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April 1, 2025

Commission Secretary
Idaho Public Utilities Commission
11331 W. Chinden Boulevard
Building 8, Suite 201-A
Boise, Idaho 83714

Re: Case No. IPC-E-25-15
Application for Its First Annual Update to the Export Credit Rate for Non-Legacy On-Site Generation Customers from June 1, 2025 through May 31, 2026, In Compliance with Order No. 36048

Commission Secretary:

Attached for electronic filing is Idaho Power Company's Application in the above-entitled matter.

In addition, please find attached the Direct Testimony of Jared Ellsworth and Mary Alice Taylor, filed in support of the Application. A Word version of the testimonies will also be sent in a separate email for the convenience of the Reporter.

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

Sincerely,

Megan Goicoechea Allen

Megan Goicoechea Allen

MGA:sg
Enclosures

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR ITS FIRST ANNUAL UPDATE TO THE EXPORT CREDIT RATE FOR NON-LEGACY ON-SITE GENERATION CUSTOMERS FROM JUNE 1, 2025 THROUGH MAY 31, 2026, IN COMPLIANCE WITH ORDER NO. 36048.	)	CASE NO. IPC-E-25-15 APPLICATION

Idaho Power Company ("Idaho Power" or "Company"), in accordance with *Idaho Code* §§ 61-502 and 61-503, Idaho Public Utilities Commission's ("Commission") Rule of Procedure[1] 52, and Order No. 36048 hereby respectfully applies to the Commission for an order authorizing Idaho Power, in compliance with Commission Order No. 36048, to implement the Export Credit Rate ("ECR") for non-legacy on-site generation customers from June 1, 2025 through May 31, 2026, and to approve the Company's corresponding proposed changes to Schedule 6, Residential Service On-Site Generation ("Schedule 6"),

[1] Hereinafter cited as RP.

Schedule 8, Small General Service On-Site Generation ("Schedule 8"), and Schedule 84, Large General, Large Power, and Irrigation On-Site Generation Service ("Schedule 84"). With this filing the Company proposes an ECR which will apply on a per kilowatt-hour ("kWh") of excess energy exported to Idaho Power's system by non-legacy Schedule 6, 8, and 84 customers of 14.0598¢ for summer on-peak exports, 1.7682¢ for summer-off peak exports, and 0.9540¢ for all exported energy in the non-summer season.

Additionally, concurrently with this filing, the Company is submitting its annual Distributed Energy Resources ("DER") report and, for the reasons more fully described herein, notifies the Commission that moving forward it intends to consolidate its annual DER reporting requirement with its annual ECR update, which the Commission directed in Order No. 36048 be filed on April 1st, and respectfully requests the Commission advise if it does not agree with the Company's proposed procedural approach in this regard.

In support of this Application, Idaho Power has filed the Direct Testimony of Mary Alice J. Taylor ("Taylor Testimony"), the Direct Testimony of Jared L. Ellsworth ("Ellsworth Testimony"). In further support of this Application, Idaho Power represents as follows:

I. BACKGROUND

On-Site Generation Offering Structure

1. Under Idaho Power's on-site generation service offerings, retail customers can choose to install their own electricity-generating equipment at their home or business to offset some or all of their electric needs. Currently, customers that generate their own electricity and who wish to interconnect Exporting Systems are billed under Schedule 6, Schedule 8, or Schedule 84.

2. The extensive history of the Company's net metering service offering demonstrates an on-going and incremental effort by the Company to establish a foundation for modernizing its on-site generation offering to support enhanced adoption of renewable energy resources and advances in energy generation technology, while simultaneously ensuring equity among all customers. Over the last several years, with guidance from the Commission, Idaho Power has modernized the on-site generation compensation structure through a series of customer-self generation dockets.

3. In 2019 and 2020, the Commission established criteria to define legacy treatment for existing systems, providing a clear distinction between existing and new customers based on the customers' reasonable expectations when they procured an on-site generation system.[2] Under this established criteria, systems qualifying for legacy treatment continue to take service under the rules for net energy metering until legacy status terminates, while non-legacy systems are subject to future changes to the program fundamentals, including to the compensation structure applied to excess energy.

4. The Commission also established a process to ensure any changes to the Company's on-site generation service offering are well-reasoned and data driven, requiring that the Company undertake a comprehensive study of the costs and benefits of on-site generation before any changes applicable to non-legacy customer compensation would be considered.[3]

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[2] *In the Matter of the Petition of Idaho Power Company to Study the Costs, Benefits, and Compensation of Net Excess Energy Supplied by Customer On-Site Generation*, Case No. IPC-E-18-15, Order No. 34509 at 10 (Dec. 20, 2019); *In the Matter of Idaho Power Company's Application for Authority to Modify Schedule 84's Metering Requirement and to Grandfather Existing Customers with Two Meters*, IPC-E-20-26, Order No. 34854 at 10 (Dec. 1, 2020).

[3] *In the Matter of the Application of Idaho Power Company for Authority to Establish New Schedules for Residential and Small General Service Customers with On-Site Generation*, Case No. IPC-E-17-13, Order No. 34046 at 22 (May 9, 2018).

5. More recently, Idaho Power initiated the multi-phase process for a comprehensive study of the costs and benefits of on-site generation. In 2021, the study design phase of the process concluded and was subsequently followed in 2022 by a study review phase.[4] Ultimately, the Commission found the Company October 2022 Value of Distributed Energy Resource ("VODER") study complied with its previous directives and "should serve as a basis for the Company's implementation recommendations in a subsequent case."[5]

6. Having completed the process established by the Commission to prepare for changes to its on-site generation offering, on May 1, 2023, Idaho Power filed Case No. IPC-E-23-14, to establish an updated offering, proposing modifications to the compensation structure for on-site generators with non-legacy systems that were intended to more accurately measure, record, and value excess energy. More specifically, the Company proposed to implement real-time net billing with an avoided cost-based financial credit rate for exported energy. Under net billing, customers first use all energy generated from their system to offset their own energy needs valued at the applicable full retail rate, which reduces the amount of energy customers consume from the grid. Non-legacy customers receive a financial bill credit for any exports to the grid based on an avoided cost-based ECR that varies based on the season and time of export. The

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[4] *In the Matter of the Application of Idaho Power Company's Application to Initiate a Multi-Phase Collaborative Process for the Study of Costs, Benefits, and Compensation of Net Excess Energy Associated with Customer On-Site Generation,* Case No. IPC-E-21-21; *In the Matter of Idaho Power Company's Application to Complete the Study Review Phase of the Comprehensive Study of Costs and Benefits of On-Site Customer Generation & For Authority to Implement Changes to Schedules 6, 8, and 84 for Non-Legacy Systems,* Case No. IPC-E-22-22 *.*
[5] *Id.,* Order No. 35631 at 31 (Dec. 19, 2022).

Company's proposal contemplated annual updates to the ECR, with the ECR updates to be based on a Commission-approved methodology.

7. In Order No. 36048, the Commission approved the Company's request to implement, effective January 1, 2024, real-time net billing to measure and charge customers for all kWh consumed from the grid at the retail rate, and measure and compensate customers for all kWh exported to the grid at a time-differentiated ECR .[6] The changes were approved to take effect with non-legacy customers' January 2024 billing period. The Commission further ordered that the Company update all components of the ECR except the season and hours of highest risk in an annual filing beginning in 2025, with a filing date of April 1 and an effective date of June 1.[7]

DER Reporting Requirements

8. Since 2014, the Company has filed an annual status report ("DER Status Report"[8]) with the Commission outlining net metering service provisions and pricing, system reliability considerations, and information on meter aggregation in accordance with Order Nos. 32846[9] and 32925[10] issued in Case No. IPC-E-12-27.

9. Subsequently, in Order No. 34955, issued in Case No. IPC-E-20-30, the Commission found it prudent to require that the Company's annual DER Status Report also include any known or foreseeable DER related distribution circuit issues or costs and potential smart inverter functionality updates that could address the issues or lower

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[6] *In the Matter of Idaho Power Company's Application for Authority to Implement Changes to the Compensation Structure Applicable to Customers On-Site Generation Under Schedules 6, 8, and 84 and to Establish an Export Credit Rate,* Case No. IPC-E-23-14, Order No. 36048 at 6 (Dec. 29, 2023).
[7] *Id.* at 18.
[8] Previously referred to as the "Net Metering Report."
[9] *In the Matter of Idaho Power Company's Application to Modify Net Metering Service,* Case No IPC-E-12-27, Order No. 32846 at 19 (Jul. 3, 2013).
[10] *Id.,* Order No. 32925 at 7 (Nov. 19, 2013).

costs.[11] In that same case, the Commission found that the annual DER Status Report should be the primary means by which the Company apprises the Commission of activity related to on-site generation, but that the Company should also include the information in its annual Demand-Side Management ("DSM") Report.

10. Recently, the Company requested to expand its reporting requirements for the DER Status Report to document and assess the quantity and cost of system upgrades caused by on-site generation customers to assess whether and when seeking to recover ongoing operations and maintenance ("O&M") costs associated with those upgrades may be prudent. The Company's proposal in this regard stemmed from the Commission directing Idaho Power to meet with Staff to discuss the feasibility of implementing a surcharge to recover the ongoing costs of system upgrades. In its compliance filing submitted on March 28, 2024, the Company set forth the results of its evaluation, pursuant to which the Company did not believe it was advisable to implement a surcharge at that time. Instead, the Company recommended collecting additional data and using its annual DER Status Report to track the quantity and cost of all upgrades for on-site generation customers, along with an approximation of the associated ongoing operations and maintenance costs.[12]

11. The Company files its annual DER Status Report as a compliance filing in closed Case No. IPC-E-12-27, which is a closed docket on the Commission's website. In recent years, the Company has submitted this filing on or before April 30 of each year.

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[11] *In the Matter of Idaho Power Company's Application for Authority to Establish Tariff Schedule 68,* Case No. IPC-E-20-30, Order No. 34955 at 11 (Mar. 9, 2021).
[12] Case No. IPC-E-23-14, Compliance Filing at 5 (Mar. 28, 2024).

The Company also includes a link to its most recent three annual DER Status Reports in its annual DSM Report, which is filed on or around March 15 of each year.

II. ECR METHODOLOGY

12. In Order No. 36048, the Commission approved a seasonal and time variant ECR with avoided cost-based value considerations.[13] The Commission-approved summer season is June 1 through September 30. During the summer season, the on-peak hours are 3 p.m. to 11 p.m. Monday through Saturday, excluding holidays, and the off-peak hours during the summer season are between 11 p.m. and 3 p.m. Monday through Saturday, and all hours on Sundays and holidays. The non-summer season is October 1 through May 31, and during the non-summer season all hours are considered off-peak.[14] As approved by the Commission in Order No. 36048, the following are the components of the ECR: Avoided Energy Costs, Avoided Line Losses, Integration Costs, Avoided Generation Capacity, and Avoided or Deferred Transmission and Distribution ("T&D") Capacity Costs. A description of the Commission approved methods for calculating each of these components is set forth below and further described in the Ellsworth Testimony.

13. Avoided Energy Costs: The avoided energy costs are determined using twelve months (January 1 through December 31) of Energy Imbalance Market ("EIM") Load Aggregation Point ("ELAP") market prices, weighted for historical customer-generator exports ("ELAP Weighted Average"). Avoided energy costs are distributed in alignment with the summer and non-summer seasons.

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[13] *Id.,* Order No. 36048 at 6.
[14] *Id.*

14. Avoided Line Losses: Avoided line losses are valued using the most recently completed line loss study. The Commission directed the Company to apply the annual energy line losses to the avoided energy value. Further, the peak loss coefficient is applied to the avoided capacity calculation.

15. Integration Costs: In Order No. 36048, the Commission approved the use of the then most recently completed Variable Energy Resource ("VER") Study, which was the 2020 VER Study. However, the Commission also directed Idaho Power to complete an updated integration study as soon as possible and to file for Commission approval and inclusion for future ECR updates. Integration costs are accounted for as an offset to the avoided energy component.

16. Avoided Generation Capacity: Three primary inputs are used to determine the avoided generation capacity value: (1) contribution to capacity (adjusted by the on-peak line loss coefficient), (2) the cost of an alternative resource, and (3) the energy exported during the on-peak hours. The avoided generation capacity value is applied to the on-peak hours of the summer season.

17. The Commission approved the Effective Load Carrying Capacity ("ELCC") method to calculate the capacity contribution for all on-site customer generation exports that occur over the course of a year. ELCC values are individually calculated by year, and these results are averaged to produce a five-year trailing average. The five-year average ELCC is then multiplied by the maximum export value from the most-recently available year's data; the resulting capacity contribution is then multiplied by the on-peak line loss coefficient. This value represents the total capacity contribution utilized in the calculation of the avoided generation capacity value.

18. The Company was ordered to use the most current levelized capacity cost for the least-cost dispatchable resource from its most recently filed Integrated Resource Plan ("IRP").

19. Avoided or Deferred T&D Capacity Costs: The Commission approved a method where T&D capacity is valued using a project-by-project deferral analysis, assessing every T&D capacity project over a 20-year time frame. To determine the 20-year time frame the Company will reference the most recently filed IRP. The T&D capacity value is applied to the on-peak hours of the summer season.

III. PROPOSED ECR UPDATE

20. Pursuant to Order No. 36048, the Company has reviewed and updated all value components of the ECR as highlighted below, except the season and on- and off-peak hours, which the Commission directed only be updated in a separate docket or in a General Rate Case ("GRC") filing as appropriate. As a result, the Company proposes to implement the following updated ECR values per kWh of exported energy for June 1, 2025, through May 31, 2026: 14.0598¢ for summer on-peak, 1.7682¢ for summer off-peak, and 0.9540¢ for all hours during the non-summer season.

21. The proposed Schedule 6, Schedule 8, and Schedule 84 tariff schedules incorporating the updated ECR values are included as Attachment 1 to this Application, in both clean and legislative format.

22. A summary of the proposed updated values for each of the ECR components is set forth in Figure 1 and more fully described, in turn, below along with a comparison with existing ECR values and explanation of the primary drivers of the differences.

Figure 1: Proposed ECR values

ECR SUMMARY		
	Season	**ECR**
Export Profile		
Volume (kWh per kW)	Annual	1,362
Capacity Contribution (%)	Annual	10.07%
Export Credit Rate by Component (cents/kWh)		
Energy	Summer	1.7682 ¢
Including integration and losses	Non-Summer	0.9540 ¢
	*Annual**	*1.2852 ¢*
Generation Capacity	On-Peak	11.9017 ¢
	Off-Peak	0.0000 ¢
	*Annual**	*1.1360 ¢*
Transmission & Distribution Capacity	On-Peak	0.3899 ¢
	Off-Peak	0.0000 ¢
	*Annual**	*0.0372 ¢*
Total	**Summer On-Peak**	**14.0598 ¢**
	Summer Off-Peak	**1.7682 ¢**
	Non-Summer	**0.9540 ¢**
	*Annual**	*2.4585 ¢*

**Annual values provided for informational purposes only and reflect seasonal weighting for 12 months ending December 2024.*

Note: Summer season is defined as June 1 - September 30. On-Peak hours is defined as 3pm - 11pm, Monday - Saturday, excluding holidays. All other Summer hours defined as Off-Peak. Non-Summer season defined as October 1 - May 31.

23. Avoided Energy Costs: To determine the avoided energy component, the Company first used the 2024 hourly ELAP market prices, weighted for historical customer-generator exports, and then included adjustments for avoided line losses and integration costs and distributed the values in alignment with the summer and non-summer season. The energy-related component (which includes avoided energy valued at the weighted average ELAP prices, line losses, and integration), per kWh of exported energy, are 1.7682¢ for the summer season and 0.9540¢ for the non-summer season.

24. The updated energy component decreased, primarily due to lower 2024 ELAP prices during export hours as compared to 2022 ELAP prices (those relied upon

for the ECR rates currently in effect). There are many factors that can lead to fluctuations in ELAP prices. Overall, the ELAP prices are a function of supply and demand and lower ELAP prices mean there was either high energy supply, or low demand, or both. Notably, in the spring months there are more negative prices due to more hydropower output during spring run-off conditions and more solar on the market combined with a lower demand for electricity. This creates oversupply conditions, which can lead to negative prices. Additional factors that affect prices include the cost of coal and gas and extreme weather events.

25. Avoided Line Losses: The Company relied on its most recent line loss study, which remains the 2023 line loss study (this study was also relied on to determine the current ECR values). Specifically, in determining the proposed line loss values applied to the energy component, the Company applied a loss coefficient of 1.044.

26. The proposed avoided per kWh line losses are 0.104¢ and 0.070¢ in the summer and non-summer seasons, respectively, which compares to 0.251¢ and 0.216¢ for the same period in the current ECR. Because the specific line loss coefficients have not changed – and the avoided line-losses are simply a function of the ELAP Weighted Average and the coefficients – the driver of the decrease in the line losses was the result of a lower ELAP Weighted Average in 2024.

27. Integration Costs: The Company relied on its 2024 VER Study, which was completed in December 2024.[15] The integration cost most appropriate to use in the ECR

[15] On December 31, 2024, the Company made a compliance filing submitting its 2024 VER Integration Study and accompanying Schedule 87 integration charges. Subsequently, the Commission opened a new docket to consider the matter and issued a Notice of Filing and Intervention Deadline, Order No. 36510, on March 14, 2024.

update is from the 0-100 megawatt solar portfolio, which translates to a reduction in the energy component of 0.697¢ per kWh. This compares to integration costs of 0.293¢ per kWh that are included in the current ECR.

28. Between the 2020 VER Study and the 2024 VER Study, the cost to integrate solar resources with Idaho Power's system has increased, primarily attributed to an increase in solar on Idaho Power's system. As the amount of solar on the system increases, the need and use of integrating resources increases proportionally. It is the increased need to provide more integration capability with the increased solar resources that has increased the cost of integration.

29. Avoided Generation Capacity: The Company updated its five-year trailing average ELCC to include 2023 and 2024. The ELCC values for years 2020 through 2024 were then averaged to produce an ELCC of 10.07 percent. To calculate the capacity contribution the Company multiplied the updated average ELCC by the maximum export value from 2024 (the latest year of available data) and the on-peak line loss coefficient. As stated in the avoided line loss section above, the line losses have not been updated since the current ECR was filed, therefore the Company is using the same on-peak line loss coefficient of 1.053. The cost of an alternate resource was also not updated as the Company has not filed a new IRP since it filed its current ECR values. The most recently filed IRP is the 2023 IRP and the least cost dispatchable resource is a simple cycle combustion turbine at a cost of $145.94/kilowatt-year. The energy generated during on-peak hours was updated using 2024 customer exports.

30. The generation capacity value of 11.9017¢ per kWh is only applied to the summer on-peak hours.

31. As noted above, only the ELCC, the maximum export value, and the energy generated during on-peak hours changed. The maximum export value and the energy generated during on-peak hours both increased because of more customer generators on the Company's system in 2024 versus 2022, the year used in the current ECR. The updated average ELCC value is 10.07 percent as compared to 10.12 percent from the current ECR.

32. Avoided or Deferred T&D Capacity Costs: Using the Commission-approved methodology to determine the value of on-site generation in deferring the need for the Company to build additional T&D resources, the Company identified local peak hours for each T&D resource. Local peak hours are specific to the amount of types of loads connected to individual resources. The analysis incorporated the 20 years of project data from the 2023 IRP, 2007 to 2026, to identify the historical trends and projected T&D projects and the capacity need for each project.

33. The updated avoided or deferred T&D capacity costs, per kWh of exported energy for summer on-peak is 0.3899¢ compared to 0.1755¢ in the current ECR.

34. The primary driver of the increase in the avoided or deferred T&D capacity costs was related to an increase in solar penetration from 0.61 percent to 2.12 percent and an increase in customer generator exports. Using 20 years of project data from the 2023 IRP, the number of deferrable T&D projects increased from nine to 42, which increased the dollar value of deferral savings.

IV. BILL IMPACTS

35. As of December 31, 2024, the Company had a total 13,825 active and pending non-legacy Exporting Systems in its Idaho jurisdiction. The DER Status Report

included as Attachment 2 to this Application contains count of systems by customer class and total installed nameplate capacity by customer class.

36. Included with the Taylor Testimony are Exhibit Nos. 6, 7, 8, and 9, which summarize the bill impact for residential, small general service, large general service, and irrigation customers, respectively.

37. Generally, the bill impact analysis relies on 12 months of hourly metering data ending December 31, 2024, for non-legacy customers with Exporting Systems who were online for all of calendar year 2024. To isolate the impact from a change in the ECR, the Company estimated annual bills for delivered services using base rates currently in effect. The Company then estimated the annual financial credit associated with exported energy under both the ECR currently in effect and then with the proposed ECR. Finally, the analysis quantifies an average monthly bill under the current ECR and an average monthly bill under the proposed ECR. The Taylor Testimony provides an overview of the results of the bill impact analysis for each of the customer classes.

V. CONSOLIDATION OF COMPLIANCE REPORTING REQUIREMENTS

38. This filing represents the Company's inaugural update of the ECR for non-legacy on-site generation customers in accordance with Commission Order No. 36048, which will hereafter continue annually with a filing date of April 1 and an effective date of June 1. As noted, the Company also files annually in April its DER Status Report, which is the primary means by which the Company apprises the Commission of activity related to on-site generation, as a compliance filing in a closed docket (Case No. IPC-E-12-27).[16]

[16] The Company also includes a link in its annual DSM Report, which is filed on or around March 15 of each year, to its most recent three annual DER Status Reports.

The DER Status Report has historically been filed by the Company on or before April 30th of each year, though this timing was based on course of practice rather than mandated by Commission order, and the Company believes that moving forward the most expeditious approach would be to align the filing of the DER Status Report with its annual ECR update based on the April 1st date directed by the Commission for the latter.

39. Moreover, the Company is concerned that submitting the DER Status Report in a closed docket, as has previously been done, does not provide broad visibility for interested stakeholders, as more fully describe in the Taylor Testimony, and suggests another procedure be utilized moving forward. More specifically, the Company believes that submitting its annual DER Status Report concurrently with its annual filing to update the ECR will increase transparency for the Commission, Staff, customers, and other stakeholders. Moreover, because the DER Status Report contains information that is relevant to the annual ECR update (namely, the number of customers who will be impacted by an update to the ECR), filing these together will make it easier to access and compare that information. Finally, filing the DER Status Report with the ECR update will make it more accessible to those who are less familiar with the historical case files on the Commission's website or may not realize the information is available in unrelated or closed dockets.

40. As such, the Company notifies the Commission that it is submitting its annual DER Status Report concurrently with its annual ECR update and intends to follow this approach moving forward on the April 1st filing deadline, and respectfully requests the Commission advise if it prefers a different procedural approach.

VI. MODIFIED PROCEDURE

41. Idaho Power believes that a technical hearing is not necessary to consider the issues presented herein and respectfully requests that this Application be processed under Modified Procedure, i.e., by written submissions rather than by hearing. RP 201, *et. seq.* The Company has, however, contemporaneously filed the Ellsworth Testimony and Taylor Testimony and stands ready to present its testimony and support the Application if the Commission determines a technical hearing is required.

VII. COMMUNICATIONS AND SERVICE OF PLEADINGS

42. This Application will be brought to the attention of impacted customers by means of a post card sent to all non-legacy Schedule 6, 8, or 84 customers. A copy of the customer communication is included as Attachment 3 to this Application. The customer notice will be mailed to customers following the filing of this Application, with all post cards being mailed no later than the week of April 14th. Additionally, the Company will send new on-site generation applicants (those who submit an application between April 1 and May 31, 2025) an email upon receipt of application containing information about this filing and the proposed ECR.

43. Communications and service of pleadings with reference to this Application should be sent to the following:

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VIII. REQUEST FOR RELIEF

44. As described in greater detail above, Idaho Power respectfully requests that the Commission issue an order: (1) authorizing that this matter be processed by Modified Procedure, and (2) authorizing Idaho Power to implement the updated ECR for non-legacy on-site generation customers from June 1, 2025 through May 31, 2026 of 14.0598¢ per kWh for summer on-peak, 1.7682¢ per kWh for summer-off peak, and 0.9540¢ per kWh for all hours during the non-summer season.

DATED at Boise, Idaho this 1st day of April 2025.

Megan Goicoechea Allen

MEGAN GOICOECHEA ALLEN
Attorney for Idaho Power Company

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-15

IDAHO POWER COMPANY

ATTACHMENT 1

PROPOSED TARIFF SCHEDULES

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	9.9398¢	8.7476¢
801-2000 kWh	11.9518¢	9.6439¢
All Additional kWh Over 2000	14.1985¢	10.6805¢

TIME-OF-USE RATES (OPTIONAL)

	Summer	Non-summer
Service Charge, per month	$15.00	$15.00
Energy Charge, per kWh		
On-Peak	24.7398¢	12.8267¢
Mid-Peak	12.3701¢	n/a
Off-Peak	6.1850¢	8.5511¢

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	14.0598¢	0.9540¢
Off-Peak	1.7682¢	0.9540¢

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)

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	7.1782¢	7.1782¢
All Additional kWh	8.2032¢	7.1800¢

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	14.0598¢	0.9540¢
Off-Peak	1.7682¢	0.9540¢

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

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 Saturday, the preceding Friday will be designated a holiday. If New Year’s Day, Independence Day, or Christmas Day falls on Sunday, the following Monday will be designated a holiday.

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:	14.0598¢	0.9540¢
Off-Peak:	1.7682¢	0.9540¢

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	9.9398¢	8.7476¢
801-2000 kWh	11.9518¢	9.6439¢
All Additional kWh Over 2000	14.1985¢	10.6805¢

TIME-OF-USE RATES (OPTIONAL)

	Summer	Non-summer
Service Charge, per month	$15.00	$15.00
Energy Charge, per kWh		
On-Peak	24.7398¢	12.8267¢
Mid-Peak	12.3701¢	n/a
Off-Peak	6.1850¢	8.5511¢

EXPORT CREDIT RATE

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

	Summer	Non-summer
Export Credit Rate, per kWh		
On-Peak	~~16.9966~~14.0598¢	~~4.8365~~0.9540¢
Off-Peak	~~5.6533~~1.7682¢	~~4.8365~~0.9540¢

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)

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	7.1782¢	7.1782¢
All Additional kWh	8.2032¢	7.1800¢

EXPORT CREDIT RATE

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

	Summer	Non-summer
Export Credit Rate, per kWh		
On-Peak	~~16.9966~~14.0598¢	~~4.8365~~0.9540¢
Off-Peak	~~5.6533~~1.7682¢	~~4.8365~~0.9540¢

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

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 Saturday, the preceding Friday will be designated a holiday. If New Year’s Day, Independence Day, or Christmas Day falls on Sunday, the following Monday will be designated a holiday.

EXPORT CREDIT RATE

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

	Summer	Non-summer
Export Credit Rate, per kWh		
On-Peak:	~~16.9966~~14.0598¢	~~4.8365~~0.9540¢
Off-Peak:	~~5.6533~~1.7682¢	~~4.8365~~0.9540¢

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-15

IDAHO POWER COMPANY

ATTACHMENT 2

2024 ANNUAL DER STATUS REPORT

2024 Distributed Energy Resources Annual Report

April 2025

INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") presents its annual Distributed Energy Resources ("DER") Status Report to the Idaho Public Utilities Commission ("Commission") as required by Order Nos. 32846[1] and 32925[2], Order No. 34955[3], and Order No. 36159[4]. The report begins with a brief regulatory update on recent orders impacting the compensation structure applicable to customers with DERs, followed by an update on current participation levels and growth rates since the Company's last DER Status Report filed with the Commission in April 2024. Next, the report discusses system reliability considerations, and provides an update on meter aggregation activity, credit transfers, and accumulated excess net energy credits. Finally, it concludes with a discussion on system upgrades caused by on-site generation customers and provides an update of the ongoing operations and maintenance ("O&M") costs associated with those upgrades.

[1] *In the Matter of the Application of Idaho Power Company for Authority to Modify its Net Metering Service and to Increase the Generation Capacity Limit*, Case No. IPC-E-12-27, Order No. 32846 at 19 (July 3, 2013).

[2] *Id.,* Order No. 32925 at 7 (Nov. 19, 2013).

[3] *In the Matter of Idaho Power Company's Application to Establish Tariff Schedule 68 – Interconnections to Customer Distributed Energy Resources*, Case No. IPC-E-20-30, Order No. 34955 at 11 (Mar. 9, 2021).

[4] *In the Matter of Idaho Power Company's Application for Authority to Implement Changes to the Compensation Structure Applicable to Customer On-Site Generation Under Schedules 6, 8, and 84 and to Establish an Export Credit Rate*, Case No. IPC-E-23-14, Order No. 36159 at 2 (Apr. 30, 2024).

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I. CUSTOMER GENERATION IN IDAHO

Regulatory Background

Over the last several years, Idaho Power, as directed by the Commission, has engaged in a series of cases related to studying the costs and benefits of on-site generation on the Company's system. In 2019 and 2020, the Commission established "legacy" and "non-legacy" status for residential and small general service customers and commercial, industrial, and irrigation customers, respectively.[5] Through their orders, the Commission found that legacy customers will continue to participate in net energy metering (one-for-one kWh credit for excess net energy) under certain criteria through 2045[6] and non-legacy customers would be subject to future changes to the program fundamentals, including to the compensation structure applied to excess energy. The Commission also ordered the Company to undertake a comprehensive study process before any changes applicable to non-legacy customer compensation would be considered.[7]

Idaho Power undertook this study process throughout 2021 and 2022.[8] Ultimately, the Commission found the Company had complied with its previous orders by acknowledging the Company's October 2022 Value of Distributed Energy Resource study.[9] In that order, the

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[5] *In the Matter of the Petition of Idaho Power Company to Study the Costs, Benefits, and Compensation of Net Excess Energy Supplied by Customer On-Site Generation*, Case No. IPC-E-18-15, Order No. 34509 at 10 (Dec. 20, 2019*); In the Matter of Idaho Power Company's Application for Authority to Modify Schedule 84's Metering Requirement and to Grandfather Existing Customers with Two Meters*, IPC-E-20-26, Order No. 34854 at 10 (Dec. 1, 2020).

[6] *In the Matter of the Petition of Idaho Power Company to Study the Costs, Benefits, and Compensation of Net Excess Energy Supplied by Customer On-Site Generation, Case No. IPC-E-18-15*, Order No. 34546 at 9 (Feb. 5, 2020*); In the Matter of Idaho Power Company's Application for Authority to Modify Schedule 84's Metering Requirement and to Grandfather Existing Customers with Two Meters*, Case No. IPC-E-20-26, Order No. 34854 at 10 (Dec. 1, 2020).

[7] *In the Matter of the Application of Idaho Power Company for Authority to Establish New Schedules for Residential and Small General Service Customers with On-Site Generation*, Case No. IPC-E-17-13, Order No. 34046 at 22 (May 9, 2018).

[8] *In the Matter of the Application of Idaho Power Company's Application to Initiate a Multi-Phase Collaborative Process for the Study of Costs, Benefits, and Compensation of Net Excess Energy Associated with Customer On-Site Generation,* Case No. IPC-E-21-21; *In the Matter of Idaho Power Company's Application to Complete the Study Review Phase of the Comprehensive Study of Costs and Benefits of On-Site Customer Generation & For Authority to Implement Changes to Schedules 6, 8, and 84 for Non-Legacy Systems,* Case No. IPC-E-22-22 .

[9] *In the Matter of Idaho Power Company's Application to Complete the Study Review Phase of the Comprehensive Study of Costs and Benefits of On-Site Customer Generation & for Authority to Implement Changes to Schedules 6, 8, and 84*, Case No. IPC-E-22-22, Order No. 35631 at 31 (Dec. 19, 2022).

Commission also directed the Company to file a new case requesting to implement changes to its on-site generation offering.[10]

On May 1, 2023, Idaho Power filed Case No. IPC-E-23-14, where it sought to implement changes to the on-site generation offering, which included a modified compensation structure (net billing) that would be applicable to non-legacy on-site generation customers. Under net billing, customers continue to offset their usage with all on-site production consumed on-site and are compensated per kWh exported with an avoided cost-based export credit rate ("ECR") that varies based on the season and time of export. In Order No. 36048, the Commission approved the Company's filing, with modifications, and authorized new program parameters to take effect with non-legacy customers' January 2024 billing period.[11] In that same order, the Commission directed Idaho Power to meet with Staff to discuss the feasibility of implementing a surcharge to recover the ongoing costs of system upgrades and to submit its findings to the Commission by means of a compliance filing.[12] On March 28, 2024, Idaho Power submitted a compliance filing setting forth the results of its evaluation, pursuant to which the Company did not believe it was advisable to implement a surcharge at that time. Instead, the Company recommended collecting additional data and expanding its reporting requirements to help assess whether and when seeking to recover ongoing O&M caused by system upgrades may be warranted. More specifically, the Company proposed to document and assess the quantity and cost of all upgrades for on-site generation customers, as part of its annual DER Status Report. The Commission accepted the Company's filing as complying with the requirements set forth in Order No. 36048.[13]

As a result of the recent changes to the Company's on-site generation offering, this year's DER Status Report contains additional elements related to: (1) meter aggregation (as 2024 was the first-year non-legacy customers were eligible to transfer financial credits), and (2) updated reporting requirements related to the quantity and cost of all upgrades for on-site generation customers, along with an approximation of their associated ongoing operations and maintenance costs.

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[10] *Id.*

[11] *In the Matter of Idaho Power Company's Application for Authority to Implement Changes to the Compensation Structure Applicable to Customer On-Site Generation Under Schedules 6, 8, and 84 and to Establish an Export Credit Rate*, Case No. IPC-E-23-14 Order No. 36048 at 6 and 18 (Dec. 29, 2023).

[12] *Id.,* at 7.

[13] *In the Matter of Idaho Power Company's Application for Authority to Implement Changes to the Compensation Structure Applicable to Customer On-Site Generation Under Schedules 6, 8, and 84 and to Establish an Export Credit Rate*, Case No. IPC-E-23-14 Order No. 36159 at 1 (Apr. 30, 2024).

Current Participation (Exporting Systems)

As of December 31, 2024, Idaho Power had 19,323 total active and pending On-Site Generation Exporting Systems ("Exporting Systems")[14] with a cumulative nameplate capacity of 188.68 megawatts ("MW") in its Idaho service area. All new systems interconnected in 2024 were solar photovoltaic ("PV").

Legacy Systems

Table 1 provides the total number of active Exporting Systems with legacy status in the Company's Idaho jurisdiction by resource type and customer class.

Table 1 Legacy- Idaho Active Exporting Systems as of December 31, 2024

Customer Segment	Solar PV	Wind	Hydro/Other	Total
Schedule 6				
Residential	5,055	21	7	**5,083**
Schedule 8				
Small General	43	-	2	**45**
Schedule 84				
Commercial & Industrial	162	-	1	**163**
Irrigation	207	-	-	**207**
Total	**5,467**	**21**	**10**	**5,498**

Table 2 provides the total nameplate capacity of active Exporting Systems with legacy status in the Company's Idaho jurisdiction by resource type and customer class.

Table 2 Legacy- Idaho Active Exporting Systems Nameplate Capacity (MW) as of December 31, 2024

Customer Segment	Solar PV	Wind	Hydro/Other	Total
Schedule 6				
Residential	39.66	0.10	0.07	**39.82**
Schedule 8				
Small General	0.30	-	0.05	**0.34**

[14] Exporting Systems take service under the terms of Schedule 6, Residential Service On-Site Generation ("Schedule 6"), Schedule 8, Small General On-Site Generation ("Schedule 8"), and Schedule 84, Large General, Large Power, and Irrigation On-Site Generation ("Schedule 84") and are designed to transfer excess energy to the Company.

Customer Segment	Solar PV	Wind	Hydro/Other	Total
Schedule 84				
Commercial & Industrial	5.60	-	0.03	**5.62**
Irrigation	19.50	-	-	**19.50**
Total	**65.05**	**0.10**	**0.14**	**65.30**

Note: Totals may not sum due to rounding.

Non-Legacy Systems

Table 3 provides the total number of active and pending Exporting Systems with non-legacy status in the Company's Idaho jurisdiction by resource type and customer class.

Table 3 Non-Legacy- Idaho Active and Pending Exporting Systems as of December 31, 2024

Customer Segment	Solar PV	Wind	Hydro/Other	Total
Schedule 6				
Residential	13,599	1	1	**13,601**
Schedule 8				
Small General	35	-	-	**35**
Schedule 84				
Commercial & Industrial	102	-	-	**102**
Irrigation	87	-	-	**87**
Total	**13,823**	**1**	**1**	**13,825**

Table 4 provides the total nameplate capacity of active and pending Exporting Systems with non-legacy status in the Company's Idaho jurisdiction by resource type and customer class.

Table 4 Non-Legacy- Idaho Active and Pending Exporting Systems Nameplate Capacity (MW) as of December 31, 2024

Customer Segment	Solar PV	Wind	Hydro/Other	Total
Schedule 6				
Residential	105.31	0.002	0.004	**105.31**
Schedule 8				
Small General	0.33	-	-	**0.33**
Schedule 84				
Commercial & Industrial	4.49	-	-	**4.49**
Irrigation	13.26	-	-	**13.26**
Total	**123.38**	**0.002**	**0.004**	**123.38**

Note: Totals may not sum due to rounding.

Total Systems

Figures 1 and 2 detail the cumulative customer Exporting System counts and nameplate capacity, respectively, by customer class in the Company's Idaho jurisdiction regardless of legacy status, from 2015 through the end of calendar year 2024 (including pending applications).

Figure 1 Cumulative Exporting System Counts by Customer Type, 2015 – 2024

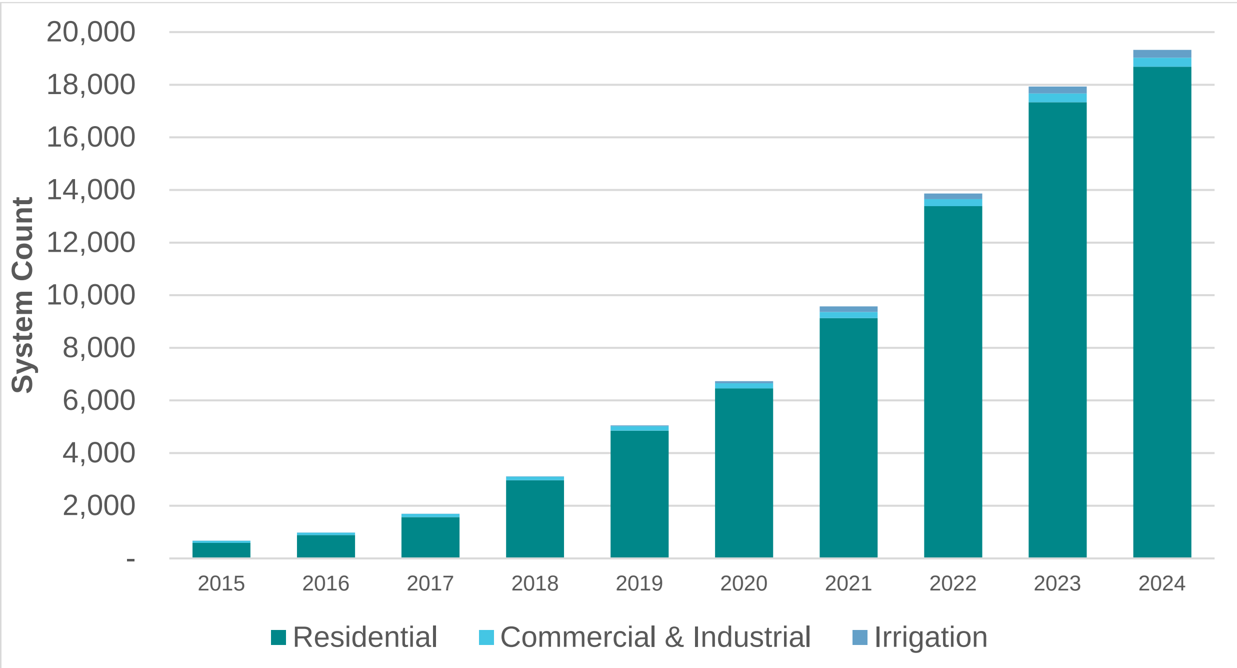
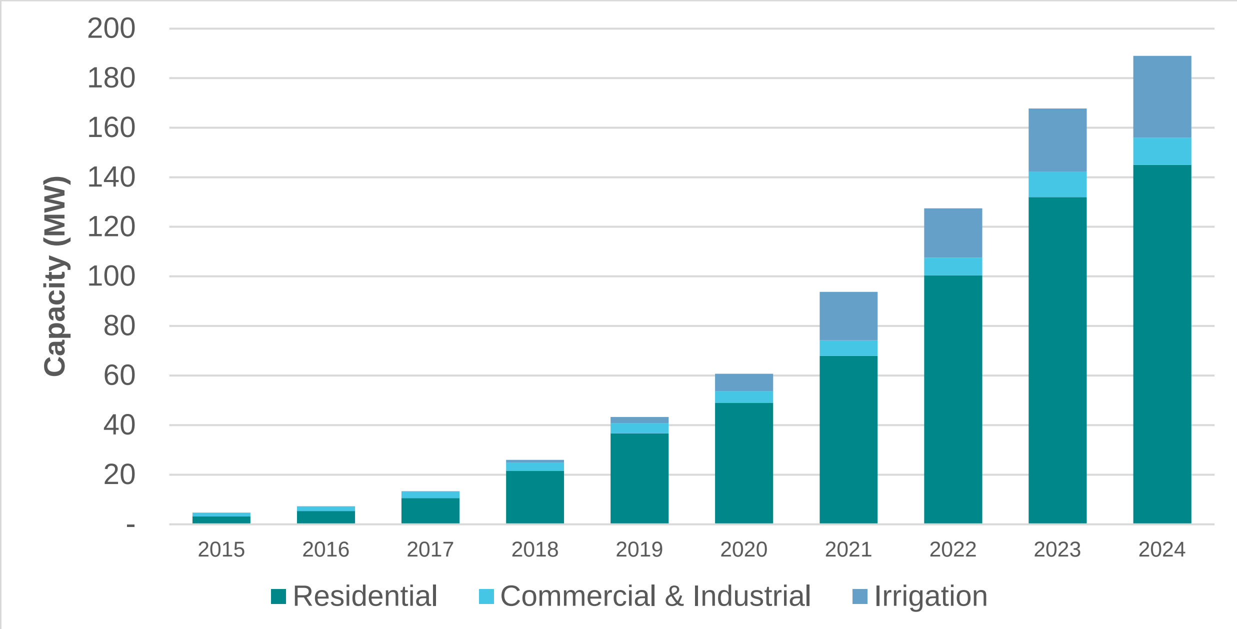


Figure 2 Cumulative Exporting System Capacity by Customer Type, 2015 – 2024



II. SYSTEM RELIABILITY CONSIDERATIONS

There are 698 electrical distribution circuits in the Company's service area. Considering all customer-owned on-site generation installations across all jurisdictions, all rate classes, and all resources, as of December 31, 2024, there were 19,185 active, customer-owned on-site generation systems. These systems total approximately 182.8 MW on 538 distribution circuits.

Installation Concentration versus Capacity

The circuits containing the greatest number of customer-owned on-site generation systems are in Ada and Elmore County, with the densest concentrations in southeast and south Boise and north Mountain Home. The largest *number* of customer-owned on-site generation systems connected on a single distribution circuit is 255, with a total rated capacity of 1,707 kilowatts ("kW"). This circuit primarily serves residential customers in Boise.

The distribution circuit in Idaho with the greatest customer-owned on-site generation *capacity* primarily serves irrigation and rural customers in the Magic Valley and has a total of 30 solar PV systems with a total rated capacity of 2,823 kW (average system size 94 kW). This circuit has a summer peak load of approximately 7,200 kW. The distribution circuit in Idaho with the second-highest customer-owned on-site generation capacity also serves irrigation and rural customers in the Magic Valley and has a total of 68 solar PV systems with a total rated capacity of 1,970 kW (average system size is 29 kW). This circuit has a summer peak load of approximately 19,400 kW.

There are 20 circuits with total customer-owned on-site generation capacity greater than 1,000 kW. Those 20 circuits hosted a total of 29.4 MW of generation. Twelve of these circuits are in the Magic Valley (one serves industrial and residential customers, and all others serve irrigation and rural customer loads). Of the remaining, five are in Ada County, two in Canyon County, and one in Elmore County, all of which primarily serve residential customers.

The customer-owned on-site generation connected capacity on the Company's distribution system as a percent of the total system peak load in 2024 was 4.7 percent. The Company has managed the impacts on these circuits, when necessary, by requiring customer-funded distribution upgrades pursuant to Rule H and, in very rare instances, requiring customer-funded substation upgrades.

Smart Inverter Installation

All new systems applying to interconnect are required to install smart inverters[15] to support the distribution system's ongoing stability and reliability. As of January 1, 2024, Idaho Power requires inverters to comply with the IEEE 1547-2018 certification[16] which meet all smart inverter requirements as defined by the Institute of Electrical and Electronics Engineers ("IEEE"). The IEEE Standard 1547 establishes the technical standard for interconnection and interoperability of distributed energy resources and Idaho Power is an active participant in the review process of this standard which is expected to be updated and revised in 2026.

[15] Order No. 34955 issued in Case No. IPC-E-20-30 approved Schedule 68, effective March 23, 2021. Schedule 68 requires smart inverter functionality to be enabled for all new applications for customer generation.

[16] Underwriters Laboratories Standard for Safety 1741 – Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources, Supplement B.

III. 2024 EXCESS NET CREDIT TRANSFERS

Meter Aggregation Eligibility- Legacy

Schedules 6, 8, and 84 provide legacy customers with Exporting Systems the ability to submit requests to transfer excess net energy credits annually. Applications must be received by January 31 and the Company applies the following criteria for legacy systems to all requests received from legacy customers:

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 (the meter psychically connected to the Exporting System) is located. For the purposes of the 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 6, or Schedule 8 credits may only be transferred to meters taking service under Schedule 1, Schedule 6, Schedule 7, or Schedule 8. For Schedule 84 customers taking service under Schedule 9, Schedule 19, or Schedule 24, credits may only be transferred to meters taking service under Schedule 9, Schedule 19, or Schedule 24.[17]

Meter Aggregation Eligibility- Non-Legacy

Schedules 6, 8, and 84 also provide non-legacy customers with Exporting Systems the ability to submit requests to transfer excess net financial credits annually. Applications must be received by January 31 and the Company applies the following criteria for non-legacy systems from Schedules 6, 8, and 84 to all requests received from non-legacy customers:

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

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

[17] Schedule 84 is an "adder" in Idaho Power's billing system. Schedules 9, 19, and 24 customers take service under those primary schedules and those with on-site generation have 84 added to their primary service schedule.

Customer Communication

In November 2024, prior to the credit transfer window opening on December 1, Schedule 6, 8, and 84 customers with excess net energy or net financial credits were sent a postcard reminding them of the meter aggregation process, a list of important things to note about the transfer process, the deadline for them to apply, and a phone number to contact. The postcard also contained a web address which contains the requirements and an online form. This postcard was sent to a total of 5,861 legacy and non-legacy customers.

In January 2025, the Company sent an email or provided a bill message on Schedule 6, 8, and 84 customers' bills to inform them of when the transfer window closed and to provide a link to a webpage where customers could find more information. Lastly, in January the Company also sent an email reminder to 121 customers who submitted transfer requests in 2023 but had not yet submitted a request for 2024. This email reminded these customers of the meter aggregation process and deadline and provided a link for them to submit a transfer request.

Credit Transfer Requests for Calendar Year 2024

As of the application deadline, January 31, 2025, the Company received 344 applications for transfer. Of the total transfer requests, 231 applications were from legacy customers and 113 were from non-legacy customers. The applications were reviewed against the applicable aggregation criteria and the Company determined that 303 of the requests were eligible for transfer based on the aggregation criteria. Of the eligible transfer requests, 201 were from legacy customers and 102 were from non-legacy customers.

The total amount of kWh credits transferred was 14,693,176 kilowatt-hours ("kWh") generated from Exporting Systems taking service under Irrigation (89 percent), Large General (seven percent), Residential (four percent), and Small General (one percent) rate schedules. The 14,693,176 kWh were transferred to customers taking service under Irrigation (77 percent), Large General (eight percent), Residential (four percent), and Small General (less than one percent) rate schedules.

The total amount of financial credits transferred was $16,989 from Exporting Systems taking service under Large General (81 percent) and Residential (19 percent) rate schedules. The $16,989 was transferred to customers taking service under Irrigation (three percent), Large General (81 percent), Residential (nine percent), and Small General (eight percent) rate schedules. [18]

[18] Totals may not sum due to rounding.

The Company received 41 applications that were ineligible for transfer based on the following:

Legacy

- Four applications requested a transfer to a meter that was not on contiguous property.
- One application was not on the same feeder.
- Two applications requested to transfer to rate schedules that do not qualify.
- 12 failed due to two or more of the criteria not being met.
- 11 applications did not qualify for other reasons.[19]

Non-Legacy

- Four applications had no excess credits.
- Two applications were from meters that were not an on-site generation service meter (a “designated meter”).
- Five applications did not qualify for other reasons.

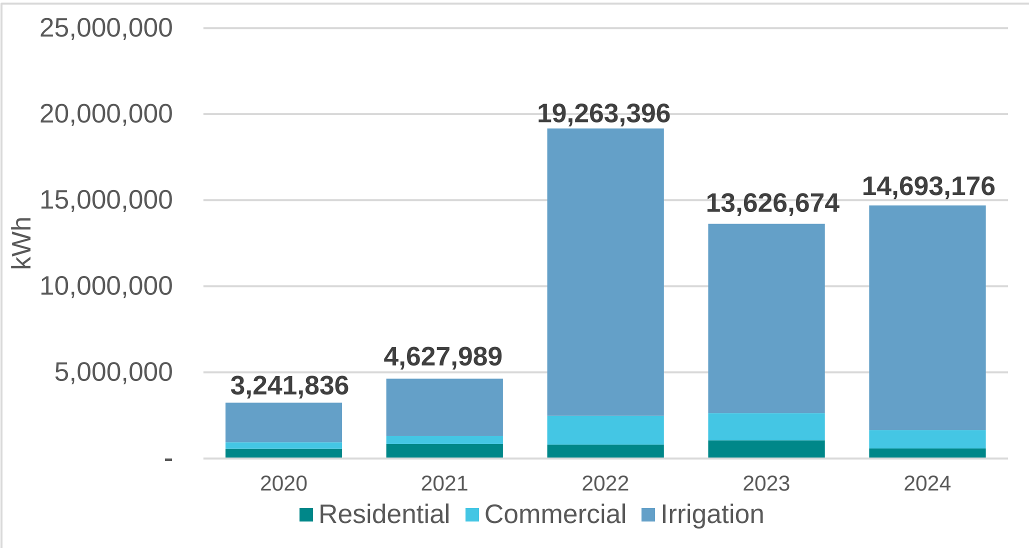
The Company sent letters to all customers whose requests were ineligible for transfer explaining the reason for the denial.

[19] Other reasons include a variety of scenarios, examples include: applications that were canceled by the customer, duplicate requests, or requests to transfer to and from the same meter.

Credit Transfer Magnitude- Legacy

Figure 3 shows the total excess kWh credit transfers for the last five years (2020 through 2024) by customer class.

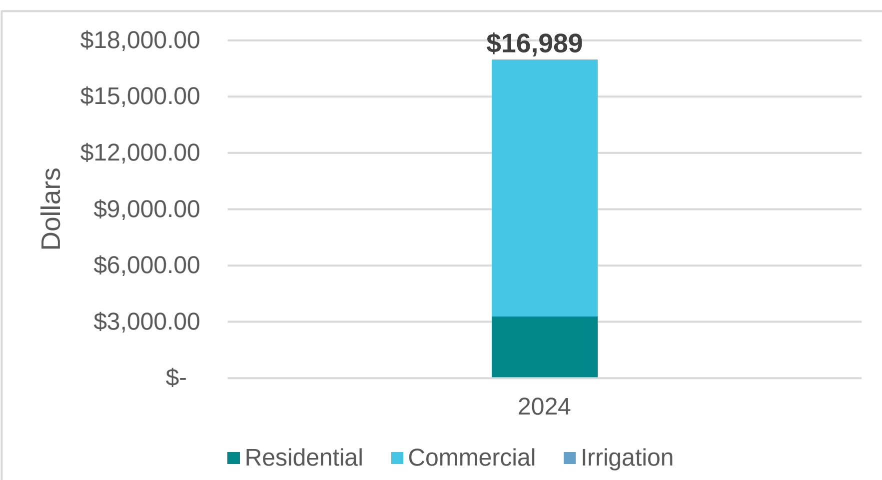
Figure 3 Excess Net Energy kWh Credit Transfers by Customer Class, 2020 – 2024



Credit Transfer Magnitude- Non-Legacy

This was the first year non-legacy customers could request to transfer excess net financial credits. Figure 4 shows the total excess net financial credit transfers for 2024, by class.

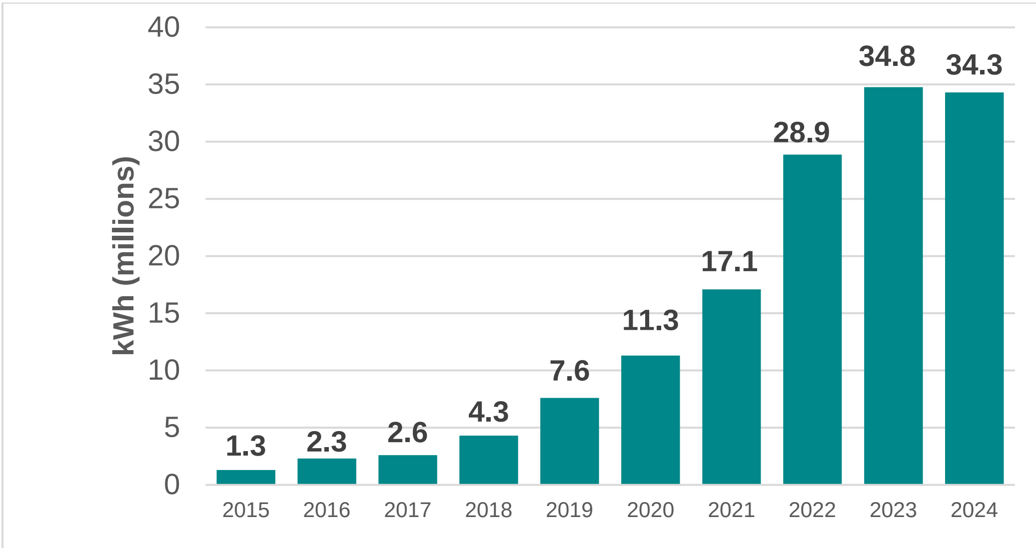
Figure 4 Excess Net Financial Credit Transfers by Customer Class, 2024



Accumulated Excess Net Energy Credit Balances

Figure 5 shows the accumulated excess net energy kWh credit balance for 2014 through 2024.[20]

Figure 5 Accumulated Unused Excess Net Energy Credit Balance, 2015 – 2024[21]



Accumulated Excess Net Financial Credit Balances

In 2024, non-legacy customers began earning financial credits. At the end of 2024, the balance of accumulated excess net financial credits was approximately $0.45 million.

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[20] In Order No. 32846, the Commission stated, "we find it fair, just, and reasonable for the kWh credit to indefinitely carry forward to offset future bills as long as the customer remains on the net metering service at the same generation site. Allowing the credits to carry forward indefinitely ensures that customers will be able to use their credits when they need them and thus receive the benefits of their systems."

[21] The accumulated excess net energy credit balance represents all unused credits as of December 31. It does not reflect the potential reduction due to future offset at the premise generated or transferred to another meter for offset.

IV. SYSTEM UPGRADES AND O&M COSTS

System Upgrades and O&M Costs

In 2024, 27 on-site generation projects out of approximately 2,150 systems were notified that transformer or feeder upgrades would be necessary as a result of the Feasibility Review. Of those 27 projects, 13 included an energy storage device. Ultimately, seven of the 27 projects chose to proceed with funding the upgrades. Four of the seven projects included a DC coupled energy storage device. Because DC coupled energy storage devices share an inverter with the on-site generation system, an upgrade would have been required even if the energy storage device had not been included with the project. Table 5 provides information for each of the seven projects, including the size of the project, the upgrade that was required, the total cost of that upgrade, and the estimated annual O&M.

Table 5 System Upgrades and O&M Costs

Project	Customer Class	Size (kW AC)	Scope of Required Upgrade	Total Cost of Upgrade	Estimated Annual O&M
1	Residential	22.8	10 kVa (single phase) to 25 kVa (single phase)	$4,195	$0.42
2	Residential	24.46*	25 kVa (single phase) to 50 kVa (single phase)	$3,259	$0.33
3	Residential	23*	15 kVa (single phase) to 50 kVa (single phase)	$5,659	$0.57
4	Residential	23*	25 kVa (single phase) to 50 kVa (single phase)	$5,769	$0.58
5	Irrigation	100	75 kVa (three phase) to 150 kVa (three phase)	$10,792	$1.08
6	Residential	15*	25 kVa (single phase) to 50 kVa (single phase)	$1,131	$0.11
7	Irrigation	260	Feeder- two controllers updated from CL6s to CL7s	$10,400	$1.04

*Project has DC coupled battery

V. CONCLUSION

The continued expansion of on-site generation on Idaho Power's system highlights the evolution of the Company's electrical grid, along with the importance of evaluating service provisions and pricing to ensure safe, reliable, and fair-priced electricity. Idaho Power will continue to monitor customer generation and keep the Commission informed of its impact on system reliability.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-15

IDAHO POWER COMPANY

ATTACHMENT 3

BILL INSERT AND CUSTOMER NOTICE

Annual Update to the Export Credit Rate

The export credit rate (ECR) is the credit value for energy exported from an on-site generation system to the electrical grid. It is updated annually, per an Idaho Public Utilities Commission (IPUC) approved methodology. Idaho Power filed the annual ECR update with the IPUC on April 1. If the ECR is approved as filed, these updated export rates will take effect June 1, 2025:

	Summer	Non-summer
On-Peak	14.0598¢	n/a
Off-Peak	1.7682¢	0.9540¢

If approved, this ECR decrease will result in the monthly bill for an average residential on-site generation customer increasing about 34%, from $62 to $84 per month. Actual bill impacts will depend on how much energy a system exports. For more details about the ECR, visit idahopower.com/customergeneration.

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

Summer Season

On-Peak: 3 p.m. to 11 p.m. (Mountain Time), Monday through Saturday, except holidays

Off-Peak: 11 p.m. to 3 p.m. (Mountain Time), Monday through Saturday and all hours on Sunday and holidays

Non-summer Season

Off-Peak: All hours Monday through Sunday

Why is the ECR decreasing?

The primary driver for the ECR decrease is lower 2024 market prices compared to the 2022 market prices used to determine the current ECR. Integration costs have also increased slightly.

How is the ECR determined?

The ECR is reflective of the market value of the energy at the time it is being exported to Idaho Power, combined with additional compensation for the benefit on-site generators bring to the grid. The annual update recognizes changing conditions on Idaho Power's electrical grid and broader power markets where electric utilities buy and sell energy as needed. Generally, the IPUC-approved methodology relies on avoided cost principles as a foundation for the ECR — meaning the costs Idaho Power avoids having to incur due to energy received from customers' on-site generation systems.

The following elements comprise the ECR:

- **Avoided Energy:** Energy from customer generators reduces the amount of energy Idaho Power needs to produce or purchase.
- **Avoided Generation:** Energy from customer generators helps meet peak demand (when all customers' energy needs are highest), which reduces the cost for additional grid generation resources.

Continued on back

Continued from front

- **Avoided Transmission and Distribution:** Energy from customer generators can reduce customer energy needs during times of peak demand, which can defer and delay the need for additional transmission and distribution resources.
- **Avoided Line Losses:** Idaho Power loses a small percentage of the energy it generates as electricity travels along powerlines. Energy exports from on-site generators help avoid some of these losses. Avoided line losses are included in the avoided energy and avoided generation components of the ECR.
- **Integration Costs:** Idaho Power incurs costs to ensure energy and power quality remain stable despite the intermittent nature of renewable energy production. These costs are included as a reduction to the avoided energy component of the ECR.

Where can I read the filing?

Idaho Power's filing is subject to public review and requires approval by the IPUC. Copies of the application are available to the public on idahopower.com, or at the IPUC website, puc.idaho.gov, at the IPUC offices (11331 W. Chinden Blvd. Building 8, Suite 201-A, Boise, ID 83714), and Idaho Power offices. Customers may also subscribe to the IPUC's RSS feed to receive periodic updates via email about the case. Written comments (Case No. IPC-E-25-15) regarding Idaho Power's application may be filed with the IPUC (puc.idaho.gov/form/casecomment).

More information on the ECR can be viewed in Schedules 6, 8, 84, and in the Frequently Asked Questions at idahopower.com/customergeneration.

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