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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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 METHODOLOGY	CASE NO. IPC-E-23-14

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

CONNIE G. ASCHENBRENNER

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

A. My name is Connie G. Aschenbrenner. My business address is 1221 West Idaho Street, Boise, Idaho, 83702. I am employed by Idaho Power as the Rate Design Senior Manager in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 2006, I received a Bachelor of Business Administration degree in Finance from Boise State University in Boise, Idaho. In December of 2011, I earned a Master of Business Administration degree from Boise State University. In addition, I have attended the electric utility ratemaking course The Basics: Practical Regulatory Training for the Electric Industry, a course offered through New Mexico State University's Center for Public Utilities.

Q. Please describe your work experience with Idaho Power.

A. In 2012, I was hired as a Regulatory Analyst in the Company's Regulatory Affairs Department. My primary responsibilities included support of the Company's Commercial and Industrial customer class's rate design and general support of tariff rules and regulations. In 2015, I assumed responsibilities associated with Residential and

Small General Service rate design, as well as regulatory support associated with demand-side management ("DSM") activities. In 2016, I was promoted to a Senior Regulatory Analyst, and my responsibilities expanded to include the development of complex cost-related studies. In 2017, I was promoted to Rate Design Manager for Idaho Power, and in 2019 I was promoted to my current role as Rate Design Senior Manager. I am currently responsible for the management of the rate design strategies of the Company, as well as oversight of all tariff administration. In my current role, I am one of the Company representatives at its Energy Efficiency Advisory Group ("EEAG") meetings.

Q. How is your testimony organized?

A. I begin my testimony by providing background for this case including an introduction to the issues and proposed solutions and an overview of the relevant regulatory history. Next, I will provide additional details and explanation regarding the role of on-site generation on Idaho Power's system and the need to modernize on-site generation policies and practices to reflect the nuances of the current environment. I will then discuss the Company's recommendations for reforming the on-site generation offering within the scope of this docket as well as further considerations that will be more properly considered in a General Rate Case ("GRC"). In doing so I will also describe areas of overlap and interdependencies between this case and a future GRC proceeding. Finally, I will address the applicability of the Company's proposed changes to legacy and non-legacy customers.

I. **INTRODUCTION**

Q. What is the purpose of this case?

A. The Company is requesting approval to implement changes to the structure and design of its on-site generation offering as directed by the Commission in Case No. IPC-E-22-22, Order No. 35631. More specifically, the Company proposes to implement changes related to how it measures and compensates for excess net energy; Idaho Power is also proposing several other modifications related to the on-site generation offering, including a modified project eligibility cap for those commercial, industrial, and irrigation ("CI&I") customers taking service under Schedule 84. The Company is proposing these changes become effective January 1, 2024, with non-legacy customers transitioning on their January 2024 billing cycle.

Q. Please describe the Company's current on-site generation offerings.

A. Under Idaho Power's on-site generation service offerings, retail customers can choose to install their own electricity-generating equipment (most commonly solar panels) at their home or business to offset some of their electric needs. These customers remain connected to Idaho Power's grid and are able to consume energy as needed from Idaho Power's system, and the vast majority also export energy to the grid. Customers that generate their own electricity and who wish to interconnect exporting systems are billed under different rate schedules as follows: Schedule 6, Residential Service On-Site Generation ("Schedule 6"), Schedule 8, Small General Service On-Site Generation ("Schedule 8"), and Schedule 84, Customer Energy Production Net Metering Service ("Schedule 84"), which is the schedule the Company's CI&I customers take net metering service under.

Alternatively, customers that do not want their generation systems to export power to the electrical grid may interconnect their non-exporting system so that they consume all the energy generated on-site. These customers continue to take service under the retail rate schedule they qualify for based on the applicability of the Company's retail tariff schedules. Both exporting and non-exporting systems are subject to Schedule 68, Interconnections to Customer Distributed Energy Resources ("Schedule 68"), which applies to all systems connected in parallel and outlines the requirements and process for interconnection. In this case, the Company is not proposing any changes to how non-exporting systems take service or interconnect under the Company’s tariff.

Q. What is the current compensation structure applicable to customers with exporting systems?

A. The compensation structure currently applicable to exporting systems is net energy metering (“NEM”), or often commonly referred to as just “net metering.” Under the NEM structure, customer-generators receive a credit in kilowatt-hours (“kWh”) for any excess energy and that credit can be applied to offset energy within the current billing cycle and carry-forward credits can be used to offset energy consumption in future periods.

Q. When was net metering initially adopted by the Commission?

A. The Commission approved net metering for on-site generation in 2002, when the Company had very few customers seeking to interconnect their generating systems in parallel with Idaho Power’s grid.[1]

Q. Has the interest in on-site customer generation changed since Schedule 84 was established in 2002?

A. Yes. The number of customers taking service under an on-site generation service offering has grown

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[1] Prior to January 2014, net metering customers were compensated through financial credits. This changed in 2014 with the implementation of kWh crediting for excess net energy authorized by the Commission in Order Nos. 32846 and 32872.

exponentially. As seen in Figure 1, the number of on-site generation customers has grown from approximately 360 in 2013 to more than 15,900 as of March 31, 2023 (including pending applications). The Company has nearly 940 pending applications (customers who have submitted applications but who have not yet completed the interconnection process). Concerns initially raised by Commission Staff ("Staff") and acknowledged by the Commission in Case No. IPC-E-01-39 (i.e., the likelihood that some of the costs of serving net metering customers will be subsidized by other customers[2]) have been greatly exacerbated by the rapid increase in on-site generation customers.

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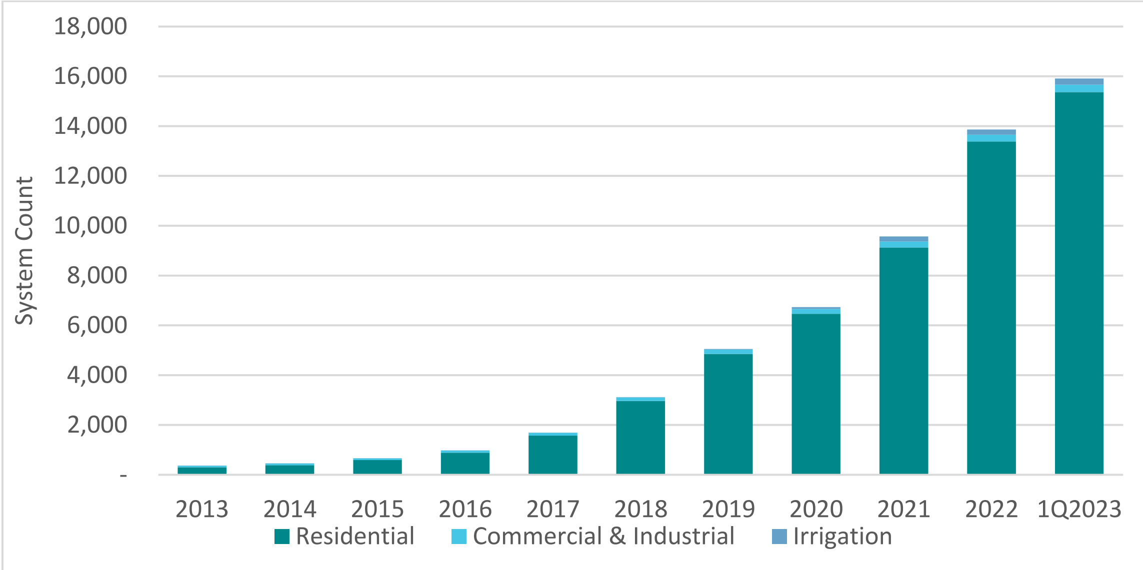
[2] *In the Matter of the Application of Idaho Power Company for Approval of a New Schedule 84 – Net Metering*, Case No. IPC-E-01-39, Order No. 28951 at 5-6, 12 (Feb. 13, 2002) and Staff Comments at 3-5 (Dec. 21, 2001).

Figure 1

Cumulative Exporting System Counts, 2013 – 1Q2023



Q. What changes to its on-site generation offerings is the Company requesting in this case?

A. Idaho Power requests the Commission issue an order effective January 1, 2024, directing it to implement: (1) real-time net billing with an avoided cost-based financial credit rate for exported energy, (2) a methodology for determining annual updates to the ECR, (3) a modified project eligibility cap for CI&I customers, (4) related changes to the accounting for and transferability of excess net energy financial credits, and (5) updated tariff schedules necessary to administer the modified on-site generation offering.

Q. Why should the Commission implement changes to the on-site generation offering?

A. The existing monthly NEM compensation structure overvalues exports from on-site generation, which if left unmodified, will lead to a continuation of growing cost shift among customers. The Commission has confirmed this finding in past regulatory cases[3] but has also recognized the importance of ensuring any changes to the Company's on-site generation service offering are well-reasoned and data driven, previously ordering the Company to "comprehensively study the costs and benefits of on-site generation on Idaho Power's system."[4]

This directive was fulfilled in Case Nos. IPC-E-21-21 and IPC-E-22-22 with the Commission's acknowledgement of the October 2022 Value of Distributed Energy Resources Study ("VODER Study")[5]:

> [W]e believe that any changes to Company's NEM program should be well-supported by a comprehensive study using robust, relevant, and publicly available data and methods, which we believe the Company's October VODER Study provides.[6]

Q. Why is now the right time to make changes to the on-site generation offering?

A. The instant case is the latest in a series of

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[3] See, e.g., Case Nos. IPC-E-12-27, IPC-E-17-13, and IPC-E-18-15.

[4] *In the Matter of Idaho Power Company's Application 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 30-31 (May 9, 2018).

[5] See Attachment 1.

[6] *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 28 (Dec. 19, 2022).

cases spanning several years related to on-site generation, each representing another incremental step towards fulfilling the Commission's ultimate objective:

> The Company's future net-metering programs will be based on a credible and fair study, developed with public input, and will reasonably balance the interests of customers with net metering, and customers without net metering.[7]

In each of the prior cases, the Commission has issued further guidance as to the scope of what changes can be implemented outside of a GRC and who the potential changes could apply to. The preceding case, Case No. IPC-E-22-22, was a culmination of the Company's efforts to implement the Commission's directives, and the resulting October 2022 VODER Study, having been found in that case to comply with the Commission's previous directives, provides a solid foundation for the Company to make implementation recommendations in this case. Further, while the Company has been diligent in its communications with customers about the potential for changes to the compensation structure (measurement interval and export credit rate), Company representatives continue to hear from customers who have made investments or who are considering investments that they were unaware that the structure could change.

[7] *In the Matter of the Application 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 15 (Dec. 20, 2019).

The Company believes the Commission should move forward expeditiously to implement a structure that will accurately measure, record, and value excess energy from on-site generation customers. A modification to the on-site generation offering will ensure every customer who chooses to invest in on-site generation has more clarity around the future structure and design of this offering.

II. OVERVIEW OF RELEVANT REGULATORY HISTORY

Q. What prompted Idaho Power to implement net metering under Schedule 84?

A. Prior to the implementation of Schedule 84 in Case No. IPC-E-01-39, the Company had offered interconnection for on-site generation under the terms of Schedule 86, Cogeneration and Small Power Production Non-Firm Energy. The service offering was in place for a single customer and consisted of applying a formula rate for exported energy. At the time, because the Company was not able to implement this as an automated option under its billing system, a manual process was necessary to bill customers taking service under that option. In an effort to streamline and simplify the process, in November 2001 the Company filed an application in Case No. IPC-E-01-39 requesting to implement Schedule 84.

Q. What were some of the drivers for requesting implementation of retail rate NEM?

A. At the time of the Company’s filing, the Company’s meters had limited capabilities and could only track inflows and outflows of energy on a single channel. This meant the measurement of energy at the end of the month was a “net” read of total inflows (i.e., energy delivered to the customer) and total outflows (i.e., excess energy received from the customer). The application of NEM provided a simple way for a customer to interconnect an exporting on-site generation system and for the Company to administer billing, and was a practice commonly applied throughout the industry.

Even at that time, there were concerns with the limitations of the practice. For example, as noted by Staff, crediting “customer generators at full retail rates will pay customers more than the actual value of the generation” and created a “likelihood that some of the costs of serving net metering customers will be subsidized by other customers.”[8] These concerns were mollified by restricting levels of participation, which at that time seemed inconsequential given that, though net metering rules had been in place since 1983, the Company only had three net metering customers nearly 20 years later.

Q. Did the Company later take steps to address some of the cost-shifting or subsidy concerns promulgated

[8] Case No. IPC-E-01-39, Order No. 28951 at 5-6.

by NEM?

A. Yes. The Company filed Case No. IPC-E-12-27 where it sought, in part, to modify the pricing structure for residential and small general service customer's taking service under Schedule 84. At that time, the Company had roughly 350 Schedule 84 customers and the aggregate nameplate capacity of installed systems was nearing the Commission's previously established total Schedule 84 capacity limit of 2.9 megawatts ("MW"). In its final order in the matter, the Commission declined to modify pricing, noting "changes such as those proposed in this case – including increasing the monthly customer charge, imposing a new BLC charge, and reducing the energy charge" for only a subset of customers "should not be examined in isolation but should be fully vetted in a general rate proceeding."[9]

Q. What prompted Idaho Power to file the next case related to on-site generation?

A. In 2017, approximately four years after the Commission's prior ruling, the number of customers who had installed or applied to install on-site generation had grown to nearly 1,500 customers, with expected nameplate capacity of over 11 MW. The Company had not filed a GRC and had no near-term expectation of the need to file. The

[9] *In the Matter of Idaho Power Company's Application 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 12-13 (Jul. 3, 2013).

Company had concerns that customers who were installing on-site generation were doing so under the presumption of the continuation of NEM.

As a result, the Company submitted an application in Case No. IPC-E-17-13, where it sought to establish Schedules 6 and 8 and asked the Commission to direct it to file a generic docket which would seek to establish a compensation structure for customer-owned on-site generation that reflects both the benefits and the costs of those installations on Idaho Power's system.

Q. What was the outcome of Case No. IPC-E-17-13?

A. In Order No. 34046, the Commission removed residential and small general service ("R&SGS") customers with exporting systems from Schedule 84 and created two new tariff schedules: Schedule 6 and Schedule 8.[10] Schedule 84 continued to define the terms for CI&I customers with exporting systems. In order to more accurately assign the appropriate share of fixed costs and unquantified benefits of on-site customer generation, the Commission also directed the Company to "initiate a docket to comprehensively study the costs and benefits of on-site generation on Idaho Power's system, as well as proper rates and rate design, transitional rates, and related issues of

[10] Case No. IPC-E-17-13, Order No. 34046 at 30-31.

compensation for net excess energy provided as a resource to the Company."[11]

Q. Did the Company initiate the docket as ordered?

A. Yes. Pursuant to the Commission's directive, Idaho Power initiated Case No. IPC-E-18-15 to study the costs, benefits, and compensation of net excess energy supplied by on-site customer generation on October 19, 2018.[12] In that case, the Company, Staff, and various stakeholders undertook a thorough, data-driven evaluation of the Company's on-site generation offering through a number of meetings and settlement negotiations. Through this collaborative process, the parties were able to reach a compromise on a significant number of critical elements to the Company's on-site generation offering ("Settlement Agreement").

Q. Did the Commission approve the Settlement Agreement?

A. No. In Order No. 34509, the Commission rejected the proposed Settlement Agreement. While the Commission found that the parties had acted in good faith and pursuant to Commission Rules of Procedure, the Commission found the process did not satisfy the

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[11] *Id.*
[12] Case No. IPC-E-18-15, Petition to Initiate a Docket (Oct. 19, 2018).

requirements established in Case No. IPC-E-17-13.[13]

Q. What guidance did the Commission provide regarding criteria for a study?

A. The Commission stated that no changes to the Company's net metering offering would be considered until Idaho Power prepared and filed a "credible and fair study" of the costs and benefits of distributed on-site customer generation meeting the following criteria: (1) the study must use the most current data possible and must be readily available to the public, and in the Commission's decision-making record; (2) the Company must design the study in coordination with the parties and the public, and the Commission will determine the final scope of the study; and (3) Idaho Power must write the study, so it is understandable to an average customer, but its analysis must be able to withstand expert scrutiny.[14] The Commission also outlined the "study design" phase and a "study review" phase that would be undertaken prior to a Commission determination being issued on the benefits and costs of on-site generation on Idaho Power's system.

Q. Did the Company comply with the Commission's directive to initiate the multi-phase process for a comprehensive study?

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[13] *Id.*, Order No. 34509 at 6.
[14] *Id.* at 9.

A. Yes. On June 28, 2021, Idaho Power applied for the Commission to initiate a multi-phase process for a comprehensive study of the costs and benefits of on-site customer generation, as directed in Order No. 34046.[15] After considering more than 250 written public comments, oral testimony at a public hearing, and written comments filed by eleven parties to the proceeding, the Commission issued Final Order No. 35284 approving a Study Framework detailed therein. The Commission found that the Study Framework "meets our directive for a credible and fair study" and reminded Idaho Power to "use the most current data possible" that is readily available to the public and submitted to the Commission's decision-making record.[16] This order concluded the "study design" phase of the process.

Q. Has the "study review" phase been completed?

A. Yes. Following the Commission's Order in Case No. IPC-E-21-21, the Company completed the VODER Study in accordance with the foundational principles outlined by the Commission and initiated Case No. IPC-E-22-22 to allow for public, stakeholder, and Commission review of the Study. The Company filed an initial study in June 2022;

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[15] *In the Matter 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, Application (Jun. 25, 2021).
[16] *Id.*, Order No. 35284 at 9 (Dec. 30, 2021). *See also,* Case No. IPC-E-18-15, Order No. 34509 at 9-10.

however, in response to stakeholder and public comments, the Company later submitted a revised VODER Study in October 2022 for the Commission's consideration.

In Order No. 35631, the Commission found "the October VODER Study complies with our previous directives and should serve as a basis for the Company's implementation recommendations in a subsequent case."[17]

III. ON-SITE GENERATION ON IDAHO POWER'S SYSTEM

Q. Please explain the Company's view on customer generation.

A. The Company understands that some of its customers desire to supply some of their energy needs through on-site generation while relying on Idaho Power's system to serve the remaining energy needs not covered by their on-site generation and as a means to export energy for compensation. Idaho Power has a long history of supporting customer choice and interest in renewable energy and has demonstrated its ongoing commitment over the years through various proposals intended to make it easier for customers to participate in on-site generation, including:

- In 2016, Idaho Power proposed a change to Schedule 84 metering requirements[18] in order to reduce barriers to participation for primary service-level customers who

[17] Case No. IPC-E-22-22, Order No 35631 at 28.
[18] Idaho tariff advice No. 16-05.

desired to install on-site generation by modifying the requirements related to the second meter's location and voltage. The Company initiated the change based on feedback from customers that wanted to install net metering systems but found compliance with the existing metering requirement to be cost prohibitive. The proposed tariff changes made it easier and less costly for CI&I customers to install systems by allowing the Company the discretion in determining the location of the second meter.

- In Case No. IPC-E-20-26,[19] the Company asked the Commission to further modify the metering requirement under Schedule 84 from a two-meter to single-meter requirement. The request to remove the two-meter requirement for new Schedule 84 customers was based on concerns voiced by customers, installers, and stakeholders, of the incremental costs and complexities that exist as a result of the two-meter requirement.[20]

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[19] *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, Application (Jun. 19, 2020).
[20] *Id.* at 5.

- In Case No. IPC-E-20-30,[21] Idaho Power sought, in part, to implement interconnection rules for customers with Distributed Energy Resources ("DERs") that do not wish to export excess energy to the Company. Notably with respect to CI&I customers with non-exporting systems, the Company requested that there be no limit on total nameplate capacity, which enabled CI&I customers greater flexibility to install systems where they can consume all generation on-site.

The Company earnestly supports customer choice in clean energy sources. Its attempts to modernize the compensation structure for on-site generation are driven by its desire to ensure that rates paid for excess generation are fair and equitable to both generating and non-generating customers.

Q. Does NEM accurately measure customer usage and exports?

A. No. Due to the simplified construct, the Company calculates a single measurement at the end of a billing period and if the customer has net consumption (meaning they consumed more energy than they exported), they are billed and compensated at the rates included in

[21] *In the Matter of Idaho Power Company's Application for Authority to Establish Tariff Schedule 68, Interconnections to Customer Distributed Energy Resources*, Case No. IPC-E-20-30, Application (Jul. 20, 2020).

the applicable rate schedule. If the customer has net exports over the billing period (meaning they exported more energy than they consumed), they receive a kWh credit for all excess energy that can be carried forward to other billing periods.

Q. Why does the Company believe it is important to accurately measure a customer's exports and consumption?

A. The existing NEM structure results in the under-measurement of both the amount of kWh consumed by the customer as well as the kWh exported by the customer. That is, throughout each day a customer may be exporting kWh at certain times (when their on-site generation system is producing more than their energy needs) and consuming from the grid at other times (in the evening or at times when the customer's energy needs are more than their system is producing); however, at the end of the billing period both the number of consumed kWh and the number of exported kWh are understated. This undermeasurement leads to the under-recovery of costs associated with utility-provided service and the overcompensation of exported energy. As a result, and potentially most impactful, it sends an incorrect price signal to potential on-site generation customers.

IV. COMPANY'S IMPLEMENTATION PROPOSAL & INTERDEPENDENCIES WITH UPCOMING GENERAL RATE CASE

Q. What were the primary objectives the Company relied upon in developing its implementation proposal in this case?

A. The Company identified four primary objectives as it developed its proposal: (1) recommend a compensation structure that will accurately measure a customer-generator's use of the system – both in recording exported energy and usage; (2) apply methods that will result in a fair and accurate valuation of customers' exported energy; (3) implement a repeatable method for updating the Export Credit Rate ("ECR") that will ensure timely recognition of changing conditions on Idaho Power's system and the broader power markets which may warrant changes to the ECR; (4) balance accuracy with customer understandability.

Application of these principles also provides the Company the foundation for proposing changes to the project eligibility cap and excess energy credits transfer process that will provide additional flexibility and opportunities for customers to install on-site generation.

Q. Please summarize the scope of this filing.

A. Generally, the focus of this filing is related to modifications to the measurement interval applied for measuring energy, valuation of the ECR, and administrative items related to the implementation of an avoided cost-based ECR. Coincident with changes to the measurement interval and ECR valuation being approved, the

Company is also seeking a change in how the project eligibility cap is defined for Schedule 84 customers.

Q. Are there any items identified by the Commission in Order No. 35631 the Company views as "out of scope" for this filing?

A. Yes. The Commission has previously determined that changes to rates for consumption is appropriately considered in a GRC, when changes for all customer classes are evaluated holistically.[22] Because the class cost-of-service ("CCOS") is the first step in the rate setting process, the Company will address that item in its upcoming GRC.[23]

Q. Why did Idaho Power choose to file this "stand-alone" case to address the compensation structure for on-site generators instead of addressing all on-site generation service matters in the GRC?

A. A GRC covers a broad range of issues related to the cost and pricing for services Idaho Power provides to its customers. Because of the relatively narrow scope of issues in this case, the Company felt a separate case would be the best way to ensure a transparent and thorough vetting of the important items related to Idaho Power's on-

[22] See, e.g., Case No. IPC-E-12-27, Order No. 32846 at 12-13; Case No. IPC-E-18-15, Order No. 34509 at 15.

[23] On April 1, 2023, Idaho Power filed Notice of Intent ("NOI") to file a General Rate Case. The NOI anticipates a GRC will be filed on or after June 1, 2023.

site generation offering.

Q. Are there any interdependencies between this case and the Company's upcoming GRC?

A. Yes. Please see Table 1 for a summary of the items the Company was previously directed to evaluate in a future filing.[24] The table differentiates between topics the Company is seeking approval in this case (ECR column) versus those specific to the Company's upcoming GRC (GRC column).

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[24] Case No. IPC-E-22-22, Order No. 35631 at 28-31.

Table 1

Export Credit Rate ("ECR") Implementation & General Rate Case ("GRC") Interdependencies

	ECR	GRC	Comments/Rationale
Measurement Interval (ECR)	✓	–	Measurement interval to (1) inform the valuation of ECR and (2) measurement used for proposed net billing compensation structure.
Measurement Interval (Cost-of-Service)	–	✓	Measurement interval to inform cost allocation. Interdependency exists with aligning measurement interval for ECR and compensation structure with CCOS.
Export Credit Rate	✓	–	ECR methods presented for approval using real-time measurement interval.
Transition	✓	✓	No proposed transition from retail rate to avoided cost ECR. Transitional considerations are appropriately addressed in the context of the ratemaking process which will be considered in the GRC.
ECR Updates	✓	–	Timing and methodology of annual updates for ECR.
Class Cost-of-Service	–	✓	Basis for Schedule 6 and 8 class-specific revenue requirement addressed holistically in GRC.
Export Credit Recovery	✓	–	Method for recovery of ECR expenditures.
Project Eligibility Cap	✓	–	Change to project cap coincident with approval of change in compensation structure to real-time net billing.
Implementation/ Other	✓	–	Other considerations include accumulated kWh credits and financial credit transfer rules.

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As reflected in Table 1, the Company proposes to address the majority of the items in this case, with only CCOS being fully addressed in the GRC. There are a few items to note when looking at the table.

First, as previously mentioned, the Company intends to address CCOS in its upcoming GRC; however, the Company was ordered to address "measurement interval" in this case, which is relevant in both evaluating the measurement of excess net energy and in allocating cost as part of the CCOS study in a GRC. The former will be addressed through the Company's proposal in this proceeding and the latter will be addressed in the upcoming GRC, expected to be filed on or after June 1, 2023.

Second, the Commission has ordered Idaho Power to evaluate transitional considerations for implementation of changes to the on-site generation offering. As more fully described later, and after careful consideration, the Company is not proposing to transition to the ECR over a period of time, rather the proposed changes will be in effect after January 1, 2024. It is important to note, however, that the upcoming GRC will be the first opportunity to evaluate how closely revenue collection for the on-site generation customers aligns with the allocation of costs to those classes. A previous analysis[25] demonstrated the potential for a large revenue deficiency in Schedules 6 and 8, and the Company believes it will be important to carefully consider the impact to those classes which may warrant transitional considerations, as it develops its revenue spread recommendations.

Finally, the Commission directed Idaho Power to make implementation recommendations as to both measurement interval and compensation structure. However, because "compensation structure" is essentially the combination of the measurement interval and the ECR, the Company will address compensation structure through the proposal for the measurement interval and ECR.

Q. What measurement interval is the Company proposing the Commission implement?

A. The Company is proposing to implement a real-time net billing structure, where the meter will record real-time net grid electricity consumption and exports independently. That is, the meter will measure and record all grid usage (energy in-flows) on one channel and will separately measure all exports (energy out-flows) on a different channel. Net billing, including a comparison of hourly and real-time intervals, is more fully explained on

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[25] *In the Matter of the Application of Idaho Power Company to Study Fixed Costs of Providing Electric Service to Customers,* Case No. IPC-E-18-16, Motion to Accept Fixed Cost Report (Sep. 30, 2019).

pages 17-24 of the October VODER Study.[26]

Q. Is real-time net billing the same as "buy-all, sell-all"?

A. No. The phrase "buy-all, sell-all" refers to a construct where a utility may separately meter all generation from a customer-generator at an interconnection point that is separate from the meter installed to measure and record all customer usage. In those arrangements, the customer is not permitted to offset their usage with their own generation; they are required to take full service from the utility and separately sell back all generation for a credit of some sort. That arrangement was not studied by the Company and is not what the Company is proposing in this case.

Q. How is the real-time net billing construct different from "buy-all, sell-all"?

A. Under the real-time net billing construct, the customer-generator will first consume any of their generation on-site, behind Idaho Power's meter. That is, they are netting off their load with their own generation. It is only the generation they are not consuming that is exported to the grid at a defined ECR.

Q. Will the customer continue to receive a 1:1 kWh credit that can offset future kWh consumption?

[26] See Attachment 1.

A. No. Under the Company’s proposal, the customer will generate a financial credit, based on the product of measured exported energy and the ECR, that can be monetized to offset current or future charges associated with utility-provided service.

q. Why does the Company believe the ECR should be modified?

A. The existing ECR is tied to the retail rate of the customer generator’s standard service schedule. This rate, however, is not reflective of the value of that energy. The retail rate is designed to collect the Company’s Commission-approved revenue requirement and includes both fixed and variable related costs of providing service. The product that customer-generators are exporting to Idaho Power’s system is inherently different than the service Idaho Power is providing to its customers.

Q. What was the Company’s focus specific to development of the proposed ECR in this case?

A. The Company’s focus centered on developing a methodology that would result in an ECR that fairly and accurately reflects the value of energy on Idaho Power’s system, while also balancing customer understandability and a need for transparent pricing. Ultimately, the Company is seeking to implement an ECR that strikes the necessary balance of providing the right value to customers for their exports and ensuring the rest of the customers are paying the right price for it in furtherance of the core regulatory objective of leaving them indifferent to the source of energy procured on their behalf.

Q. What is the Company's proposed ECR?

A. In this filing, the Company is proposing to establish a methodology that can be updated annually (each June 1) and will provide customers with compensation based on the actual settled market energy prices from the prior calendar year. Company witness Ellsworth's testimony describes each of the benefit and cost streams and the proposed methods that will be relied on for the annual update and Company witness Anderson's testimony describes the Company's proposed timing and procedural approach to updating the ECRs annually.

See Figure 2 for the proposed ECRs to be in effect from January 1, 2024 through May 31, 2024.

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Figure 2
Proposed Export Credit Rate

	Season	ECR
Export Profile		
Volume (kWh per kW)	Annual	1,465
Capacity Contribution (%)	Annual	8.76%
Export Credit Rate by Component (cents/kWh)		
Energy	On-Peak	8.59 ¢
Including integration and losses	Off-Peak	4.91 ¢
	*Annual**	*5.16 ¢*
Generation Capacity	On-Peak	11.59 ¢
	Off-Peak	0.00 ¢
	*Annual**	*0.79 ¢*
Transmission & Distribution Capacity	On-Peak	0.25 ¢
	Off-Peak	0.00 ¢
	*Annual**	*0.02 ¢*
Total	**On-Peak**	**20.42 ¢**
	Off-Peak	**4.91 ¢**
	*Annual**	*5.96 ¢*

**Annual values provided for informational purposes only and reflect seasonal weighting for 12 months ending December 2022.*

Note: On-Peak defined as June 15 - September 15, Monday - Saturday (exluding holidays), 3pm - 11pm. All other hours defined as Off-Peak.

If its proposal is approved as filed, the Company anticipates next updating the ECR in an April 2024 filing, with new ECRs to be in effect June 1, 2024 through May 31, 2025.

Q. Is the Company proposing to modify rates for consumption as part of this proceeding?

A. No. In this case, the Company is only addressing the compensation rates for exported energy from on-site generators. The Commission has previously found that a GRC is the appropriate venue for modifying consumption rates for all customers. Accordingly, the Company is not proposing any changes to the rates applicable for utility-provided service in this docket.

Q. What is the revenue impact of implementing real-time net billing for customers with non-legacy systems?

A. Attachment 3 to the Application filed coincident with my testimony provides a summary of the overall revenue impact of this filing for each customer class. As shown in Attachment 3, applying real-time net billing to customers with non-legacy systems for the January 2023 through December 2023 test year results in an overall revenue increase of $4.5 million, or 0.41 percent.

V. APPLICABILITY OF CHANGES FOR NON-LEGACY CUSTOMERS

Q. Please explain the term "legacy" in the context of the Company's on-site generation offerings.

A. The Company uses the term legacy to refer to those systems that the Commission has previously determined would continue to take NEM, under certain conditions, for a period of 25 years (also known as "grandfathered" systems). More specifically, these systems will be eligible for the continued application of full retail rate net metering throughout the defined legacy period.

Q. Can you generally describe what systems qualify for legacy treatment?

A. Yes. In Case No. IPC-E-18-15, the Commission found it was "prudent and justifiable to distinguish between existing customers and new customers based on the customer's reasonable expectations when making significant personal investments in on-site generation systems."[27] The Commission found that prior to the service date of that order (December 20, 2019) residential and small general service customers "reasonably assumed the net-metering program fundamentals would not change."[28] The Commission established criteria[29] to define legacy treatment for existing systems under Schedule 6 and Schedule 8, which would be subject to the rules in place as of the service date of Order No. 34509, December 20, 2019.

Likewise, in Case No. IPC-E-20-26, the Commission ultimately established criteria similar to that established in Case No. IPC-E-18-15 to provide legacy treatment to existing Schedule 84 systems (applicable to CI&I customers) under the rules in place as of the service date of Order No. 34854, December 1, 2020.[30]

Q. Are there requirements for a system to receive continued legacy status?

A. Yes. All customers who initially qualified for

[27] Case No. IPC-18-15, Order No. 34509 at 10.
[28] *Id.*
[29] *See Id.*, Order No. 34509 at 14-15 and Order No. 34546 at 8-11 (Feb. 5, 2020).
[30] Case No. IPC-E-20-26, Order No. 34854 at 11 (Dec. 1, 2020).

legacy status will continue to receive legacy status subject to the following conditions:

(1) the legacy status stays with the system at the meter site;

(2) if the system is offline for over six months, or is moved to another site, the legacy status is forfeited;

(3) to allow for the replacement of degraded or broken panels, the customer may increase the capacity of the legacy system by no more than 10 percent of the originally installed nameplate capacity or 1 kW, whichever is greater; and

(4) legacy status terminates after 25 years from the relevant order (i.e., December 2045).[31]

Q. How many legacy and non-legacy customers does the Company have?

A. As of March 31, 2023, the Company has a total of 5,544 legacy systems and 9,429 non-legacy systems. Table 2 breaks down the customers by class and total installed nameplate capacity. The Company also has 940 pending customers (i.e., customers who have submitted an application but who have not yet interconnected a system).

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[31] See Case No. IPC-E-18-15, Order No. 34546 at 9; Case No. IPC-E-20-26, Order No. 34854 at 11.

Table 2
Count of Legacy and Non-Legacy Systems by Customer Class - March 31, 2023

Customer Segment	Legacy	Non-Legacy	Total
Residential & Small General	5,177	9,379	**14,556**
Commercial & Industrial	160	42	**202**
Irrigation	207	8	**215**
Total Idaho	**5,544**	**9,429**	**14,973**

Q. To whom will the Company's proposed changes in this case apply?

A. Consistent with the Commission's prior directives, the Company proposes that modifications in this case will apply to non-legacy customers taking service under Schedules 6, 8, and 84.

Q. Did the Company consider proposing a transition period whereby modifications wouldn't apply for some period of time?

A. The Company carefully considered whether a transition period was warranted, but after reviewing the relevant Commission orders and considering the extensive communication the Company and Commission have done to notify customers of the potential for change, the Company does not believe it is prudent to continue to overcompensate customers for their exported energy.

Q. Why does the Company disfavor a transition period?

A. In developing its recommendation in this regard, the Company considered the substantial history on this issue as summarized in Table 3, which provides an overview of information regarding legacy status provided to customers through Commission orders, direct customer communication from the Company, or required to be provided by solar retailers.[32] As reflected in the table, the Company has remained diligent in its efforts to notify customers of the possibility for changes to the on-site generation offering.

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[32] The Residential Solar Energy System Disclosure Act (codified in *Idaho Code* Title 48, Chapter 18) defines persons who sell or lease residential solar energy systems as "solar retailers." *Idaho Code* 48-1802(5).

Table 3

Overview of Customer Communication and Notice of Future Changes to On-Site Generation Offering

Date	Communication	Relevant Language
October 2019	**Residential Solar Energy System Disclosure Act requires written disclosures be provided by the installer/seller to consumers (Idaho Code 48-1805)**	LEGISLATIVE OR REGULATORY ACTION MAY AFFECT OR ELIMINATE YOUR ABILITY TO SELL OR GET CREDIT FOR ANY EXCESS POWER GENERATED BY THE SYSTEM AND MAY AFFECT THE PRICE OR VALUE OF THAT POWER
December 2019	**Commission Order No. 34509**	"After the issuance of this Order, however, we believe it will no longer be reasonable for a customer to assume the net-metering program fundamentals will remain the same over the expected payback period of their investment."
January 2020	**Idaho Power's Application for On-Site Generation Modified per Commission Order** **Customer must initial/sign both disclosures on the application**	I understand that the net metering program design is subject to change including, but not limited to, the interval length over which netting occurs, compensation for excess generation and the interconnection requirements for on-site generation systems. I UNDERSTAND THAT LEGISLATIVE OR REGULATORY ACTION MAY AFFECT OR ELIMINATE MY ABILITY TO SELL OR GET CREDIT FOR ANY EXCESS POWER GENERATED BY THE SYSTEM AND MAY AFFECT THE PRICE OR VALUE OF THAT POWER. (ID RESIDENTIAL ENERGY SYSTEM DISCLOSURE ACT, ID CODE §§48-1801-§§48-1809)
January 2020	**Company Email Communications to Prospective On-Site Generation Customers Modified to Include Additional Language**	The rules for on-site generation, including compensation structure, are outlined in Schedules 6, 8, 84 and 72, which have been approved by the Idaho Public Utilities Commission and the Oregon Public Utility Commission (Commissions). Tariff schedules are subject to change with approval from the Commissions. This means the rules in place today (including pricing, compensation structure, excess energy value and system requirements) can change in the future. We will notify you of any future changes to the schedules.
February 2020	**Commission Order No. 34546**	"We made it abundantly clear in Order No. 34509 that the program fundamentals are subject to change. It would contravene our rationale to extend the date at which customers are eligible for grandfathered status, and we therefore decline to do so."
December 2020	**Commission Order No. 34854**	"We find it prudent to make the determination on grandfathering existing Schedule 84 customer-generators now, rather than waiting until a successor program is approved as many parties and commenters suggested, because it clarifies to potential CI&I customer-generators that the program fundamentals are undergoing a comprehensive review and are likely to change."
January 2021	**Commission Order No. 34892**	"No person, entity, business or organization should be representing that investment in and installation of solar panels under a particular tariff will result in payback within a time certain because the rates under the then current tariff do not become fixed at the time such an investment is made"
June 2021	**Company Press Release & Bill Inserts Mailed to All Customers**	Customers who install on-site generation after the dates of those orders (December 20, 2019 for Schedule 6 and 8; December 1, 2020 for Schedule 84) are subject to future changes to compensation structure, including how much they are compensated for excess energy.
December 2021	**Commission Order No. 35284**	"We urge stakeholders in the on-site generation industry to be completely transparent with potential investors. A utility's rate schedules, including net-metering program fundamentals, are subject to change. As such, there is no guaranteed return on investment."
June 2022	**Company Press Release & Bill Inserts Mailed to All Customers**	Customers who do not have legacy systems are subject to changes to the on-site generation compensation structure, including the value of the ECR. Customers are notified when applying for interconnection that the value of excess energy is subject to change.
December 2022	**Commission Order No. 35631**	"We are very concerned, though, by the number of commenters expressing worry that they will be unable to pay off their solar panel investments if the NEM program changes...It should come as no surprise to anyone who invested in an on-site generation solar system after December 20, 2019, that the Company may be authorized by the Commission to change fundamental aspects of its NEM program—including the imposition of an ECR—which can affect the payback period for customers."
January 2023	**Commission Order No. 35667**	"Contrary to Petitioner's implication otherwise, the Order provides that customers 'should know today that they will be getting a reduced credit for the electricity they generate.'"

In what is likely the most direct communication with each prospective customer, the Company has required every customer generation applicant to sign an application acknowledging they understand the program fundamentals can change. Within weeks of the Commission issuing Order No. 34509 in Case No. IPC-E-18-15, the Company updated the affirmative acknowledgement section in its application (shown in Figure 3) to further clarify that the measurement interval and compensation for excess energy is subject to change.

Figure 3

Customer Application Acknowledgement

Customer Acknowledgment

The following acknowledgments must be INITIALED for Idaho Power to complete its review of this application.

___I authorize Idaho Power to discuss my interconnection request and on-site generation project, as well as share information about my electric usage history, with the Project Contact/Company listed above. I further authorize such Project Contact/Company to act on my behalf to complete the necessary documentation and requirements to interconnect my on-site generation system. (If customer does not initial this authorization, all of Idaho Power's communications, information-sharing, and interconnection requirements for this project must be handled directly with customer.)

___I certify that the information provided in this application is correct to the best of my knowledge.

___I understand that a return trip charge of $61 **may be billed to my account** each time Idaho Power personnel are dispatched to the job site but are unable to conduct the on-site inspection for any of the conditions described in Schedule 68.

___I understand that the net metering program design is subject to change including, but not limited to, the interval length over which netting occurs, compensation for excess generation and the interconnection requirements for on-site generation systems.

___I UNDERSTAND THAT LEGISLATIVE OR REGULATORY ACTION MAY AFFECT OR ELIMINATE MY ABILITY TO SELL OR GET CREDIT FOR ANY EXCESS POWER GENERATED BY THE SYSTEM AND MAY AFFECT THE PRICE OR VALUE OF THAT POWER. (ID RESIDENTIAL ENERGY SYSTEM DISCLOSURE ACT, ID CODE §§48-1801-§§48-1809)

Customer printed name___________________________________

Customer Signature_______________________________________**Date**_______________

After careful review of the breadth of publicly issued Commission orders, the extensive legal disclosures required of installers, and Company efforts to ensure customer awareness of the potential for changes, the Company believes customers should have reasonably understood the fundamentals of the on-site generation offering could change.

Q. Does the Company believe its recommendation is consistent with prior Commission orders?

A. Yes. In its December 2022 order, the Commission found:

> We decline to rule, at this juncture, on the appropriateness of a transitional rate—this is a proposal more properly explored during the implementation case. However, we recommend that our previous determinations and reasoning on legacy systems in Order Nos. 34509, 34546, and 34892 inform any implementation proposal brought before this Commission.

Q. Did the Company consider statements made by customers in Case Nos. IPC-E-21-21 and IPC-E-22-22 that they were unaware changes could apply to them?

A. Yes. While the Commission and Company have been consistent in efforts to inform potential customers about how future changes to the offering could impact them, it is clear there are some customers who have been led to believe otherwise. Likewise, some customers appear to have not read or internalized the Company's application acknowledgment reproduced in Figure 3 and materials listed in Table 3.

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In talking with Customer Solution Advisors ("CSAs") in the Company's customer service center and other customer-facing employees on the Company's Customer Generation team, I am aware that a number of customers have indicated their installer did not tell them they would be subject to future changes in the on-site generation offering, and in many cases, have told the CSAs the installer specifically told them they <u>would</u> receive legacy treatment.

The Company is also aware of other customers who, knowing that they would be subject to anticipated changes to the on-site generation offering, are waiting to install on-site generation until an order is issued outlining changes to the offering. Shortly after the Commission issued its December 2022 order acknowledging the October 2022 VODER Study, the Company received two email inquiries from solar installers who actively followed and participated in the IPC-E-22-22 proceeding. Both installers inquired as to when the Company anticipated making an implementation filing, with one noting they had potential clients waiting to make investment decisions until a determination had been made.

Q. Did the Company quantify the customer impact of moving from NEM to a real-time net billing compensation structure?

A. Yes. As explained in the testimony of Mr. Anderson, the Company evaluated the changes on non-legacy customer bills that would result from moving to the real-time net billing compensation structure from the existing NEM structure. The analysis showed impacts to customer bills with an average increase of $12.12 per month[33] as a result of modifying the measurement interval and implementing real-time net billing.

Q. Has the Commission provided any guidance on whether the "payback" of a customer's investment should be considered in establishing an ECR?

A. Yes. In a recent order, the Commission found:

> the purpose of establishing a NEM rate *is not* to ensure that customers who have installed self-generation facilities are able to recoup their investment or earn a return on investment, it is to ensure that customers are paid fair, just, and reasonable rates for their exports and non-self-generating customers are not subsidizing the rates for self-generating customers.[34]

Q. Do you believe the bill impact supports extending the "legacy" period through a transition from NEM

[33] Average bill impact for non-legacy residential customer-generators. Bill impact calculations for Schedule 6, 8, and 84, Anderson Exhibit Nos. 6-8.
[34] Case No. IPC-E-22-22, Order No. 35631 at 28 (emphasis in original).

to real-time net billing?

A. No. For those customers that installed non-legacy systems prior to knowing the extent of changes to be made to the on-site generation program, the pendency of the regulatory proceedings has essentially provided a de facto transition period, during which time customers have been receiving NEM despite not qualifying for legacy status. The Company does not believe it is appropriate to continue maintaining NEM for non-legacy systems beyond January 1, 2024, when the Company's proposed changes to the service offering would take effect if approved by the Commission. Based on the findings from the Commission-acknowledged VODER Study, the continued application of NEM 1:1 retail rate crediting is not representative of the value that energy brings to the system.

VI. CONCLUSION

Q. Please summarize the Company's request in this case.

A. The Company is requesting approval to implement changes to the structure and design of its on-site generation offering as directed by the Commission in Case No. IPC-E-22-22, Order No. 35631. More specifically, the Company requests the Commission issue an order directing it to implement: (1) real-time net billing with an avoided cost-based export credit rate, (2) a methodology for determining annual updates to the ECR, (3) a modified project eligibility cap for CI&I customers, (4) related changes to the accounting for and transferability of excess net energy financial credits, and (5) updated tariff schedules necessary to administer the modified on-site generation offering. The Company is requesting the changes apply to all non-legacy customers effective with their January 2024 billing cycle.

Q. Does this conclude your testimony?

A. Yes.

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DECLARATION OF CONNIE G. ASCHENBRENNER

I, Connie G. Aschenbrenner, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Connie G. Aschenbrenner. I am employed by Idaho Power Company as the Senior Manager of Rate Design in the Regulatory Affairs Department.

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

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

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

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

Connie Aschenbrenner

Connie G. Aschenbrenner