0.058489	$ 9,685,349		
(11)	Mid-Peak	238,482,029	0.058489	13,948,575		
(12)	Off-Peak	800,122,543	0.052709	42,173,659		
(13)	Subtotal - Summer Energy	1,204,197,234	$ 0.054649	$ 65,807,584		
(14)	Non-Summer Energy (Oct-May) - Current					
(15)	On-Peak	483,916,916	$ 0.055755	$ 26,980,788		
(16)	Mid-Peak	521,990,534	0.053259	27,800,694		
(17)	Off-Peak	1,204,233,382	0.051273	61,744,658		
(18)	Subtotal - Non-Summer Energy	2,210,140,832	$ 0.052723	$ 116,526,140		
(19)	Subtotal - Total Energy	3,414,338,066		$ 182,333,723		
(20)	Summer Energy (Jun-Sep) - Proposed					
(21)	On-Peak	165,592,662			$ 0.064329	$ 10,652,410
(22)	Mid-Peak	785,036,345			0.049542	38,892,271
(23)	Off-Peak	253,568,226			0.046366	11,756,944
(24)	Subtotal - Summer Energy	1,204,197,234			$ 0.050907	$ 61,301,625
(25)	Non-Summer Energy (Oct-May) - Proposed					
(26)	On-Peak	483,916,916			$ 0.054425	$ 26,337,178
(27)	Mid-Peak	1,362,166,169			0.049191	67,006,316
(28)	Off-Peak	364,057,747			0.046375	16,883,178
(29)	Subtotal - Non-Summer Energy	2,210,140,832			$ 0.049873	$ 110,226,672
(30)	Subtotal - Total Energy	3,414,338,066				$ 171,528,298
(31)	Transfer Adjustment Revenue			(2,883,819)		
(32)	Total Adjusted Base Revenue			$ 297,519,646		$ 309,506,180

▪ END **END ▪**

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Large General Service
Schedule 9 Primary Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	3,567	$ 340.00	$ 1,212,860	$ 345.00	$ 1,230,696
(2)	Minimum Charge	3	50.00	150	50.00	150
(3)	Basic Charge					
(4)	Total Basic Charge	2,039,979	$ 1.83	$ 3,733,162	$ 2.04	$ 4,161,558
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	467,927	$ 8.35	$ 3,907,194	$ 12.04	$ 5,633,846
(7)	Non-Summer (Oct-May)	1,183,700	7.91	9,363,064	10.48	12,405,173
(8)	Total Demand	1,651,627		$ 13,270,259		$ 18,039,019
(9)	On-Peak Summer Demand (Jun-Sep)	463,301	$ 1.59	$ 736,648	$ 2.29	$ 1,060,959
(10)	Summer Energy (Jun-Sep) - Current					
(11)	On-Peak	32,583,784	$ 0.053937	$ 1,757,472		
(12)	Mid-Peak	45,744,926	0.053937	2,467,344		
(13)	Off-Peak	160,417,178	0.048346	7,755,529		
(14)	Subtotal - Summer Energy	238,745,888	$ 0.050180	$ 11,980,345		
(15)	Non-Summer Energy (Oct-May) - Current					
(16)	On-Peak	90,019,493	$ 0.048995	$ 4,410,505		
(17)	Mid-Peak	92,480,016	0.046579	4,307,627		
(18)	Off-Peak	218,953,648	0.044649	9,776,061		
(19)	Subtotal - Non-Summer Energy	401,453,157	$ 0.046068	$ 18,494,193		
(20)	Subtotal - Total Energy	640,199,045		$ 30,474,538		
(21)	Summer Energy (Jun-Sep) - Proposed					
(22)	On-Peak	32,583,784			$ 0.053636	$ 1,747,664
(23)	Mid-Peak	157,420,718			0.039840	6,271,641
(24)	Off-Peak	48,741,386			0.036875	1,797,339
(25)	Subtotal - Summer Energy	238,745,888			$ 0.041118	$ 9,816,644
(26)	Non-Summer Energy (Oct-May) - Proposed					
(27)	On-Peak	90,019,493			$ 0.044679	$ 4,021,981
(28)	Mid-Peak	247,328,559			0.039475	9,763,295
(29)	Off-Peak	64,105,105			0.036674	2,350,991
(30)	Subtotal - Non-Summer Energy	401,453,157			$ 0.040195	$ 16,136,266
(31)	Subtotal - Total Energy	640,199,045				$ 25,952,910
(32)	Transfer Adjustment Revenue			(540,725)		
(33)	Total Adjusted Base Revenue			$ 48,886,891		$ 50,445,292

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Large General Service
Schedule 9 Transmission Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
(1)	Service Charge	77	$ 340.00	$ 26,166	$ 345.00	$ 26,550
(2)	Minimum Charge	-	50.00	-	50.00	-
(3)	Basic Charge					
(4)	Total Basic Charge	38,534	$ 1.09	$ 42,002	$ 0.67	$ 25,818
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	10,689	$ 7.38	$ 78,887	$ 8.29	$ 88,614
(7)	Non-Summer (Oct-May)	17,567	6.46	113,483	8.69	152,658
(8)	Total Demand	28,256		$ 192,371		$ 241,272
(9)	On-Peak Summer Demand (Jun-Sep)	5,890	$ 1.59	$ 9,364	$ 2.29	$ 13,487
(10)	Summer Energy (Jun-Sep) - Current					
(11)	On-Peak	216,999	$ 0.053305	$ 11,567		
(12)	Mid-Peak	309,876	0.053305	16,518		
(13)	Off-Peak	1,375,021	0.047648	65,517		
(14)	Subtotal - Summer Energy	1,901,896	$ 0.049215	$ 93,602		
(15)	Non-Summer Energy (Oct-May) - Current					
(16)	On-Peak	910,934	$ 0.048079	$ 43,797		
(17)	Mid-Peak	895,626	0.045663	40,897		
(18)	Off-Peak	2,476,174	0.043725	108,271		
(19)	Subtotal - Non-Summer Energy	4,282,734	$ 0.045056	$ 192,964		
(20)	Subtotal - Total Energy	6,184,630		$ 286,567		
(21)	Summer Energy (Jun-Sep) - Proposed					
(22)	On-Peak	216,999			$ 0.056136	$ 12,181
(23)	Mid-Peak	1,222,613			0.042114	51,489
(24)	Off-Peak	462,284			0.039101	18,076
(25)	Subtotal - Summer Energy	1,901,896			$ 0.042982	$ 81,746
(26)	Non-Summer Energy (Oct-May) - Proposed					
(27)	On-Peak	910,934			$ 0.046703	$ 42,543
(28)	Mid-Peak	2,516,092			0.041465	104,330
(29)	Off-Peak	855,708			0.038647	33,071
(30)	Subtotal - Non-Summer Energy	4,282,734			$ 0.042016	$ 179,944
(31)	Subtotal - Total Energy	6,184,630				$ 261,690
(32)	Transfer Adjustment Revenue			(5,224)		
(33)	Total Adjusted Base Revenue			$ 551,245		$ 568,817

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Large Power Service
Schedule 19 Secondary Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
(1)	Service Charge	13	$ 85.00	$ 1,120	$ 110.00	$ 1,450
(2)	Minimum Charge	-	3.00	-	3.00	-
(3)	Basic Charge					
(4)	Total Basic Charge	14,212	$ 2.01	$ 28,567	$ 2.27	$ 32,262
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	4,119	$ 10.50	$ 43,250	$ 14.46	$ 59,561
(7)	Non-Summer (Oct-May)	8,368	8.45	70,707	13.05	109,198
(8)	Total Demand	12,487		$ 113,956		$ 168,759
(9)	On-Peak Summer Demand (Jun-Sep)	3,694	$ 1.82	$ 6,723	$ 2.51	$ 9,272
(10)	Summer Energy (Jun-Sep) - Current					
(11)	On-Peak	298,539	$ 0.059941	$ 17,895		
(12)	Mid-Peak	378,317	0.059941	22,677		
(13)	Off-Peak	1,390,942	0.054287	75,510		
(14)	Subtotal - Summer Energy	2,067,798	$ 0.056138	$ 116,081		
(15)	Non-Summer Energy (Oct-May) - Current					
(16)	On-Peak	861,406	$ 0.054204	$ 46,692		
(17)	Mid-Peak	890,197	0.051783	46,097		
(18)	Off-Peak	2,228,865	0.049842	111,091		
(19)	Subtotal - Non-Summer Energy	3,980,468	$ 0.051220	$ 203,880		
(20)	Subtotal - Total Energy	6,048,266		$ 319,961		
(21)	Summer Energy (Jun-Sep) - Proposed					
(22)	On-Peak	298,539			$ 0.059565	$ 17,782
(23)	Mid-Peak	1,370,910			0.045019	61,717
(24)	Off-Peak	398,349			0.041894	16,688
(25)	Subtotal - Summer Energy	2,067,798			$ 0.046517	$ 96,188
(26)	Non-Summer Energy (Oct-May) - Proposed					
(27)	On-Peak	861,406			$ 0.049879	$ 42,966
(28)	Mid-Peak	2,512,550			0.044723	112,369
(29)	Off-Peak	606,512			0.041950	25,443
(30)	Subtotal - Non-Summer Energy	3,980,468			$ 0.045416	$ 180,778
(31)	Subtotal - Total Energy	6,048,266				$ 276,966
(32)	Transfer Adjustment Revenue			(5,108)		
(33)	Total Adjusted Base Revenue			$ 465,220		$ 488,709

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Large Power Service
Schedule 19 Primary Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Description	Test Year Billing Units	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
(1)	Service Charge	1,624	$ 415.00	$ 674,104	$ 450.00	$ 730,956
(2)	Minimum Charge	-	50.00	-	50.00	-
(3)	Basic Charge					
(4)	Total Basic Charge	4,997,899	$ 2.21	$ 11,045,356	$ 2.32	$ 11,595,125
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	1,490,176	$ 10.04	$ 14,961,364	$ 13.51	$ 20,132,273
(7)	Non-Summer (Oct-May)	2,924,469	8.64	25,267,414	12.68	37,082,270
(8)	Total Demand	4,414,645		$ 40,228,778		$ 57,214,543
(9)	On-Peak Summer Demand (Jun-Sep)	1,328,154	$ 1.59	$ 2,111,764	$ 2.14	$ 2,842,249
(10)	Summer Energy (Jun-Sep) - Current					
(11)	On-Peak	105,332,662	$ 0.052314	$ 5,510,373		
(12)	Mid-Peak	136,006,423	0.052314	7,115,040		
(13)	Off-Peak	498,834,125	0.046655	23,273,106		
(14)	Subtotal -Summer Energy	740,173,209	$ 0.048500	$ 35,898,519		
(15)	Non-Summer Energy (Oct-May) - Current					
(16)	On-Peak	314,955,889	$ 0.047227	$ 14,874,422		
(17)	Mid-Peak	318,731,217	0.044805	14,280,752		
(18)	Off-Peak	816,258,432	0.042863	34,987,285		
(19)	Subtotal - Non-Summer Energy	1,449,945,538	$ 0.044238	$ 64,142,459		
(20)	Subtotal - Total Energy	2,190,118,747		$ 100,040,978		
(21)	Subtotal 19P Excluding Clean Energy Your Way			$ 154,100,980		
(22)	Summer Energy (Jun-Sep) - Proposed					
(23)	On-Peak	105,332,662			$ 0.053694	$ 5,655,732
(24)	Mid-Peak	496,428,762			0.039145	19,432,704
(25)	Off-Peak	138,411,785			0.036018	4,985,316
(26)	Subtotal -Summer Energy	740,173,209			$ 0.040631	$ 30,073,752
(27)	Non-Summer Energy (Oct-May) - Proposed					
(28)	On-Peak	314,955,889			$ 0.044112	$ 13,893,334
(29)	Mid-Peak	920,912,295			0.038960	35,878,743
(30)	Off-Peak	214,077,354			0.036187	7,746,817
(31)	Subtotal - Non-Summer Energy	1,449,945,538			$ 0.039670	$ 57,518,894
(32)	Subtotal - Total Energy	2,190,118,747				$ 87,592,646
(33)	Subtotal 19P Excluding Clean Energy Your Way					$ 159,975,519

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Large Power Service
Schedule 19 Primary Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(34)	*Schedule 62 Clean Energy Your Way - Optional*					
(35)	Summer Embedded Energy Fixed Cost (June-Sep)					
(36)	On-Peak	1,299,249	$ 0.010012	$ 13,008	$ 0.012551	$ 16,307
(37)	Mid-Peak	3,459,015	0.010012	34,632	0.012551	43,414
(38)	Off-Peak	1,288,171	0.009611	12,381	0.012551	16,168
(39)	Subtotal - Summer Embedded Energy Fixed C	6,046,435	$ 0.009927	$ 60,020	$ 0.012551	$ 75,889
(40)	Non-Summer Embedded Energy Fixed Cost (Oct-May)					
(41)	On-Peak	1,996,175	$ 0.018270	$ 36,470	$ 0.012254	$ 24,461
(42)	Mid-Peak	3,575,615	0.018130	64,826	0.012254	43,816
(43)	Off-Peak	1,772,649	0.018018	31,940	0.012254	21,722
(44)	Subtotal - Non-Summer Embedded Energy Fix	7,344,440	$ 0.018141	$ 133,236	$ 0.012254	$ 89,999
(45)	Subtotal - Total Embedded Energy Fixed Cost	13,390,875		$ 193,256		$ 165,888
(46)	Transfer Adjustment Revenue			(1,849,818)		
(47)	Total Adjusted Base Revenue			$ 152,444,418		$ 160,141,407

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Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Large Power Service
Schedule 19 Transmission Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	34	$ 415.00	$ 14,178	$ 450.00	$ 15,374
(2)	Minimum Charge	-	50.00	-	50.00	-
(3)	Basic Charge					
(4)	Total Basic Charge	71,485	$ 1.87	$ 133,676	$ 1.16	$ 82,922
(5)	Demand Charge					
(6)	Summer (Jun-Sep)	19,497	$ 10.20	$ 198,868	$ 15.19	$ 296,157
(7)	Non-Summer (Oct-May)	41,449	8.78	363,923	13.37	554,174
(8)	Total Demand	60,946		$ 562,790		$ 850,331
(9)	On-Peak Summer Demand (Jun-Sep)	14,790	$ 1.59	$ 23,516	$ 2.14	$ 31,651
(10)	Summer Energy (Jun-Sep) - Current					
(11)	On-Peak	1,335,421	$ 0.052142	$ 69,632		
(12)	Mid-Peak	1,693,103	0.052142	88,282		
(13)	Off-Peak	7,157,157	0.046451	332,457		
(14)	Subtotal - Summer Energy	10,185,681	$ 0.048143	$ 490,370		
(15)	Non-Summer Energy (Oct-May) - Current					
(16)	On-Peak	4,763,451	$ 0.046927	$ 223,534		
(17)	Mid-Peak	4,769,702	0.044504	212,271		
(18)	Off-Peak	12,526,659	0.042561	533,147		
(19)	Subtotal - Non-Summer Energy	22,059,811	$ 0.043924	$ 968,952		
(20)	Subtotal - Total Energy	32,245,493		$ 1,459,323		
(21)	Summer Energy (Jun-Sep) - Proposed					
(22)	On-Peak	1,335,421			$ 0.054173	$ 72,344
(23)	Mid-Peak	6,849,229			0.039529	270,743
(24)	Off-Peak	2,001,031			0.036381	72,799
(25)	Subtotal - Summer Energy	10,185,681			$ 0.040830	$ 415,886
(26)	Non-Summer Energy (Oct-May) - Proposed					
(27)	On-Peak	4,763,451			$ 0.044324	$ 211,135
(28)	Mid-Peak	13,991,496			0.039169	548,033
(29)	Off-Peak	3,304,865			0.036395	120,281
(30)	Subtotal - Non-Summer Energy	22,059,811			$ 0.039867	$ 879,449
(31)	Subtotal - Total Energy	32,245,493				$ 1,295,335
(32)	Transfer Adjustment Revenue			(27,235)		
(33)	Total Adjusted Base Revenue			$ 2,166,248		$ 2,275,612

▪ END **END ▪**

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Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Agricultural Irrigation Service
Schedule 24 Secondary Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	*Current Season - Meter Read Cycle*					
(2)	Service Charge In-Season	78,236	$ 30.00	$ 2,347,087		
(3)	Service Charge Out-of-Season	157,992	6.00	947,949		
(4)	Minimum Charge	621	3.00	1,862		
(5)	Demand Charge (Current Season)					
(6)	In-Season	3,975,361	$ 15.06	$ 59,868,937		
(7)	Out-of-Season	-	-	-		
(8)	Energy Charge (Current Season)					
(9)	In-Season	1,490,396,996	$ 0.061295	$ 91,353,884		
(10)	Out-of-Season	347,772,454	0.072053	25,058,049		
(11)	Total Energy	1,838,169,450		$ 116,411,932		
(12)	*Proposed Season - Calendar Month*					
(13)	Service Charge In-Season	80,992			$ 35.00	$ 2,834,710
(14)	Service Charge Out-of-Season	155,236			9.00	1,397,124
(15)	Minimum Charge	621			3.00	1,862
(16)	Demand Charge (Proposed Season)					
(17)	In-Season	3,896,929			$ 16.50	$ 64,299,326
(18)	Out-of-Season	-			-	-
(19)	Energy Charge (Proposed Season)					
(20)	In-Season	1,443,146,046			$ 0.067222	$ 97,011,164
(21)	Out-of-Season	394,992,435			0.070752	27,946,505
(22)	Total Energy	1,838,138,482				$ 124,957,668
(23)	Transfer Adjustment Revenue			(1,552,555)		
(24)	Total Adjusted Base Revenue			$ 178,025,213		$ 193,490,690

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Agricultural Irrigation Service
Schedule 24 Transmission Service

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge In-Season	-	$ 415.00	$ -	$ 450.00	$ -
(2)	Service Charge Out-of-Season	-	6.00	-	9.00	-
(3)	Minimum Charge	-	3.00	-	3.00	-
(4)	Demand Charge					
(5)	In-Season	-	$ 13.92	$ -	$ 15.25	$ -
(6)	Out-of-Season	-	-	-		
(7)	Energy Charge					
(8)	In-Season	-	$ 0.057529	$ -	$ 0.063092	$ -
(9)	Out-of-Season	-	0.067352	-	0.066136	-
(10)	Total Energy	-		$ -		$ -
(11)	Transfer Adjustment Revenue			-		
(12)	Total Adjusted Base Revenue			$ -		$ -

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Dusk to Dawn Customer Lighting
Schedule 15

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Annual Lamps**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Lamps					
(2)	Area Lighting					
(3)	40 Watt Max	87,846	$ 9.82	$ 862,652	$ 10.95	$ 961,918
(4)	85 Watt Max	9,574	11.95	114,406	11.67	111,725
(5)	200 Watt Max	1,780	17.27	30,737	14.38	25,593
(6)	Subtotal - Lamps			$ 1,007,795		
(7)	Flood Lighting					
(8)	85 Watt Max	16,494	$ 19.50	$ 321,623	$ 16.14	$ 266,205
(9)	150 Watt Max	436	21.47	9,361	17.03	7,425
(10)	300 Watt Max	1,129	25.28	28,539	22.42	25,311
(11)	Subtotal - Lamps			$ 359,524		
(12)	Transfer Adjustment Revenue			(1,634)		
(13)	Total Adjusted Base Revenue			$ 1,365,685		1,398,178

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Non-Metered General Service
Schedule 40

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	22,449	$ -	$ -	$ -	$ -
(2)	Minimum Bills	1,179	2.00	2,359	2.00	2,359
(3)	Total Energy	14,544,979	0.100058	1,455,342	0.103710	1,508,460
(4)	Intermittent Usage	156	2.00	312	2.50	390
(5)	Transfer Adjustment Revenue			(12,285)		
(6)	Total Adjusted Base Revenue			$ 1,445,727		$ 1,511,209

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Street Lighting Service
Schedule 41 - Summary

Column	(A)	(B)	(C)	(D)
Line No.	**Description**	**Test Year Usage**	**Test Year Base Revenue**	**Proposed Effective Revenue**
(1)	A - Company-Owned, Non-Metered, Maintenar	2,308,188	$ 2,632,419	$ 3,344,753
(2)	C - Customer-Owned, Non-Metered, No Maint	11,829,043	803,310	443,518
(3)	CM - Customer-Owned, Metered, No Maintena	6,677,084	561,194	285,626
(4)	Total kWh	20,814,315		
(5)	Transfer Adjustment Revenue		$ (17,580)	
(6)	Total Adjusted Base Revenue		$ 3,979,343	$ 4,073,897

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Street Lighting Service

A - Company-Owned, Non-Metered, Maintenance

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Description	Annual Lamps	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
(7)	**LED Fixture**					
(8)	40W Max	183,274	$ 12.30	$ 2,254,265	$ 15.84	$ 2,903,053
(9)	85W Max	20,345	14.31	291,133	$ 17.05	346,878
(10)	140W Max	2,726	16.43	44,791	$ 18.54	50,543
(11)	200W Max	1,853	20.44	37,879	$ 21.46	39,769
(12)	Total LED	208,198		$ 2,628,067		$ 3,340,243
(13)	Non-Metered - Variable Energy Use	43,492	$ 0.100058	$ 4,352	$ 0.103710	$ 4,511
(14)	A - Company-Owned, Non-Metered, Maintenance			$ 2,632,419		$ 3,344,753

NM Adj
$ 0.021665

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

Line No.	Description	Test Year Usage	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
(15)	Energy Charge					
(16)	Per kWh	11,829,043	$ 0.067910	$ 803,310	$ 0.037494	$ 443,518
(17)	C - Customer-Owned, Non-Metered, No Maintenance			$ 803,310		$ 443,518

CM - Customer-Owned, Metered, No Maintenance

Line No.	Description	Test Year Usage	Current Base Rate	Test Year Base Revenue	Proposed Effective Rate	Proposed Effective Revenue
(18)	Service Charge per Meter	19,276	$ 5.59	$ 107,753	$ 1.83	$ 35,275
(19)	Energy Charge					
(20)	Per kWh	6,677,084	$ 0.067910	$ 453,441	$ 0.037494	$ 250,351
(21)	CM - Customer-Owned, Metered, No Maintenance			$ 561,194		$ 285,626

▪ END **END ▪**

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Traffic Control Signal Lighting Service
Schedule 42

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Service Charge	4,295	$ -	$ -	$ -	$ -
(2)	Total Energy	3,125,463	0.078462	245,230	0.085293	266,580
(3)	Transfer Adjustment Revenue			(2,640)		
(4)	Total Adjusted Base Revenue			$ 242,590		$ 266,580

▪ END **END ▪**

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Micron Technology, Inc.
Schedule 26

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Contract Demand	1,062,000	$ 3.37	$ 3,578,940	$ 3.12	$ 3,313,440
(2)	Billing Demand	971,293	17.83	17,318,159	21.04	20,436,010
(3)	Excess Demand	-	1.288	-	1.248	-
(4)	Embedded Energy Fixed Cost	-	-	-	-	-
(5)	Total Energy	599,124,265	$ 0.030394	18,209,783	$ 0.027165	16,275,211
(6)	Transfer Adjustment Revenue			(506,032)		
(7)	Total Adjusted Base Revenue			$ 38,600,849		$ 40,024,661

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

J.R. Simplot Company - Pocatello
Schedule 29

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Contract Demand	300,000	$ 3.25	$ 975,000	$ 3.12	$ 936,000
(2)	Billing Demand	290,903	14.80	4,305,358	17.41	5,064,614
(3)	Excess Demand	-	1.267	-	1.248	-
(4)	Total Energy	169,812,387	0.031006	5,265,203	0.027377	4,648,954
(5)	Transfer Adjustment Revenue			(143,427)		
(6)	Total Adjusted Base Revenue			$ 10,402,134		$ 10,649,568

▪ END **END ▪**

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

United States Department of Energy
Schedule 30

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Contract Demand					
(2)	Billing Demand	387,060	$ 10.17	$ 3,936,404	$ 14.49	$ 5,608,504
(3)	Excess Demand					
(4)	Total Energy	214,503,623	$ 0.042488	$ 9,113,830	0.037699	$ 8,086,572
(5)	Transfer Adjustment Revenue			(181,174)		
(6)	Total Adjusted Base Revenue			$ 12,869,059		$ 13,695,076

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

J.R. Simplot Company - Caldwell
Schedule 32

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	Contract Demand					
(2)	Summer	100,000	$ 3.30	$ 330,000	$ 3.12	$ 312,000
(3)	Non-Summer	200,000	3.30	660,000	3.12	624,000
(4)	Billing Demand					
(5)	Summer	86,462	$ 19.60	$ 1,694,664	$ 22.11	$ 1,911,685
(6)	Non-Summer	162,474	16.20	2,632,080	20.17	3,277,102
(7)	Excess Demand					
(8)	Summer	-	$ 1.293	$ -	$ 1.248	$ -
(9)	Non-Summer	-	1.293	-	1.248	-
(10)	Energy					
(11)	Summer	51,609,967	$ 0.030405	$ 1,569,201	$ 0.027520	$ 1,420,306
(12)	Non-Summer	97,127,610	0.032844	3,190,059	0.027202	2,642,065
(13)	Transfer Adjustment Revenue			(125,627)		
(14)	Total Adjusted Base Revenue			$ 9,950,378		$ 10,187,158

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Brisbie, LLC.
Schedule 33

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	*Block 1*					
(2)	Service Charge	10	$ 415.00	$ 4,150	$ 450.00	$ 4,500
(3)	Basic Charge					
(4)	Total Basic Charge	200,000	$ 1.87	$ 374,000	$ 1.16	$ 232,000
(5)	Demand Charges					
(6)	Summer (Jun-Sep)	80,000	$ 10.20	$ 816,000	$ 15.19	$ 1,215,200
(7)	Non-Summer (Oct-May)	120,000	8.78	1,053,600	13.37	1,604,400
(8)	Total Demand	200,000		$ 1,869,600		$ 2,819,600
(9)	On-Peak Summer Demand (Jun-Sep)	7,632	$ 1.59	$ 12,135	$ 2.14	$ 16,332
(10)	Summer Energy (Jun-Sep) - Current					
(11)	On-Peak	186,309	$ 0.052142	$ 9,715		
(12)	Mid-Peak	110,052	0.052142	5,738		
(13)	Off-Peak	904,321	0.046451	42,007		
(14)	Subtotal - Summer Energy	1,200,682		$ 57,459		
(15)	Non-Summer Energy (Oct-May) - Current					
(16)	On-Peak	3,486	$ 0.046927	$ 164		
(17)	Mid-Peak	10,047	0.044504	447		
(18)	Off-Peak	124,439	0.042561	5,296		
(19)	Subtotal - Non-Summer Energy	137,972		$ 5,907		
(20)	Subtotal - Total Energy	1,338,655		63,366		
(21)	Summer Energy (Jun-Sep) - Proposed					
(22)	On-Peak	186,309			$ 0.054173	$ 10,093
(23)	Mid-Peak	819,158			0.039529	32,380
(24)	Off-Peak	195,216			0.036381	7,102
(25)	Subtotal - Summer Energy	1,200,682			$ 0.041289	$ 49,576
(26)	Non-Summer Energy (Oct-May) - Proposed					
(27)	On-Peak	3,486			$ 0.044324	$ 155
(28)	Mid-Peak	111,474			0.039169	4,366
(29)	Off-Peak	23,012			0.036395	838
(30)	Subtotal - Non-Summer Energy	137,972			$ 0.038837	$ 5,358
(31)	Subtotal - Total Energy	1,338,655				$ 54,934
(32)	Subtotal 33 Excluding Clean Energy Your Way					$ 3,127,366

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Brisbie, LLC.
Schedule 33

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(33)	*Schedule 62 Clean Energy Your Way - Optional*					
(34)	Summer Embedded Energy Fixed Cost (June-Sep)					
(35)	On-Peak	275,535	$ 0.010007	$ 2,757	$ 0.012752	$ 3,514
(36)	Mid-Peak	570,564	0.010007	5,710	0.012752	7,276
(37)	Off-Peak	2,331,719	0.009603	22,391	0.012752	29,734
(38)	Subtotal - Summer Embedded Energy Fixed C	3,177,818		$ 30,858	$ 0.012752	$ 40,524
(39)	Non-Summer Embedded Energy Fixed Cost (Oct-May)					
(40)	On-Peak	76,707	$ 0.018257	$ 1,400	$ 0.012451	$ 955
(41)	Mid-Peak	81,188	0.018117	1,471	0.012451	1,011
(42)	Off-Peak	107,934	0.018005	1,943	0.012451	1,344
(43)	Subtotal - Non-Summer Embedded Energy Fix	265,829		$ 4,815	$ 0.012451	$ 3,310
(44)	Subtotal - Total Embedded Energy Fixed Cost	3,443,646		35,673		$ 43,833
(45)	Subtotal - Block 1			$ 2,358,924		$ 3,171,200
(46)	*Block 2*					
(47)	Contract Demand	100,000	$ 3.28	$ 328,000	$ 3.12	$ 312,000
(48)	Billing Demand	-	22.29	-	22.29	-
(49)	Excess Demand		1.293	-	1.248	-
(50)	Subtotal - Block 2			$ 328,000		$ 312,000
(51)	Transfer Adjustment Revenue			-		-
(52)	Total Adjusted Base Revenue			$ 2,686,924		$ 3,483,200

▪ END END ▪

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Lamb Weston, Inc.
Schedule 34

Column	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Description**	**Test Year Billing Units**	**Current Base Rate**	**Test Year Base Revenue**	**Proposed Effective Rate**	**Proposed Effective Revenue**
(1)	*Block 1*					
(2)	Service Charge	12	$ 415.00	$ 4,980	$ 450.00	$ 5,400
(3)	Basic Charge					
(4)	Total Basic Charge	243,474	$ 2.21	$ 538,078	$ 2.32	$ 564,860
(5)	Demand Charges					
(6)	Summer (Jun-Sep)	80,000	$ 10.04	$ 803,200	$ 13.51	$ 1,080,800
(7)	Non-Summer (Oct-May)	160,000	8.64	1,382,400	$ 12.68	2,028,800
(8)	Total Demand			$ 2,185,600		$ 3,109,600
(9)	On-Peak Summer Demand (Jun-Sep)	73,876	$ 1.59	$ 117,463	$ 2.14	$ 158,095
(10)	Summer Energy (Jun-Sep) - Current					
(11)	On-Peak	5,890,298	$ 0.052314	$ 308,145		
(12)	Mid-Peak	7,514,127	0.052314	393,094		
(13)	Off-Peak	27,742,320	0.046655	1,294,318		
(14)	Subtotal - Summer Energy	41,146,744		$ 1,995,557		
(15)	Non-Summer Energy (Oct-May) - Current					
(16)	On-Peak	16,729,387	$ 0.047227	$ 790,079		
(17)	Mid-Peak	16,625,725	0.044805	744,916		
(18)	Off-Peak	44,705,115	0.042863	1,916,195		
(19)	Subtotal - Non-Summer Energy	78,060,227		$ 3,451,190		
(20)	Subtotal - Total Energy	119,206,972		5,446,747		
(21)	Summer Energy (Jun-Sep) - Proposed					
(22)	On-Peak	5,890,298			$ 0.051897	$ 305,689
(23)	Mid-Peak	28,187,170			0.037373	1,053,439
(24)	Off-Peak	7,069,276			0.034253	242,144
(25)	Subtotal - Summer Energy	41,146,744			$ 0.038916	$ 1,601,272
(26)	Non-Summer Energy (Oct-May) - Proposed					
(27)	On-Peak	16,729,387			$ 0.042438	$ 709,962
(28)	Mid-Peak	50,203,403			0.037285	1,871,834
(29)	Off-Peak	11,127,437			0.034513	384,041
(30)	Subtotal - Non-Summer Energy	78,060,227			$ 0.037994	$ 2,965,837
(31)	Subtotal - Total Energy	119,206,972				4,567,109
(32)	Subtotal - Block 1			$ 8,292,867		$ 8,405,063
(33)	*Block 2*					
(34)	Contract Demand	48,000	$ 3.30	$ 158,400	$ 3.12	$ 149,760
(35)	Billing Demand	9,556	24.19	231,149	24.19	231,149
(36)	Excess Demand		1.293	-	1.248	-
(37)	Subtotal - Block 2			$ 389,549		$ 380,909
(38)	Transfer Adjustment Revenue			(100,685)		-
(39)	Total Adjusted Base Revenue			$ 8,581,731		$ 8,785,972

▪ END END ▪

Schedule 9P

Charge Type	Summer	Non-Summer
Service Charge (per customer)	$ 345.00	$ 345.00
Basic Charge per kW of BLC	$ 2.04	$ 2.04
Demand Charge per kW	$ 12.04	$ 10.48
On-Peak Demand charge per kW	$ 2.29	n/a
On Peak Energy Charge per kWh	$ 0.053636	$ 0.044679
Mid Peak Energy Charge per kWh	$ 0.039840	$ 0.039475
Off Peak Energy Charge per kWh	$ 0.036875	$ 0.036674

Schedule 9T

Charge Type	Summer	Non-Summer
Service Charge (per customer)	$ 345.00	$ 345.00
Basic Charge per kW of BLC	$ 0.67	$ 0.67
Demand Charge per kW	$ 8.29	$ 8.69
On-Peak Demand charge per kW	$ 2.29	n/a
On Peak Energy Charge per kWh	$ 0.056136	$ 0.046703
Mid Peak Energy Charge per kWh	$ 0.042114	$ 0.041465
Off Peak Energy Charge per kWh	$ 0.039101	$ 0.038647

	Marginal Cost ($/kWh)	S	NS
(a)	On-Peak	$ 0.052673	$ 0.048694
	Mid-Peak	$ 0.048677	$ 0.041512
	Off-Peak	$ 0.035849	$ 0.038059

(b)	Peak Demand Adder ($/kW)	$ 0.64
(c)	Embedded Energy Rate ($/kWh)	$ 0.027251
(d)	Interruption Compensation	$ 0.0453

Schedule 20 Large General Service Primary Rates - Proposed

	Charge Type	Summer	Non-Summer
	Service Charge (per customer)	$ 345.00	$ 345.00
	Basic Charge per kW of BLC	$ 2.04	$ 2.04
(rate + b)	Demand Charge per kW	$ 12.68	$ 11.12
	On-Peak Demand charge per kW	n/a	n/a
(rate - c + a)	On Peak Energy Charge per kWh	$ 0.079058	$ 0.066122
(rate - c + a)	Mid Peak Energy Charge per kWh	$ 0.061266	$ 0.053736
(rate - c + a)	Off Peak Energy Charge per kWh	$ 0.045473	$ 0.047482

Schedule 20 Large General Service Transmission Rates - Proposed

	Charge Type	Summer	Non-Summer
	Service Charge (per customer)	$ 345.00	$ 345.00
	Basic Charge per kW of BLC	$ 0.67	$ 0.67
(rate + b)	Demand Charge per kW	$ 8.93	$ 9.33
	On-Peak Demand charge per kW	n/a	n/a
(rate - c + a)	On Peak Energy Charge per kWh	$ 0.081558	$ 0.068146
(rate - c + a)	Mid Peak Energy Charge per kWh	$ 0.063540	$ 0.055726
(rate - c + a)	Off Peak Energy Charge per kWh	$ 0.047699	$ 0.049455

Schedule 19P

Charge Type	Summer	Non-Summer
Service Charge (per customer)	$ 450.00	$ 450.00
Basic Charge per kW of BLC	$ 2.32	$ 2.32
Demand Charge per kW	$ 13.51	$ 12.68
On-Peak Demand charge per kW	$ 2.14	n/a
On Peak Energy Charge per kWh	$ 0.053694	$ 0.044112
Mid Peak Energy Charge per kWh	$ 0.039145	$ 0.038960
Off Peak Energy Charge per kWh	$ 0.036018	$ 0.036187

Schedule 19T

Charge Type	Summer	Non-Summer
Service Charge (per customer)	$ 450.00	$ 450.00
Basic Charge per kW of BLC	$ 1.16	$ 1.16
Demand Charge per kW	$ 15.19	$ 13.37
On-Peak Demand charge per kW	$ 2.14	n/a
On Peak Energy Charge per kWh	$ 0.054173	$ 0.044324
Mid Peak Energy Charge per kWh	$ 0.039529	$ 0.039169
Off Peak Energy Charge per kWh	$ 0.036381	$ 0.036395

Schedule 20 Large Power Primary Rates - Proposed

	Charge Type	Summer	Non-Summer
	Service Charge (per customer)	$ 450.00	$ 450.00
	Basic Charge per kW of BLC	$ 2.32	$ 2.32
(rate + b)	Demand Charge per kW	$ 14.15	$ 13.32
	On-Peak Demand charge per kW	n/a	n/a
(rate - c + a)	On Peak Energy Charge per kWh	$ 0.078652	$ 0.065091
(rate - c + a)	Mid Peak Energy Charge per kWh	$ 0.060107	$ 0.052757
(rate - c + a)	Off Peak Energy Charge per kWh	$ 0.044152	$ 0.046531

Schedule 20 Large Power Transmission Rates - Proposed

	Charge Type	Summer	Non-Summer
	Service Charge (per customer)	$ 450.00	$ 450.00
	Basic Charge per kW of BLC	$ 1.16	$ 1.16
(rate + b)	Demand Charge per kW	$ 15.83	$ 14.01
	On-Peak Demand charge per kW	n/a	n/a
(rate - c + a)	On Peak Energy Charge per kWh	$ 0.079131	$ 0.065303
(rate - c + a)	Mid Peak Energy Charge per kWh	$ 0.060491	$ 0.052966
(rate - c + a)	Off Peak Energy Charge per kWh	$ 0.044515	$ 0.046739

(a)	Marginal Cost ($/kWh)	S	NS
	On-Peak	$ 0.052673	$ 0.048694
	Mid-Peak	$ 0.048677	$ 0.041512
	Off-Peak	$ 0.035849	$ 0.038059

(b) Peak Demand Adder ($/kW) **$ 0.64**

(c) Embedded Energy Rate ($/kWh) **$ 0.027715**

(d) Interruption Compensation **$ 0.0451**

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Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Amalgamated Standby Agreement
Schedule 31A

Column	(A)	(B)	(C)	(D)
Line No.	**Description**	**Total Cost**	**Billing Units**	**Unit Cost, per kW**
(1)	Standby Contract Demand Charge, per kW			**$ 3.12**
(2)	Generation Capacity (Non-summer)	$ 42,970,620	2,974,286	$ 14.45
(3)	Transmission Capacity	13,607,639	4,488,077	3.03
(4)	Distribution Capacity			
(5)	Substation	$ 5,239,049	4,488,077	$ 1.17
(6)	Primary Lines	8,208,139	4,488,077	1.83
(7)	Primary Line Trans.	1,112,458	4,488,077	0.25
(8)	Total Standby Demand Component			$ 20.72
(9)	Ratio of $12.68 to $20.34 (Note 1)			0.6233
(10)	Standby Demand Component			$ 12.92
(11)	Less: Standby Reservation Charge			(5.98)
(12)	Standby Billing Demand Charge, per kW			**$ 6.93**

Note 1: Proposed non-summer demand charge for Schedule 19P is $12.68. Sum of total of generation, transmission, and distribution components is $20.34.

▪ END **END ▪**

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Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Amalgamated Standby Agreement
Schedule 31B

Column	(A)	(B)
Line No.	**Description**	**Unit Cost, per kW**
(1)	Standby Facilities Contract Demand Charge	
(2)	Paul Facility	$ 2.72
(3)	Nampa Facility	$ 2.74
(4)	Twin Falls Facility	$ 2.39

▪ END **END ▪**

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

DERIVATION OF STANDBY RESERVATION CHARGES - SCHEDULE 9

				Unit Cost, per kW	Standby Reservation Charge Primary	Standby Reservation Charge Transmission	Standby Reservation Charge Secondary
	Generation & Transmission Standby Reservation Component						
1	Open Access Transmission Tariff			$3.12	$3.12	$3.12	$3.12
	Distribution Reserve Component	Rev. Req.	Billing Units				
	Schedule 9P						
2	Schedule 9P Substation	$ 1,985,008	2,078,513	$0.95501	$0.96		
3	Schedule 9P Primary Lines	3,106,780	2,078,513	$1.49471	$1.49		
4	Schedule 9P Primary Trans.	421,689	2,078,513	$0.20288	$0.20		
5	Schedule 9P Dist. Subtotal	$5,513,477	2,078,513	$2.65261	$2.65		
	Schedule 9S						
6	Schedule 9S Substation	$ 11,323,901	15,707,257	$0.72093			$0.72
7	Schedule 9S Primary Lines	17,688,591	15,707,257	$1.12614			$1.13
8	Schedule 9S Primary Trans.	2,407,722	15,707,257	$0.15329			$0.15
9	Schedule 9S Secondary Lines	1,492,603	15,707,257	$0.09503			$0.10
10	Schedule 9S Secondary Trans.	7,913,994	15,707,257	$0.50384			$0.50
11	Schedule 9S Dist. Subtotal	$40,826,811	15,707,257	$2.59923			$2.60
	Schedule 45 Standby Reservation Charge						
12	Total				**$5.77**	**$3.12**	**$5.72**

DERIVATION OF STANDBY DEMAND CHARGES - SCHEDULE 9

					Unit Cost, per kW	Standby Demand Charge Primary	Standby Demand Charge Transmission	Standby Demand Charge Secondary
			Rev. Req.	Billing Units				
	Generation Demand Component							
	Schedule 9P & 9T							
13	Summer		$ 8,095,767	478,617	$16.91493	$16.91	$16.91	
14	Non-Summer		$ 13,064,937	1,201,267	$10.87597	$10.88	$10.88	
	Schedule 9S							
15	Summer		$ 46,791,824	4,157,240	$11.25550			$11.26
16	Non-Summer		$ 72,599,896	7,447,672	$9.74800			$9.75
	Transmission Demand Component							
17	Schedule 9P & 9T		$ 4,313,081	1,679,884	$2.56749	$2.57	$2.57	
18	Schedule 9S		25,027,351	11,604,913	$2.15662			$2.16
	Distribution Demand Component							
19	Schedule 9P Dist. Subtotal		$5,513,477	2,078,513	$2.65261	$2.65		
20	Schedule 9S Dist. Subtotal		$40,826,811	15,707,257	$2.59923			$2.60
	Schedule 45 Total Demand Component							
	Schedule 9P & 9T							
21	Summer					$22.14	$19.48	
22	Non-Summer					$16.10	$13.44	
	Schedule 9S							
23	Summer							$16.01
24	Non-Summer							$14.50
25	Ratio of Sch. 9P/COS; S	$12.04	$19.48250			0.61799		
26	Ratio of Sch. 9P/COS; NS	$10.48	$13.44354			0.77956		
27	Ratio of Sch. 9T/COS; S	$8.29	$19.48250				0.42551	

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28	Ratio of Sch. 9T/COS; NS	$8.69	$13.44354		0.64641	
29	Ratio of Sch. 9S/COS; S	$9.49	$13.41212			0.70757
30	Ratio of Sch. 9S/COS; NS	$7.75	$11.90462			0.65101
	Schedule 45 Standby Demand Charge					
31	Summer			**$13.68**	**$8.29**	**$11.33**
32	Non-Summer			**$12.55**	**$8.69**	**$9.44**

DERIVATION OF STANDBY RESERVATION CHARGES - SCHEDULE 19

					Standby Reservation Charge Primary	Standby Reservation Charge Transmission
				Unit Cost, per kW		
	Generation & Transmission Standby Reservation Component					
1	Open Access Transmission Tariff			$3.12	$3.12	$3.12
				Unit Cost,		
	Distribution Reserve Component	Rev. Req.	Billing Units	per kW		
2	Schedule 19P Substation	$ 5,239,049	5,083,596	$1.03058	$1.03	
3	Schedule 19P Primary Lines	$ 8,208,139	5,083,596	$1.61463	$1.61	
4	Schedule 19P Primary Trans.	$1,112,458	5,083,596	$0.21883	$0.22	
5	Schedule 19P Dist. Subtotal	$14,559,646	5,083,596	$2.86404	$2.86	
	Schedule 45 Standby Reservation Charge					
6	Total				**$5.98**	**$3.12**

DERIVATION OF STANDBY DEMAND CHARGES - SCHEDULE 19

						Standby Demand Charge Primary	Standby Demand Charge Transmission
			Rev. Req.	Billing Units	Unit Cost, per kW		
	Generation Demand Component						
	Schedule 19 Production						
7	Summer		$25,473,464	1,513,792	$16.82759	$16.83	$16.83
8	Non-Summer		$42,970,620	2,974,286	$14.44737	$14.45	$14.45
	Transmission Demand Component						
9	Schedule 19 Transmission		$13,607,639	4,488,077	$3.03195	$3.03	$3.03
	Distribution Demand Component						
10	Schedule 19P Dist. Subtotal		$14,559,646	$5,083,596	$2.86404	$2.86	
	Schedule 45 Total Demand Component						
11	Summer					$22.72	$19.86
12	Non-Summer					$20.34	$17.48
13	Ratio of Sch. 19P/COS; S	$13.51	$19.85954			0.68028	
14	Ratio of Sch. 19P/COS; NS	$12.68	$17.47933			0.72543	
15	Ratio of Sch. 19T/COS; S	$15.19	$19.85954				0.76487
16	Ratio of Sch. 19T/COS; NS	$13.37	$17.47933				0.76490
	Schedule 45 Standby Demand Charge						
17	Summer					**$15.46**	**$15.19**
18	Non-Summer					**$14.76**	**$13.37**

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Idaho Power Company
State of Idaho
Calculation of Proposed Rates
Settlement Stipulation
IPC-E-25-16

Alternative Distribution Service
Schedule 46

DERIVATION OF THE CAPACITY CHARGE

	Unit Cost, per kW
Capacity Charge	**$2.86**
Distribution Line Mileage Charge	
Average Construction Mile Cost -	
3PH 12.5 kV Crossarm Construction	
(Current Design Standard)	$78,519.31
Schedule 66 Facilities Charge Maintenance	0.65%
Per kW Per Tenth of a Mile	**$0.005**

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Schedule 62

	Fixed Cost Component of the Retail Energy Charge, per kWh		
Time Period	Secondary Service	Primary Service	Transmission Service
Summer On-Peak	1.8437 ¢	1.2551 ¢	1.2752 ¢
Summer Mid-Peak	1.8437 ¢	1.2551 ¢	1.2752 ¢
Summer Off-Peak	1.8437 ¢	1.2551 ¢	1.2752 ¢
Non-Summer On-Peak	1.8001 ¢	1.2254 ¢	1.2451 ¢
Non-Summer Mid-Peak	1.8001 ¢	1.2254 ¢	1.2451 ¢
Non-Summer Off-Peak	1.8001 ¢	1.2254 ¢	1.2451 ¢

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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

EXHIBIT NO. 3
NET POWER SUPPLY EXPENSE

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
PCA Components by FERC Account
Settlement Stipulation
IPC-E-25-16

Exhibit No. 3 - Base Net Power Supply Expense

2025 Base Level NPSE

95% Accounts (with 95% recovery in PCA)		
501, Steam	$	108,005,080
536, Water for Power	$	-
547, Other Fuel	$	50,540,155
555, Non-PURPA Purchased Power	$	124,823,345
447, Surplus Sales	$	(74,447,697)
447-050, Surplus Sales - Transmission	$	(10,045,519)
565, Third Party Transmission	$	12,357,059
Net 95% Accounts	$	211,232,422
100% Accounts (with 100% recovery in PCA)		
577.4 Energy Storage Rents	$	21,546,000
555, PURPA	$	226,719,444
555, Demand Response	$	9,342,758
Total	**$**	**468,840,624**

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

EXHIBIT NO. 4
FCC AND FCE

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Summary of Proposed FCC & FCE Rates
Settlement Stipulation
IPC-E-25-16

Exhibit No. 4 - FCC and FCE

Description	Rate Schedule No.	FCC ($/Customer/Yr.)	FCE ($/kWh)	FCC - Distribution ($/Customer/Yr.)	FCE - Distribution ($/kWh)
Residential Service	1 & 3	$ 907.64	$ 0.081838	$ 280.10	$ 0.025255
Residential Service - Time-of-Use: SONP	5 & 6 TOU		0.230184		0.094895
Residential Service - Time-of-Use: SMP	5 & 6 TOU		0.115094		0.047449
Residential Service - Time-of-Use: SOFP	5 & 6 TOU	907.64	0.057547	280.10	0.023724
Residential Service - Time-of-Use: NSONP	5 & 6 TOU		0.099780		0.024161
Residential Service - Time-of-Use: NSOFP	5 & 6 TOU		0.066519		0.016107
Residential Service - On-Site Generation	6	799.60	0.090836	293.77	0.033372
Small General Service	7	286.98	0.061233	72.64	0.015498
Small General Service - On-Site Generation	8	$ 325.39	$ 0.073330	$ 107.18	$ 0.024155

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Derivation of Proposed FCC & FCE Rates
Settlement Stipulation
IPC-E-25-16

Exhibit No. 4 - FCC and FCE

Description	Rate Schedule No.	CCOS Revenue Requirement	Generation Fixed Costs	Transmission Fixed Costs	Distribution and Customer Fixed Costs	Total Fixed Costs	Fixed Cost % of Rev. Req.
Residential Service	1, 3 & 5	$ 744,593,493	$ 276,674,717	$ 58,352,282	$ 245,743,237	$ 580,770,236	78.00%
Residential Service - On-Site Generation	6	33,860,902	12,117,866	2,491,966	13,685,598	28,295,430	83.56%
Small General Service	7	21,647,364	5,234,644	1,216,973	11,216,666	17,668,283	81.62%
Small General Service - On-Site Generation	8	105,623	25,497	5,727	58,264	89,487	84.72%
Large General Service	9	345,195,000	140,552,424	29,340,569	62,043,309	231,936,301	67.19%
Dusk/Dawn Lighting	15	891,901	48,891	-	788,778	837,669	93.92%
Large Power Service	19	155,978,090	68,444,085	13,607,639	12,333,589	94,385,312	60.51%
Irrigation Service	24	196,461,638	65,993,109	15,847,205	64,935,481	146,775,794	74.71%
Unmetered Service	40	1,446,953	432,069	84,601	520,438	1,037,108	71.68%
Municipal Street Lighting	41	3,453,538	565,175	11,912	2,293,553	2,870,640	83.12%
Traffic Control Lighting	42	367,894	103,045	21,970	154,804	279,819	76.06%
Special Contracts	26, 29, 30, 32, 33 & 34	76,223,681	34,672,352	6,377,510	1,865,624	42,915,486	56.30%
Total		**$ 1,580,226,077**	**$ 604,863,872**	**$ 127,358,353**	**$ 415,639,340**	**$ 1,147,861,566**	

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Derivation of Proposed FCC & FCE Rates
Settlement Stipulation
IPC-E-25-16

Exhibit No. 4 - FCC and FCE

Description	Rate Schedule No.	Proposed Base Rate Revenue	CCOS Revenue Requirement	Difference	Revenue Short-Fall	Fixed Cost % of Total Cost	Fixed Cost Portion of Rev. Short-Fall
Residential Service	1, 3 & 5	$ 726,106,082	$ 744,593,493	$ (18,487,411)	$ (18,487,411)	78.00%	$ (14,419,865)
Residential Service - On-Site Generation	6	21,540,944	33,860,902	(12,319,958)	(12,319,958)	83.56%	(10,295,016)
Small General Service	7	21,523,536	21,647,364	(123,828)	(123,828)	81.62%	(101,067)
Small General Service - On-Site Generation	8	55,592	105,623	(50,031)	(50,031)	84.72%	(42,388)
Large General Service	9	360,526,783	345,195,000	15,331,783	-		-
Dusk/Dawn Lighting	15	1,398,188	891,901	506,286	-		-
Large Power Service	19	162,905,833	155,978,090	6,927,743	-		-
Irrigation Service	24	193,490,955	196,461,638	(2,970,683)	(2,970,683)	74.71%	(2,219,387)
Unmetered Service	40	1,511,219	1,446,953	64,266	-		-
Municipal Street Lighting	41	4,074,051	3,453,538	620,513	-		-
Traffic Control Lighting	42	266,582	367,894	(101,312)	(101,312)	76.06%	(77,057)
Special Contracts	26, 29, 30, 32, 33 & 34	86,826,311	76,223,681	10,602,631	-		-
Total		**$ 1,580,226,077**	**$ 1,580,226,077**	**$ -**	**$ (34,053,222)**		**$ (27,154,780)**

Weighted Average Fixed Cost Percent of Revenue Short-Fall: 79.74%

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Idaho Power Company
State of Idaho
Derivation of Proposed FCC & FCE Rates
Settlement Stipulation
IPC-E-25-16

Exhibit No. 4 - FCC and FCE

Description	Rate Schedule No.	2025 Avg. Number of Customers	2025 Normalized Sales (kWhs)	Total CCOS Fixed Costs	Total CCOS Variable Costs	Revenue Short-Fall/Subsidy	Proposed Base Rate Revenue
Residential Service	1, 3 & 5	520,315	5,770,677,760	$ 580,770,236	$ 163,823,257	$ (18,487,411)	$ 726,106,082
Residential Service - On-Site Generation	6	18,854	165,969,284	28,295,430	5,565,472	(12,319,958)	21,540,944
Small General Service	7	29,931	140,278,384	17,668,283	3,979,081	(123,828)	21,523,536
Small General Service - On-Site Generation	8	79	351,868	$ 89,487	$ 16,135	$ (50,031)	$ 55,592

Description	Rate Schedule No.	Proposed Fixed Cost Revenue from Fixed Charges	Proposed CCOS Fixed Cost Revenue from Energy Charges	Fixed Cost Portion of Revenue Short-Fall/Subsidy	Proposed Fixed Cost Revenue from Energy Charges	Calculation of FCC ($/Cust./Yr.)	Calculation of FCE ($/kWh)
Residential Service	1, 3 & 5*	$ 93,766,569	$ 487,003,667	$ (14,742,263)	$ 472,261,404	$ 907.64	$ 0.081838
Residential Service - On-Site Generation	6	3,395,165	24,900,265	(9,824,202)	15,076,063	799.60	0.090836
Small General Service	7	8,979,926	8,688,358	(98,743)	8,589,615	286.98	0.061233
Small General Service - On-Site Generation	8	$ 23,789	$ 65,698	$ (39,896)	$ 25,802	$ 325.39	$ 0.073330

**FCE not applicable to Residential Schedule 5; see TOU FCE derivation.*

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Derivation of Proposed FCC & FCE Rates
Settlement Stipulation
IPC-E-25-16

Exhibit No. 4 - FCC and FCE

Description	Rate Schedule No.	2025 Avg. Number of Customers	2025 Normalized Sales (kWhs)	Total Generation CCOS Fixed Costs	Total Transmission CCOS Fixed Costs	Total Distribution CCOS Fixed Costs	Total CCOS Fixed Costs
Residential Service	1, 3 & 5	520,315	5,770,677,760	$ 276,674,717	$ 58,352,282	$ 245,743,237	$ 580,770,236
Fixed Cost Proportion	1, 3 & 5			47.6%	10.0%	42.3%	100.0%
Residential Service - On-Site Generation	6	18,854	165,969,284	12,117,866	2,491,966	13,685,598	28,295,430
Fixed Cost Proportion	6			42.8%	8.8%	48.4%	100.0%
Small General Service	7	29,931	140,278,384	5,234,644	1,216,973	11,216,666	17,668,283
Fixed Cost Proportion	7			29.6%	6.9%	63.5%	100.0%
Small General Service - On-Site Generation	8	79	351,868	$ 25,497	$ 5,727	$ 58,264	$ 89,487
Fixed Cost Proportion	8			28.5%	6.4%	65.1%	100.0%

Description	Rate Schedule No.	Fixed Cost Portion of Revenue Short-Fall/Subsidy	Distribution Fixed Cost Portion of Revenue Short-Fall/ Subsidy	Proposed Fixed Cost Revenue from Fixed Charges	Proposed Distribution Fixed Cost Revenue from Energy Charges	Calculation of FCC-Dist. ($/Cust./Yr.)	Calculation of FCE-Dist. ($/kWh)
Residential Service	1, 3 & 5*	$ (14,742,263)	$ (6,237,943)	$ 93,766,569	$ 145,738,725	$ 280.10	$ 0.025255
Residential Service - On-Site Generation	6	(9,824,202)	(4,751,654)	3,395,165	5,538,779	293.77	0.033372
Small General Service	7	(98,743)	(62,687)	8,979,926	2,174,053	72.64	0.015498
Small General Service - On-Site Generation	8	$ (39,896)	$ (25,976)	$ 23,789	$ 8,499	$ 107.18	$ 0.024155

**FCE not applicable to Residential Schedule 5; see TOU FCE derivation.*

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Derivation of Proposed FCC & FCE Rates
Settlement Stipulation
IPC-E-25-16

Exhibit No. 4 - FCC and FCE

Description		Existing Customer January 1, 2026		New Customer January 1, 2026
Average Number of Customers		1,030		1,030
Fixed Cost per Customer	$	908	$	280
Total Fixed Cost Recovery	$	935,195	$	288,604
Fixed Cost of Energy	$	0.081838	$	0.025255
Total kWhs		18,562,155		18,562,155
Fixed Cost Recovery in Energy	$	1,519,090	$	468,787
Revenue Collection:				
Service Charge	$	185,486	$	185,486
Summer Energy	$	771,333	$	771,333
Non-Summer Energy		1,283,434		1,283,434
Total Energy	$	2,054,767	$	2,054,767
Total Revenue	**$**	**2,240,253**	**$**	**2,240,253**
Energy-related Costs in Energy Revenue	$	535,677	$	1,585,980
Summer Share:				
Energy-related Costs in Energy Revenue	$	177,891	$	526,681
On-Peak Energy		0.069001		0.204290
Mid-Peak Energy		0.034500		0.102145
Off-Peak Energy		0.017250		0.051073
Average	$	0.029319	$	0.086805
Non-Summer Share:				
Energy-related Costs in Energy Revenue	$	357,787	$	1,059,299
On-Peak Energy		0.038567		0.114186
Off-Peak Energy		0.025712		0.076124
Average	$	0.028635	$	0.084780
Summer Rates (per kWh)				
On-Peak Energy	$	0.299185	$	0.299185
Mid-Peak Energy		0.149594		0.149594
Off-Peak Energy	$	0.074797	$	0.074797
Non-Summer Rates (per kWh)				
On-Peak Energy	$	0.138347	$	0.138347
Off-Peak Energy	$	0.092231	$	0.092231
Implied Summer On-Peak FCE Rate	**$**	**0.230184**	**$**	**0.094895**
Implied Summer Mid-Peak FCE Rate		**0.115094**		**0.047449**
Implied Summer Off-Peak FCE Rate		**0.057547**		**0.023724**
Implied Non-Summer On-Peak FCE Rate		**0.099780**		**0.024161**
Implied Non-Summer Off-Peak FCE Rate	**$**	**0.066519**	**$**	**0.016107**

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

EXHIBIT NO. 5
SALES BASED ADJUSTMENT RATE

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Derivation of Proposed SBAR
Settlement Stipulation
IPC-E-25-16

Exhibit No. 5 - SBAR

Description	Rate Base	Expenses	Income Tax	A&G Expense Exclusion	Other Revenue	Subsidiary Income	Current Return	Desired Return	Revenue Shortfall	Tax Gross-up	Total Revenue Requirement
Production Function											
Energy - Power Supply	$ 67,722,070	$ 513,739,350	$ 535,835	$ 2,292,498	$ 82,924,682	$ 2,802,265	$ 5,550,689	$ 5,018,015	$ (532,674)	$ (177,833)	$ 431,095,923

Docusign Envelope ID: 98A2779B-A262-4A1F-A686-6936505CD71D

Idaho Power Company
State of Idaho
Derivation of Proposed SBAR
Settlement Stipulation
IPC-E-25-16

Exhibit No. 5 - SBAR

Description	Total Federal Income Tax	Total State Income Tax	Energy-Related Generation Rate Base	Total Rate Base	Allocated Income Taxes
Production Function					
Energy - Power Supply	$ 39,741,057	$ (1,116,810)	$ 67,722,070	$ 4,881,563,721	$ 535,835

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Idaho Power Company
State of Idaho
Derivation of Proposed SBAR
Settlement Stipulation
IPC-E-25-16

Exhibit No. 5 - SBAR

Description	Energy-Related Generation Rev. Req.	2025 Test Year Idaho Retail Sales (MWh)	Sales Based Adjusted Rate ($/MWh)
Production Function			
Energy - Power Supply	$ 431,095,923	15,496,385	$ 27.82

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

ATTACHMENT NO. 2

GENERAL RULES AND REGULATIONS INDEX

RULE	TITLE	SHEET NUMBER
	Title Page	i
	Index Page	ii -- iv
Rule A	Introduction	A-1
Rule B	Definitions	B-1 -- B-2
Rule C	Service and Limitations	C-1 -- C-2
Rule D	Metering	D-1 -- D-2
Rule E	Master Metering Standards	E-1
Rule F	Service Establishment and Discontinuance	F-1
Rule G	Billings	G-1 -- G-2
Rule H	New Service Attachments and Distribution Line Installations or Alterations	H-1 -- H-14
Rule I	Budget Pay Plans	I-1 -- I-2
Rule J	Continuity, Curtailment and Interruption of Electric Service	J-1 – J-4
Rule K	Customer's Load and Operations	K-1 -- K-2
Rule L	Deposits	L-1 -- L-2
Rule M	Facilities Charge Service	M-1 -- M-3
Rule N	Special Arrangements for Substation Allowances and Transmission Vested Interest	N-1 --N-3

SCHEDULE INDEX

SCHEDULE	TITLE	SHEET NUMBER
1	Residential Service Standard Plan	1-1 – 1-2
3	Master-Metered Mobile Home Park Residential Service	3-1
5	Residential Service Time-of-Use Plan (Optional)	5-1 – 5-3
6	Residential Service On-Site Generation	6-1 – 6-9
7	Small General Service	7-1 – 7-2
8	Small General Service On-Site Generation	8-1 – 8-8
9	Large General Service	9-1 – 9-5
15	Dusk to Dawn Customer Lighting	15-1 – 15-2
19	Large Power Service	19-1 – 19-4
20	Speculative High-Density Load	20-1 – 20-8
23	Irrigation Peak Rewards Program (Optional)	23-1 – 23-10
24	Agricultural Irrigation Service	24-1 – 24-6
26	Micron Technology, Inc. Special Contract	26-1 – 26-2
29	J.R. Simplot (Pocatello, Idaho) Special Contract	29-1
30	Department of Energy Special Contract	30-1 – 30-2
31	Supply of Standby Electric Service for Amalgamated Sugar Company	31-1
32	J.R. Simplot (Caldwell, Idaho) Special Contract	32-1
33	Brisbie, LLC Special Contract	33-1 – 33-5
34	Lamb Weston, Inc.	34-1 – 34-4
40	Non-Metered General Service	40-1 – 40-2
41	Street Lighting Service	41-1 – 41-4
42	Traffic Control Signal Lighting Service	42-1
45	Standby Service	45-1 – 45-5
46	Alternate Distribution Service	46-1 – 46-4
54	Fixed Cost Adjustment	54-1 – 54-2
55	Power Cost Adjustment	55-1 – 55-3
61	Payment for Home Wiring Audit	61-1
62	Clean Energy Your Way Program (Optional)	62-1 – 62-5
66	Miscellaneous Charges	66-1 – 66-3
68	Interconnections to Customer Distributed Energy Resources	68-1 – 68-28
72	Generator Interconnections to PURPA Qualifying Facility Sellers	72-1 – 72-28

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 – 81-4
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
97	Kilowatt-Hour Tax	97-1
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	$ 80.00
overhead including 2” riser	$ 1,072.00
overhead including 3” riser	$ 1,352.00
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	$15.00	$15.00
Energy Charge, per kWh		
First 800 kWh	12.1195¢	9.9332¢
801-2000 kWh	13.2995¢	10.4305¢
All Additional kWh Over 2000	14.6185¢	11.0052¢

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
Energy Charge, per kWh	
all kWh	11.9450¢

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	$15.00	$15.00
Energy Charge, per kWh		
On-Peak	29.9185¢	13.8347¢
Mid-Peak	14.9594¢	n/a
Off-Peak	7.4797¢	9.2231¢

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	$15.00	$15.00
Energy Charge, per kWh		
First 800 kWh	12.1195¢	9.9332¢
801-2000 kWh	13.2995¢	10.4305¢
All Additional kWh Over 2000	14.6185¢	11.0052¢

TIME-OF-USE RATES (OPTIONAL)

	Summer	Non-summer
Service Charge, per month	$15.00	$15.00
Energy Charge, per kWh		
On-Peak	29.9185¢	13.8347¢
Mid-Peak	14.9594¢	n/a
Off-Peak	7.4797¢	9.2231¢

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	15.6836¢	2.9019¢
Off-Peak	3.3920¢	2.9019¢

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	$25.00
Energy Charge, per kWh		
First 300 kWh	8.7174¢	8.7174¢
All Additional kWh	9.9619¢	8.7194¢

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 CONDITIONS (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	$25.00	$25.00
Energy Charge, per kWh		
First 300 kWh	8.7174¢	8.7174¢
All Additional kWh	9.9619¢	8.7194¢

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	15.6836¢	2.9019¢
Off-Peak	3.3920¢	2.9019¢

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)

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest non-zero monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period.

BILLING DEMAND

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

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

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 p.m. Monday through Saturday, except holidays
Mid-Peak:	11:00 p.m. to 10:00 a.m. and 2:00 p.m. to 7:00 p.m. Monday through Saturday, except holidays
Off-Peak:	10:00 a.m. to 2:00 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
Mid-Peak:	9:00 a.m. to 10:00 a.m., 2:00 p.m. to 5:00 p.m., and 8:00 p.m. to 6:00 a.m. Monday through Saturday, except holidays
Off-Peak:	10:00 a.m. to 2:00 p.m. Monday through Saturday and all hours on Sunday and holidays

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 (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 a Sunday, the Monday immediately following that Sunday will be considered a holiday.

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	$25.00
Basic Charge, per kW of Basic Load Capacity		
Basic Load Capacity	$1.84	$1.84
Demand Charge, per kW of Billing Demand		
Billing Demand	$9.49	$7.75
Energy Charge, per kWh		
All kWh	5.0908¢	4.9875¢

SECONDARY SERVICE – TIME-OF-USE (OPTIONAL)	Summer	Non-summer
Service Charge, per month	$25.00	$25.00
Basic Charge, per kW of Basic Load Capacity		
Basic Load Capacity	$1.84	$1.84
Demand Charge, per kW of Billing Demand		
Billing Demand	$9.49	$7.75
Energy Charge, per kWh		
On-Peak	6.4329¢	5.4425¢
Mid-Peak	4.9542¢	4.9191¢
Off-Peak	4.6366¢	4.6375¢

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$345.00	$345.00
Basic Charge, per kW of Basic Load Capacity	$2.04	$2.04
Demand Charge, per kW of Billing Demand	$12.04	$10.48
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.29	n/a
Energy Charge, per kWh		
On-Peak	5.3636¢	4.4679¢
Mid-Peak	3.9840¢	3.9475¢
Off-Peak	3.6875¢	3.6674¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$345.00	$345.00
Basic Charge, per kW of Basic Load Capacity	$0.67	$0.67
Demand Charge, per kW of Billing Demand	$8.29	$8.69
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.29	n/a
Energy Charge, per kWh		
On-Peak	5.6136¢	4.6703¢
Mid-Peak	4.2114¢	4.1465¢
Off-Peak	3.9101¢	3.8647¢

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	$10.95
85	7,200	$11.67
200	18,000	$14.38

FLOOD LIGHTING

LED Fixture		
Watt (Maximum)	Lumen (Minimum)	Base Rate
85	8,100	$16.14
150	18,000	$17.03
300	32,000	$22.42

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)

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period, but not less than 1,000 kW.

BILLING DEMAND

The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor, but not less than 1,000 kW.

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

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 p.m. Monday through Saturday, except holidays
Mid-Peak:	11:00 p.m. to 10:00 a.m. and 2:00 p.m. to 7:00 p.m. Monday through Saturday, except holidays
Off-Peak:	10:00 a.m. to 2:00 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
Mid-Peak:	9:00 a.m. to 10:00 a.m., 2:00 p.m. to 5:00 p.m., and 8:00 p.m. to 6:00 a.m. Monday through Saturday, except holidays
Off-Peak:	10:00 a.m. to 2:00 p.m. Monday through Saturday and all hours on Sunday and holidays

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 (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 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.

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	$110.00	$110.00
Basic Charge, per kW of Basic Load Capacity	$2.27	$2.27
Demand Charge, per kW of Billing Demand	$14.46	$13.05
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.51	n/a
Energy Charge, per kWh		
On-Peak	5.9565¢	4.9879¢
Mid-Peak	4.5019¢	4.4723¢
Off-Peak	4.1894¢	4.1950¢

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$450.00	$450.00
Basic Charge, per kW of Basic Load Capacity	$2.32	$2.32
Demand Charge, per kW of Billing Demand	$13.51	$12.68
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.14	n/a
Energy Charge, per kWh		
On-Peak	5.3694¢	4.4112¢
Mid-Peak	3.9145¢	3.8960¢
Off-Peak	3.6018¢	3.6187¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$450.00	$450.00
Basic Charge, per kW of Basic Load Capacity	$1.16	$1.16
Demand Charge, per kW of Billing Demand	$15.19	$13.37
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.14	n/a
Energy Charge, per kWh		
On-Peak	5.4173¢	4.4324¢
Mid-Peak	3.9529¢	3.9169¢
Off-Peak	3.6381¢	3.6395¢

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)

DELETED

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

DELETED

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

DELETED

SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD
(Continued)

TYPE OF SERVICE

The Type of Service provided under this schedule is three-phase at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period, but not less than 1,000 kW for Large Power Service.

BILLING DEMAND

The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor, but not less than 1,000 kW for Large Power Service.

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 p.m. Monday through Saturday, except holidays
Mid-Peak:	11:00 p.m. to 10:00 a.m. and 2:00 p.m. to 7:00 p.m. Monday through Saturday, except holidays
Off-Peak:	10:00 a.m. to 2:00 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
Mid-Peak:	9:00 a.m. to 10:00 a.m., 2:00 p.m. to 5:00 p.m., and 8:00 p.m. to 6:00 a.m. Monday through Saturday, except holidays
Off-Peak:	10:00 a.m. to 2:00 p.m. Monday through Saturday and all hours on Sunday and holidays

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 (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 considered a holiday.

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	$345.00	$345.00
Basic Charge, per kW of Basic Load Capacity	$2.04	$2.04
Demand Charge, per kW of Billing Demand	$12.68	$11.12
Energy Charge, per kWh		
On-Peak	7.9058¢	6.6122¢
Mid-Peak	6.1266¢	5.3736¢
Off-Peak	4.5473¢	4.7482¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$345.00	$345.00
Basic Charge, per kW of Basic Load Capacity	$0.67	$0.67
Demand Charge, per kW of Billing Demand	$8.93	$9.33
Energy Charge, per kWh		
On-Peak	8.1558¢	6.8146¢
Mid-Peak	6.3540¢	5.5726¢
Off-Peak	4.7699¢	4.9455¢

SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD
(Continued)

MONTHLY CHARGE (Continued)

Large Power Service Rates

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$450.00	$450.00
Basic Charge, per kW of Basic Load Capacity	$2.32	$2.32
Demand Charge, per kW of Billing Demand	$14.15	$13.32
Energy Charge, per kWh		
On-Peak	7.8652¢	6.5091¢
Mid-Peak	6.0107¢	5.2757¢
Off-Peak	4.4152¢	4.6531¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$450.00	$450.00
Basic Charge, per kW of Basic Load Capacity	$1.16	$1.16
Demand Charge, per kW of Billing Demand	$15.83	$14.01
Energy Charge, per kWh		
On-Peak	7.9131¢	6.5303¢
Mid-Peak	6.0491¢	5.2966¢
Off-Peak	4.4515¢	4.6739¢

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	**$0.0453 per kilowatt of reduction per event hour**
Large Power Service Rates	**$0.0451 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	$16.50	n/a
Energy Charge All kWh	6.7222¢	7.0752¢

TRANSMISSION SERVICE	In-Season	Out-of-Season
Service Charge, per month	$450.00	$9.00
Demand Charge, per kW of Billing Demand	$15.25	n/a
Energy Charge All kWh	6.3092¢	6.6136¢

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
$21.04 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
2.7165¢ 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,
$17.41 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
2.7377¢ 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	$14.49
2.	Energy Charge, per kWh	3.7699¢

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:	$2.72
Nampa Facility:	$2.74
Twin Falls Facility:	$2.39

Standby Billing Demand Charge, per kW of Standby Billing Demand	$6.93

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	$22.11	$20.17
Daily Excess Demand Charge		
per each kW over the Contract Demand	$1.248	$1.248
Energy Charge		
per kWh	2.7520¢	2.7202¢

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.

SPECIAL CONTRACT DATED DECEMBER 22, 2021, AMENDED MARCH 14, 2024

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than 95 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 95 percent and dividing by the actual Power Factor.

BLOCK 1

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period, but not less than 1,000 kW for Large Power Service.

BILLING DEMAND

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

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

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 p.m. Monday through Saturday, except holidays
Mid-Peak:	11:00 p.m. to 10:00 a.m. and 2:00 p.m. to 7:00 p.m. Monday through Saturday, except holidays
Off-Peak:	10:00 a.m. to 2:00 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
Mid-Peak:	9:00 a.m. to 10:00 a.m., 2:00 p.m. to 5:00 p.m., and 8:00 p.m. to 6:00 a.m. Monday through Saturday, except holidays
Off-Peak:	10:00 a.m. to 2:00 p.m. Monday through Saturday and all hours on Sunday and holidays

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	$450.00	$450.00
Basic Charge, per kW of Basic Load Capacity	$1.16	$1.16
Demand Charge, per kW of Billing Demand	$15.19	$13.37
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.14	n/a
Energy Charge, per kWh		
On-Peak	5.4173¢	4.4324¢
Mid-Peak	3.9529¢	3.9169¢
Off-Peak	3.6381¢	3.6395¢
Embedded Energy Fixed Cost Rate, per kWh		
On-Peak	1.2752¢	1.2451¢
Mid-Peak	1.2752¢	1.2451¢
Off-Peak	1.2752¢	1.2451¢

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)

BLOCK 1

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period, but not less than 1,000 kW for Large Power Service.

BILLING DEMAND

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

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

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 p.m. Monday through Saturday, except holidays
Mid-Peak:	11:00 p.m. to 10:00 a.m. and 2:00 p.m. to 7:00 p.m. Monday through Saturday, except holidays
Off-Peak:	10:00 a.m. to 2:00 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
Mid-Peak:	9:00 a.m. to 10:00 a.m., 2:00 p.m. to 5:00 p.m., and 8:00 p.m. to 6:00 a.m. Monday through Saturday, except holidays
Off-Peak:	10:00 a.m. to 2:00 p.m. Monday through Saturday and all hours on Sunday and holidays

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 (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 a Sunday, the Monday immediately following that Sunday will be considered a holiday.

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	$450.00	$450.00
Basic Charge, per kW of Basic Load Capacity	$2.32	$2.32
Demand Charge, per kW of Billing Demand	$13.51	$12.68
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$2.14	n/a
Energy Charge, per kWh		
On-Peak	5.1897¢	4.2438¢
Mid-Peak	3.7373¢	3.7285¢
Off-Peak	3.4253¢	3.4513¢

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
$24.19 per kW of Billing Demand but not less than Minimum Monthly Billing Demand.

Energy Charge
4.2638¢ 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	10.3710¢
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	$15.84
85	7,200	$17.05
140	10,800	$18.54
200	18,000	$21.46

Non-Metered Service – Variable Energy

Energy Charge, per kWh	10.3710¢

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	3.7494¢

Metered Service (41CM)

Service Charge, per meter	$1.83
Energy Charge, per kWh	3.7494¢

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	8.5293¢

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

Standby Reservation Charge, per kW of Available Standby Capacity	Summer	Non-summer
Secondary Service	$5.72	$5.72
Primary Service	$5.77	$5.77
Transmission Service	$3.12	$3.12
Standby Demand Charge, per kW of Standby Billing Demand		
Secondary Service	$11.33	$9.44
Primary Service	$13.68	$12.55
Transmission Service	$8.29	$8.69

Customers taking service under Schedule 19

Standby Reservation Charge, per kW of Available Standby Capacity	Summer	Non-summer
Primary Service	$5.98	$5.98
Transmission Service	$3.12	$3.12
Standby Demand Charge, per kW of Standby Billing Demand		
Primary Service	$15.46	$14.76
Transmission Service	$15.19	$13.37

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
$2.86 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	$907.64	$280.10
Schedule 5	$907.64	$280.10
Schedule 6	$799.60	$293.77

Small General Service	FCC	FCC-Dist
Schedule 7	$286.98	$72.64
Schedule 8	$325.39	$107.18

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	8.1838¢ per kWh	2.5255¢ per kWh
Schedule 5 – Summer On-Peak	23.0184¢ per kWh	9.4895¢ per kWh
Schedule 5 – Mid-Peak	11.5094¢ per kWh	4.7449¢ per kWh
Schedule 5 – Summer Off-Peak	5.7547¢ per kWh	2.3724¢ per kWh
Schedule 5 – Non-Summer On-Peak	9.9780¢ per kWh	2.4161¢ per kWh
Schedule 5 – Non-Summer Off-Peak	6.6519¢ per kWh	1.6107¢ per kWh
Schedule 6	9.0836¢ per kWh	3.3372¢ per kWh

Small General Service	FCE	FCE-Dist
Schedule 7	6.1233¢ per kWh	1.5498¢ per kWh
Schedule 8	7.3330¢ per kWh	2.4155¢ 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 (0.0503) cents per kWh. The monthly Fixed Cost Adjustment for Small General Service (Schedules 7 and 8) is (0.0614) cents per kWh.

EXPIRATION

The Fixed Cost Adjustment included on this schedule will expire May 31, 2026.

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 in Category 4; 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.	1.30181	1.89897	0.59716	95%	0.56730
2	Purchased power expense from cogeneration and small power producers.	1.39726	1.39941	0.00215	100%	0.00215
3	Demand response incentive payments.	0.06008	0.06695	0.00687	100%	0.00687
4	Payments for battery energy storage system leases	0.13279	0.11066	(0.02213)	100%	(0.02213)
Total		**2.89193**	**3.47599**	**0.58406**		**0.55420**

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	0.5673	0.0022	0.0069	(0.0221)	(0.3351)	(0.0000)	0.2191
3	0.5673	0.0022	0.0069	(0.0221)	(0.3351)	(0.0000)	0.2191
5	0.5673	0.0022	0.0069	(0.0221)	(0.3351)	(0.0000)	0.2191
6	0.5673	0.0022	0.0069	(0.0221)	(0.3350)	(0.0000)	0.2192
7	0.5673	0.0022	0.0069	(0.0221)	(0.3353)	(0.0000)	0.2189
8	0.5673	0.0022	0.0069	(0.0221)	(0.3355)	(0.0000)	0.2187
9S	0.5673	0.0022	0.0069	(0.0221)	(0.3346)	(0.0000)	0.2196
9P	0.5673	0.0022	0.0069	(0.0221)	(0.3350)	(0.0000)	0.2192
9T	0.5673	0.0022	0.0069	(0.0221)	(0.3349)	(0.0000)	0.2193
15	0.5673	0.0022	0.0069	(0.0221)	(0.3357)	(0.0000)	0.2185
19S	0.5673	0.0022	0.0069	(0.0221)	(0.3350)	(0.0000)	0.2192
19P	0.5673	0.0022	0.0069	(0.0221)	(0.3348)	(0.0000)	0.2194
19T	0.5673	0.0022	0.0069	(0.0221)	(0.3348)	(0.0000)	0.2194
24	0.5673	0.0022	0.0069	(0.0221)	(0.3340)	(0.0000)	0.2202
40	0.5673	0.0022	0.0069	(0.0221)	(0.3349)	(0.0000)	0.2193
41	0.5673	0.0022	0.0069	(0.0221)	(0.3354)	(0.0000)	0.2188
42	0.5673	0.0022	0.0069	(0.0221)	(0.3352)	(0.0000)	0.2190
26	0.5673	0.0022	0.0069	(0.0221)	(0.3347)	*	0.2195
29	0.5673	0.0022	0.0069	(0.0221)	(0.3348)	*	0.2194
30	0.5673	0.0022	0.0069	(0.0221)	(0.3348)	*	0.2194
32	0.5673	0.0022	0.0069	(0.0221)	(0.3348)	*	0.2194
34	0.5673	0.0022	0.0069	(0.0221)	(0.3348)	*	0.2194

* 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, 2026.

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	1.8437 ¢	1.2551 ¢	1.2752 ¢
Summer Mid-Peak	1.8437 ¢	1.2551 ¢	1.2752 ¢
Summer Off-Peak	1.8437 ¢	1.2551 ¢	1.2752 ¢
Non-Summer On-Peak	1.8001 ¢	1.2254 ¢	1.2451 ¢
Non-Summer Mid-Peak	1.8001 ¢	1.2254 ¢	1.2451 ¢
Non-Summer Off-Peak	1.8001 ¢	1.2254 ¢	1.2451 ¢

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	1.38%	0.64%
Schedule 15	1.74%	1.74%
Schedule 19	1.38%	0.64%
Schedule 24	1.38%	0.64%
Schedule 29	1.38%	0.64%
Schedule 32	1.38%	0.64%
Schedule 41	1.17%	1.17%
Schedule 45	1.38%	0.64%
Schedule 46	1.38%	0.64%

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	0.64%

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 0.8 kW 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:

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

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

NET BILLING – CONDITIONS OF PURCHASE AND SALE (Continued)

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. 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.

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

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

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.

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.

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 Interconnection 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 systems will be removed from service under this schedule and placed on the appropriate standard service schedule.

GENERAL RULES AND REGULATIONS INDEX

RULE	TITLE	SHEET NUMBER
	Title Page	i
	Index Page	ii -- iv
Rule A	Introduction	A-1
Rule B	Definitions	B-1 -- B-2
Rule C	Service and Limitations	C-1 -- C-2
Rule D	Metering	D-1 -- D-2
Rule E	Master Metering Standards	E-1
Rule F	Service Establishment and Discontinuance	F-1
Rule G	Billings	G-1 -- G-2
Rule H	New Service Attachments and Distribution Line Installations or Alterations	H-1 -- H-14
Rule I	Budget Pay Plans	I-1 -- I-2
Rule J	Continuity, Curtailment and Interruption of Electric Service	J-1 – J-4
Rule K	Customer's Load and Operations	K-1 -- K-2
Rule L	Deposits	L-1 -- L-2
Rule M	Facilities Charge Service	M-1 -- M-3
Rule N	Special Arrangements for Substation Allowances and Transmission Vested Interest	N-1 --N-3

SCHEDULE INDEX

SCHEDULE	TITLE	SHEET NUMBER
1	Residential Service Standard Plan	1-1 – 1-2
3	Master-Metered Mobile Home Park Residential Service	3-1
5	Residential Service Time-of-Use Plan (Optional)	5-1 – 5-~~2~~3
6	Residential Service On-Site Generation	6-1 – 6-~~6~~9
7	Small General Service	7-1 – 7-2
8	Small General Service On-Site Generation	8-1 – 8-~~5~~8
9	Large General Service	9-1 – 9-5
15	Dusk to Dawn Customer Lighting	15-1 – 15-2
19	Large Power Service	19-1 – 19-~~7~~4
20	Speculative High-Density Load	20-1 – 20-8
23	Irrigation Peak Rewards Program (Optional)	23-1 – 23-10
24	Agricultural Irrigation Service	24-1 – 24-6
26	Micron Technology, Inc. Special Contract	26-1 – 26-2
29	J.R. Simplot (Pocatello, Idaho) Special Contract	29-1
30	Department of Energy Special Contract	30-1 – 30-2
31	Supply of Standby Electric Service for Amalgamated Sugar Company	31-1
32	J.R. Simplot (Caldwell, Idaho) Special Contract	32-1
33	Brisbie, LLC Special Contract	33-1 – 33-~~4~~5
34	Lamb Weston, Inc.	34-1 – 34-4
40	Non-Metered General Service	40-1 – 40-2
41	Street Lighting Service	41-1 – 41-4
42	Traffic Control Signal Lighting Service	42-1
45	Standby Service	45-1 – 45-5
46	Alternate Distribution Service	46-1 – 46-4
54	Fixed Cost Adjustment	54-1 – 54-2
55	Power Cost Adjustment	55-1 – 55-3
61	Payment for Home Wiring Audit	61-1
62	Clean Energy Your Way Program (Optional)	62-1 – 62-5
66	Miscellaneous Charges	66-1 – 66-3
68	Interconnections to Customer Distributed Energy Resources	68-1 – 68-28
72	Generator Interconnections to PURPA Qualifying Facility Sellers	72-1 – 72-28

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-~~34~~
82	Flex Peak Program (Optional)	82-1 – 82-7
84	Customer Energy Production Net Metering Service	84-1 – 84-~~69~~
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
97	Kilowatt-Hour Tax	97-1
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.

~~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	$ 80.00
overhead including 2” riser	$ 1,072.00
overhead including 3” riser	$ 1,352.00
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	$15.00
Energy Charge, per kWh		
First 800 kWh	~~10.177~~12.1195¢	~~8.956~~9.9332¢
801-2000 kWh	~~12.238~~13.2995¢	~~9.875~~10.4305¢
All Additional kWh Over 2000	~~14.538~~14.6185¢	~~10.936~~11.0052¢

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
Energy Charge, per kWh	
all kWh	~~10.948~~11.9450¢

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~~	~~25.2957¢~~	~~13.1150¢~~
~~Mid-Peak~~	~~12.6480¢~~	~~n/a~~
~~Off-Peak~~	~~6.3241¢~~	~~8.7433¢~~

~~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	$15.00
Energy Charge, per kWh		
On-Peak	~~25.2957~~29.9185¢	~~13.1150~~13.8347¢
Mid-Peak	~~12.6480~~14.9594¢	n/a
Off-Peak	~~6.3241~~7.4797¢	~~8.7433~~9.2231¢

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. kWh Credits~~Excess Net Energy 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~~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 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 area~~any unused Financial Credits will be paid out following the time the final bill is prepared.

~~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	$15.00
Energy Charge, per kWh		
First 800 kWh	~~10.177~~12.1195¢	~~8.956~~9.9332¢
801-2000 kWh	~~12.238~~13.2995¢	~~9.875~~10.4305¢
All Additional kWh Over 2000	~~14.538~~14.6185¢	~~10.936~~11.0052¢

TIME-OF-USE RATES (OPTIONAL)

	Summer	Non-summer
Service Charge, per month	$15.00	$15.00
Energy Charge, per kWh		
On-Peak	~~25.295~~29.9185¢	~~13.115~~13.8347¢
Mid-Peak	~~12.648~~14.9594¢	n/a
Off-Peak	~~6.324~~7.4797¢	~~8.743~~9.2231¢

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	15.6836¢	2.9019¢
Off-Peak	3.3920¢	2.9019¢

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	$25.00
Energy Charge, per kWh		
First 300 kWh	~~7.4534~~8.7174¢	~~7.4534~~8.7174¢
All Additional kWh	~~8.5176~~9.9619¢	

~~7.4552~~8.7194¢

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~~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~~kWh ~~c~~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.~~

ii.

~~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.~~

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 CONDITIONS (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	$25.00
Energy Charge, per kWh		
First 300 kWh	~~7.4534~~8.7174¢	~~7.4534~~8.7174¢
All Additional kWh	~~8.5176~~9.9619¢	~~7.4552~~8.7194¢

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	15.6836¢	2.9019¢
Off-Peak	3.3920¢	2.9019¢

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)

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest non-zero monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period.

BILLING DEMAND

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

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

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 p.m. Monday through Saturday, except holidays
Mid-Peak:	~~3~~11:00 p.m. to ~~7~~10:00 ~~p~~a.m. and ~~11~~2:00 p.m. to ~~12~~7:00 ~~a~~p.m. Monday through Saturday, except holidays
Off-Peak:	~~12~~10:00 a.m. to ~~3~~2:00 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
Mid-Peak:	9:00 a.m. to 1~~2~~0:00 ~~p~~a.m., 4~~2~~:00 p.m. to 5:00 p.m., and 8:00 p.m. to ~~10~~6:00 ~~p~~a.m. Monday through Saturday, except holidays
Off-Peak:	~~12:00 a.m. to 6:00 a.m., 12:00 p.m. to 4:00 p.m., and~~ 10:00 ~~p~~a.m. to ~~1~~2:00 ~~a~~p.m. Monday through Saturday and all hours on Sunday and holidays

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 (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 a Sunday, the Monday immediately following that Sunday will be considered a holiday.

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	$25.00
Basic Charge, per kW of Basic Load Capacity Basic Load Capacity $~~1.58~~1.84	$~~1.58~~1.84	
Demand Charge, per kW of Billing Demand Billing Demand $~~6.39~~7.75	$~~8.12~~9.49	
Energy Charge, per kWh All kWh ~~5.2721~~4.9875¢	~~5.4658~~5.0908¢	

SECONDARY SERVICE – TIME-OF-USE (OPTIONAL)	Summer	Non-summer
Service Charge, per month	$25.00	$25.00
Basic Charge, per kW of Basic Load Capacity Basic Load Capacity $~~1.58~~1.84	$~~1.58~~1.84	
Demand Charge, per kW of Billing Demand Billing Demand $~~6.39~~7.75	$~~8.12~~9.49	
Energy Charge, per kWh On-Peak ~~5.5755~~5.4425¢	~~5.8489~~6.4329¢	
Mid-Peak ~~5.3259~~4.9191¢	~~5.8489~~4.9542¢	
Off-Peak ~~5.1273~~4.6375¢	~~5.2709~~4.6366¢	

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	~~$340.00~~345.00	
Basic Charge, per kW of Basic Load Capacity	~~$1.83~~2.04	~~$1.83~~2.04
Demand Charge, per kW of Billing Demand	~~$8.35~~12.04	~~$7.91~~10.48
On-Peak Demand Charge, per kW of On-Peak Billing Demand	~~$1.59~~2.29	n/a
Energy Charge, per kWh		
On-Peak	~~5.39375~~.3636¢	
	~~4.89954~~.4679¢	
Mid-Peak	~~5.39373~~.9840¢	
	~~4.65793~~.9475¢	
Off-Peak	~~4.83463~~.6875¢	
	~~4.46493~~.6674¢	

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	~~$340.00~~345.00	
Basic Charge, per kW of Basic Load Capacity	~~$1.09~~.067	~~$1.09~~.067
Demand Charge, per kW of Billing Demand	~~$7.38~~8.29	~~$6.46~~8.69
On-Peak Demand Charge, per kW of On-Peak Billing Demand	~~$1.59~~2.29	n/a
Energy Charge, per kWh		
On-Peak	~~5.33055~~.6136¢	
	~~4.80794~~.6703¢	
Mid-Peak	~~5.33054~~.2114¢	
	~~4.56634~~.1465¢	
Off-Peak	~~4.76483~~.9101¢	
	~~4.37253~~.8647¢	

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	$ ~~9.82~~10.95
85	7,200	$~~11.95~~11.67
200	18,000	$~~17.27~~14.38

FLOOD LIGHTING

LED Fixture		
Watt (Maximum)	Lumen (Minimum)	Base Rate
85	8,100	$~~19.50~~16.14
150	18,000	$~~21.47~~17.03
300	32,000	$~~25.28~~22.42

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)

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period, but not less than 1,000 kW.

BILLING DEMAND

The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor, but not less than 1,000 kW.

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

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 p.m. Monday through Saturday, except holidays
Mid-Peak:	~~3~~11:00 p.m. to ~~7~~10:00 ~~p~~a.m. and ~~11~~2:00 p.m. to ~~12:007~~:00 ~~a~~p.m. Monday through Saturday, except holidays
Off-Peak:	~~12~~10:00 a.m. to ~~3~~2:00 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
Mid-Peak:	9:00 a.m. to ~~12~~10:00 ~~p~~a.m., ~~4~~2:00 p.m. to 5:00 p.m., and 8:00 p.m. to ~~10~~6:00 ~~p~~a.m. Monday through Saturday, except holidays
Off-Peak:	~~12:00 a.m. to 6:00 a.m., 12:00 p.m. to 4:00 p.m., and~~ 10:00 ~~p~~a.m. to ~~1~~2:00 ~~a~~p.m. Monday through Saturday and all hours on Sunday and holidays

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 (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 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.

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~~110.00	~~$85.00~~110.00
Basic Charge, per kW of Basic Load Capacity	$~~2.01~~2.27	$~~2.01~~2.27
Demand Charge, per kW of Billing Demand	$~~10.50~~14.46	$~~8.45~~13.05
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.82~~2.51	n/a
Energy Charge, per kWh		
On-Peak	~~5.9941~~5.9565¢	
~~5.4204~~4.9879¢		
Mid-Peak	~~5.9941~~4.5019¢	
~~5.1783~~4.4723¢		

Off-Peak	~~5.4287~~4.1894¢
~~4.9842~~4.1950¢	

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$~~415.00~~450.00	
Basic Charge, per kW of Basic Load Capacity	$~~2.21~~2.32	$~~2.21~~2.32
Demand Charge, per kW of Billing Demand	$~~10.04~~13.51	$~~8.64~~12.68
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.59~~ 2.14	n/a
Energy Charge, per kWh		
On-Peak	~~5.2314~~5.3694¢	~~4.7227~~4.4112¢
Mid-Peak	~~5.2314~~3.9145¢	~~4.4805~~3.8960¢
Off-Peak	~~4.6655~~3.6018¢	~~4.2863~~3.6187¢

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$~~415.00~~450.00	
Basic Charge, per kW of Basic Load Capacity	$~~1.87~~1.16	$~~1.87~~1.16
Demand Charge, per kW of Billing Demand	$~~10.20~~15.19	$~~8.78~~13.37
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.59~~2.14	n/a
Energy Charge, per kWh		
On-Peak	~~5.2142~~5.4173¢	~~4.6927~~4.4324¢
Mid-Peak	~~5.2142~~3.9529¢	~~4.4504~~3.9169¢
Off-Peak	~~4.6451~~3.6381¢	~~4.2561~~3.6395¢

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)

~~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.~~

DELETED

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

~~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:~~

DELETED

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

~~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.~~

DELETED

SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD
(Continued)

TYPE OF SERVICE

The Type of Service provided under this schedule is three-phase at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period, but not less than 1,000 kW for Large Power Service.

BILLING DEMAND

The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor, but not less than 1,000 kW for Large Power Service.

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 p.m. Monday through Saturday, except holidays
Mid-Peak:	~~3~~11:00 p.m. to ~~7~~10:00 ~~p~~a.m. and ~~11~~2:00 p.m. to ~~12~~7:00 ~~a~~p.m. Monday through Saturday, except holidays
Off-Peak:	~~12~~10:00 a.m. to ~~3~~2:00 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
Mid-Peak:	9:00 a.m. to ~~12~~10:00 ~~p~~a.m., ~~4~~2:00 p.m. to 5:00 p.m., and 8:00 p.m. to ~~10~~6:00 ~~p~~a.m. Monday through Saturday, except holidays
Off-Peak:	~~12:00 a.m. to 6:00 a.m., 12:00 p.m. to 4:00 p.m., and~~ 10:00 ~~p~~a.m. to ~~12~~2:00 ~~a~~p.m. Monday through Saturday and all hours on Sunday and holidays

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 (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 considered a holiday.

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	$~~340.00~~345.00	
$~~340.00~~345.00		
Basic Charge, per kW of Basic Load Capacity	$~~1.83~~2.04	$~~1.83~~2.04
Demand Charge, per kW of Billing Demand	$~~8.79~~12.68	$~~8.35~~11.12
Energy Charge, per kWh		
On-Peak	~~7.629~~7.9058¢	
~~6.7376~~6.6122¢		
Mid-Peak	~~7.2301~~6.1266¢	
~~5.7778~~5.3736¢		
Off-Peak	~~5.3882~~4.5473¢	
~~5.2395~~4.7482¢		

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$~~340.00~~345.00	
$~~340.00~~345.00		
Basic Charge, per kW of Basic Load Capacity	$~~1.09~~0.67	$~~1.09~~0.67
Demand Charge, per kW of Billing Demand	$~~7.82~~8.93	$~~6.90~~9.33
Energy Charge, per kWh		
On-Peak	~~7.5665~~8.1558¢	
~~6.6460~~6.8146¢		
Mid-Peak	~~7.1669~~6.3540¢	
~~5.6862~~5.5726¢		
Off-Peak	~~5.3184~~4.7699¢	
~~5.1471~~4.9455¢		

SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD
(Continued)

MONTHLY CHARGE (Continued)

Large Power Service Rates

PRIMARY SERVICE	Summer	Non-summer
Service Charge, per month	$~~415.00~~450.00	
Basic Charge, per kW of Basic Load Capacity	$~~2.21~~2.32	$~~2.21~~2.32
Demand Charge, per kW of Billing Demand	$~~10.52~~ 14.15	$~~9.12~~13.32
Energy Charge, per kWh		
On-Peak	~~7.462~~7.8652¢	
	~~6.5556~~6.5091¢	
Mid-Peak	~~7.0626~~6.0107¢	
	~~5.5952~~5.2757¢	
Off-Peak	~~5.2139~~4.4152¢	
	~~5.0557~~4.6531¢	

TRANSMISSION SERVICE	Summer	Non-summer
Service Charge, per month	$~~415.00~~450.00	
Basic Charge, per kW of Basic Load Capacity	$~~1.87~~1.16	$~~1.87~~1.16
Demand Charge, per kW of Billing Demand	$~~10.68~~15.83	$~~9.26~~14.01
Energy Charge, per kWh		
On-Peak	~~7.4450~~7.9131¢	
	~~6.5256~~6.5303¢	
Mid-Peak	~~7.0454~~6.0491¢	
	~~5.5651~~5.2966¢	
Off-Peak	~~5.1935~~4.4515¢	
	~~5.0255~~4.6739¢	

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~~0.0453 per kilowatt of reduction per event hour**

Large Power Service Rates **$~~0.0382~~0.0451 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	$~~15.06~~ 16.50	n/a
Energy Charge All kWh	~~6.1295~~6.7222¢	
~~7.2053~~7.0752¢		

TRANSMISSION SERVICE	In-Season	Out-of-Season
Service Charge, per month	$~~415.00~~450.00	
$~~6.00~~9.00		
Demand Charge, per kW of Billing Demand	$~~14.21~~15.25	n/a
Energy Charge All kWh	~~5.8727~~6.3092¢	
~~6.8754~~6.6136¢		

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
$~~3.37~~3.12 per kW of Contract Demand.

Monthly Billing Demand Charge
$~~17.83~~21.04 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
$~~1.339~~1.248 per each kW over the Contract Demand.

Monthly Energy Charge
~~3.039~~42.7165¢ 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
$~~3.25~~3.12 per kW of Contract Demand

Demand Charge,
$~~14.80~~17.41 per kW of Billing Demand but no less than the Contract Demand less 5,000 kW

Daily Excess Demand Charge
$~~1.293~~1.248 per each kW over the Contract Demand

Energy Charge
~~3.1006~~2.7377¢ 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	$~~10.17~~14.49
2.	Energy Charge, per kWh	~~4.2488~~3.7699¢

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:	$~~3.45~~2.72
Nampa Facility:	$~~3.47~~2.74
Twin Falls Facility:	$~~3.15~~2.39

Standby Billing Demand Charge, per kW of Standby Billing Demand	$~~1.67~~6.93

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	$~~3.30~~3.12	$~~3.30~~3.12
Demand Charge per kW of Billing Demand but no less than the Contract Demand less 10,000 kW	$~~19.60~~22.11	$~~16.20~~20.17
Daily Excess Demand Charge per each kW over the Contract Demand	$~~1.319~~1.248	$~~1.319~~1.248
Energy Charge per kWh	~~3.0405~~2.7520¢	~~3.2844~~2.7202¢

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.

SPECIAL CONTRACT DATED DECEMBER 22, 2021, AMENDED MARCH 14, 2024

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than 95 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 95 percent and dividing by the actual Power Factor.

BLOCK 1

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period, but not less than 1,000 kW for Large Power Service.

BILLING DEMAND

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

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

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 p.m. Monday through Saturday, except holidays
Mid-Peak:	~~3~~11:00 p.m. to 7:00 ~~p~~a.m. and ~~1~~12:00 p.m. to ~~1~~27:00 ~~a~~p.m. Monday through Saturday, except holidays
Off-Peak:	1~~2~~0:00 a.m. to ~~3~~2:00 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
Mid-Peak:	9:00 a.m. to 1~~2~~0:00 ~~p~~a.m., 4~~2~~:00 p.m. to 5:00 p.m., and 8:00 p.m. to ~~10~~6:00 ~~p~~a.m. Monday through Saturday, except holidays
Off-Peak:	~~12:00 a.m. to 6:00 a.m., 12:00 p.m. to 4:00 p.m., and~~ 10:00 ~~p~~a.m. to ~~1~~2:00 ~~a~~p.m. Monday through Saturday and all hours on Sunday and holidays

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~~450.00	
Basic Charge, per kW of Basic Load Capacity	$~~1.87~~1.16	$~~1.87~~1.16
Demand Charge, per kW of Billing Demand	$~~10.20~~15.19	$~~8.78~~13.37
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.59~~2.14	n/a
Energy Charge, per kWh		
On-Peak	~~5.2142~~5.4173¢	
~~4.6927~~4.4324¢		
Mid-Peak	~~5.2142~~3.9529¢	
~~4.4504~~3.9169¢		
Off-Peak	~~4.6451~~3.6381¢	
~~4.2561~~3.6395¢		
Embedded Energy Fixed Cost Rate, per kWh		
On-Peak	~~1.0007~~1.2752¢	
~~1.8257~~1.2451¢		

Mid-Peak	~~1.0007~~1.2752¢
	~~1.8117~~1.2451¢
Off-Peak	~~0.9603~~1.2752¢
	~~1.8005~~1.2451¢

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
$~~1.320~~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
$~~3.283~~.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)

BLOCK 1

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period, but not less than 1,000 kW for Large Power Service.

BILLING DEMAND

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

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

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 p.m. Monday through Saturday, except holidays
Mid-Peak:	~~3~~11:00 p.m. to ~~7~~10:00 ~~p~~a.m. and ~~11~~2:00 p.m. to ~~12~~7:00 ~~a~~p.m. Monday through Saturday, except holidays
Off-Peak:	1~~2~~0:00 a.m. to 2~~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
Mid-Peak:	9:00 a.m. to 1~~2~~0:00 ~~p~~a.m., 4~~2~~:00 p.m. to 5:00 p.m., and 8:00 p.m. to ~~10~~6:00 ~~p~~a.m. Monday through Saturday, except holidays
Off-Peak:	~~12:00 a.m. to 6:00 a.m., 12:00 p.m. to 4:00 p.m., and~~ 10:00 ~~p~~a.m. to ~~12~~2:00 ~~a~~p.m. Monday through Saturday and all hours on Sunday and holidays

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 (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 a Sunday, the Monday immediately following that Sunday will be considered a holiday.

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~~450.00	
Basic Charge, per kW of Basic Load Capacity	$~~2.21~~2.32	$~~2.21~~2.32
Demand Charge, per kW of Billing Demand	$~~10.04~~13.51	$~~8.64~~12.68
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$~~1.59~~2.14	n/a
Energy Charge, per kWh		
On-Peak	~~5.2314~~5.1897¢	~~4.7227~~4.2438¢
Mid-Peak	~~5.2314~~3.7373¢	~~4.4805~~3.7285¢
Off-Peak	~~4.6655~~3.4253¢	~~4.2863~~3.4513¢

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
$~~1.319~~1.248 per each kW over the Contract Demand.

Monthly Contract Demand Charge
$~~3.30~~3.12 per kW of Contract Demand.

Monthly Billing Demand Charge
$24.19 per kW of Billing Demand but not less than Minimum Monthly Billing Demand.

Energy Charge
4.2638¢ 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	~~10.006~~10.3710¢
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.~~05~~0

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	$~~12.30~~15.84
85	7,200	$~~14.31~~17.05
140	10,800	$~~16.43~~18.54
200	18,000	$~~20.44~~21.46

Non-Metered Service – Variable Energy

Energy Charge, per kWh	~~10.006~~10.3710¢

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	~~6.791~~3.7494¢

Metered Service (41CM)

Service Charge, per meter	$~~5.59~~1.83
Energy Charge, per kWh	~~6.791~~3.7494¢

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	~~7.846~~8.5293¢

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

Standby Reservation Charge, per kW of Available Standby Capacity	Summer	Non-summer
Secondary Service	$~~5.45~~5.72	$~~5.45~~5.72
Primary Service	$~~5.43~~5.77	$~~5.43~~5.77
Transmission Service	$~~3.11~~ 3.12	$~~3.11~~3.12
Standby Demand Charge, per kW of Standby Billing Demand		
Secondary Service	$~~9.35~~11.33	$~~7.61~~9.44
Primary Service	$~~9.37~~13.68	$~~9.08~~12.55
Transmission Service	$~~6.95~~8.29	$~~6.09~~8.69

Customers taking service under Schedule 19

Standby Reservation Charge, per kW of Available Standby Capacity	Summer	Non-summer
Primary Service	$~~6.70~~5.98	$~~6.70~~5.98
Transmission Service	$~~3.11~~ 3.12	$~~3.11~~3.12
Standby Demand Charge, per kW of Standby Billing Demand		
Primary Service	$~~11.69~~15.46	$~~10.31~~14.76
Transmission Service	$~~9.61~~15.19	$~~8.27~~13.37

Customers taking service under Schedule 9 or Schedule 19

Excess Demand Charge
$1.24~~8~~ 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
$~~3.59~~2.86 per contracted kW of capacity

Mileage Charge
$0.00~~35~~ 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	$~~679.20~~907.64	$~~227.96~~280.10
Schedule 5	$~~679.20~~907.64	$~~227.96~~280.10
Schedule 6	$~~594.72~~799.60	$~~244.20~~293.77

Small General Service	FCC	FCC-Dist
Schedule 7	$~~174.96~~286.98	$~~24.02~~72.64
Schedule 8	$~~221.61~~325.39	$~~63.33~~107.18

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	~~6.1651~~8.1838¢ per kWh	
~~2.0692~~2.5255¢ per kWh		
Schedule 5 – Summer On-Peak	~~16.2698~~23.0184¢ per kWh	
~~6.9989~~9.4895¢ per kWh		
Schedule 5 – Mid-Peak	~~8.1345~~11.5094¢ per kWh	
~~3.4990~~4.7449¢ per kWh		
Schedule 5 – Summer Off-Peak	~~4.0675~~5.7547¢ per kWh	
~~1.7497~~2.3724¢ per kWh		
Schedule 5 – Non-Summer On-Peak	~~7.7990~~9.9780¢ per kWh	
~~2.2059~~2.4161¢ per kWh		
Schedule 5 – Non-Summer Off-Peak	~~5.1993~~6.6519¢ per kWh	
~~1.4705~~1.6107¢ per kWh		
Schedule 6	~~6.4294~~9.0836¢ per kWh	
~~2.6400~~3.3372¢ per kWh		

Small General Service	FCE	FCE-Dist
Schedule 7	~~3.8463~~6.1233¢ per kWh	
~~0.5282~~1.5498¢ per kWh		
Schedule 8	~~5.2308~~7.3330¢ per kWh	
~~1.4949~~2.4155¢ 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 (0.0503) cents per kWh. The monthly Fixed Cost Adjustment for Small General Service (Schedules 7 and 8) is (0.0614) cents per kWh.

EXPIRATION

The Fixed Cost Adjustment included on this schedule will expire May 31, 2026.

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 in Category 4; 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.~~6037~~130181	1.89897	0.~~2952~~659716	95%	0.~~2805~~056730
2	Purchased power expense from cogeneration and small power producers.	1.~~3216~~339726	1.39941	0.~~0777~~800215	100%	0.~~0777~~800215
3	Demand response incentive payments.	0.~~0658~~506008	0.06695	0.~~0011~~000687	100%	0.~~0011~~000687
4	Payments for battery energy storage system leases	0.~~0000~~013279	0.11066	(0.~~110660~~2213)	100%	(0.~~110660~~2213)
Total		**2.~~9911~~989193**	**3.47599**	**0.~~4848~~058406**		**0.~~4700~~455420**

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.~~280~~5673	0.~~0778~~0022	0.~~0011~~0069	(0.~~1107~~0221)	(0.3351)	(0.0000)	0.2191~~0.1349~~
3	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3351)	(0.0000)	0.2191~~0.1349~~
5	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3351)	(0.0000)	0.2191~~0.1349~~
6	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3350)	(0.0000)	0.2192~~0.1350~~
7	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3353)	(0.0000)	0.2189~~0.1347~~
8	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3355)	(0.0000)	0.2187~~0.1345~~
9S	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3346)	(0.0000)	0.2196~~0.1354~~
9P	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3350)	(0.0000)	0.2192~~0.1350~~
9T	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3349)	(0.0000)	0.2193~~0.1351~~
15	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3357)	(0.0000)	0.2185~~0.1343~~
19S	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3350)	(0.0000)	0.2192~~0.1350~~
19P	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3348)	(0.0000)	0.2194~~0.1352~~
19T	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3348)	(0.0000)	0.2194~~0.1352~~
24	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3340)	(0.0000)	0.2202~~0.1360~~
40	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3349)	(0.0000)	0.2193~~0.1351~~
41	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3354)	(0.0000)	0.2188~~0.1346~~
42	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3352)	(0.0000)	0.2190~~0.1348~~
26	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221)~~0.1107~~	(0.3347)	*	0.2195~~0.1353~~

29	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221) ~~0.1107~~	(0.3348)	*	0.2194~~0.1352~~
30	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221) ~~0.1107~~	(0.3348)	*	0.2194~~0.1352~~
32	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221) ~~0.1107~~	(0.3348)	*	0.2194~~0.1352~~
34	0.5673~~0.2805~~	0.0022~~0.0778~~	0.0069~~0.0011~~	(0.0221) ~~0.1107~~	(0.3348)	*	0.2194~~0.1352~~

* 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, 2026.

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	~~1.0442~~1.8437 ¢	~~1.0012~~1.2551 ¢	~~1.0007~~1.2752 ¢
Summer Mid-Peak	~~1.0442~~1.8437 ¢	~~1.0012~~1.2551 ¢	~~1.0007~~1.2752 ¢
Summer Off-Peak	~~1.0041~~1.8437 ¢	~~0.9611~~1.2551 ¢	~~0.9603~~1.2752 ¢
Non-Summer On-Peak	~~1.8663~~1.8001 ¢	~~1.8270~~1.2254 ¢	~~1.8257~~1.2451 ¢
Non-Summer Mid-Peak	~~1.8523~~1.8001 ¢	~~1.8130~~1.2254 ¢	~~1.8117~~1.2451 ¢
Non-Summer Off-Peak	~~1.8411~~1.8001 ¢	~~1.8018~~1.2254 ¢	~~1.8005~~1.2451 ¢

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~~1.38%	~~0.61~~0.64%
Schedule 15	~~1.62~~1.74%	~~1.62~~1.74%
Schedule 19	~~1.34~~1.38%	~~0.61~~0.64%
Schedule 24	~~1.34~~1.38%	~~0.61~~0.64%
Schedule 29	~~1.34~~1.38%	~~0.61~~0.64%
Schedule 32	~~1.34~~1.38%	~~0.61~~0.64%
Schedule 41	~~1.13~~1.17%	~~1.13~~1.17%
Schedule 45	~~1.34~~1.38%	~~0.61~~0.64%
Schedule 46	~~1.34~~1.38%	~~0.61~~0.64%

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 0.64%

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. Schedules 9 and 19:

a. ~~i.~~ 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. 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. ~~iv.~~ 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 0.8 kW to define the demand for the Point of Delivery.

~~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.~~ 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)

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:

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

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~~Credits:

a. If a balance of ~~Excess Net Energy~~kWh C~~c~~redits 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)

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. 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 Excess Net Energy kWh ¢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 EnergykWh ¢Credits by the January 31 submission deadline Excess Net EnergykWh ¢Credits will carry forward to offset consumption at the Designated Meter until they become eligible the following year.

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

d. If multiple meters are eligible for aggregation, Excess Net EnergykWh ¢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)

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 EnergyFinancial ¢ 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 ¢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 by midnight, Mountain Standard Time, 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 ~~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.~~

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

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

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.

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.

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 Interconnection 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 systems will be removed from service under this schedule and placed on the appropriate standard service schedule.