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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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| 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

GRANT T. ANDERSON

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

A. My name is Grant T. Anderson. My business address is 1221 West Idaho Street, Boise, Idaho, 83702. I am employed by Idaho Power as a Regulatory Consultant in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 2013, I received a Bachelor of Science degree in Microbiology from Oregon State University. In May of 2015, 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 2018, I was hired as a Regulatory Analyst in the Company's Regulatory Affairs Department. My primary responsibilities as a Regulatory Analyst included supporting the Company's Commercial and Industrial customer classes' rate design and general support of tariff rules and regulations. In 2021, I was promoted to my current position as a Regulatory Consultant. My responsibilities expanded to include the development of complex cost-related studies and support of the Company’s Residential and Small General Service ("R&SGS") and on-site generation customer classes’ rate design.

Q. How is your testimony organized?

A. My testimony begins with an overview of the Company’s modified project eligibility cap proposal for all non-legacy on-site customer generation systems. Next, I will provide an overview of the customer bill impact from the proposed change in the compensation structure. I will then address the Company’s proposal for other implementation considerations, including recovery of export credit expenditures, billing and transfer criteria for net billing financial credits, conversion of accumulated kilowatt-hour (“kWh”) credits to financial credits for customers with non-legacy systems, and customer education and outreach. I also address the Company’s proposed tariff revisions related to the net billing compensation structure and interconnection requirements for systems under a modified project eligibility cap. Last, I will describe the Company’s proposed annual Export Credit Rate (“ECR”) update schedule.

Q. Have you prepared any exhibits?

A. Yes. My testimony incudes Exhibit Nos. 6 - 8, which calculate the bill impact for non-legacy customer generators for the twelve months ending December 31, 2022, for residential, small commercial, and large commercial, respectively.

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## I. **PROJECT ELIGIBILTY CAP**

Q. What is the current project eligibility cap for Idaho Power customer-generators?

A. The current project eligibility cap varies by customer class. Schedule 6, Residential Service On-Site Generation ("Schedule 6") and Schedule 8, Small General Service On-Site Generation ("Schedule 8") applicability defines the current project eligibility cap with a total nameplate capacity rating of 25 kilowatts ("kW"). Schedule 84, Customer Energy Production Net Metering Service ("Schedule 84") is applicable to Schedule 9, Large General Service ("Schedule 9"), Schedule 19, Large Power Service ("Schedule 19"), and Schedule 24, Agricultural Irrigation Service ("Schedule 24") customers. Schedule 84 defines the current project eligibility cap for customers under Schedule 9, 19, and 24, with a total nameplate capacity rating of 100 kW.

Q. What information did the Company consider in evaluating the appropriateness of the existing cap for Schedule 6 and 8 non-legacy systems?

A. The Company evaluated the potential output from installing rooftop solar up to 25 kW for a residential customer. A 25 kW system could generate approximately 37,000 kWh per year[1] – equating to around 3,100 kWh per month. In comparison, the average residential customer uses about 930 kWh per month, or

[1] Assumes a capacity factor of 17 percent.

less than one-third of the energy a 25 kW system is expected to produce on average. Relative to the 25 kW cap, the average residential customer service point maximum annual hourly demand is approximately 6-7 kW. Additionally, the most commonly installed residential system is about 7.5 kW, or 30 percent of the 25 kW cap.

Q. Based on its analysis, is the Company proposing to modify the project eligibility cap for exporting systems under Schedules 6 and 8?

A. No. The data suggests the current cap is not limiting for residential and small general service customers and the Company believes the 25 kW cap continues to be reasonable for the administration of interconnection for service under Schedules 6 and 8.

Q. What information did the Company rely on to evaluate whether the Schedule 84 cap continues to be reasonable?

A. The intent of net metering is to offset one's energy usage behind the meter. Therefore, the Company evaluated electrical demand by service point for non-solar commercial, industrial, and irrigation ("CI&I") service points.

Figure 1 is a histogram for all non-solar CI&I service points by annual demand. Figures 9.2 and 9.3 in the October 2022

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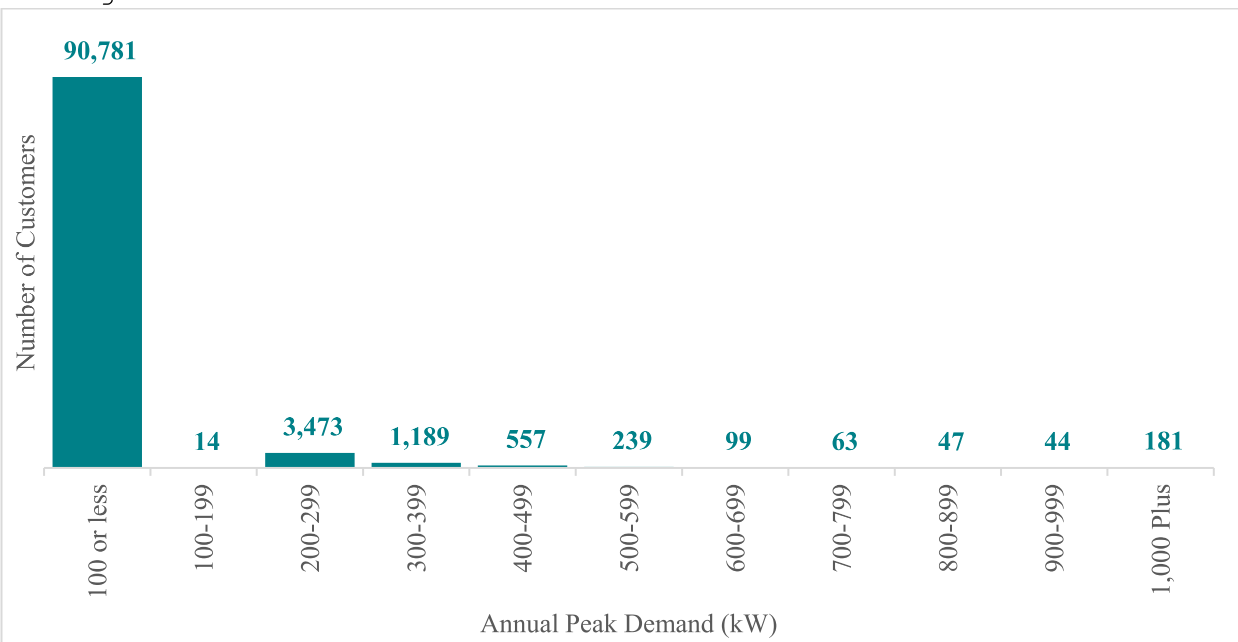
VODER Study[2] provide a more detailed breakdown of this same data by service point between commercial/industrial and irrigation customer service points.

**Figure 1**
Non-Solar Commercial, Industrial, and Irrigation Service Point Histogram




Q. In your opinion, what are the key takeaways from this figure?

A. Generally, the cap is not limiting to the majority of customers at a given service point. Approximately six percent of CI&I service points registered an annual demand over 100 kW, with the remaining 94 percent registering a demand of 100 kW or less. While it may not appear to be limiting for the majority of

[2] See Attachment 1. See also, 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, Attachment 1 (October 2022 VODER Study) to Idaho Power Company's Final Comments (Oct. 26, 2022).

customers, in the Company's experience customers who have some of those larger service point demands desire to install larger on-site generation systems. Rather than installing a system sized commensurate with their demand at a given site, those customers have had to rely on the Company's existing "meter aggregation rules" by installing smaller, disaggregated 100 kW systems. Those customers then apply annually to transfer kWh credits to qualifying service points.

Q. Based on its analysis, is the Company proposing to modify the project eligibility cap for Schedule 84?

A. Yes. The Company proposes that the project eligibility cap for Schedule 84 be set at the greater of 100 kW or 100 percent of demand at the service point.

Q. Please describe the relationship between customer and service point as it relates to administration of Idaho Power's tariff.

A. Often, the Company will refer to "customer" and "service point" synonymously when discussing a request for service. Each of Idaho Power's service schedules in its tariff – including the on-site generation schedules – are administered according to service point. A service point is akin to the point of delivery which is often the Company's meter.

Q. Did the Company consider a proposal that would have measured aggregate demand at a customer level versus service point?

A. Yes. The Company considered aggregating demand by customer rather than service point but did not find that to be a feasible approach.

As I previously noted, the Company does not administer any of its tariff schedules based on aggregated service point data and the Company is concerned that introducing that requirement for the purpose of determining certain criteria only applicable to its on-site generation service schedules would lead to a burdensome administrative process that could be prone to error.

Decoupling the project eligibility cap from the service point will also create the potential for over-sized systems that could lead to distribution circuit upgrades solely to support on-site generation. While the on-site generation customer would be responsible for the initial cost of the upgrades, the ongoing cost, including maintenance, replacement, property taxes, and other ancillary costs will become the responsibility of the Company. These costs are collectively paid for by all customers.

Q. How does the Company propose to measure demand for purposes of administering the cap?

A. For customers with at least 12 months of historical billing data, the Company proposes using the maximum billing demand from the last 12 months, measured when the customer generation application is submitted - to establish a project eligibility cap.

For new customers, or those without at least 12 months of historical billing, the Company has identified a few methods for determining demand, depending on the circumstances. In the first instance, the Company will evaluate and rely on available historical billing data at that service location. For example, if a new customer assumes service at a service point that has historical usage, that historical usage could be relied upon. In the absence of that information, or in the case where a new customer believes their demand will exceed that of a past customer, the Company proposes requiring an analysis of the facility’s power needs performed by a professional engineer.

For irrigation customers without a full in-season billing history, a conversion factor related to the horsepower of their pump(s) at the service point would determine the maximum demand.

Q. Has the Company considered how it would administer a situation where a customer’s demand decreases after the initial installation?

A. Yes. The Company plans to determine the cap for the service point at the time of application. If the customer demand at the service point later decreases or a new customer takes over the premise with a lower power requirement, the Company does not propose the Commission require a change or reduction in the existing system size based on their new demand and power needs. Not only would tracking and managing changes be administratively burdensome, but it would have significant impacts on the customer – most of which would undoubtedly be costly and would likely result in confusion and frustration.

Alternatively, if the customer's demand increases and they desire to interconnect a system expansion, this could be conducted pursuant to the existing interconnection requirements of Schedule 68, Interconnections to Customer Distributed Energy Resources ("Schedule 68") by applying for a system modification.

Q. Have other parties or customers taken a position on the project eligibility cap in previous dockets?

A. Yes. Clean Energy Opportunities for Idaho ("CEO") filed a petition in Case No. IPC-E-22-12, which proposed setting the project eligibility cap for Schedule 84 customers at 100 percent of demand. The Idaho Irrigation Pumpers Association ("IIPA") did not support a change to the cap until changes to the compensation structure were approved by the Commission.[3] In context of discussing the project eligibility cap, the Idaho Public Utility Commission Staff ("Staff") acknowledged that subsidies exist under the current net energy metering ("NEM") framework.[4] Additionally, Staff stated that if the cap is increased before an avoided-cost-based ECR is implemented, it would result in more customer generation capacity being added with additional cost shifts to non-generating customers.[5] The

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[3] Case No. IPC-E-22-22, IIPA Comments at 8 (Sep. 21, 2022).
[4] Case No. IPC-E-22-22, Staff Comments at 17 (Sep. 21, 2022).
[5] *Id.*

Company has also heard anecdotally from its irrigation customers that a demand-based cap would be favorable.

Q. Does the Company believe its proposed modification to the project eligibility cap for non-legacy systems addresses concerns raised by customers and other stakeholders?

A. Yes. The Company believes this modification to the cap contingent upon the concurrent replacement of the existing NEM with a net billing compensation structure and an ECR based on avoided cost appropriately considers stakeholder feedback and will improve the service offering.

Q. Please explain whether the Company continues to have the concerns it raised previously about modifying the project eligibility cap under Schedule 84, and if not what has changed?

A. It does; however, these concerns are generally mitigated when evaluating all issues in this docket simultaneously. The primary purpose of the cap was to mitigate safety and reliability concerns. Mr. Jared Ellsworth's testimony addresses the requirements to ensure that all interconnected systems do not compromise safety and reliability. An additional rationale for the cap was to limit subsidies present as a result of NEM. In this docket, the Company has proposed modifying the measurement interval and ECR - the combination of which I will generally refer to as "compensation structure." The proposed compensation structure will better align cost recovery with system utilization and compensation for excess energy with the costs and values of those activities. For these reasons, the Company proposes changes to both the compensation structure and the project eligibility cap occur coincidentally.

Q. Would the Company support a modification to the project eligibility cap under Schedule 84 absent a change to the compensation structure?

A. No. For the reasons I just mentioned, the Company believes the existing project eligibility cap mitigates some cost-shifting under the current retail rate NEM compensation structure. Therefore, the Company does not advocate changing the project eligibility cap without an avoided-cost-based rate for excess generation measured under a net billing compensation structure.

Q. Is the Company proposing modifications to the administration of how energy storage devices are applied to the project eligibility cap?

A. Yes. The Company is aware of limited circumstances where AC-coupled energy storage devices have resulted in a customer's proposed system to exceed the project eligibility cap. The Company proposes to modify its administration of the cap to only evaluate capacity of an energy storage device for purposes of its Feasibility Review to continue to ensure the interconnection does not impact safety or reliability of Idaho Power's system. However, for all future applications for interconnection, an energy storage device would not count towards the capacity limits for applicability of exporting systems under Schedule 6, 8, and 84.Q. Are there other items that should be considered in relation to the Company's proposed modification to the project eligibility cap?

A. Yes. Mr. Ellsworth's testimony includes more detail about the interconnection requirements for customer-generators and the considerations associated with modifying the project eligibility cap for Schedule 84.

## II. COMPENSATION STRUCTURE & BILL IMPACT

Q. Did the Company evaluate the impact on customer bills that will result with the change to a real-time net billing compensation structure?

A. Yes. Included with my testimony are Exhibit Nos. 6-8, which summarize the bill impact for non-legacy on-site generation customers with billing data for the twelve months ending December 31, 2022.

Q. Please provide an overview of the results of the bill impact analysis.

A. There were approximately 3,750 non-legacy residential customers taking service under Schedule 6 for the twelve months ending December 31, 2022. Exhibit No. 6 summarizes the bill impact calculations for non-legacy Schedule 6 service points. The Company compared base rates under the existing NEM and proposed real-time net billing compensation structure. On an average monthly basis, residential customer-generators monthly bill under NEM was $39.63 and under real-time net billing increased to $51.75, an average increase of $12.12 per month. Approximately 50 percent of customers would experience an average monthly bill increase less than $10 and 75 percent would experience a bill increase less than $15 per month.

**Figure 2**
Average monthly bill for non-legacy residential customer-generators in 2022, by average net monthly energy use

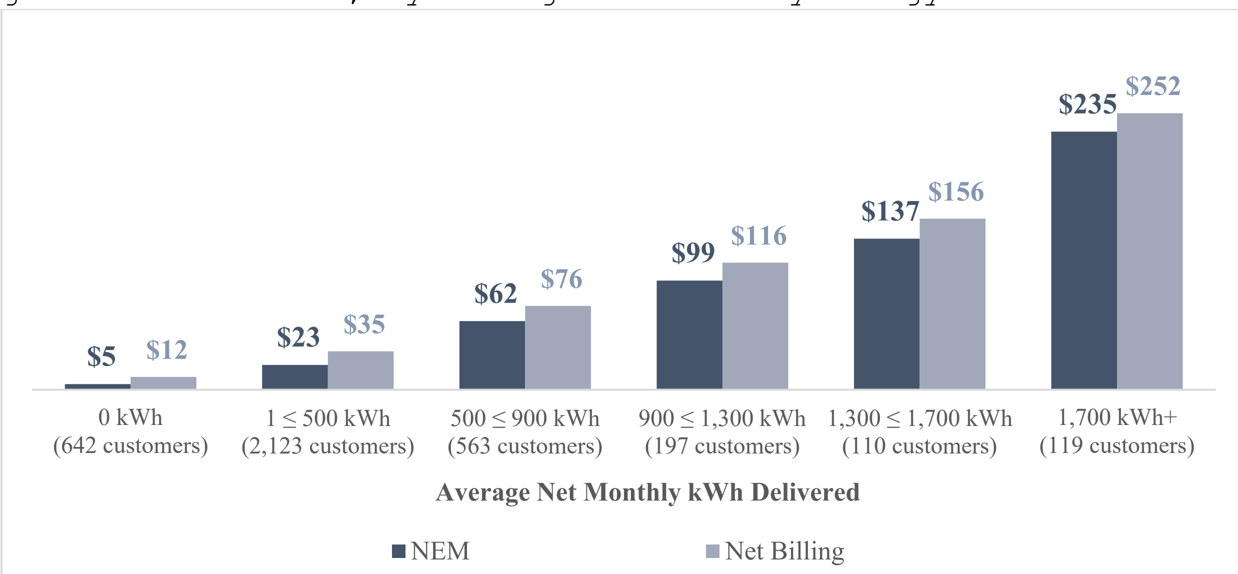



Figure 2 separates the customer-generators by their average monthly energy consumption in 2022 under a monthly measurement interval. The residential customer-generators have been grouped into six categories to evaluate the average magnitude of bill impacts. Figure 2 does not account for the residential customer-generators average monthly bill before solar was installed, which, all else held equal, would have been higher than the real-time net billing average monthly bill.[6]

For the twelve months ending December 31, 2022, there were 13 non-legacy small general service customers and 8 non-legacy large commercial service customers taking service under Schedule 8 and Schedule 84, respectively. Exhibit Nos. 7 and 8 summarize a similar analysis for these customers. There were no non-legacy irrigation customers taking service for the respective 12-month period.

Q. Did the Company consider implementing a transition period to mitigate customer impacts associated with a modified ECR?

A. Yes. Ms. Aschenbrenner's testimony addresses the Company's evaluation of a transition plan, which considered the results of the bill impact analysis.

## III. IMPLEMENTATION CONSIDERATIONS

Q. What implementation considerations and recommendations are included in the Company's proposal?

A. In Order No. 35631, the Commission stated that the October 2022 VODER Study complied with its previous directives and should serve as a basis for the Company's implementation recommendation in a subsequent case.[7] Ms. Aschenbrenner's testimony addresses the Company's proposal to utilize a real-

[6] Attachment 1 at 94-95, Figures 6.1 and 6.2.
[7] Case No. IPC-E-22-22, Order No. 35631 at 28 (Dec. 19, 2022).

time measurement interval for the compensation structure and Mr. Ellsworth's testimony addresses the methods the Company has proposed for the valuation of the ECR. In this section, I will address the following implementation considerations: (1) recovery of ECR expenditures; (2) application of financial credits for billing items and transfer criteria, (3) conversion of accumulated kWh credits to financial credit, and (4) customer education and outreach.

Q. Do these implementation considerations impact customers with legacy systems?

A. No. The proposed on-site generation compensation structure changes would only apply to customers with non-legacy systems. As a result, customers with legacy systems will continue to take service under the rules of NEM until legacy status terminates. Therefore, these implementation considerations do not impact customers with legacy systems.

**Recovery of Export Credit Expenditures**

Q. Please describe the Company's recommendation related to recovering export credit expenditures.

A. For customers with non-legacy systems, the Company proposes to treat the ECR expenditures as a net power supply expense ("NPSE") subject to 100 percent recovery through the Power Cost Adjustment ("PCA"), similar to the practice for Public Utility Regulatory Policies Act of 1978 ("PURPA") Qualifying Facilities ("QF"). The October 2022 VODER Study evaluates recovering export credit expenditures in Section 8 (pages 115-117).

Q. Why is it appropriate to recover the cost of ECR expenses through the PCA?

A. ECR expenses represent the cost of energy that the Company is purchasing for the benefit of all of its customers. Therefore, it is reasonable for all customers to pay for that energy through the PCA. Prior to 2014, net metering customers were compensated for their net excess generation through financial credits, the cost of which were recovered through the PCA.[8]

Q. Why is it appropriate that ECR expenditures be recovered through the PCA at 100 percent not subject to the 95 percent/5 percent sharing mechanism?

A. The Energy Policy Act of 2005 amended Section 111 of PURPA by adding five new federal ratemaking standards for electric utilities. Notably, however, many of the basic concepts embodied in the "new" federal standards were not new in Idaho. For example, in considering the amendments to PURPA the Commission concluded that the federal net metering standard, which required electric utilities to make available upon request a service offering under which a customer could offset their

[8] *In the Matter of the Application of Idaho Power Company for Authority to Implement a Power Cost Adjustment (PCA) Rate for Electric Service from May 16, 2003 through May 15, 2004*, Case No. IPC-E-03-05, Exhibit No. 3 to Direct Testimony of Gregory W. Said (Apr. 15, 2003).

energy usage with their own generation, had already been implemented in Idaho.[9] Regardless, similar to resources a utility is forced to acquire under federal law, which the Commission has allowed the Company 100 percent recovery of since the PCA was established in 1983,[10] customer-generator exports have become a must-take resource at the state level and as such 100 percent of ECR expenditures should be recovered through the PCA. In all other instances where the Company is required to make payments at prices consistent with Commission order, such as demand response and PURPA, those payments are recovered at 100 percent.

**Financial Credits – Billing and Transfer Criteria**

Q. Please describe the Company's recommendation for how it proposes to apply financial credits to the bill.

A. The Company proposes that financial credits offset all billing components of the bill – not just the energy-related portion of a customer bill.

Q. Does the Company propose that financial credits could be transferred to other meters or service points?

A. Yes, for customers with non-legacy systems the Company proposes that a customer could transfer financial credits to another account held in their name for their own

[9] *In the Matter of the Commission's Consideration of the Five Amendments to Section 111 of PURPA Contained in the Energy Policy Act of 2005*, Case No. GNR-E-06-02, Order No. 30229 at 3-5 (Jan. 24, 2007).

[10] *In the Matter of the Application of Idaho Power Company for Authority to Implement a Power Cost Adjustment Tariff for Electric Service to Customers in the State of Idaho and for Approval of New Rates for Service Under the FMC Special Contract*, Case No. IPC-E-92-25, Order No. 24806 at 17 (Mar. 29, 1993).

usage. Financial credits would be non-transferrable in the event the customer relocates and/or discontinues service at the point of delivery associated with the exporting system. Any unused financial credit from discontinued service would be absorbed to the benefit of customers through a credit, or reduction, to the PCA.

Q. How would the transfer of excess financial credits be administered?

A. Idaho Power proposes that the transfer of excess financial credits be administered similar to its current NEM service offering for customers transferring kWh credits.

Customers would submit requests to transfer financial credits by January 31. After reviewing the eligibility of each request, Idaho Power would execute approved transfers no later than March 31. Between the time forms are submitted by the January deadline and the transfers are executed in March, energy generation and consumption will continue to occur, impacting the available balance of financial credits. Therefore, customers would be asked to specify a percent of financial credits to transfer rather than an actual dollar amount. Transfers would be limited to other accounts in the customer’s name and customers would be asked to attest that the account they are transferring credits to is for their own usage. Like the current NEM offering, there would be a $10 charge per meter receiving the credit.

Q. Did the Company identify any potential concerns with the proposed transfer of financial credits?

A. Yes. The Company does not have the ability to validate that the account where credits would be transferred is for the customer's own usage, and therefore proposes to rely on an attestation from the customer. The potential for gaming exists if a customer were to put accounts in their name where the usage was not for their own use. The same risk factor exists under the Commission-approved rules for legacy transfer of kWh credits and the Company believes this risk is in part mitigated by the adoption of a project eligibility cap based on the demand at the service point.

Q. Is the Company proposing to change the transferability of kWh credits for legacy customers?

A. No. In Order No. 32925, the Commission granted limited transferability of kWh credits. In part, the Commission found that:

> As discussed in prior comments and testimony, even with one delivery point, net metering customers may not pay their full fixed costs given the current rate structure. We find that allowing customers to apply credits to offset usage on continuous meters that are served by the same primary feeder is a reasonable means by which to limit the potential under-recovery of fixed costs.

To the extent a legacy on-site generation customer wishes to transfer financial credits to service points not eligible under the rules applicable to legacy systems, that customer can elect to forfeit legacy status. The Customer will take service under the modified on-site generation offering, which will include the flexibility to transfer credits more broadly than what was allowed under NEM.

**Accumulated kWh Credit Conversion – Non-Legacy Customers**

Q. How does the Company propose to treat kWh credits that were accumulated prior to the proposed January 1, 2024, effective date?

A. The Company proposes that accumulated kWh credits held at service points with non-legacy systems be converted to financial credits one year after the effective date of a Commission-authorized change in compensation structure.

Q. Please describe the Company's recommendation related to the conversion of accumulated kWh credits for customers with non-legacy systems.

A. Customers with non-legacy systems would have had the opportunity to accumulate kWh credits from the time they interconnected their system. If the Company's proposal is approved, these customers would begin receiving financial credits that could be monetized when they have billable amounts to offset.

The Company proposes that these customers have one year after moving to the net billing compensation structure to use their pre-existing kWh credit balance from NEM.[11] Any remaining kWh credits that have not been used by the customer would be converted to a financial credit on their January 2025 billing cycle.

Q. How does the Company propose for kWh credits to convert to a financial credit balance?

A. The Company proposes monetization into a financial credit balance at the blended average retail energy rate as of December 31, 2023, for the respective customer class under which they take retail service from Idaho Power. These credits were generated under the NEM compensation structure and to avoid retroactive ratemaking, Idaho Power believes it is reasonable to assume they would have monetized the credits at the applicable blended average energy retail rate in effect while NEM was in place. The final kWh credits will be applied prior to the customer's January billing cycle.

Q. Did the Company consider allowing accumulated kWh credits to continue to be used to offset energy usage beyond one year after implementation of a change in the compensation structure?

A. Yes. However, to facilitate the transition from NEM with a one-for-one kWh credit to a net billing financial credit

[11] Pursuant to the existing Conditions of Purchase and Sale in Schedule 6, 8, and 84, the Company will process Excess Net Energy (kWh) credit transfer requests from non-legacy customer-generators in January 2024 and requests to transfer financial credits will occur December 2024 - January 2025.

approach, the Company suggests converting the kWh credits to financial credits one year after the effective date of net billing to reduce administrative burden and possible customer confusion associated with carrying two separate credit balances. The Company also believes one year post-implementation of a change in the compensation structure gives customers time to use remaining kWh credit balances.

Q. How does the Company propose the cost of these financial credits be recovered?

A. Under the existing NEM policy, if the accumulated kWh credits were used to offset usage, the cost to R&SGS customers would primarily be recovered from R&SGS customers through the Fixed Cost Adjustment ("FCA") mechanism. To maintain consistency with the current recovery method, the Company believes it is reasonable to recover the transition cost of converting the accumulated kWh credits to financial credits from R&SGS customers through a one-time adjustment to the FCA balance as of December 31, 2024, which would then be collected in FCA rates from June 1, 2025, through May 31, 2026.

In the event there are any remaining accumulated kWh credits for CI&I customers as of December 31, 2024, the Company believes it is reasonable to recover the transition cost of converting those accumulated kWh credits to financial credits through the PCA.

For context, as of December 31, 2022, there were approximately 4.7 million non-legacy accumulated kWh credits - the vast majority being residential - which, valued at the then-current blended average energy rate was approximately $496,000.

**Customer Outreach and Education**

Q. Please explain how the Company will notify customers about its proposal in this docket.

A. Coincident with filing this docket, Idaho Power will issue a news release to notify the public of its Application. Additionally, Idaho Power will directly notify its customers of the Application with a bill insert included with their monthly bill. The bill insert will inform all customers that Idaho Power has filed a case requesting changes to the structure and design of its on-site generation offering with a requested effective date of January 1, 2024. A copy of the press release and customer bill insert is included as Attachment 4 to the Application.

Q. How will the Company notify existing and pending on-site generation customers of the filing?

A. In addition to providing a bill insert to all customers under the major customer classes, the Company will send direct-mail letters to all existing and pending on-site generation customers notifying them that the Company has filed its proposal for changes informed by the Commission-acknowledged VODER Study. The letters that customers with legacy systems receive will also remind them of their legacy status, the criteria for legacy systems, and the reasons legacy status may be forfeited. The letter that customers with non-legacy systems receive will advise them on how they may be impacted by the outcome of the case. All existing and pending on-site generation customers, irrespective of the legacy status of their system, will receive information on how they can participate in the proceeding. A copy of the draft customer letters is included as Attachment 5 to the Application.

In addition, the Company will have information available on its website, and customers may contact the Customer Service Center with questions about the filing.

Q. Has the Company considered how it would educate existing non-legacy customers about the new compensation structure once it is changed?

A. Yes. The Company has considered modifications to customer bill presentment for printed and online bills, as well as modifications to usage and billing information presented through the Company's MyAccount online and mobile app. Implementing bill and usage presentation changes will provide pertinent details to existing customers to help them better understand how they are billed under real-time net billing.

Q. What information will Idaho Power make available to prospective on-site generation customers who seek information about how an installation may impact their Idaho Power bill?

A. Customers can access their historical hourly grid consumption data through an online portal or by calling the Customer Service Center. Additionally, generation system hourly production estimates are publicly available from sources such as the National Renewable Energy Laboratory's PV Watts® Calculator or the customer's installer. Customers can pair their grid consumption data from Idaho Power with the generation system production data to evaluate the potential economics of installing on-site generation.

Idaho Power also understands that its customers are considering considerable investments and strives to provide tools to them where possible. For residential and small general service customers, Idaho Power plans to provide its customers access to a third-party calculator tool on Idaho Power's website. The calculator will provide the option to use uploaded hourly consumption data in calculations, or a customer can use an estimate of their monthly electric costs if they don't have twelve months of billing history, or an average electric bill if they have no billing history. For CI&I customers, Idaho Power's Energy Advisors, and Agriculture Representatives will continue to make additional information available to its customers.

Q. In your opinion, does the Company's plan for customer communication and outreach position it to successfully implement a net billing compensation structure?

A. Yes. Idaho Power's customer relations teams have been thorough and diligent in developing communication strategies and evaluating the option to make a calculator tool available to its customers. Customers can understand real-time net billing, and it is the most accurate and fair measurement of energy flows to and from the customer.

The Company endeavors to properly notify all current and prospective on-site generation customers of its proposed changes by sending direct-mail letters and bill inserts. Post-implementation, it is also critical to the long-term success of the on-site generation service offering that Idaho Power provide consumption and export information that allows existing customers to understand the bi-directional relationship and impacts on billing. Additionally, prospective on-site generation customers need access to the necessary data and tools to make the most informed and decision based on accurate information – while understanding that the Company's tariff is subject to change. Idaho Power's plans for customer communication, billing presentment, and a calculator tool will facilitate a successful shift towards an improved and modernized compensation structure for on-site customer generation.

## IV. PROPOSED TARIFF REVISIONS

Q. What tariff revisions are necessary to implement the Company's proposal?

A. Revisions to Schedules 6, 8, 68, and 84 are necessary to implement the proposed changes in this docket. The Company has included its proposed tariff revisions in Attachment 2 to the Application in this docket.

Q. Please explain what tariff revisions the Company has proposed for Schedules 6 and 8.

A. The Company has included tariff revisions to reflect the change in compensation structure for non-legacy systems from NEM to real-time net billing. The tariff revisions lay out the compensation structure that would be separately applicable to customers with legacy and non-legacy systems. The "conditions to purchase and sale" have been separated into three sections. The first are those provisions that only apply to legacy systems under the NEM compensation structure and the second are those provisions that only apply to non-legacy systems under the proposed net billing compensation structure. The third section includes provisions that broadly apply to all customers taking service under Schedule 6 and 8. The revised tariff also includes line items for the ECR applicable to non-legacy systems, and specifies the proposed change in the administration of energy storage devices towards the 25 kW cap. Finally, the Company has proposed a few minor operational administrative items.

Q. Please summarize the revisions the Company has proposed for Schedule 84.

A. The proposed revisions to Schedule 84, similar to those for Schedules 6 and 8, account for a modification to the service offering from NEM to real-time net billing for customers with non-legacy systems and the administration of energy storage devices. In addition, the revisions to Schedule 84 define the modification to the project eligibility cap for non-legacy systems.

Q. What revisions has the Company proposed for Schedule 68?

A. As more fully explained in Mr. Ellsworth's testimony, the Company has included modifications to update the interconnection requirements for Schedule 84 customers that install systems larger than 100 kW. Schedule 68 also reflects minor administrative updates for the interconnection process.

## V. PROPOSED SCHEDULE FOR ECR UPDATES

Q. Mr. Ellsworth's testimony describes the Company's proposed methodology for establishing an ECR and methods the Company is proposing for valuing each of the components of the ECR. What is the Company's proposed timing and frequency for updating the ECR?

A. The Company recommends an annual ECR update filed in April, where Commission-approved updates would take effect June 1 each year, concurrent with other spring filing and seasonal rate changes. The primary driver for the proposed update schedule is to ensure that Energy Imbalance Market Load

Aggregation Point ("ELAP") hourly prices have been disputed and reconciled. The Company also believes it is important from a timing perspective to have the effective ECR changes occur in June in advance of the summer season.

Q. Please describe the Company's proposed update cycle for each of the respective methods and components of the ECR.

A. The Company has identified updates for the proposed methods as fitting into two general categories: (1) annual updates, and (2) routine updates less frequent than annual. The routine updates that are less frequent than annual are informed by other filings or studies, such as Idaho Power's Integrated Resource Plan ("IRP"). Table 1 provides a summary of each of the inputs to the ECR and the proposed update cadence. Annual updates will rely on data from the most recent twelve months ending December 31 and routine updates will rely on the most recently available information at the time of its annual filing to update the ECR.

//

**Table 1**
ECR Proposed Update Schedule by Input

| Input | ECR Component | Type of Update |
|---|---|---|
| **Real-Time Exports**<br>*12 months ending Dec 31* | Avoided Energy;<br>Avoided Generation Capacity | Annual |
| **ELAP Hourly Market Prices**<br>*12 months ending Dec 31* | Avoided Energy | Annual |
| **Contribution Capacity - ELCC**<br>*3-year rolling average* | Avoided Generation Capacity | Annual |
| **Peak Annual Exports**<br>*Total MW* | Avoided Generation Capacity | Annual |
| **Levelized Cost of Avoided Resource**<br>*Cost per kW-year* | Avoided Generation Capacity | Routine - Most recently filed IRP |
| **Hours of Capacity Need**<br>*On-Peak Hours* | Avoided Energy;<br>Avoided Generation Capacity | Routine - Most recently filed IRP |
| **Transmission & Distribution Deferral**<br>Annual Deferral Value | Avoided Transmission & Distribution Capacity | Routine - Most recently filed IRP |
| **Line Loss Study**<br>*Loss Coefficients* | Avoided Line Losses | Routine - Updated with periodic line loss study |
| **Variable Energy Resource Integration Study** | Integration Costs | Routine - Updated with periodic VER Study |

Q. How does the Company propose to update the avoided energy component of the ECR?

A. The avoided energy value would be updated annually using the most recent 12 months, ending December 31, for both customer-generator exports and ELAP prices. ELAP hourly settled price corrections are typically available within approximately 60 days – this timing, in part, drives the Company's proposed update schedule to file in April of each year.

Q. How does the Company propose to update the avoided generation capacity component of the ECR?

A. The avoided generation capacity calculation would be updated annually to reflect real-time customer exports and peak annual export for the most recent calendar year. As described by Mr. Ellsworth, the ECR would utilize a three-year rolling average ELCC calculation to mitigate year-to-year volatility. The annual update would rely on the most-recently filed IRP for defining the on-peak hours and the value of the levelized cost of the avoided resource.

Q. Please describe how the Company plans to update the T&D capacity value.

A. The annual update for the T&D capacity value component of the ECR will reference the most recently filed IRP. The calculation of the T&D capacity value relies on the same 20 years of project data that are used to determine IRP energy efficiency values. This data includes 15 years of historical data and 5 years of projected data.

Q. How does the Company propose to update the avoided line loss value to inform the proposed annual ECR updates?

A. The annual update for the ECR will rely on the most recently completed line loss study. Line loss studies are comprised of extensive analyses and are not performed on a frequent basis; however, line losses are expressed as percentages, which do not significantly vary over time. Therefore, the periodic update of the input is reasonable and will not negatively impact customer-generators or non-participants.

Q. How does the Company propose to update the integration costs in the ECR annual update?

A. The annual ECR update will rely on the most recently completed VER Integration Study. As explained in Mr. Ellsworth's testimony, integration studies are completed periodically, based on current and expected variable non-dispatchable resources on the Company's system. The annual update would incorporate updated integration costs into the ECR in the annual update subsequent to completion of the next VER Integration Study.

## VI. <u>CONCLUSION</u>

Q. Does the Company's proposal to modify the Schedule 84 project eligibility cap, other implementation considerations, and the proposed schedule for ECR updates meet the Company's primary objectives in this case?

A. Yes. The Company's objectives provide the foundation for proposing changes to the project eligibility cap and excess energy transfer process that will provide additional flexibility and opportunities for customers to install on-site generation. The proposed schedule for ECR updates is repeatable and will ensure timely recognition of changing conditions on Idaho Power's system and the broader power markets. Last, the proposed tariff revisions and planned customer education and outreach regarding a change to a net billing compensation structure provide for enhanced customer understandability.

Q. Does this conclude your testimony?
A. Yes.
//

**DECLARATION OF Grant T. Anderson**

I, Grant T. Anderson, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Grant T. Anderson. I am employed by Idaho Power Company as Regulatory Consultant 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 and exhibits are true and accurate.

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

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

Signed: Grant T. Anderson

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-14

IDAHO POWER COMPANY

ANDERSON, DI
TESTIMONY

EXHIBIT NO. 6

# Schedule 6 - Residential On-Site Generation — Non-Legacy Bill Impact

## Average Energy Delivered/Imported

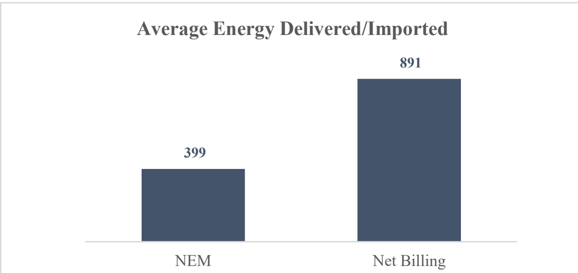
| Category | Count | Energy Delivered NEM | Energy Delivered Net Billing |
|---|---|---|---|
| 0 kWh | 642 | 0 | 524 |
| 1 ≤ 500 kWh | 2,123 | 211 | 686 |
| 500 ≤ 900 kWh | 563 | 672 | 1,163 |
| 900 ≤ 1,300 kWh | 197 | 1,078 | 1,623 |
| 1,300 ≤ 1,700 kWh | 110 | 1,486 | 2,060 |
| 1,700 kWh+ | 119 | 2,491 | 2,964 |
| **All Customers** | **3,754** | **399** | **891** |

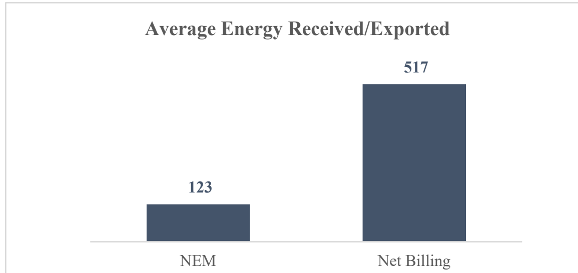
## Average Energy Received/Exported

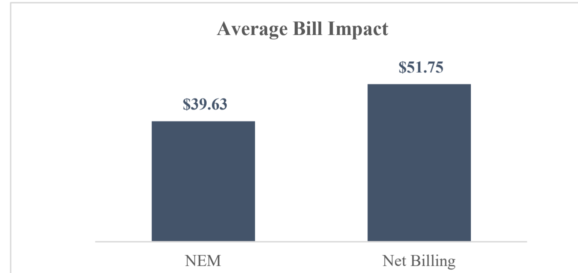
| Category | Count | Energy Exported NEM | Energy Exported Net Billing |
|---|---|---|---|
| 0 kWh | 642 | 289 | 672 |
| 1 ≤ 500 kWh | 2,123 | 103 | 475 |
| 500 ≤ 900 kWh | 563 | 64 | 491 |
| 900 ≤ 1,300 kWh | 197 | 63 | 545 |
| 1,300 ≤ 1,700 kWh | 110 | 57 | 574 |
| 1,700 kWh+ | 119 | 20 | 473 |
| **All Customers** | **3,754** | **123** | **517** |

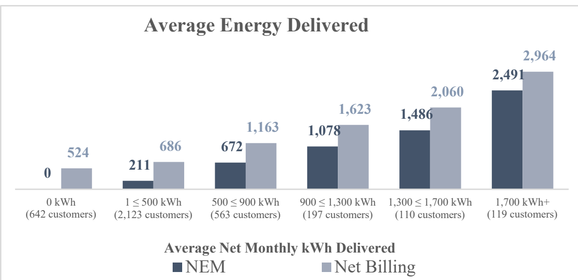
## Average Bill Impact

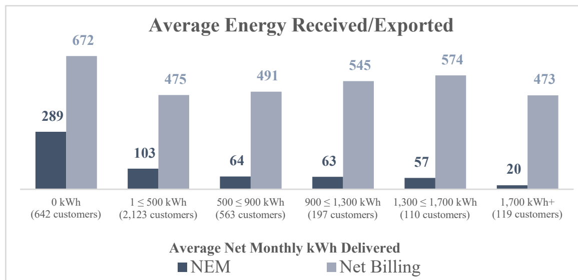
| Category | Count | Avg. Monthly Bill NEM | Avg. Monthly Bill Net Billing |
|---|---|---|---|
| 0 kWh | 642 | $ 5.00 | $ 11.56 |
| 1 ≤ 500 kWh | 2,123 | $ 22.50 | $ 34.88 |
| 500 ≤ 900 kWh | 563 | $ 62.38 | $ 76.23 |
| 900 ≤ 1,300 kWh | 197 | $ 99.31 | $ 115.60 |
| 1,300 ≤ 1,700 kWh | 110 | $ 137.46 | $ 155.75 |
| 1,700 kWh+ | 119 | $ 235.01 | $ 251.90 |
| **All Customers** | **3,754** | **$ 39.63** | **$ 51.75** |

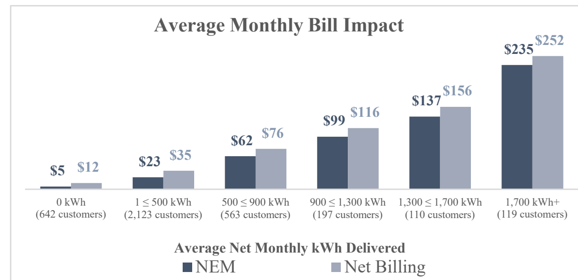


**BEFORE THE**

**IDAHO PUBLIC UTILITIES COMMISSION**

**CASE NO. IPC-E-23-14**

**IDAHO POWER COMPANY**

**ANDERSON, DI**
**TESTIMONY**

**EXHIBIT NO. 7**

# Schedule 8 - Small General Service On-Site Generation — Non-Legacy Bill Impact

## Average Energy Delivered/Imported

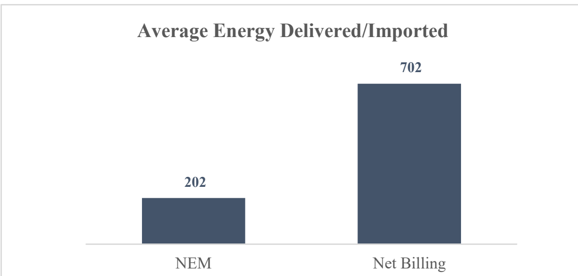
| Category | Count | Energy Delivered NEM | Energy Delivered Net Billing |
|---|---|---|---|
| 0 kWh | 6 | - | 439 |
| 1 ≤ 200 kWh | 4 | 100 | 631 |
| 200 ≤ 400 kWh | 1 | 248 | 1,248 |
| 400 ≤ 600 kWh | - | - | - |
| 600 ≤ 800 kWh | - | - | - |
| 800 kWh+ | 2 | 989 | 1,357 |
| **All Customers** | **13** | **202** | **702** |

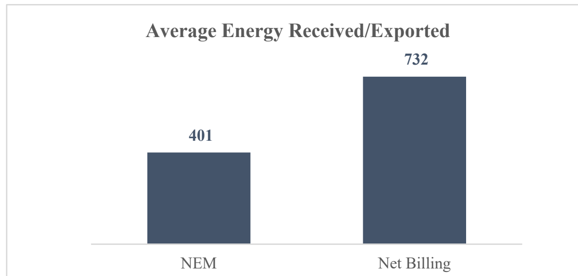
## Average Energy Received/Exported

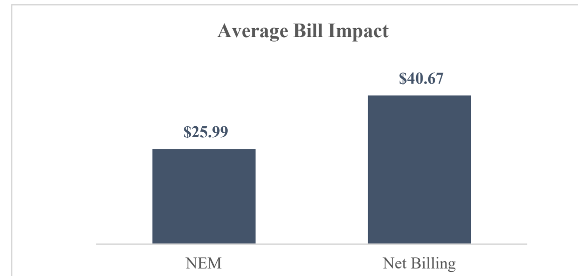
| Category | Count | Energy Exported NEM | Energy Exported Net Billing |
|---|---|---|---|
| 0 kWh | 6 | 652 | 943 |
| 1 ≤ 200 kWh | 4 | 191 | 532 |
| 200 ≤ 400 kWh | 1 | 517 | 1,000 |
| 400 ≤ 600 kWh | - | - | - |
| 600 ≤ 800 kWh | - | - | - |
| 800 kWh+ | 2 | 11 | 368 |
| **All Customers** | **13** | **401** | **732** |

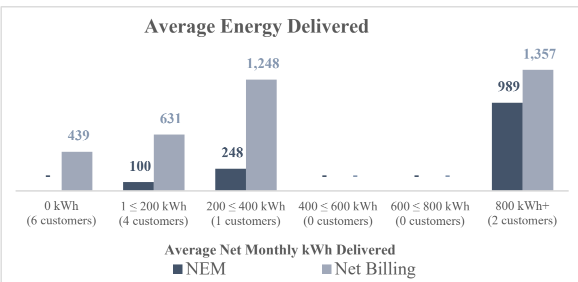
## Average Bill Impact

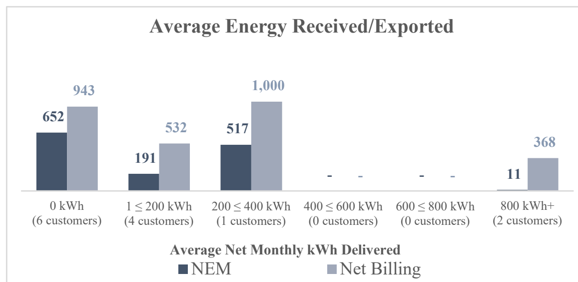
| Category | Count | Avg. Monthly Bill NEM | Avg. Monthly Bill Net Billing |
|---|---|---|---|
| 0 kWh | 6 | $ 5.00 | $ 10.09 |
| 1 ≤ 200 kWh | 4 | $ 15.02 | $ 38.36 |
| 200 ≤ 400 kWh | 1 | $ 30.32 | $ 61.25 |
| 400 ≤ 600 kWh | - | $ - | $ - |
| 600 ≤ 800 kWh | - | $ - | $ - |
| 800 kWh+ | 2 | $ 108.75 | $ 126.72 |
| **All Customers** | **13** | **$ 25.99** | **$ 40.67** |

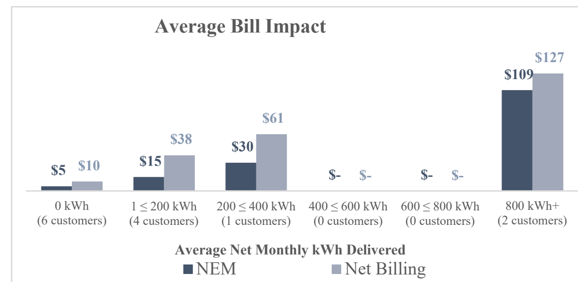


BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-14

IDAHO POWER COMPANY

ANDERSON, DI
TESTIMONY

EXHIBIT NO. 8

# Schedule 9/84 - Large General Service On-Site Generation — Non-Legacy Bill Impact

## Average Energy Delivered

| Category | Count | Energy Delivered NEM | Energy Delivered Net Billing |
|---|---|---|---|
| 0 kWh | 2 | - | 556 |
| 1 ≤ 500 kWh | 2 | 299 | 841 |
| 500 ≤ 900 kWh | 2 | 648 | 2,349 |
| 900 ≤ 1,300 kWh | 1 | 1,209 | 1,638 |
| 1,300 ≤ 1,700 kWh | 1 | 1,615 | 2,684 |
| 1,700 kWh+ | - | - | - |
| **All Customers** | **8** | **590** | **1,477** |

## Average Energy Received/Exported

| Category | Count | Energy Exported NEM | Energy Exported Net Billing |
|---|---|---|---|
| 0 kWh | 2 | 2,990 | 3,505 |
| 1 ≤ 500 kWh | 2 | 152 | 542 |
| 500 ≤ 900 kWh | 2 | 752 | 1,701 |
| 900 ≤ 1,300 kWh | 1 | 73 | 429 |
| 1,300 ≤ 1,700 kWh | 1 | 231 | 1,069 |
| 1,700 kWh+ | - | - | - |
| **All Customers** | **8** | **1,011** | **1,624** |

## Average Bill Impact

| Category | Count | Avg. Monthly Bill NEM | Avg. Monthly Bill Net Billing |
|---|---|---|---|
| 0 kWh | 2 | $ 16.00 | $ 16.00 |
| 1 ≤ 500 kWh | 2 | $ 43.86 | $ 61.29 |
| 500 ≤ 900 kWh | 2 | $ 60.03 | $ 76.52 |
| 900 ≤ 1,300 kWh | 1 | $ 117.57 | $ 131.40 |
| 1,300 ≤ 1,700 kWh | 1 | $ 135.77 | $ 152.49 |
| 1,700 kWh+ | - | $ - | $ - |
| **All Customers** | **8** | **$ 61.64** | **$ 73.94** |