An IDACORP Company

OCTOBER • 2022

2022 VALUE OF DISTRIBUTED ENERGY RESOURCES (VODER) STUDY

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Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

Glossary

Bulk Power System (BPS)—A large interconnected electrical system made up of generation and transmission facilities and their control systems. A BPS does not include facilities used in the local distribution of electric energy. In the United States, bulk power systems are overseen by the North American Electric Reliability Corporation (NERC) and other regulatory agencies. Idaho Power is part of the Western Interconnection BPS.

Carbon Tax—Tax levied on the carbon emissions required to produce goods and services. A carbon tax is designed to reduce carbon dioxide emissions by increasing the prices of the fossil fuels that emit them when burned to incentivize efforts to make them less carbon intensive. In its simplest form, a carbon tax covers carbon dioxide emissions; however, it can also cover other greenhouse gases, such as methane or nitrous oxide, by taxing such emissions based on their carbon dioxide equivalent.

Class Cost-of-Service (CCOS)—Study to assign or allocate the utility's revenue requirement to the various customer rate classes. The CCOS process recognizes the way the utility's costs are incurred by relating these costs to how the utility operates to provide electrical service.

Code of Federal Regulations (CFR)—Codification of the general and permanent rules published in the Federal Register by the Executive departments and agencies of the Federal Government. The CFR is divided into 50 titles which represent broad areas subject to Federal regulation. Title 18 of the CFR contains rules and regulations applicable to public utilities. The purpose of the CFR is to make available the large body of laws that govern Federal practice.

Customer Generator System—An Exporting System or a Non-Exporting System.

Demand Response—A change in the energy consumption of an electric utility customer to better match the demand for energy with the supply (e.g., reducing air conditioning use during select hot summer evenings).

Demand Side Management (DSM)—Initiatives and technologies that encourage consumers to use energy efficiently. Idaho Power provides financial incentives for customers to participate in DSM programs, which includes both energy efficiency and demand response programs.

Distributed Energy Resource (DER)—A source of electric power that is not directly connected to the BPS. Any combination of Generation Facilities and/or Energy Storage Devices connected in parallel is considered a DER, such as rooftop solar.

Distributed Energy Resource Management System (DERMS)—The combination of hardware and software that allows real-time communication and control across the variety of connected DER on the system.

Effective Load Carrying Capability (ELCC)—Reliability-based metric used to assess capacity contribution of a given power plant or generation unit, including DERs. ELCC determines an individual generator's contribution to the overall system reliability and is primarily driven by the timing of the highest risk hours. A dispatchable power plant has a relatively high ELCC value, meaning the power plant can be relied upon to produce it's expected energy volume during hours of highest risk. ELCC also captures the variability of solar and other DERs ability to generate during highest risk hours.

Energy Efficiency—The goal to reduce the amount of energy to produce the same result. In other words, using energy wisely to reduce total energy use (e.g., using LEDs instead of incandescent bulbs).

Energy Imbalance Market Load Aggregation Point (ELAP)—Energy Imbalance Market weighted average hourly price derived from sub-hourly prices for Idaho Power's entire system.

Energy Limited Resource (ELR)—A resource that can be dispatched for a limited number of hours and days, such as energy storage.

Energy Storage Device—A device that captures energy produced at a point in time and stores the energy for use as electricity at a future point in time, such as lithium-ion batteries that provide backup power at a home. An Energy Storage Device is a DER.

Equivalent Forced Outage Rate (EFOR)—Represents the number of hours a generation unit is forced off-line compared to the number of hours the unit runs. For example, an EFOR of 3% means a generator is forced off-line 3% of its running time.

Export Credit Rate (ECR)—Under a Net Billing compensation structure for customer-generators with Exporting Systems, the ECR is the amount paid to a generator for energy exported.

Exporting Systems—A customer-owned DER which is designed to provide for the transfer of electric energy to the electric utility system. For Idaho Power, an Exporting System takes service under the terms of Idaho Power's Schedules 6, 8, or 84.

Federal Energy Regulatory Commission (FERC)—The United States Federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce and regulates the transportation of oil by pipeline in interstate commerce.

Firm Energy—Energy that is to be scheduled, delivered, sold, received, and purchased on an uninterruptible basis. Firm energy cannot be interrupted at the seller's discretion.

Fixed Cost Adjustment (FCA)—A true-up mechanism that separates energy sales from revenue to ensure Idaho Power recovers the operational costs it incurs to maintain the electrical grid and provide electric service. The intent of the FCA is to reduce the financial disincentive that would otherwise exist when Idaho Power invests in demand-side management (DSM), which can contribute to customer's using less energy.

General Rate Case (GRC)—Proceedings with the Commission used to address the costs of operating and maintaining the utility system and to allocate those costs among customer classes.

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

Idaho Power Energy Risk Management Standards (ERMS)—The Energy Risk Management Policy and Energy Risk Management Standards define the Energy Risk Management Program to systematically identify, measure, evaluate, and manage both the physical and financial exposures to business and market-driven uncertainties within a defined and controlled framework, in collaboration with customer representatives.

Idaho Public Utilities Commission (Commission)—State governing body that regulates the rates and services of public utilities like Idaho Power.

Idaho Results of Operations (Idaho ROO or ROO)—A report of Idaho Power's system costs based on a 12-month period which may be based on a historical year and includes regulatory adjustments for normalizing and annualizing adjustments. Results of Operations are developed at Idaho Power's system level, and then allocated between the Idaho and Oregon jurisdictions to determine the Idaho ROO.

Institute of Electrical and Electronic Engineers (IEEE)—A professional association that develops, defines, and reviews electronics and computer science standards.

Integrated Resource Plan (IRP)—Examines the demand for energy in Idaho Power's service area over the next 20 years and the best ways to meet that demand. The plan is updated every two years and includes a series of public meetings that help guide the planning process. The IRP describes projected need for additional electricity and the resources necessary to meet that need while balancing reliability, environmental responsibility, efficiency, risk, and cost. Idaho Power enlists the assistance of its customers in developing the IRP through an advisory council.

Intercontinental Exchange Mid-Columbia (ICE Mid-C) Index—Global futures exchange for electrical energy specifically traded at the Mid-Columbia geographical region in central Washington. The Mid-Columbia is a liquid market allowing energy to be traded between utilities, merchants, and energy marketing agencies. The ICE Mid-C Index provides daily settled prices that include a high-load and a low-load price that is created based on day-ahead transactions executed on the ICE platform.

Jurisdictional Separation Study (JSS)—Allocates the system level revenue requirement between Idaho Power's Idaho and Oregon jurisdictions.

Kilowatt (kW)—Unit of power equal to 1,000 watts.

Kilowatt-hour (kWh)—A measure of electrical energy equivalent to a power consumption of 1,000 watts for one hour.

Load-Duration Curve (LDC)—A Load-Duration Curve indicates variation of the load, but with the load arranged in descending order of magnitude.

Loss of Load Expectation (LOLE)—The expected number of days per time interval for which the available generation capacity is insufficient to serve the demand at least once per day. The LOLE can be calculated by adding the maximum Loss of Load Probability from each day for a time interval (typically over one year).

Loss of Load Probability (LOLP)—The likelihood of the net system load exceeding the available generating capacity during a given time interval (typically an hour). The LOLP can be calculated by determining the probability that the available generation at any given hour is able to meet the net load during that same hour.

Megawatt (MW)—A unit of power equal to one million watts or 1,000 kilowatts. Typically used as a measure of the output of generation facilities.

Megawatt-hour (MWh)—A measure of electrical energy equivalent to 1,000 kWh.

National Renewable Energy Laboratory (NREL)—A federally funded research and development center sponsored by the Department of Energy and operated by the Alliance for Sustainable Energy. NREL specializes in the research and development of renewable energy, energy efficiency, energy systems integration, and sustainable transportation.

Net Billing—An alternative compensation method to Net Energy Metering (NEM). Like NEM, customer-generators can consume electricity generated by their system in real-time and export any generation in excess of on-site consumption to the utility grid. However, under Net Billing, banking of kWh within a billing cycle to offset future consumption does not occur. All net energy exports are measured at a shorter interval, typically hourly or real-time, and are credited at an ECR.

Net Energy Metering (NEM)—Allows on-site customer-generators to export excess energy to the utility grid when their systems are generating more electricity than they are consuming. NEM is a compensation structure where customer-generators receive a kWh credit for excess energy delivered to the grid. The kWh credit can be applied to offset energy consumption within the current billing cycle or future billing cycles. NEM requires a single bi-directional meter read for the billing period.

Net Load-Duration Curve (NLDC)—The total Load Duration Curve minus the time-synchronized contribution from DER generation. The resulting net load is then sorted by hour, from the highest load to the lowest load.

Net Power Supply Expense (NPSE)—The sum of the following Federal Energy Regulatory Commission (FERC) accounts: Account 501, Fuel (coal); Account 536, Water for Power; Account 547, Fuel (gas); Account 555, Purchased Power; Account 565, Transmission of Electricity by Others; and Account 447, Sales for Resale (typically referred to as surplus sales).

Non-Exporting System—A customer-owned DER that limits or prevents electrical energy from transferring to the electric utility system. For Idaho Power, a Non-Exporting System takes service under the standard applicable retail schedule.

Non-Firm Energy—Energy that is to be scheduled, delivered, sold, received, and purchased on an interruptible basis. Non-firm energy can be interrupted at the seller's discretion.

On-Site Customer-Generator or Customer-Generator—A customer applying to operate or operating a DER in parallel with the electric utility system.

Parallel—Parallel connection means operating DER that is connected to and receives voltage from Idaho Power's system. Operating in parallel allows the system to connect to and interact with the electric utility's grid. A system that is not wired in parallel does not connect to or affect the electric utility's grid.

Peak Capacity Allocation Factor (PCAF)—A method to estimate the contribution to peak of solar on distribution systems using a certain number (or percentage) of the highest load (i.e., peak) hours.

Perfect Generator—A generation unit whose EFOR value is 0%, meaning that it is always available and never forced off-line.

Power Cost Adjustment (PCA)—Cost-recovery mechanism that passes on both the benefits and costs of supplying energy to Idaho Power customers.

Power Purchase Agreement (PPA)—Contract between two parties, one which generates electricity (the seller) and one which purchases electricity (the buyer). The PPA defines all of the commercial terms for the sale of electricity between the two parties, including when the project will begin commercial operation, schedule for delivery of electricity, penalties for under delivery, payment terms, and termination.

Public Utility Regulatory Policies Act of 1978 **(PURPA)—**The United States Act passed as part of the National Energy Act. It was meant to promote energy conservation (reduce demand) and promote greater use of domestic energy and renewable energy (increase supply). The main vehicle that the PURPA law used to try and accomplish these goals was by creating a new class of electric generating facilities called “qualifying facilities” or “QFs”— PURPA gave QFs special rate and regulatory treatment.

Qualifying Facilities (QF)—Generating facility that meets the criteria specified by the FERC and that sells power to an electrical company.

Renewable Energy Certificate (REC)—A REC is a financial mechanism that allows for the purchase of environmental attributes associated with renewable resources. One REC represents the environmental benefits of one megawatt-hour of renewable electricity. RECs can either be sold together with energy from that resources (bundled RECs), or sold separately from the energy (unbundled RECs).

Renewable Portfolio Standard (RPS)—State regulation that requires the increased production of energy from renewable energy sources, such as wind, solar, biomass, and geothermal. The RPS mechanism places an obligation on electricity supply companies to provide electricity from renewable energy sources.

Sales Based Adjustment Rate (SBA)—A component of the Power Cost Adjustment that accounts for changes in power supply expense recovery due to differences between the sales forecast used to set the amount of base net power supply expense recovery in rates and actual sales.

Schedule 6, Residential Service On-Site Generation (Schedule 6)—Idaho Power’s tariff schedule for Idaho residential service customers that operate a generation facility fueled by solar, wind, biomass, geothermal, hydropower, or fuel cell technology, with a total nameplate capacity rating of 25 kW or less connected in parallel with the Idaho Power system.

Schedule 8, Small General Service On-Site Generation (Schedule 8)—Idaho Power’s tariff schedule for Idaho small general service customers that operate a generation facility fueled by solar, wind, biomass, geothermal, hydropower, or fuel cell technology, with a total nameplate capacity rating of 25 kW or less connected in parallel with the Idaho Power system.

Schedule 68, Interconnections to Customer Distributed Energy Resources (Schedule 68)—Idaho Power’s tariff schedule that applies to construction, operation, and maintenance of a customer-generator system interconnected in parallel with Idaho Power’s system.

Schedule 84, Customer Energy Production/Net Metering Service (Schedule 84)—Idaho Power’s tariff schedule for Oregon residential and small general service customers, and Idaho and Oregon commercial, industrial, and irrigation customers that operate a generation facility fueled by solar, wind, biomass, geothermal, hydropower, or fuel cell technology connected in parallel with the Idaho Power system.

Schedule 86, Cogeneration and Small Power Production Non-Firm Energy (Schedule 86)—Idaho Power's tariff schedule applicable to any seller that owns or operates a QF with a nameplate capacity rate of less than 10 MW and desires to sell energy generated by the QF to Idaho Power on a non-firm, if, as, and when available basis.

Study Framework—Framework to study the costs, benefits, and compensation of net excess energy associated with on-site customer generation approved by the Commission in Case No. IPC-E-21-21 in Order No. 35284.

Underwriter Laboratories (UL)—Safety organization that sets industry-wide standards for new products. UL testing ensures that wire sizes are correct and that electronic devices can handle the amount of current claimed by the manufacturer. UL is one of several companies approved to perform safety testing by the Occupational Safety and Health Administration.

Variable Energy Resource (VER)—Any renewable generation resource whose output cannot be directly stored or controlled by the facility owner or operator. Examples include wind or solar resources, whose hourly output is dependent on a multitude of factors like weather and environmental conditions.

Western Energy Imbalance Market (Western EIM or EIM)—Real-time energy market that allows participants to buy and sell power close to the time electricity is generated and consumed and gives system operators real-time visibility across neighboring grids. The EIM balances fluctuations in supply and demand by automatically finding lower-cost resources to meet real-time power needs. The EIM manages congestion on transmission lines to maintain grid reliability and supports integrating renewable resources. The EIM focuses on real-time imbalances and allows participants to retain all balancing responsibilities and transmission provider duties.

1. Executive Summary

On December 30, 2021, the Idaho Public Utilities Commission (Commission) approved a final framework to comprehensively study the costs and benefits of on-site customer generation (Study Framework) in Order No. 35284 in Case No. IPC-E-21-21. This Value of Distributed Energy Resources (VODER) study was developed under the direction of the Commission and documents analysis of the benefits and costs of on-site customer generation within Idaho Power's service area. The comprehensive study incorporates data for residential, small general, commercial, industrial, and irrigation customers with Exporting Systems installed and active for all 12 months of 2021. The study does not advocate for a single position regarding potential modifications to Idaho Power's net metering service, but rather explores several methods of valuing customer on-site generation energy exports and explores other important considerations.

The Study Framework included an analysis of an hourly and real-time measurement interval to measure excess energy to present a fair picture for public evaluation. The analysis for the Export Credit Rate (ECR) builds up the components of potential benefits and costs that on-site customer generation net exports bring when interconnected with the electric system. The Study Framework included the general categories related to the ECR illustrated in Figure 1.1, which are evaluated in Section 4 of the study.

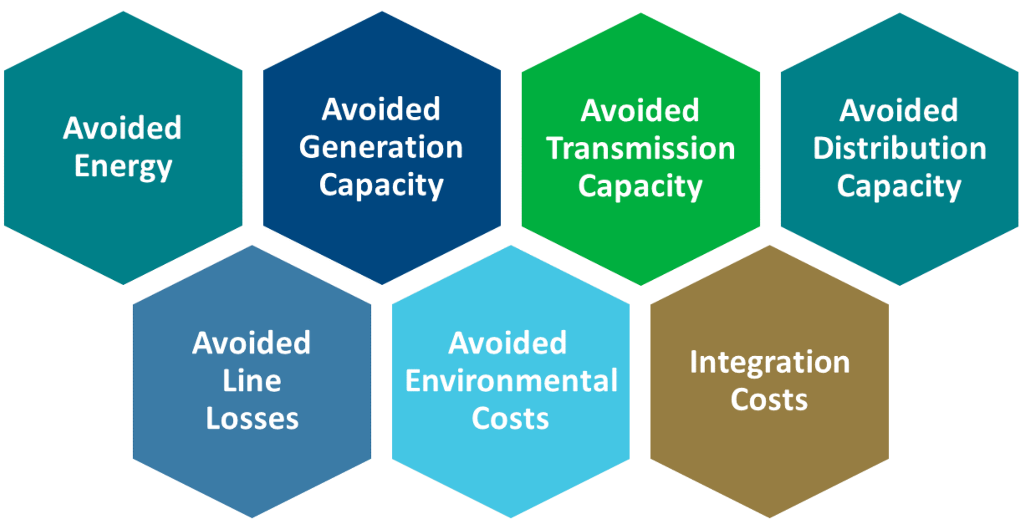


Figure 1.1
Study Framework — ECR benefits and cost components

The ECR benefit and cost components described in the study can vary in value depending on the use of net excess exported energy measured on a net hourly or real-time measurement interval. For the study, export credit values are summarized under a real-time measurement interval, but values under both an hourly and real-time measurement have been evaluated and included within the appendices referenced herein. The values used in the study are only intended to be indicative or illustrative of the different methods evaluated. For example, Section 4 of the study uses a three-year average of energy prices to illustrate the potential value. The study is not forward-looking, and market energy prices are subject to a certain degree of volatility. As discussed in Section 4 (Export Credit Rate) and Section 5 (Frequency of Export Credit Rate Updates), the energy prices used could be based on historical actuals, a historical average over two or more years, or real-time actual market prices. The considerations of each approach are discussed herein and would require further discussion while implementing changes to the on-site customer generation service offering.

In addition to evaluating the ECR and net hourly and real-time measurement intervals, the Study Framework incorporated several other areas of study related to on-site customer generation. The Commission directed the study to provide a thorough evaluation of the 25 kilowatt (kW) and 100 kW Commission-approved project eligibility caps through this study. The Study Framework also directed the study to include consideration for other areas of study, such as the timing of updates to the ECR, an evaluation of expiring credits, and billing structure considerations. The study concludes with a summary of implementation considerations, including transitional rates, administrative and system updates, and customer notice and communication. The study provides the public, stakeholders, and the Commission with the necessary information to be well informed for recommendations and, ultimately, Commission approval and authorization of any changes to the on-site customer generation offering.

2. Introduction

2.1 On-Site Generation Overview

Idaho Power supports customer choice and interest in clean energy. Under Idaho Power's on-site generation service offerings, Idaho Power's customers can choose to install electricity-generating equipment at their home or business to offset some of their electric needs. Most commonly, customers install solar photovoltaic technology, which for ease of understanding, will be referred to as solar in the remainder of this study. This subset of customers is referred to throughout this study as "on-site customer-generators." On-site customer-generators choose to remain connected to Idaho Power's grid, or "interconnected," which allows them to consume energy as needed from Idaho Power's system. The vast majority of on-site customer-generators also export energy to the grid.

For example, a rooftop solar system may generate more energy than the building needs during the day, and that excess energy can be sent, or "exported," to Idaho Power's grid. At night or anytime solar panels are not generating enough energy, the customer uses Idaho Power's grid for their energy needs. Figure 2.1 provides a simplified illustration of an on-site customer-generator interconnected with the utility's system.

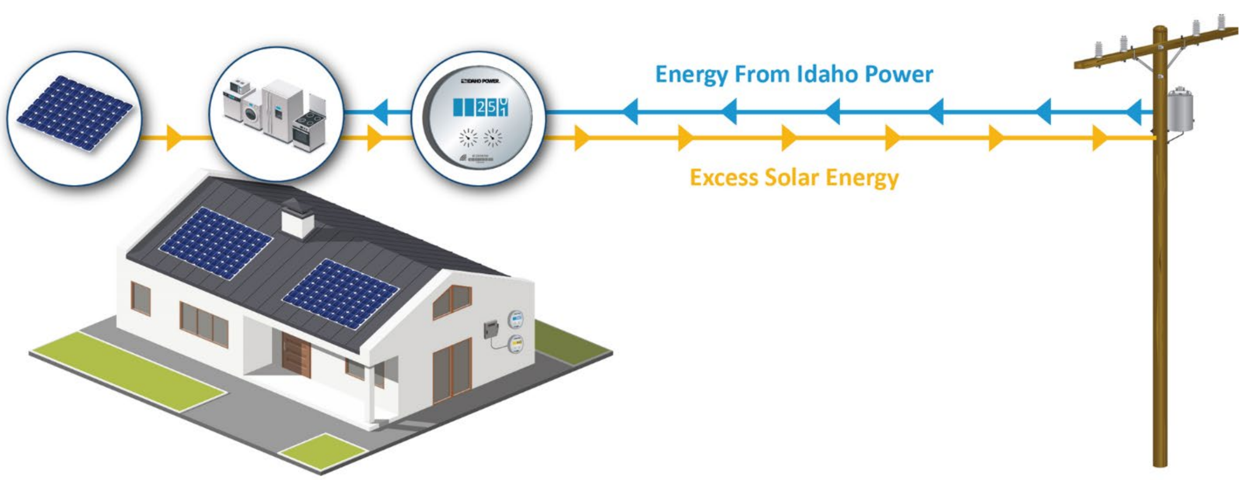


Figure 2.1
Illustration of on-site generation

Customers who generate some of their electricity and who interconnect an Exporting System 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)
- Schedule 84, Customer Energy Production/Net Metering Service (Schedule 84)

MEASURMENTS OF ENERGY & DEMAND

Throughout this study, energy is reported in kilowatts (kW) and kilowatt-hours (kWh), or megawatts (MW) and megawatt-hours (MWh).

A kilowatt is a measure of how much power is needed or produced at a moment in time. Equipment, including wires, breakers, and transformers must be sized to support the maximum amount of power in kilowatts that will flow through them. One megawatt is equivalent to 1,000 kilowatts.

A kilowatt-hour is a measure of how many kilowatts are needed or produced over an hour. A megawatt-hour is equivalent to 1,000 kilowatt-hours.

A one-kilowatt solar array can produce one kilowatt of power at a moment in time. If the array generates power for 2 hours, it can produce 2 kilowatt-hours of energy (1 kilowatt array x 2 hours = 2 kilowatt-hours).

Schedule 84 is the schedule under which the company's Idaho commercial, industrial, and irrigation customers and all Oregon customers take net metering service.[1]

Customers who do not want their generation systems to export energy to the electrical grid may interconnect with a Non-Exporting System so that they consume all energy generated on-site. Customers with Non-Exporting Systems do not require a change to their rate schedule. Rather, they take service under the retail rate schedule they qualify for based on the

[1] Pursuant to ORS 757.300, an electric utility serving fewer than 25,000 customers in Oregon that has its headquarters located in another state and offers net metering services or a substantial equivalent offset against retail sales in that state shall be deemed to be in compliance with this section if the electric utility offers net metering services to its customers in Oregon in accordance with tariffs, schedules, and other regulated promulgated by the appropriate authority in the state where the electric utility's headquarters are located.

applicability of Idaho Power'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.

As of May 31, 2022, Idaho Power had 12,322 active and pending Exporting Systems under Schedules 6, 8, and 84. Active systems completed Idaho Power's interconnection process and are approved to operate, pending systems are working through the interconnection process. Collectively, these customer systems represent approximately 118 MW of total nameplate capacity. Table 2.1 provides the total number of active and pending Exporting Systems in Idaho Power's service area by resource and customer type.

Table 2.1
Active and pending Exporting Systems as of May 31, 2022

Customer Type	Solar PV	Wind	Hydro/Other	Total
Residential	11,773	27	7	11,807
Small General	69	-	4	73
Commercial & Industrial	200	-	-	200
Irrigation	242	-	-	242
Total	**12,284**	**27**	**11**	**12,322**

Table 2.2 provides the total nameplate capacity, or size, of active and pending Exporting Systems in Idaho Power's service area by resource and customer type.

Table 2.2
Active and pending Exporting System nameplate capacity in megawatts (MW) as of May 31, 2022

Customer Type	Solar PV	Wind	Hydro/Other	Total
Residential On-Site Generation	88.73	0.11	0.07	88.92
Small General On-Site Generation	0.48	-	0.09	0.57
Commercial & Industrial	6.56	-	-	6.56
Irrigation	22.00	-	-	22.00
Total	**117.77**	**0.11**	**0.16**	**118.04**

Note: Totals may not sum due to rounding.

Figures 2.2 and 2.3 detail the cumulative number of Exporting Systems and nameplate capacity, respectively, by customer type in Idaho Power's service area from 2002 through May 31, 2022 (including pending applications).

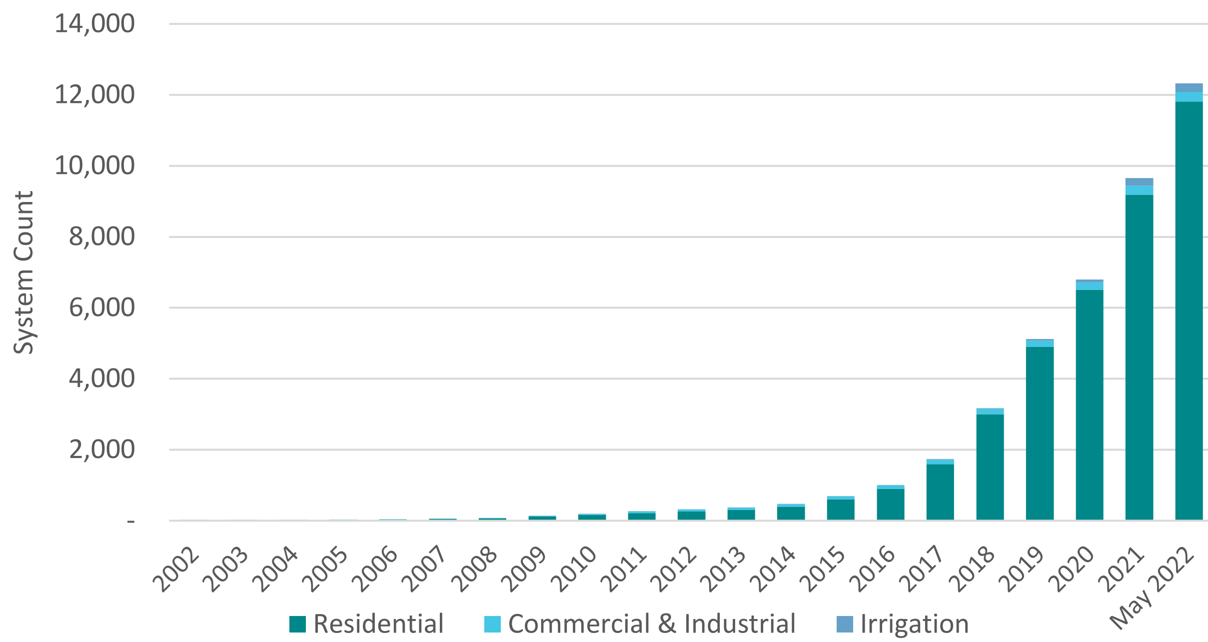


Figure 2.2
Cumulative Exporting System counts by customer type, 2002 — May 31, 2022

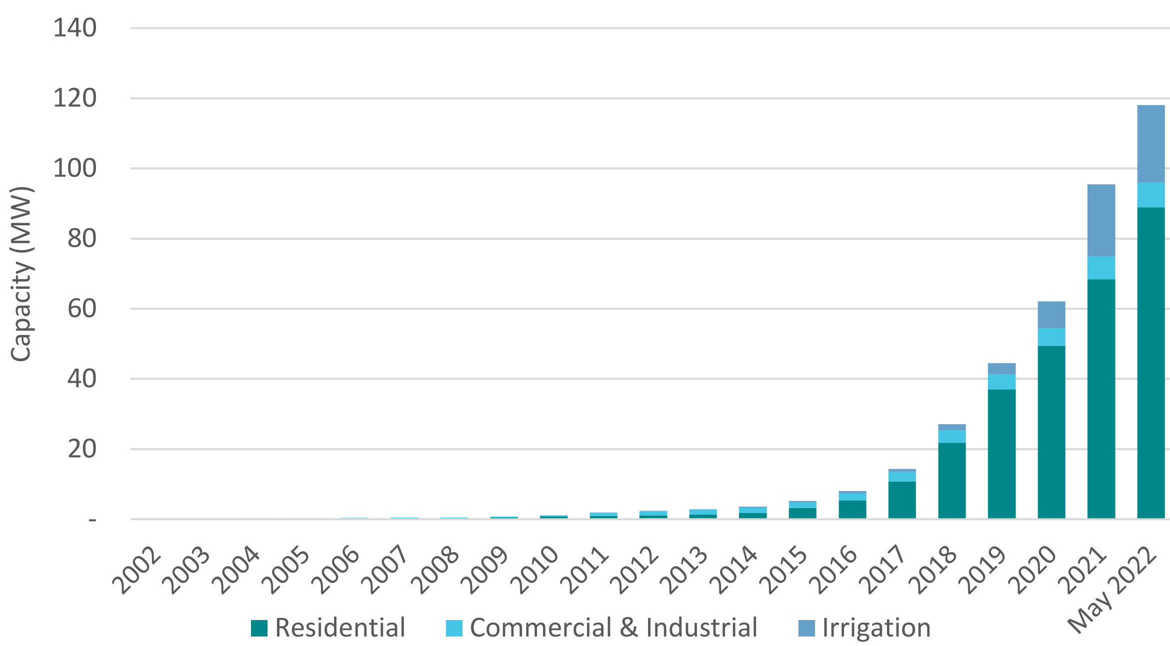


Figure 2.3
Cumulative Exporting System capacity by customer type, 2012 — May 31, 2022

When customers billed under Schedules 6, 8, and 84 generate more energy than they consume on-site, they earn a “kWh credit” for the excess energy sent to the grid. In addition to a fixed monthly service charge, the customer is billed for their net energy use, which is the amount they use from Idaho Power minus the excess energy they export to the grid over the monthly bill period.

Figure 2.4 shows the average residential customer-generator system size installed by year of interconnection. From 2011 through May 31, 2022, the average residential system size has increased from 4 to 7.6 kW, representing a 6.7% compound annual growth rate.

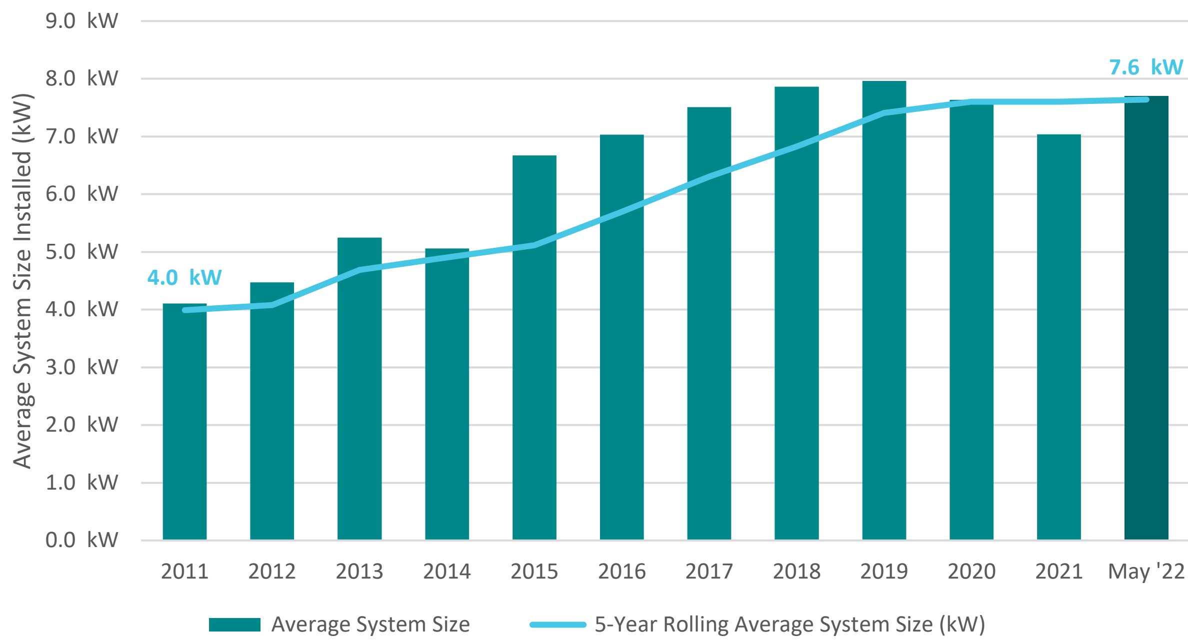
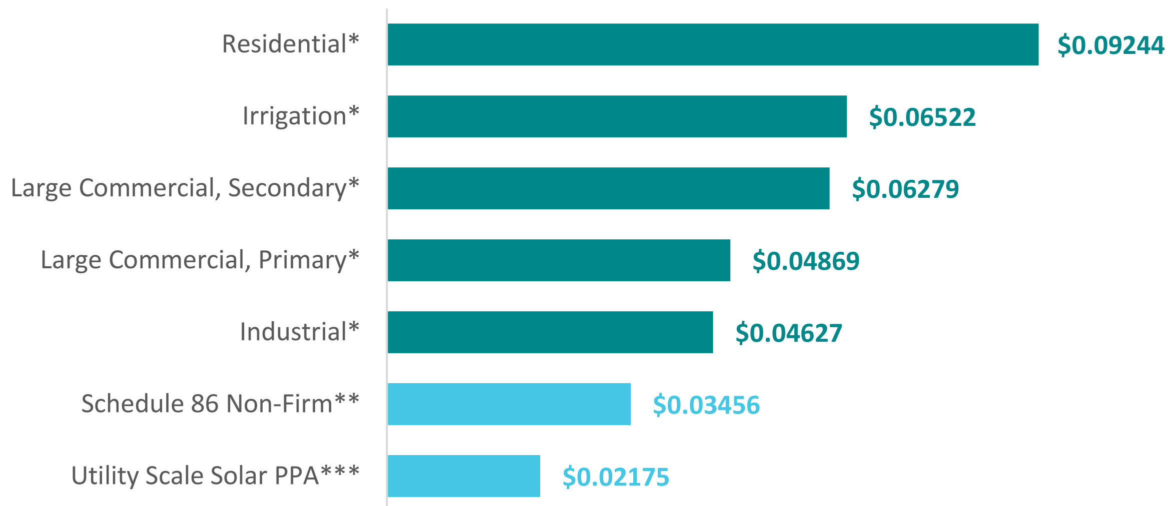


Figure 2.4
Residential customer-generator average system size by year and five-year rolling average

The circumstances that existed when the Commission initially established Idaho Power's net metering policies and practices have changed dramatically over the last two decades. As more customers install on-site generation, the existing compensation structures do not account for the nuances of the current environment. For example, on-site customer-generators use energy from the utility at night, when the sun doesn't shine, or at any moment the on-site generation system cannot meet a customer's energy needs. As a result, a monthly measurement interval doesn't accurately reflect the value of the grid's bi-directional service (energy sent both to and from the utility's electric grid) provided to on-site customer-generators during different hours and days of the billing period nor the value of the energy being produced.

The existing compensation structure ties the Export Credit Rate (ECR) to the retail energy rate, which varies by customer class (e.g., residential, irrigation, commercial, etc.) and is not inherently based on the value of the exported energy. Instead, the variation in the retail energy rate between customer classes is the result of outcomes from the rate making process.
The retail energy rate includes variable energy-related components and fixed operations and

maintenance and plant-related costs associated with the electrical grid and customer care. For example, approximately 35% of the residential retail energy rate represents variable energy-related components and 65% represents fixed operations and maintenance and plant-related costs. Figure 2.5 illustrates the retail energy rate, which results in the effective ECR realized by customers under the existing net metering structure, and how that varies between customer classes.



Notes:
* Current average retail energy rate, including 2021 Power Cost Adjustment
** Schedule 86, 2021 annual average market based rate
*** Jackpot Solar Power Purchase Agreement, first year contract price for 120 MW

Figure 2.5
Retail energy rate comparison chart

2.2 Regulatory History

Idaho Power has offered a net metering option for its customers since 1983, when Idaho Power had a single customer with on-site generation who wished to interconnect to the company's system. At that time, the company's net metering service was offered as an option under Schedule 86, Cogeneration and Small Power Production Non-Firm Energy (Schedule 86). However, the pricing structure that was applied under Schedule 86 required a manual billing process that was complex, time intensive, and was only designed to accommodate solar installations.

In 2002, and still with only the single customer taking net metering service, the Commission established Schedule 84 to specifically apply to net metering customers. The creation of Schedule 84 simplified the pricing for net metering customers by implementing the retail rate credit for excess energy, which allowed Idaho Power to use its existing billing system, a single meter, and enabled Idaho Power to expand its net metering service more easily to a broader range of generation resources. The Commission also established a 2.9 MW limit, or "cap," on the cumulative nameplate capacity for generation taking service under Schedule 84.

In 2012, the company initiated a case with the Commission requesting the Commission expand the cumulative nameplate capacity cap and implement other pricing changes that would have taken steps towards modernizing the company's on-site generation service offering.

In the last five years, Idaho Power filed five cases related to on-site customer generation, with the focus of those cases aimed at modernizing Idaho Power's pricing structure to reflect the value of bi-directional energy flow. Through these proceedings, the Commission has determined that a comprehensive study should inform the ultimate determination of the costs and benefits of on-site customer generation to Idaho Power's system with the opportunity for public comment and participation. The Commission approved a Study Framework that defined the scope of this study in Case No. IPC-E-21-21.[2]

The following section summarizes the most recent regulatory history related to on-site generation.

2.2.1 Case No. IPC-E-17-13

In Case No. IPC-E-17-13, Idaho Power explained that the rates charged to net metering customers were not designed to reflect the value of the service being provided to them and that the inaccuracies in pricing could result in cost-shifting between customers who choose to install on-site generation and those who do not.[3] Idaho Power asked to first establish new customer classes for residential and small general service customers with on-site generation. Subsequently, Idaho Power asked to select a compensation structure for on-site customer generation that reflects the benefits and costs of distributed energy resource interconnection to the electrical system.[4] In its application, Idaho Power stated its ultimate goal was to ensure a service offering for on-site customer-generators that is fair-priced, scalable, and sustainable into the future.

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[2] *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, Order No. 35284 at 32-33.

[3] *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, Application at 1 (July 27, 2017).

[4] *Id*. at 15-16.

In Order No. 34046, the Commission removed Idaho residential and small general service customers with Exporting Systems from Schedule 84 and created two new tariff schedules: Schedule 6 and Schedule 8.[5] Schedule 84 continues to define the terms for Idaho commercial, industrial, and irrigation customers with Exporting Systems. To more accurately assign the appropriate share of fixed costs and benefits of on-site customer generation, the Commission also directed Idaho Power 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 compensation for net excess energy provided as a resource to the company."[6] The Commission encouraged the parties to work through these issues together in compromise.[7]

2.2.2 Case No. IPC-E-18-15

As a result of Order No. 34046, 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.[8] Subsequently, Idaho Power, Commission Staff, and various stakeholders undertook a thorough, data-driven evaluation of Idaho Power's on-site generation offering. Through this collaborative process, the parties agreed to compromise on many critical elements of Idaho Power's on-site generation offering. The proposed settlement agreement[9] would have changed several fundamental aspects of Idaho Power's net metering program. Under the settlement, Idaho Power would have changed from monthly to hourly net calculations for on-site customer-generators' energy production and consumption, and customers would have been credited with a monetary export credit rate for hourly net energy exported to the grid instead of net excess energy being compensated at a 1:1 kWh credit. The settlement agreement envisioned that existing residential and small general service customers would transition from retail rate monthly net metering to net hourly billing over eight years.[10] At the end of the

[5] Case No. IPC-E-17-13, Order No. 34046 at 30-31 (May 9, 2018).

[6] *Id*. at 31.

[7] *Id*. at 22.

[8] *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, Petition to Initiate a Docket (October 19, 2018).

[9] Case No. IPC-E-18-15, Motion to Approve Settlement Agreement (October 11, 2019).

[10] The study describes Net Energy Metering and Net Billing in more detail in Section 3 (Measurement Interval).

transition period, net exports would have been compensated at roughly half of the then current residential energy consumption rate.

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 requirements established in Case No. IPC-E-17-13.[11] As a result, the Commission reiterated that it would consider no changes to Idaho Power's net metering service until Idaho Power prepared and filed a "credible and fair study" of the costs and benefits of distributed on-site customer generation that meets the following criteria:[12]

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) Idaho Power 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, and its analysis must be able to withstand expert scrutiny.

LEGACY STATUS – RESIDENTIAL & SMALL GENERAL SERVICE CUSTOMER SYSTEMS

A legacy (i.e., grandfathered) system is defined as either an on-site generation system interconnected with Idaho Power's system as of the service date of Order No. 34509 or a customer with a binding financial commitment to install an on-site generation system that proceeds to interconnect their system on or before December 20, 2020. Legacy systems are subject to the rules in place as of the service date of Order No. 34509, including the excess energy compensation structure. The Commission determined that Schedule 6 and Schedule 8 systems that qualify for legacy treatment continue to be subject to changes in consumption rates but not to changes in the 1:1 monthly kWh retail rate compensation structure until legacy status terminates on December 20, 2045. As of March 31, 2022, there are approximately 5,300 legacy residential and small general service systems interconnected to Idaho Power's system.

[11] Case No. IPC-E-18-15, Order No. 34509 at 6 (December 20, 2019).

[12] *Id*. at 9.

LEGACY STATUS – COMMERCIAL, INDUSTRIAL & IRRIGATION CUSTOMER SYSTEMS

Similar to Case No. IPC-E-18-15, the Idaho Public Utilities Commission determined that Schedule 84 systems that qualify for legacy treatment, also referred to as grandfathered systems, continue to be subject to changes in consumption rates but not to changes in the 1:1 monthly kWh retail rate compensation structure until legacy status terminates on December 1, 2045. As of March 31, 2022, there are approximately 390 legacy Schedule 84 systems interconnected to Idaho Power's system.

In its Order, the Commission outlined a "study design" phase and a "study review" phase. During the "study design" phase, Commission Staff and Idaho Power will both "host public workshops to share information and perspectives on net-metering program design with the public and listen to customer concerns and input."[13] In the "study review" phase, the public will have the opportunity to comment on whether the study sufficiently addressed their concerns and opinions on what the study shows.[14]

While the study is intended to inform the implementation of changes to on-site generation compensation and billing structures, the Commission established criteria[15] to define legacy treatment for existing systems under Schedule 6 and Schedule 8.

2.2.3 Case Nos. IPC-E-19-15 and IPC-E-20-26

The company initiated Case No. IPC-E-19-15 while the issues in Case No. IPC-E-18-15 were still under Commission review. In the application, Idaho Power highlighted concerns that Schedule 84 customers were continuing to rely on the expectation of the ongoing application of the net monthly billing and compensation structure and asked the Commission to initiate the new docket to consider similar issues as to what was under review in Case No. IPC-E-18-15, but for commercial, industrial, and irrigation customers taking service under Schedule 84. Over the next several months, Idaho Power and parties engaged in settlement negotiations similar to those occurring simultaneously in Case No. IPC-E-18-15. Subsequent to the Commission rejecting the settlement agreement in Case No. IPC-E-18-15, Idaho Power withdrew its application, indicating the matters related to compensation structure and export credit rate for

[13] *Id*. at 9-10.

[14] *Id*.

[15] *See* Case No. IPC-E-18-15, Order No. 34509 at 14-15 and Order No. 34546 at 8-11 (February 5, 2020).

Schedule 84 would be appropriately considered in the new future comprehensive study docket, as prescribed by Order Nos. 34509 and 34546.

In June 2020, the company initiated Case No. IPC-E-20-26 for authorization to change Schedule 84's two-meter requirement to a single-meter requirement for new customer-generators and establish legacy treatment for existing customer-generators under the current rules as of December 1, 2020. The Commission ultimately established criteria similar to Case No. IPC-E-18-15, to provide legacy treatment to existing Schedule 84 systems under the rules in place as of the service date of Order No. 34854, December 1, 2020.[16] Order Nos. 34854 and 34892[17] delineated legacy systems and new systems subject to future changes informed by a comprehensive study. A legacy system is defined as either an on-site generation system interconnected with Idaho Power's system as of the service date of Order No. 34854 or a customer with a binding financial commitment to install an on-site generation that proceeds to interconnect their system on or before December 1, 2021.[18]

2.2.4 Case No. IPC-E-21-21

On June 28, 2021, Idaho Power applied for the Commission to initiate the multi-phase process for a comprehensive study of the costs and benefits of on-site generation as directed in Order No. 34046.[19] 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 the Study Framework. 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.[20]

The Commission ordered Idaho Power to "complete the study in 2022 as soon as feasible" and indicated that "persons and parties will have another opportunity to participate during the study review phase."[21] Finally, the Commission reminded stakeholders in the on-site customer

[16] *In the Matter of Idaho Power Company's Application for Authority to Modify Schedule 84's Metering Requirement and to Grandfather Existing Customers with Two Meters*, Case No. IPC-E-20-26, Order No. 34854 at 11 (December 1, 2020).

[17] Case No. IPC-E-20-26, Order No. 34892 (January 14, 2021).

[18] *Id*. at 9.

[19] Case No. IPC-E-21-21, Application (June 25, 2021).

[20] Case No. IPC-E-21-21, Order No. 35284 at 9. *See also* Case No. IPC-E-18-15, Order No. 34509 at 9-10.

[21] Case No. IPC-E-21-21, Order No. 35284 at 32 and 10.

generation industry to act with transparency when engaging with potential investors and emphasized yet again that "[a] utility's rate schedules, including net metering program fundamentals, are subject to change...[and][a]s such, there is no guaranteed return on investment."[22]

2.3 Commission-Approved Study Framework

The Commission approved a final framework to study the costs, benefits, and compensation of net excess energy associated with on-site customer generation in Order No. 35284 in Case No. IPC-E-21-21. The study was developed under the direction of the Commission and documents the comprehensive analysis of the benefits and costs of on-site customer generation for all Exporting Systems within Idaho Power's service area.

The study complies with the Commission-approved Study Framework. The study and accompanying appendices represent a comprehensive study for the "study review" and implementation phases. The following sections of the study are listed below.

- Section 3 — Measurement Interval
- Section 4 — Export Credit Rate
- Section 5 — Frequency of Export Credit Rate Updates
- Section 6 — Compensation Structure
- Section 7 — Class Cost-of-Service
- Section 8 — Recovering Export Credit Rate Expenditures
- Section 9 — Project Eligibility Cap
- Section 10 — Other Areas of Study (e.g., billing structure, credit transfer/expiration)
- Section 11 — Implementation Considerations

[22] *Id*. at 10.

3. Measurement Interval

This study evaluates two metering and billing arrangements: 1) Net Energy Metering (NEM) and 2) Net Billing.[23] The study considers three measurement intervals: 1) monthly, 2) hourly, and 3) real-time. The "measurement interval" refers to the length of time between meter reads to measure the energy *delivered to* and *received from* the customer-generator. The monthly measurement interval used for Net Energy Metering is the billing arrangement and compensation structure currently used for Idaho Power customers and will serve as the base case for the comparison in the study. The study compares the base case (Net Energy Metering) with Net Billing under hourly and real-time measurement intervals as illustrated in Figure 3.1.

	Compensation Structures	
Measurement Intervals	**Net Energy Metering**	**Net Billing**
Monthly	✓	
Hourly		✓
Real-Time		✓

Figure 3.1
Measurement intervals and compensation structures studied

Net Energy Metering was initially implemented when residential rate designs were limited by meters that could only measure one variable — inflow and outflow of energy across a single point or channel. The utility had one data point — monthly net energy — on which to base the compensation structure for excess energy. The circumstances that existed when the Commission initially established Net Energy Metering policies and practices have changed dramatically. In Idaho Power's service area, advanced metering infrastructure has been deployed. Meters can now measure energy flowing to the utility on one channel and all energy flowing from the utility on another channel. This provides more options and more precise measurement intervals from which to develop a compensation structure. Figure 3.2 illustrates the difference in the metering data capabilities of a traditional bi-directional meter and advanced metering infrastructure with separate channel meter read capabilities.

[23] Net Energy Metering is described in more detail in Section 3.1 of the study. Net Billing is described in more detail in Section 3.2 of the study.

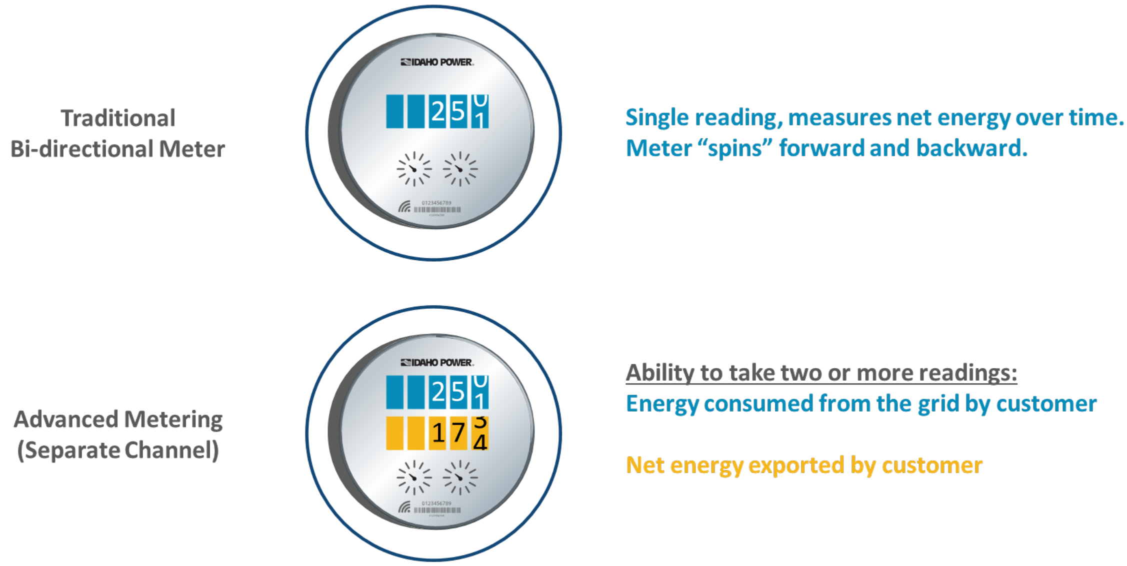

Figure 3.2
Illustration of bi-directional meter and advanced separate channel meter

3.1 Net Energy Metering

Net Energy Metering, often referred to as "net metering," allows on-site customer-generators to export excess energy to the utility grid when their systems are generating more electricity than they are consuming. Customer-generators receive a credit in kWh for the excess energy. The credit is in terms of a kWh, so it can be applied to offset energy consumption within the current billing cycle (i.e., one month) and often in future billing cycles. The on-site customer-generator is billed for net energy consumption during a billing cycle (i.e., energy consumed during the billing cycle, less energy generated during the same period, each measured in kWh). In practice, the bi-directional meter "spins backward" when the system is generating more than the customer-generator is using, decreasing the meter's measurement of the customer-generator's net monthly kWh consumption. Net Energy Metering requires a single bidirectional meter read.

Figure 3.3 is a Net Energy Metering schematic and illustrates how net consumption or generation is measured over the billing period with a single meter read.

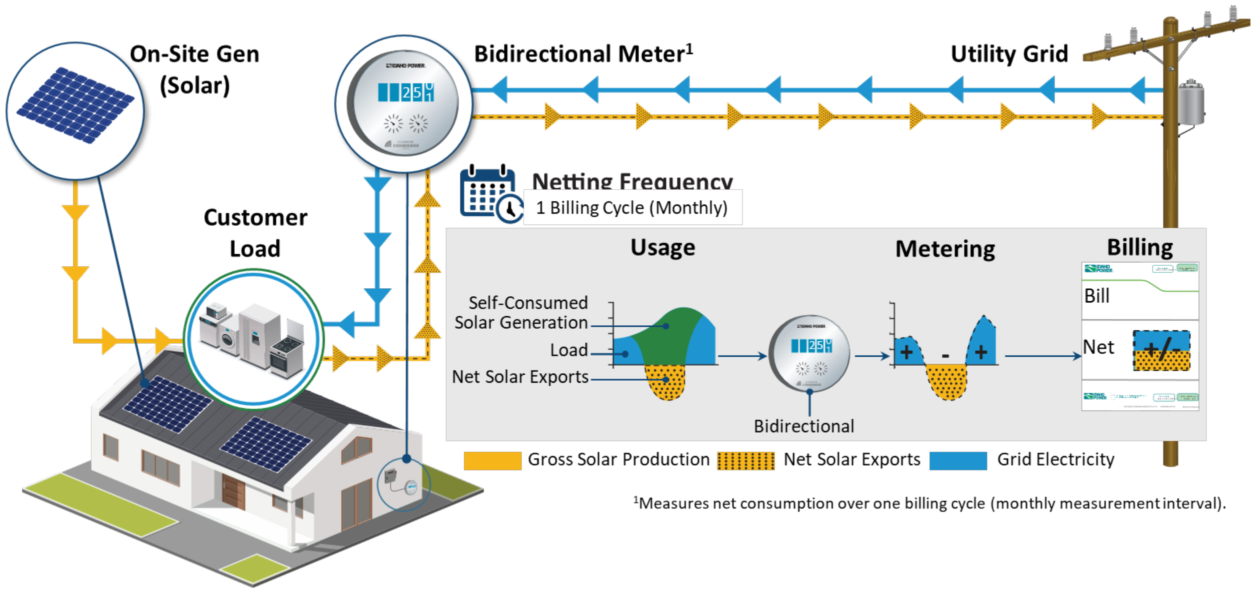

Figure 3.3
Net Energy Metering schematic

Under Net Energy Metering, an on-site customer-generator can carry the balance or "bank" kWh within a billing cycle because the meter only reports net consumption at the end of the billing cycle. During a billing cycle, the customer-generator's electricity generated may exceed electricity consumed from the grid; in this case, customer-generators can typically bank those credits between cycles (i.e., carry the balance forward to the next billing cycle). Typically, these credits can be banked indefinitely or may expire at a predetermined time and be credited at an Export Credit Rate (ECR), depending on the specific Net Energy Metering offering. Under Idaho Power's existing net metering offering, credits do not expire if the account remains open and may be transferred to qualifying accounts[24] on an annual basis.

3.2 Net Billing

Net Billing is similar to Net Energy Metering in that an on-site customer-generator can consume electricity generated by their system in real-time and export any generation in excess of on-site consumption to the utility grid. However, under Net Billing, banking of kWh within a billing cycle to offset future consumption does not occur — in fact, credits are not granted in kWh terms at all. Instead, when exported to the grid, all net energy exports are metered and credited at an Export Credit Rate (ECR), which will have a monetary value rather than a kWh value.

[24] Schedules 6, 8, and 84 contain requirements for annual transfer of unused Excess Net Energy credits.

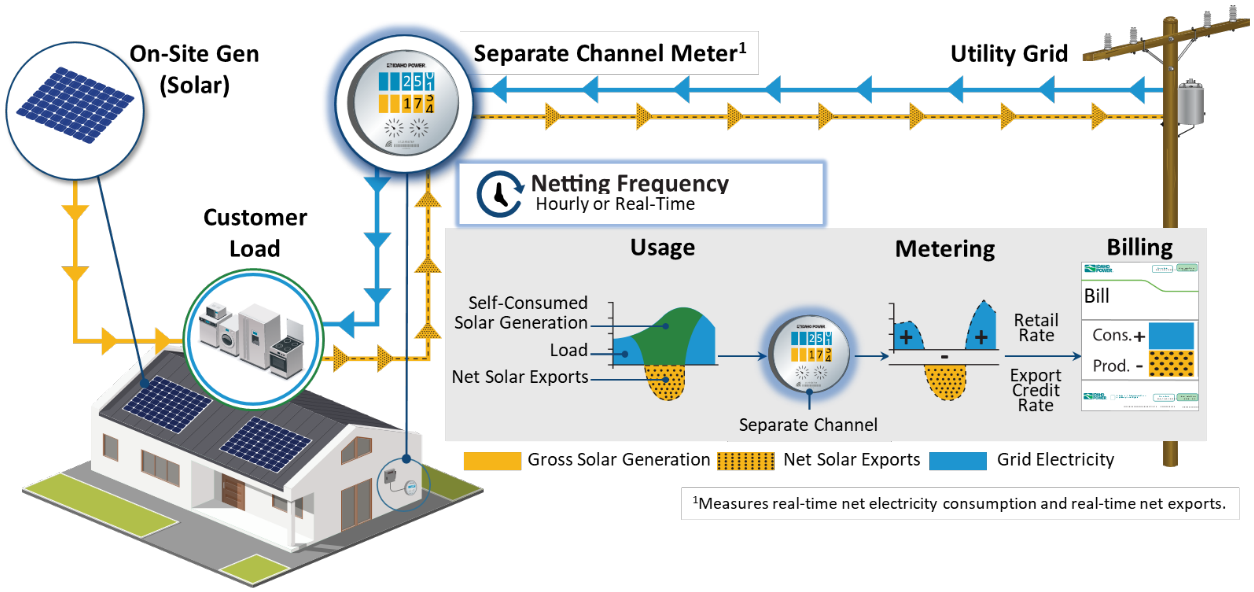

Figure 3.4
Net Billing schematic

If at any point the customer is generating more electricity than they are using on-site, then the customer is net exporting — injecting electricity into the grid. Similarly, if at any point the customer is using more electricity than they are producing, then the customer is net consuming and drawing electricity from the grid. The advanced meter's "received" channel would spin forward, measuring the exported kWh, and the customer would receive the export credit rate for the exported electricity. The advanced meter's "delivered" channel would spin forward, measuring the electricity being drawn from the grid, and the customer would pay the applicable retail energy rate for this energy. Neither the "received" or "delivered" channel can "spin backward" during a billing cycle under Net Billing. Instead, they only spin forward when separately measuring net consumption and net exports in real-time. The meter records real-time net grid electricity consumption and exports separately — both are measured and aggregated independently by the meter.

Figure 3.4 is a Net Billing schematic that illustrates how net exports and grid electricity are separately aggregated and measured over either an hourly or real-time measurement interval. Note that the meter cannot measure gross or total solar generation. The meter only measures the excess solar energy that is exported to the grid and does not capture the amount of solar energy that is used on the customer's side of the meter. The solar energy that the meter does not measure is depicted in Figure 3.4 as "Self-Consumed Solar Generation" in the Usage graph. This volume is not shown in the Metering graph, as this energy never crosses the meter.

3.2.1 Hourly Net Billing Overview

Under hourly Net Billing, a customer is billed for net energy consumption *or* credited for net exports during every hour of the billing cycle (i.e., what the system owner consumed from the grid during the hour, less what the system exported during the hour). If the customer generates more electricity than they are using on-site in any hour, they will be credited at the applicable Export Credit Rate for hourly net exports. If the customer consumes more electricity than they are generating on-site at any hour, the customer will pay the applicable retail rate for hourly net consumption. At the end of the billing cycle, all hourly net charges will be totaled, and all the hourly net credits will be totaled.

3.2.2 Real-Time Net Billing Overview

Under real-time Net Billing, a customer is billed for all energy consumed from the grid *and* credited for all exports over the course of the billing period. All net exports will be measured separately, and all kWh will receive the Export Credit Rate. Similarly, the meter will measure all net consumption from the grid separately, and all kWh will be charged the retail energy rate. Real-time Net Billing removes the need to mathematically "net" consumption and exports each hour in the billing system like would occur for Hourly Net Billing (i.e., subtract what the system owner consumed from the grid and what they net exported in each hour). Instead, the distributed energy resource system owner simply receives the export credit rate for all exports, and all consumption from the grid is charged at the applicable retail rate.

3.2.3 Average Residential Customer Energy Consumed & Exported

As the measurement interval length decreases (i.e., monthly to either hourly or real-time), the result is a more accurate reflection of how energy is physically consumed (delivered) and exported (received) from the customer-generator to the electric grid allowing more accurate billing for consumption and compensation for exported energy for customers. When the measurement interval is shortened from monthly to hourly or real-time, the kWh measurements are essentially "stored" at the meter for a shorter time. Therefore, energy received and delivered do not offset for as long before they are recorded for billing. For example, under hourly or real-time Net Billing, a kWh exported at 2 p.m. can't be "stored" as a result of the measurement interval and used to offset a kWh consumed from the grid at 11 p.m. at night. However, in reality, the exported energy is not stored at the meter at all — the exported energy is used to supply other system loads or sold as surplus on the wholesale market, all of which has a variable value by hour.

To illustrate how the different measurement intervals track and account for energy consumption, Idaho Power started with the usage characteristics of an average residential customer without on-site generation. This customer's average consumption is then modeled with solar generation. The study selected residential customer-generators to illustrate the impact of a change in the measurement interval because residential systems account for 95% of all customer-generators by system count. Appendices 3.2–3.4 include 2021 meter data for customer-generators on Schedule 6, 8, and 84.

The average residential customer uses approximately 1,000 kWh per month, or 12,000 kWh per year. The amount of energy consumed and generated depends on the relative size of the generating system installed. For this analysis, the study has illustratively modeled two scenarios for the system size installed to provide a sensitivity analysis for the impacts of measurement intervals under different system sizes: 1) annual generation output approximately equal to annual energy consumption; and 2) annual generation output equal to approximately 50% of annual energy consumption.[25]

For the first scenario, PVWatts Calculator[26] forecasts an 8.5 kW system generating approximately 12,100 kWh, roughly equal to 100% of the average residential customer's annual energy consumption. Figure 3.5 illustrates the average monthly *consumption* measured under Net Energy Metering (monthly), Net Billing (hourly), and Net Billing (real-time) as compared to the consumption prior to the solar installation. This figure does not show energy exported, which is illustrated in Figure 3.6.

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[25] The average residential system size installed between 2018 and May 31, 2022, is 7.6 kW (see Figure 2.4).

[26] The National Renewable Energy Laboratory (NREL) is a national laboratory of the U.S. Department of Energy operated by the Alliance for Sustainable Energy, LLC. NREL's PVWatts Calculator estimates the energy production of PV energy systems. It allows homeowners, small building owners, installers, and manufacturers to easily develop estimates of the performance of potential PV installations. For purposes of the examples contained in the study, an installation in Boise, Idaho, with a standard roof-mounted system and default PVWatts inputs was used.

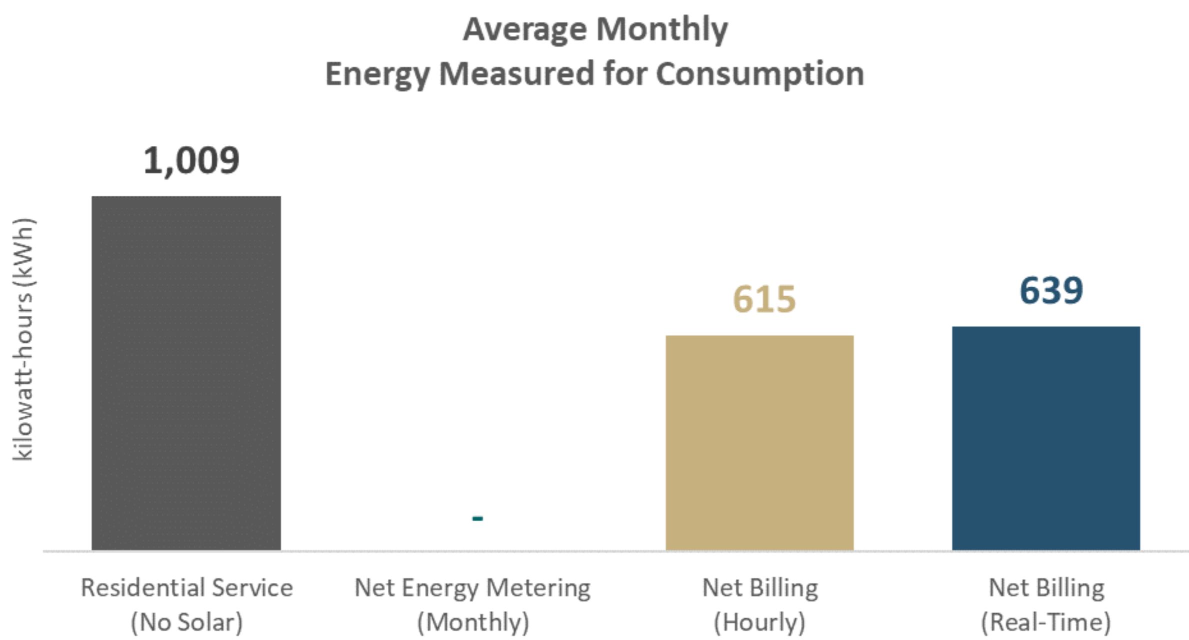


Figure 3.5
Average monthly energy measured for consumption for an average residential customer with 8.5 kW solar system

As shown in Figure 3.5, the customer's energy needs average 1,009 kWh per month. When an 8.5 kW solar system is installed, the customer's average monthly measured consumption is 0 kWh. This does not mean the customer did not use Idaho Power produced electricity. The customer did use electricity from Idaho Power at night, when it was cloudy or anytime the panels did not produce enough energy to meet the customer's energy needs. However, over the course of the month, the panels produced enough energy to offset energy consumed in the same month. The customer essentially is able to store excess energy to offset future use by using Idaho Power's grid as a battery due to the monthly measurement interval.

When the measurement interval changes from monthly to hourly, the average monthly measured consumption increases from 0 kWh to 615 kWh, and when the measurement interval is changed from hourly to real-time, there is a 4% increase in measured energy for consumption. The real-time measurement reflects all energy that is delivered from the utility over the course of the billing month.

Figure 3.6 illustrates the average monthly *exported energy* measured under Net Energy Metering (monthly), Net Billing (hourly), and Net Billing (real-time) for an 8.5 kW system.

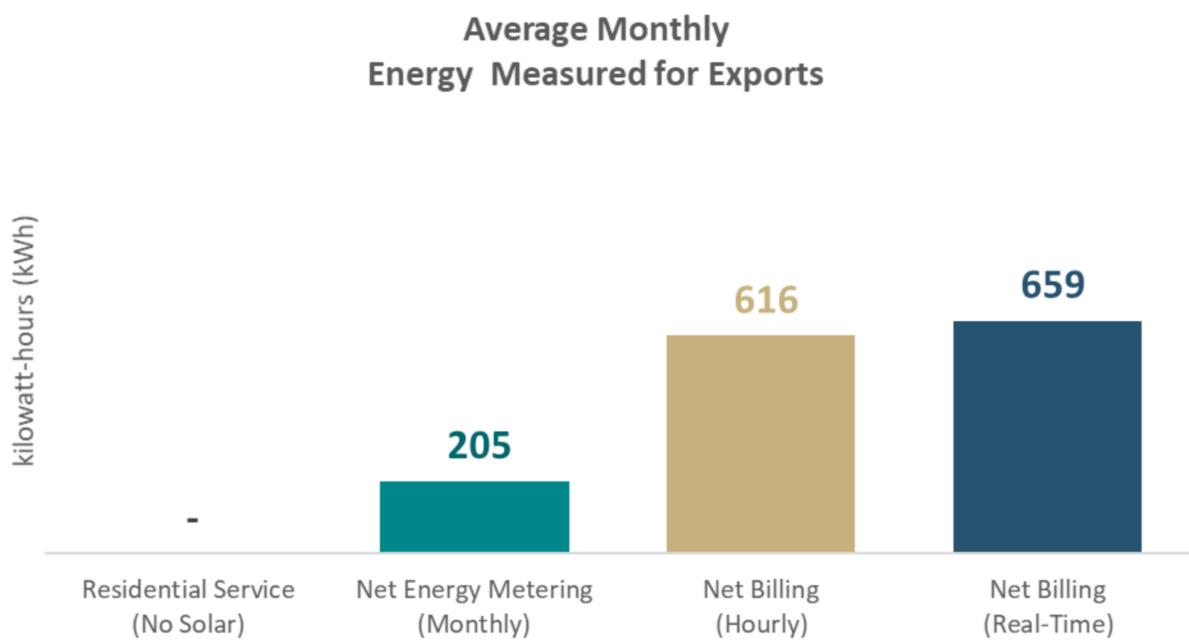


Figure 3.6
Average monthly energy measured for exports for an average residential customer with 8.5 kW solar system

As shown in Figure 3.6, when an 8.5 kW solar system is installed, the customer's average monthly measured export is approximately 205 kWh under the monthly measurement interval.

When the measurement interval changes from monthly to hourly, the average monthly measured exports increase from 205 kWh to 616 kWh. When the measurement interval is changed from hourly to real-time, there is a 7% increase in measured energy for exports. The real-time measurement reflects all energy that is exported from the customer-generator over the billing month.

For the second scenario, a 4.25 kW system would generate roughly 6,050 kWh, or roughly 50% of the customer's annual energy consumption. Figure 3.7 illustrates the average monthly *consumption* measured under Net Energy Metering (monthly), Net Billing (hourly), and Net Billing (real-time) as compared to the consumption prior to the solar installation.

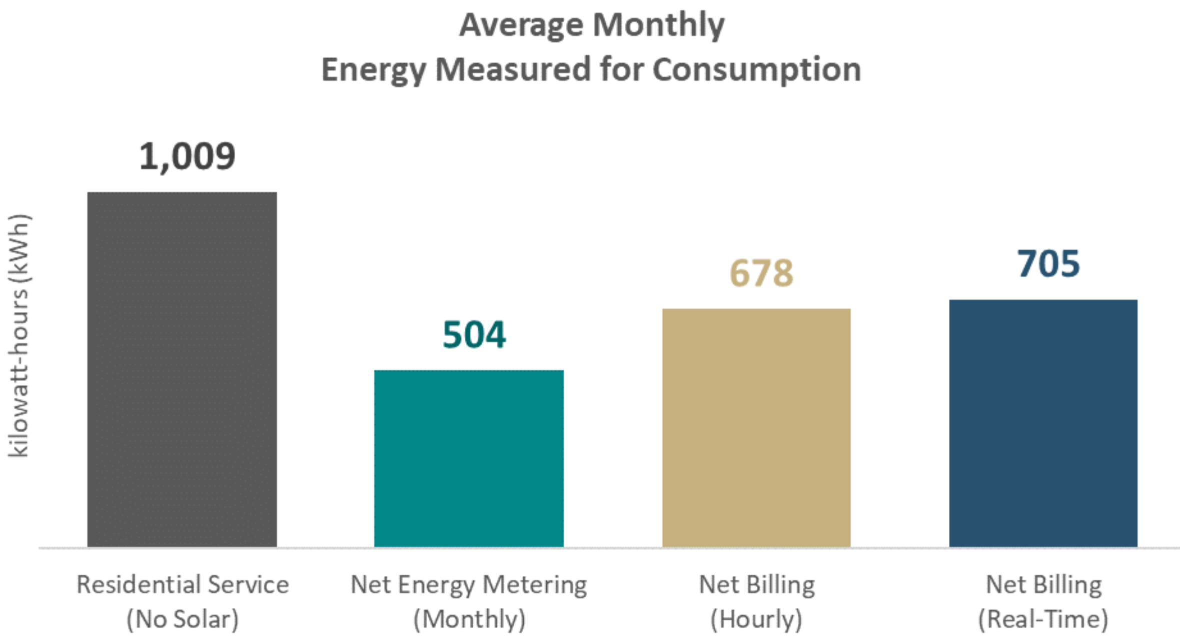


Figure 3.7
Average monthly energy measured for consumption for an average residential customer with 4.25 kW solar system

As shown in Figure 3.7, when a 4.25 kW solar system is installed, the customer's average monthly measured consumption is 504 kWh. Due to the smaller sized system relative to the customer's energy consumption, energy measured by the utility for consumption is higher when compared to the 8.5 kW system; however, a larger percentage of the total energy generated is consumed on-site. When the measurement interval is decreased from monthly to hourly, the measured consumption increases from 504 kWh to 678 kWh, or a 34% increase. Last, when the measurement interval is changed from hourly to real-time, there is a 4% increase in measured energy for consumption.

Figure 3.8 illustrates the average monthly *exported energy* measured under Net Energy Metering (monthly), Net Billing (hourly), and Net Billing (real-time) for the 4.25 kW system.

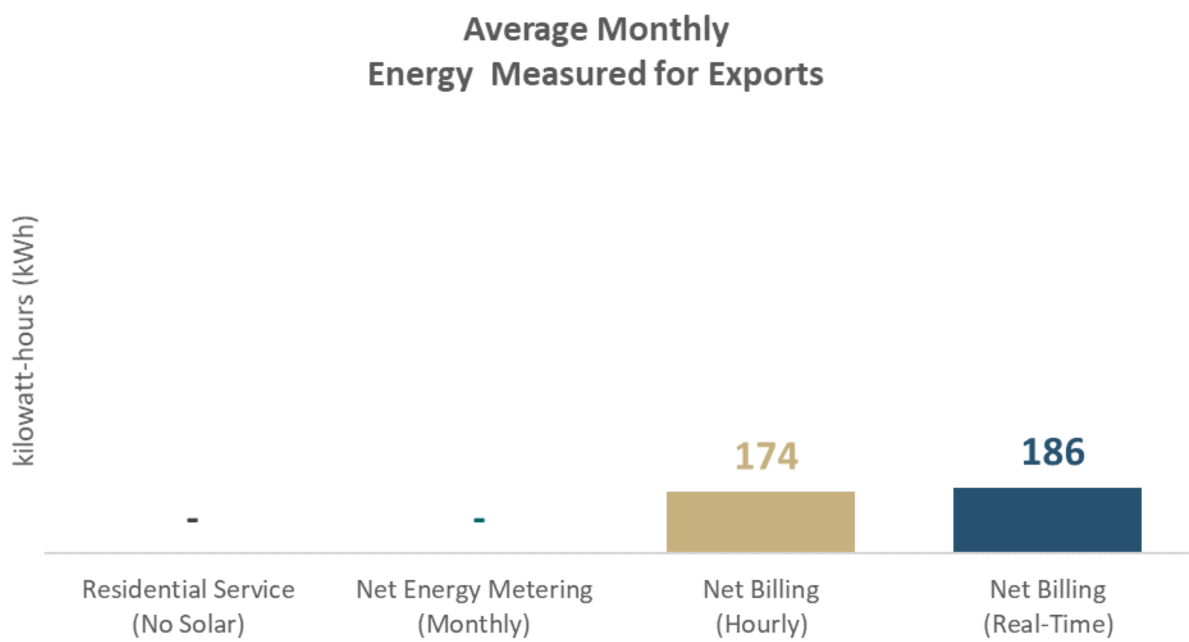


Figure 3.8
Average monthly energy measured for exports for an average residential customer with 4.25 kW solar system

Due to the smaller sized system relative to the customer's energy consumption, energy measured for exports is lower when compared to the 8.5 kW system. When the measurement interval is decreased from monthly to hourly, the measured exports average 174 kWh per month under an hourly measurement interval compared to no measured exported energy on a monthly interval. When the measurement interval is changed from hourly to real-time, there is a 7% increase in measured energy for exports.

Regardless of the size of the system installed, the measurement for real-time is the most accurate depiction of how energy is delivered to the customer and received or exported to the electric grid. Under the modeled 8.5 kW and 4.25 kW scenarios, as the measurement interval decreases, the amount of energy measured for both consumption and exports increases. The supporting data for Figures 3.5–3.8 are included with this study in Appendix 3.1.

3.2.4 2021 Schedule 6 (Residential) Customer-Generator Energy Consumed & Exported

To determine the impact a change to the measurement interval would have on existing customers, the study evaluated the change from monthly to hourly and real-time measurement intervals for residential customer-generators with 12 months of data in 2021. The total population of customers for this analysis was 6,425 residential customer-generators. Legacy systems account for 5,141 of the population or approximately 80%. The study analyzed the population of all residential customer-generators, but also isolated the analysis to only non-legacy systems and found that the total population was representative of the change in measurement interval for non-legacy systems. As such, the summary in this study discusses the results for all residential customer-generators. Appendix 3.2 includes all supporting data and the ability to select or remove legacy systems from the summary analysis.

Figures 3.9 and 3.10 summarize all residential customer-generators with exporting systems. As shown in Figure 3.9, for the customer-generators in the analysis, the average monthly consumption is 463 kWh per month. Meaning on average, systems do not produce enough energy to meet all the customers' energy needs. The average measured energy consumption increases to 896 and 932 kWh per month under an hourly and real-time measurement interval, respectively.

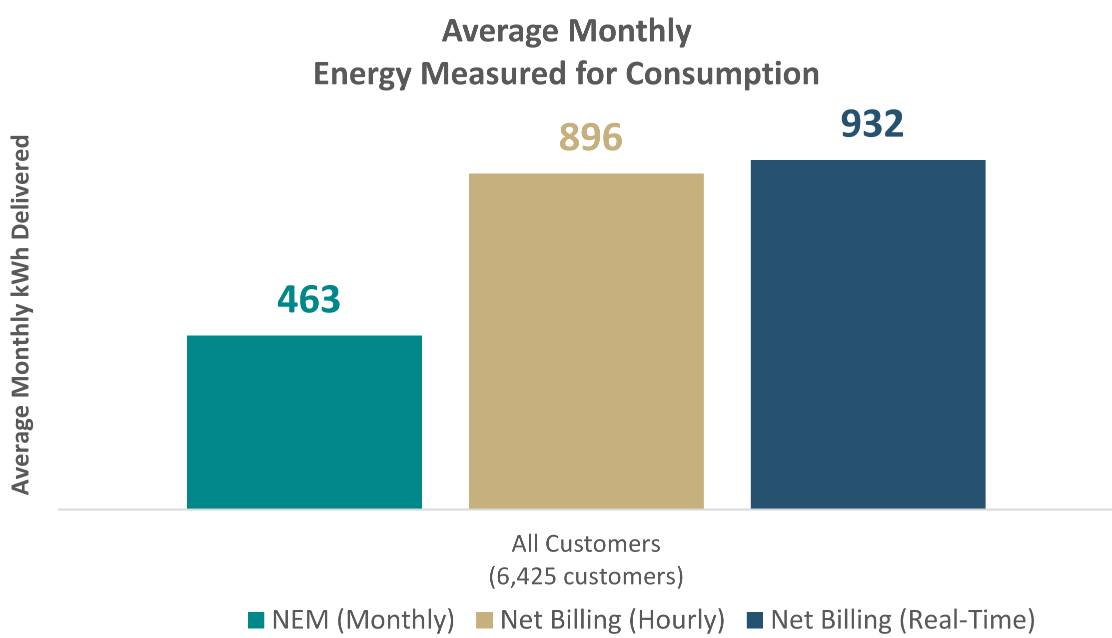


Figure 3.9
Average monthly energy measured for consumption for all residential customer-generators in 2021

As shown in Figure 3.10, measured exported energy is 128, 464, and 500 kWh per month under a monthly, hourly, and real-time measurement interval, respectively.

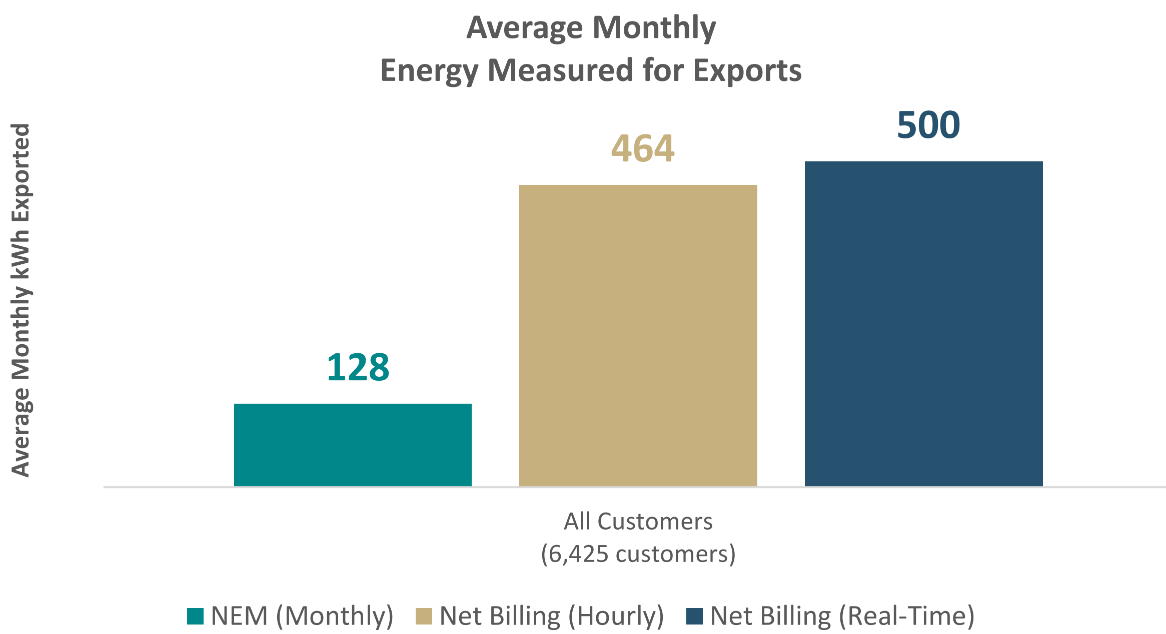


Figure 3.10
Average monthly energy measured for exports for all residential customer-generators in 2021

In Figures 3.11 and 3.12, the residential customer-generators have been grouped into six categories based on their average monthly consumption under the monthly measurement interval. Figure 3.11 compares energy measured for consumption.

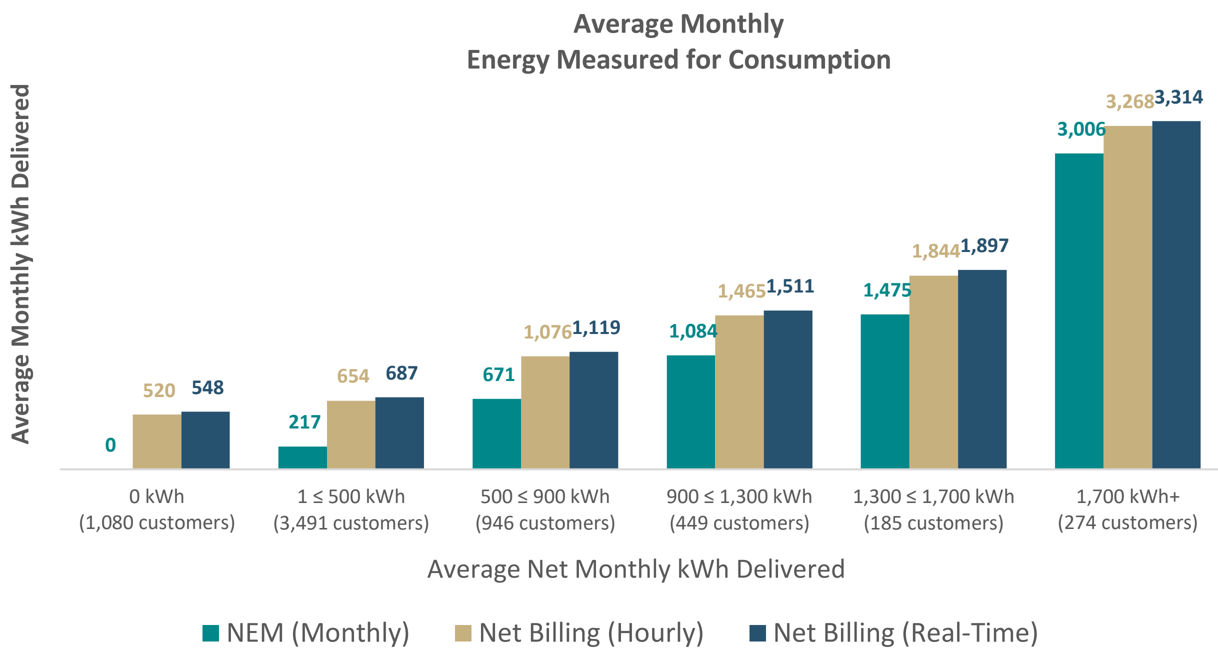


Figure 3.11
Average monthly energy measured under monthly, hourly, and real-time intervals, for consumption for all residential customer-generators in 2021, by average net monthly energy use

Figure 3.12 compares average monthly energy measured for exports under each measurement interval.

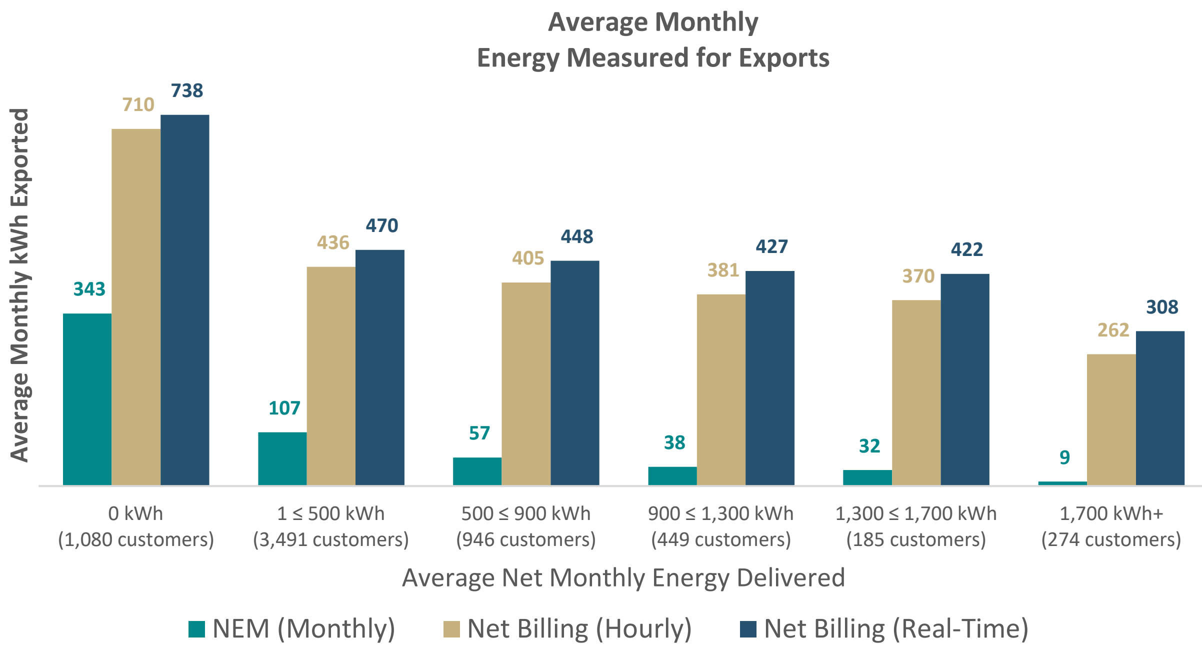


Figure 3.12
Average monthly energy measured under monthly, hourly, and real-time intervals, for exports for all residential customer-generators in 2021, by average net monthly energy use

After evaluating the inputs and assumptions for each of the components of the Export Credit Rate in Section 4, the study will address resulting bill impacts for changes in the measurement interval under a given export credit rate in Section 6.

3.2.5 2021 Schedule 8 (Small General) Customer-Generator Energy Consumed & Exported

The study also evaluated the change from monthly to hourly and real-time measurement intervals for small general customer-generators with 12 months of data in 2021. The total population for this customer segment is significantly smaller than the residential customer-generators, with only 52 small general customer-generators. Legacy systems account for 49 systems or approximately 94%. Due to the smaller population, the study only analyzed the population of all small general customer-generators and did not isolate the analysis to the three non-legacy systems. Appendix 3.3 includes all supporting data for 2021 meter read measurements.

Figures 3.13 and 3.14 summarize all small general customer-generators with exporting systems. As shown in Figure 3.13, for the customer-generators in the analysis, the average monthly consumption is 146 kWh per month. Meaning, on average, systems do not produce enough energy to meet all the customers' energy needs. The average measured energy consumption increases to 463 and 484 kWh per month under an hourly and real-time measurement interval, respectively.

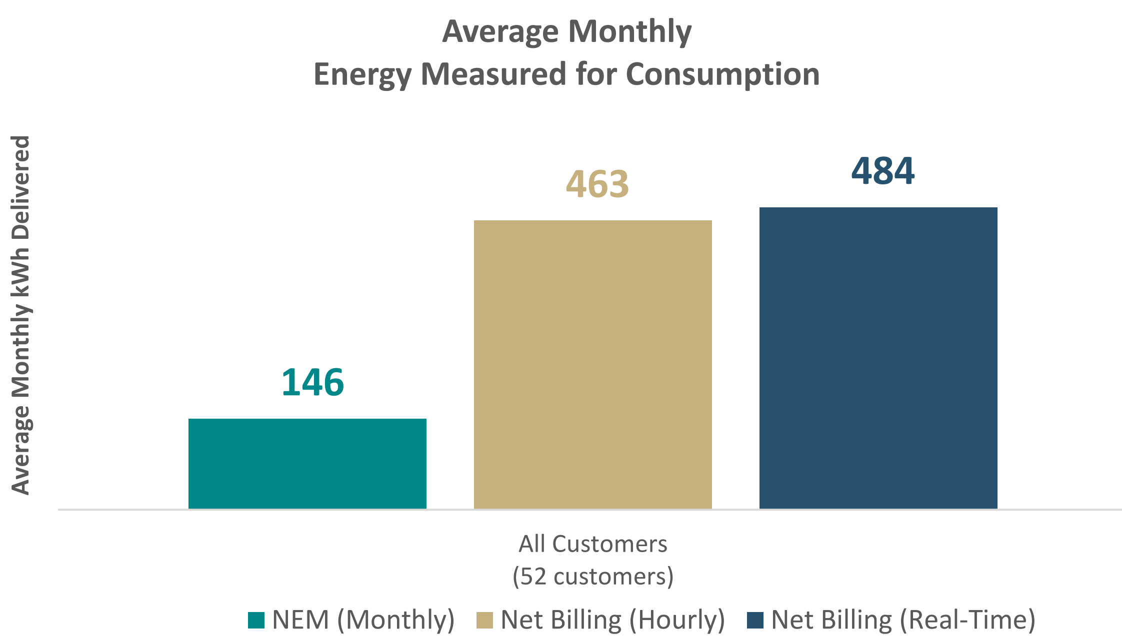


Figure 3.13
Average monthly energy measured for consumption for all small general customer-generators in 2021

As shown in Figure 3.14, measured exported energy is 368, 587, and 608 kWh per month under a monthly, hourly, and real-time measurement interval, respectively.

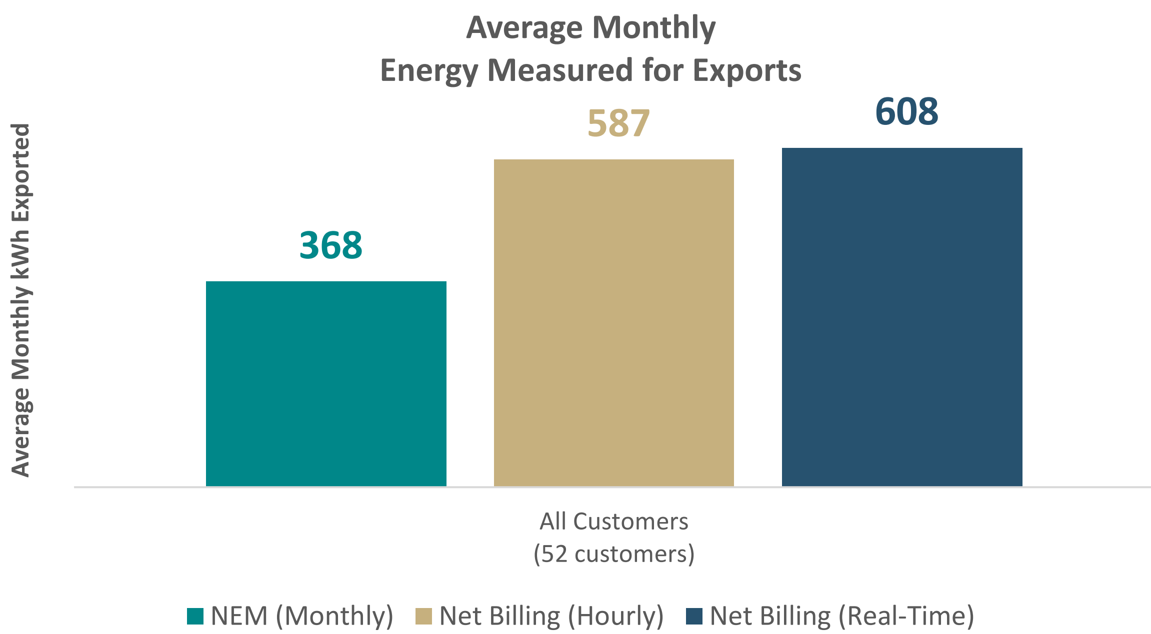


Figure 3.14
Average monthly energy measured for exports for all small general customer-generators in 2021

In Figures 3.15 and 3.16, the small general customer-generators have been grouped into six categories based on their average monthly consumption under the monthly measurement interval. Figure 3.15 compares energy measured for consumption.

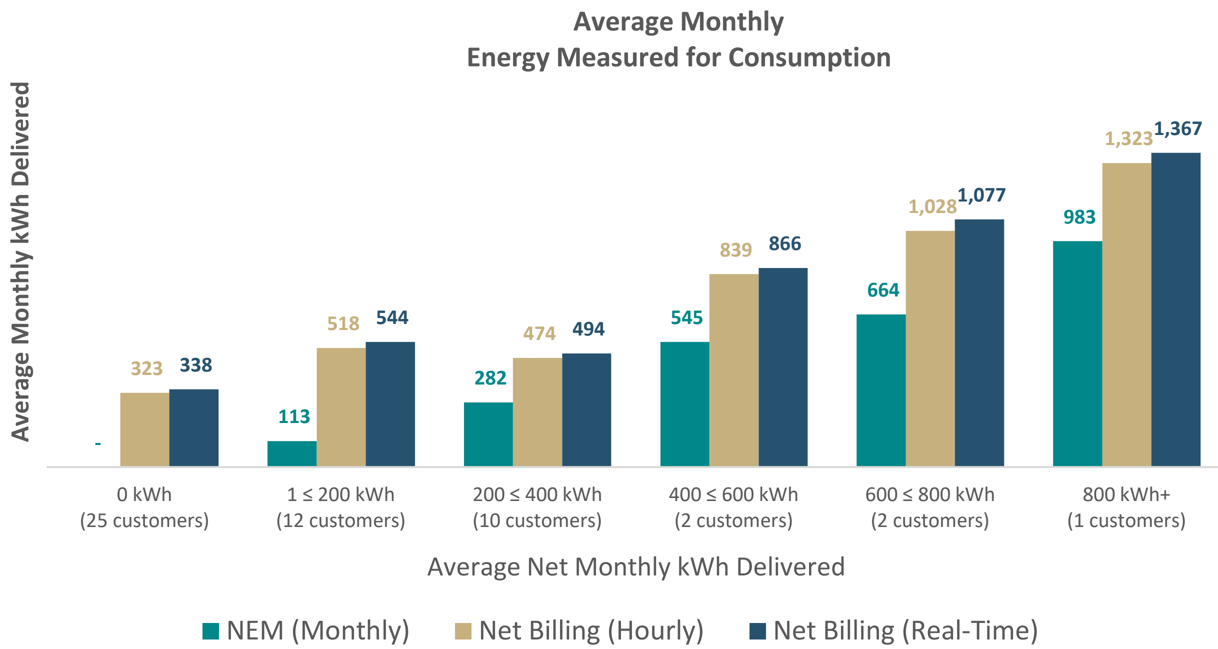


Figure 3.15
Average monthly energy measured under monthly, hourly, and real-time intervals, for consumption for all small general customer-generators in 2021, by average net monthly energy use

Figure 3.16 compares average monthly energy measured for exports under each measurement interval.

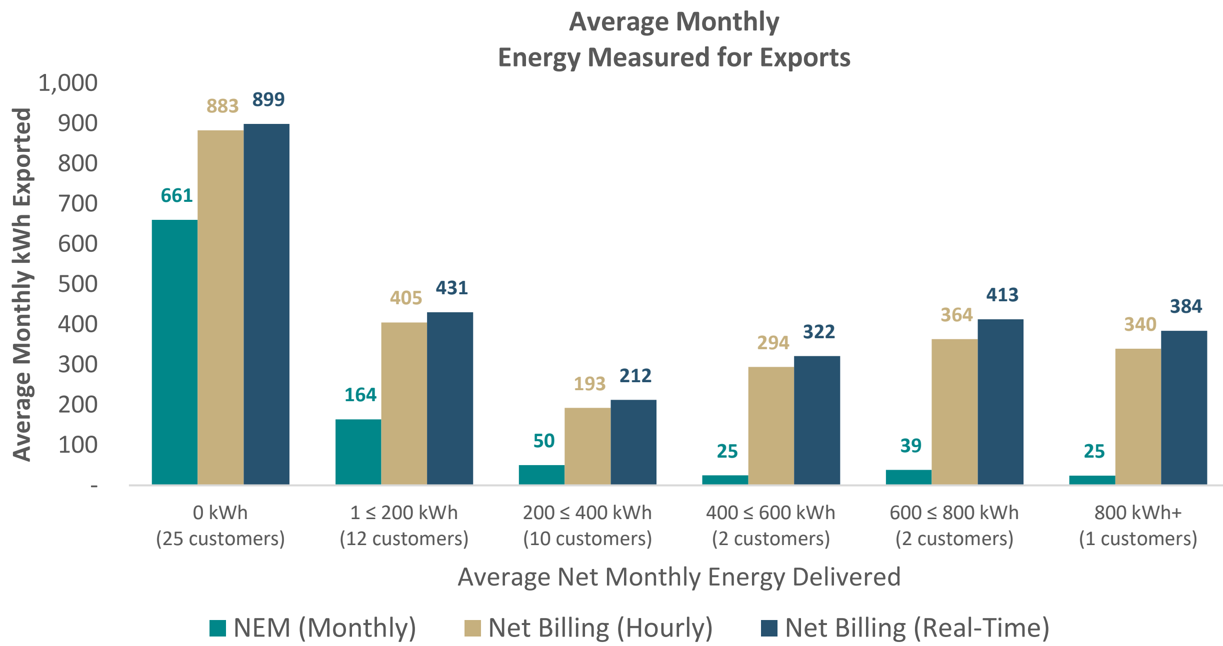


Figure 3.16
Average monthly energy measured under monthly, hourly, and real-time intervals, for exports for all small general customer-generators in 2021, by average net monthly energy use

3.2.6 Schedule 84 (Commercial, Industrial & Irrigation) Customer-Generator Energy Consumed & Exported

The study includes similar data for commercial, industrial, and irrigation customer-generators with 12 months of data in 2021. However, these customer-generators with legacy systems have a different interconnection configuration than residential and small general customers. Legacy systems have a two-meter interconnection and non-legacy systems have a single-meter interconnection. The additional meter for these legacy systems separately meters generation and consumption. As a result, a similar analysis for Net Billing with a real-time interval would measure all generation as exports. For this reason, the study did not consider the same analysis as conducted for existing Schedule 6 and Schedule 8 single-meter customers.

Based on the data available, the study has evaluated Schedule 84 customers under the following three scenarios: (1) no solar; (2) monthly; and (3) hourly. The hourly data for these customers is made available in Appendix 3.4. It is possible to quantify the no solar scenario for existing customers due to the unique two-meter interconnection separately metering consumption. The second and third scenario are similar to the analysis in Section 3.2.4 and 3.2.5 for Schedule 6 and Schedule 8 customer-generators. The real-time scenario is not analyzed because the real-time netting does not occur and is not able to be measured with two-meter configurations.

The analysis of Schedule 84 systems is for illustrative purposes only, as all customers evaluated with 12 months of data in 2021 were legacy two-meter systems that would not be subject to changes in the on-site customer generation offering. The supporting detail for the measurement interval analysis for Schedule 84 commercial and irrigation customers is provided in Appendix 3.5 and Appendix 3.6, respectively.

In Figure 3.17 and Figure 3.18, the commercial customer-generators have been grouped into six categories based on their average monthly consumption under the monthly measurement interval. The total population of commercial customer-generators evaluated was 127 customers — all with legacy systems. Figure 3.17 compares energy measured for consumption.

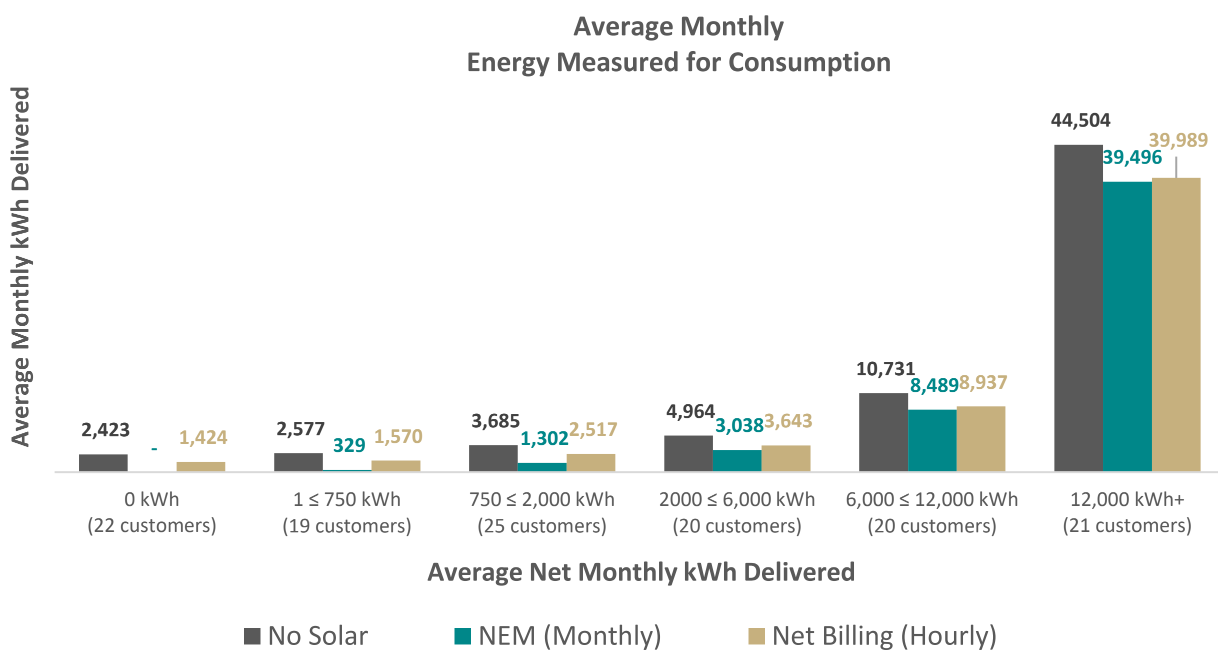


Figure 3.17
Average monthly energy measured under no solar, monthly, and hourly intervals, for consumption for all commercial customer-generators in 2021, by average net monthly energy use

Figure 3.18 compares average monthly energy measured for exports under each measurement interval.

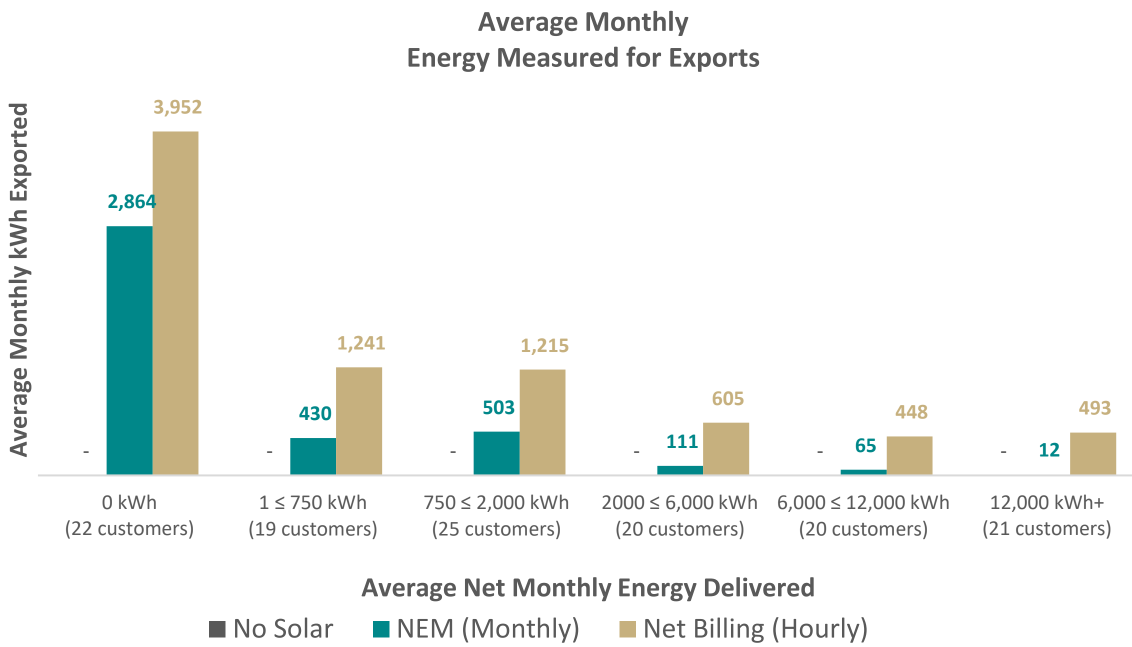


Figure 3.18
Average monthly energy measured under no solar, monthly, and hourly intervals, for exports for all commercial customer-generators in 2021, by average net monthly energy use

In Figures 3.19 and 3.20, the irrigation customer-generators have been grouped into six categories based on their average monthly consumption under the monthly measurement interval. The total population of irrigation customer-generators evaluated was 79 customers — all with legacy systems. Figure 3.19 compares energy measured for consumption.

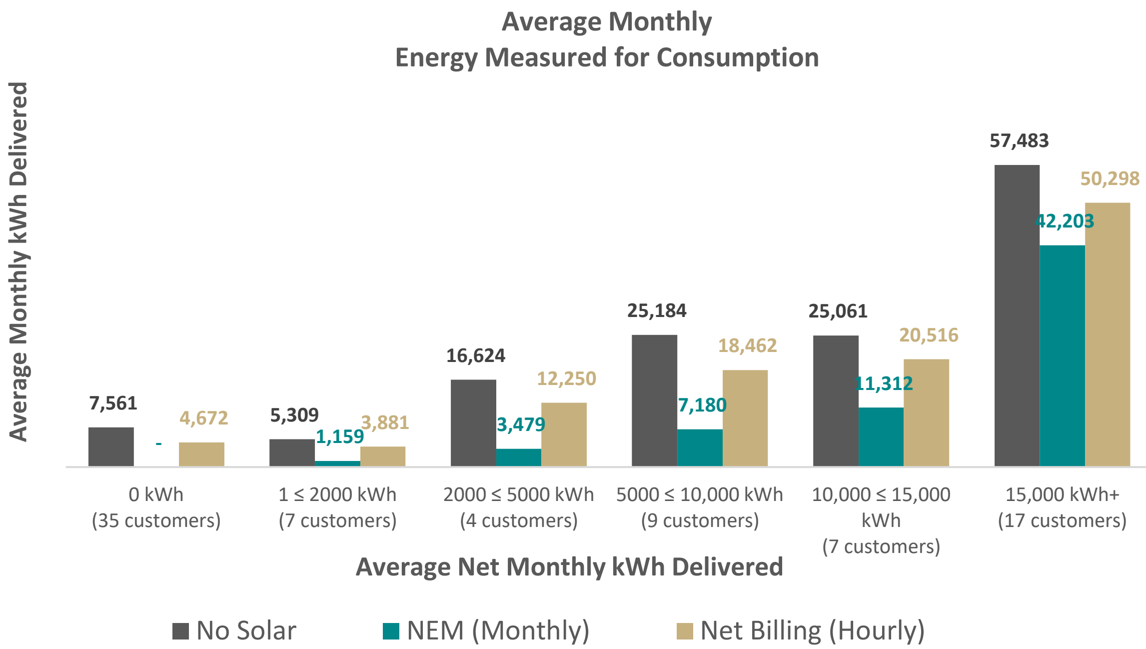


Figure 3.19
Average monthly energy measured under no solar, monthly, and hourly intervals, for consumption for all irrigation customer-generators in 2021, by average net monthly energy use

Figure 3.20 compares average monthly energy measured for exports under each measurement interval.

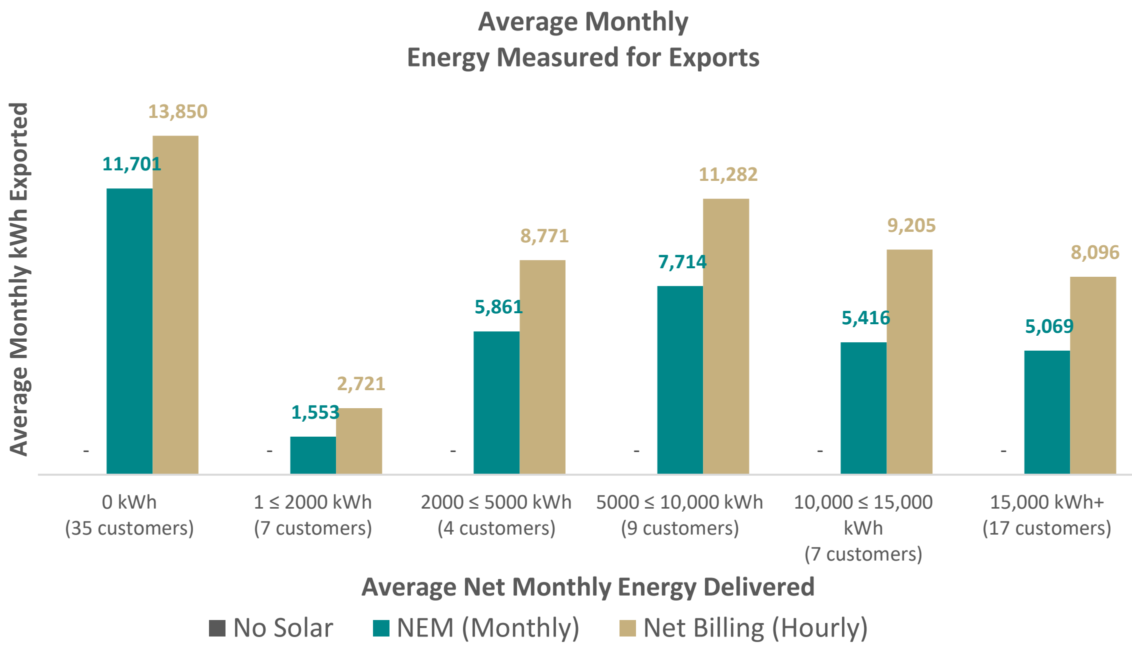


Figure 3.20
Average monthly energy measured under no solar, monthly, and hourly intervals, for exports for all irrigation customer-generators in 2021, by average net monthly energy use

Measurement Interval – Supporting Appendices

Appendix 3.1
2021 Measurement Interval and Bill Impact — Average Residential

Appendix 3.2
2021 Measurement Interval and Bill Impact — Schedule 6

Appendix 3.3
2021 Measurement Interval and Bill Impact — Schedule 8

Appendix 3.4
2021 Metering Data — Schedule 84

Appendix 3.5
2021 Measurement Interval and Bill Impact — Schedule 84 (Commercial)

Appendix 3.6
2021 Measurement Interval and Bill Impact — Schedule 84 (Irrigation)

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

4. Export Credit Rate

To determine a methodology and value for excess energy delivered from customers to the grid, the study looked at multiple variables from the generation of power to the movement of that power through the transmission and distribution system. This section describes each variable in more detail including any inputs or assumptions and options for data sources.

Variables Considered in Determining the Export Credit Rate (ECR):

- Avoided Energy Costs
- Avoided Generation Costs
- Avoided Transmission and Distribution Costs
- Avoided Line Losses
- Avoided Environmental Costs
- Integration Costs

4.1 Avoided Energy Costs

Idaho Power meets its customers' energy needs by generating electricity from its energy resources, through the promotion of energy efficiency programs, or by purchasing energy (either via purchase agreements or energy markets). When a customer generates energy in excess of its own energy consumption and exports it to Idaho Power's system, the company may be able to use that energy to meet its customers' energy needs. As a result, this will reduce the energy that Idaho Power would otherwise generate or purchase. When this occurs, Idaho Power will avoid the cost of that generation or energy purchase. An actual, hourly market-based price applied to exports in a given hour would be the most accurate means of assigning value, but it is the least stable and predictable option for the customer because these values would not be known in advance of when the energy is exported to the system. Alternatively, a weighted average of established energy prices (either historical actuals or those from a forecasted pricing stream) would be stable and predictable, but less accurate.

To illustrate the value of avoided energy costs, the following factors were considered:

- **Energy Price:** Forecasted and Market Prices
    - Forecast: Integrated Resource Plan (IRP)
    - Actual Market: Intercontinental Exchange Mid-Columbia (ICE Mid-C) and Western Energy Imbalance Market (EIM) Load Aggregation Point (ELAP)
- **Credit Design:** Evaluation of energy price under a flat and variable pricing mechanism
- **Non-Firm Discount:** Description of firm and non-firm energy and evaluation of how non-firm energy is discounted relative to prices for firm energy

- **Wheeling Costs:** Applicability evaluation of wheeling charges or fees to wheel power. Wheeling costs are essentially the rental cost of moving power on a transmission line to end-users.

4.1.1 Energy Price: Inputs and Assumptions

Electric energy is a commodity with prices that vary significantly by time and location. Electric energy markets are generally driven by supply and demand economics and based on the fundamentals of the Bulk Power System (BPS) conditions and costs. Pursuant to the Commission-approved Study Framework, the study evaluates current energy price inputs, consistent with Idaho Power's IRP model inputs and market price index assumptions. The following sections will describe the three sources evaluated for the pricing of energy: 1) IRP Idaho Power price forecast; 2) ICE Mid-C Index; and 3) EIM Load Aggregation Point (ELAP).

4.1.1.1 Integrated Resource Plan — Idaho Power Price

Every two years, Idaho Power develops and publishes an IRP. The company's most recent IRP was published in late-2021. The 2021 IRP covers a 20-year planning period from 2021 through 2040. The 2021 IRP hourly pricing forecast for the Idaho Power area used in this study is provided as Appendix 4.1.

The primary goal of the IRP is to ensure Idaho Power's system has sufficient resources to reliably serve customer peak demand and flexible capacity needs over the 20-year planning period while also minimizing costs and risks to customers. To ensure Idaho Power's growing need for energy and peak demand is sufficiently met, the capability of the existing system is included and then resources are added (or removed). Multiple portfolios consisting of varying resource additions are produced. Resource additions include supply-side resources like wind generation facilities; demand-side resources like energy efficiency measures; and transmission projects that increase access to energy markets. The portfolios are then compared, and the portfolio that best minimizes cost and risk is selected to be the Preferred Portfolio.

Idaho Power develops the portfolios utilizing a software program called Aurora. Energy Exemplar's Aurora electric forecasting software is a highly robust and computationally intensive program that can optimize a system given numerous inputs and constraints. The company develops inputs and constraints every other year and shares these values — as well as seeks input regarding these values — through its IRP Advisory Committee process. Key inputs include, but are not limited to, forecasts such as hydroelectric production; natural gas pricing; customer demand; future resource pricing; constraints such as the cost of carbon; emissions compliance requirements; resource parameters such as potential shaping for intermittent resources; or operational restrictions for flexible dispatchable (i.e., firm) resources.

Once the Preferred Portfolio is identified, Aurora can output an hourly pricing forecast for the Idaho Power area (the Idaho Power node within the model) for the full 20-year planning period.

The study utilized Idaho Power's 2021 hourly pricing values from the Aurora model, for the Idaho Power area over the 2021 calendar year and applied these prices to actual 2021 customer exports to develop the weighted average energy value for the ECR.

The 2021 IRP pricing method is a forecast. A forecasted energy pricing input provides certainty in the form of a static export credit value and ease of understandability for customer-generators. However, a forecasted price also carries a level of uncertainty relative to fluctuations in the actual market prices and would not change with increases or decreases seen in the market.

4.1.1.2 ICE Mid-C Index Price

The Intercontinental Exchange Mid-Columbia, or ICE Mid-C, is a global futures exchange, like the NASDAQ or New York Stock Exchange, except it is for electrical energy specifically traded at the Mid-C. Mid-Columbia represents a geographical region in central Washington, where a fluid market exists allowing energy to be traded between utilities, merchants, and energy marketing agencies. The ICE Mid-C Index Price represents the cost of firm energy, one day in advance of real-time operations (day-ahead), at an electrical energy market hub in close proximity to the Idaho Power system. Prior to Idaho Power's entrance into the Western EIM, the company would often use a Mid-C Index to balance energy transactions with counterparties (energy market buyers and sellers).

ICE Mid-C Index Price is published for two time periods: 1) Heavy Load, and 2) Light Load. In context of electricity, "load" is the amount of electricity on the grid at any given instant. Heavy Load hours fall between 7 a.m. and 11 p.m. Mountain Time, Monday through Saturday, when customer energy usage is higher. Light Load hours fall between 11 p.m. and 7 a.m. Mountain Time, and all day on Sundays and holidays.

For purposes of the study, the value for the ECR uses a historically based indicative price based on a three-year average of the ICE Mid-C Index. The three-year average was provided to illustrate an average price using recent data; however, it is important to note there are a variety of implementation possibilities if the Commission were to adopt the ICE Mid-C Index Price as an input. Those implementation considerations are also discussed in Section 11.1. Hourly pricing for 2019 through 2021 used in this study are provided in Appendix 4.2.

The study also evaluated the feedback that a benefit of customer exports may be the price-risk hedge (also referred to as a "fuel price risk") provided by customer-generator exported energy. The pricing of electricity markets can vary due to effects such as water (hydroelectric) conditions, or fuel pricing (such as natural gas or coal), and customer exports may provide some increased pricing certainty. By utilizing the ICE Mid-C Index Price, the ECR would capture changes in market conditions resulting in higher or lower energy prices — customers would be directly compensated for any potential price-risk hedge benefits. However, a market-based price may provide less certainty and understandability to customer-generators on the value they would receive in a given hour for exported energy. If an hourly real-time market-based methodology were selected, the ICE Mid-C Price only provides price signals and granularity by two daily prices — one price for heavy load (HL) hours and a second price for light load (LL) hours. Therefore, this pricing input may not be the preferred input for an hourly real-time pricing methodology.

The ICE Mid-C Price Index is published for subscription and not generally available to the public. This will limit most customers from having access to this information and creates a limit to the transparency of using this price value.

4.1.1.3 Energy Imbalance Market Load Aggregation Point (ELAP) Price

The Western EIM determines the EIM Price on a sub-hourly basis based on competitively bid energy prices submitted by participating market entities. The market itself is focused on more than just energy imbalance, rather, the market attempts to find the most economically efficient way to meet the needs of its footprint (members), while also maintaining power flows throughout the BPS within reliability ranges. The design of the market requires each entity to have sufficient resource capacity to meet load while also incentivizing those entities to bid in their participating resources at or near the cost to produce power. Therefore, the EIM pricing is a real-time indicator of the value of energy on the Idaho Power system at any point in time.

The Idaho Power system has numerous EIM nodes within the Western EIM. For this pricing approach, the study uses a weighted average hourly price that is derived from sub-hourly node prices for its entire system. This calculated value is called an EIM Load Aggregation Point, or ELAP. Idaho Power utilizes this same pricing amount for the settling of various energy transactions with energy counterparties.

The value for the ECR, for purposes of the study, uses a historically based indicative price based on a three-year average of the ELAP price. The three-year average was provided to illustrate an average price using recent data; however, it is important to note there are a variety of implementation possibilities if the Commission were to adopt the ELAP Price as an input. Those implementation considerations are also discussed in Section 11.1. Appendix 4.3 provides the average ELAP hourly price for 2019 through 2021.

The ELAP price would capture real changes in market conditions resulting in higher or lower energy prices — customers would be directly compensated for any potential price-risk hedge benefits. However, as mentioned in Section 4.1.1.2, the actual market-based price may provide less advanced planning certainty and understandability to customer-generators on the value they would receive in a given hour for exported energy.

The ELAP price is generally available to the public which allows customers access to this information. The publicly available pricing provides transparency in using this price value.

4.1.2 Weighted Average Energy Price Methods

For each energy price input (i.e., IRP, ICE Mid-C, ELAP) described in Section 4.1.1, a method for applying the inputs to calculate the export credit value is required. Idaho Power evaluated two methods for calculating the export credit value for each potential energy price input.

1) Flat, or single, annual export credit value
2) Seasonal and time-variant export credit value

Each of these methods is described in more detail in the following sections. Appendix 4.4 and Appendix 4.5 include the net hourly and real-time measured exports by hour for active customer-generators in 2021 used in the weighted average energy price methods described below.

The study evaluates these methods under three different pricing inputs which are described in more detail in Section 4.1.1. One of the pricing inputs is a forecast and the other two are market prices. The market prices could be either a historical or actual market price. The weighted average calculations in Section 4.1.2.1 and Section 4.1.2.2 illustrate the two market prices assuming a historical three-year average (2019–2021). The study relied on an average of multiple recent years to provide an illustrative price for each input. However, the method could use a variety of other options as a basis. For example, instead, the use of a single historical year of market prices or actual market prices could be leveraged depending on the importance of most recent and accurate price signals.

As an example of using actual market prices, a customer exporting energy between 6 p.m. and 7 p.m. on July 1 could be compensated the actual market price for that hour-ending 7 p.m. on July 1. In this manner, the determination of critical hours, or hours of highest risk, would not factor into the price of energy and instead the ECR avoided energy component would reflect actual market prices for every hour. The appropriateness of the input should be evaluated by stakeholders and the Commission during implementation.

4.1.2.1 Energy: Flat Annual Export Credit Value

A simple method for calculating a value would be to apply a non-weighted average to the energy price for every hour in the year. However, this method would not weight the difference in prices during different times of the day. For example, energy prices during the night, when most customer-generators are not exporting should not carry the same weight as hours when most customer-generators have energy exported to the grid. Therefore, Idaho Power did not include a non-weighted average as a method for evaluation within the study.

Instead, the study evaluated an annual energy price for each of the three energy inputs weighted for all exports from customer-generators that were active in all of 2021. For the study, the results show all exports delivered (i.e., real-time measurement). The 2021 total customer generated exported energy was measured at approximately 50,000 MWh on an hourly basis and 59,000 MWh on a real-time basis. The 2021 peak customer exported generation was measured at over 36 MW on an hourly basis and over 40 MW on a real-time basis. Appendix 4.4 shows net hourly exports for customer-generators active in 2021, and Appendix 4.5 shows real-time exports for customer-generators active in 2021.

For each of the price inputs discussed in Section 4.1.1, the flat rate for the energy component of the ECR was calculated by taking the product of the energy price input and the 2021 actual customer exports. This yields the total energy value of the customer exports for the year, and this number is then divided by the total energy exported in 2021 to produce a customer export value per kWh. Figure 4.1 provides a hypothetical example of calculating the flat annual export credit value as a weighted average of customer-generator exports. Appendix 4.6 shows the hourly calculations to evaluate the annual weighted average energy price for the Idaho Power IRP, ICE Mid-C, and ELAP price weighted for net hourly and real-time exports.

(A) Hour	(B) Illustrative Hourly Price	(C) Exported Energy (kWh)	(D) (B) * (C) Hourly Energy Value
1	$ 0.05	-	$ -
2	0.04	-	-
3	0.04	-	-
4	0.04	-	-
5	0.04	-	-
6	0.04	-	-
7	0.04	-	-
8	0.04	-	-
9	0.04	1	0.04
10	0.04	1	0.04
11	0.03	2	0.06
12	0.04	3	0.12
13	0.03	4	0.12
14	0.03	5	0.15
15	0.04	6	0.24
16	0.03	5	0.15
17	0.03	4	0.12
18	0.03	3	0.09
19	0.05	2	0.10
20	0.05	1	0.05
21	0.07	-	-
22	0.06	-	-
23	0.04	-	-
24	0.04	-	-
Total/Average	**$ 0.0408**	**37**	**$ 1.28**
	Average	*Total*	*Total*

Total Energy Value	$ 1.28	*Total of Column D*
(/) Total Exported Energy	37 kWh	*Total of Column C*
Weighted Average Energy Price ($/kWh)	**$ 0.0346**	*Total Energy Value / Total Exported Energy*
Simple Average Energy Price ($/kWh)	**$ 0.0408**	*Average of Column B*

Figure 4.1
Hypothetical example of weighted average calculation

Figure 4.2 summarizes the results of the annual weighted average calculation for each of the avoided energy inputs calculated in Appendix 4.6. These values do not reflect a non-firm adjustment, which is discussed in Section 4.1.3.

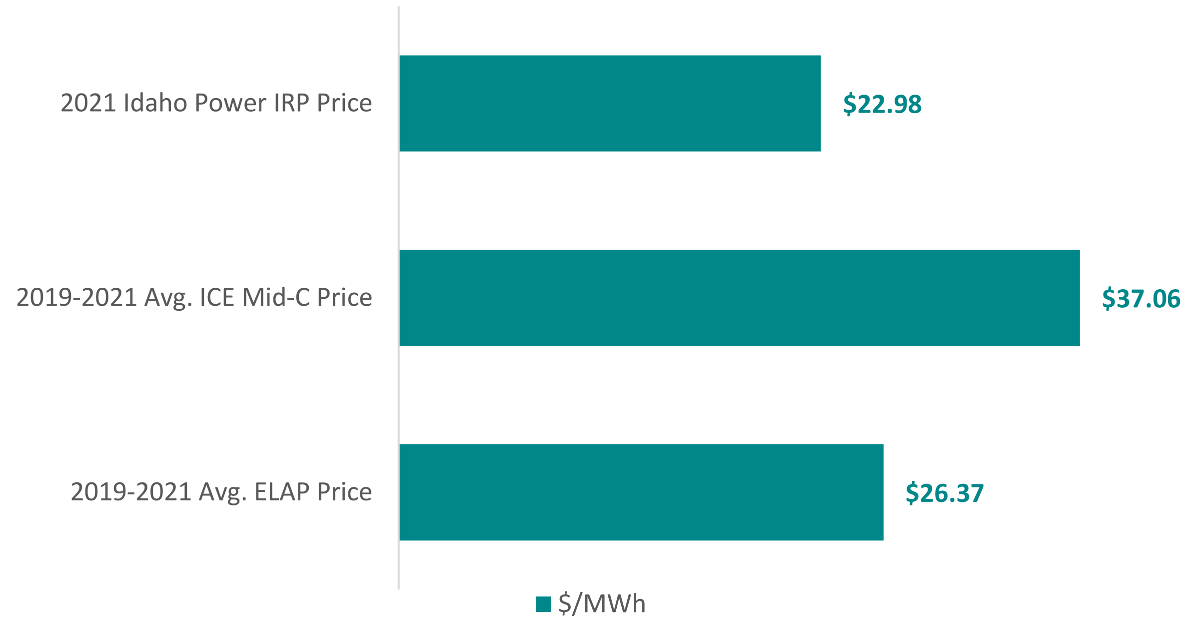


Figure 4.2
Summary results for a flat annual weighted calculation of avoided energy value with real-time 2021 customer-generator exports

4.1.2.2 Energy: Seasonal Time Variant Export Credit Value

A second way to calculate the export credit value is based on a seasonal time-variant export credit value which could provide a variable pricing mechanism. Energy is more expensive at certain times of the year or times of the day depending on market conditions. A time-variant credit values excess generation exports based on the time they are delivered to the utility, providing a higher credit when electricity is worth more. The study evaluated two different parameters to define seasonality and on- and off-peak periods for energy. However, if a real-time actual market price were adopted, the price paid for energy would follow market prices irrespective of the defined season periods that would still inform the value for the capacity-related ECR components. As part of implementation, stakeholders should consider and weigh the benefits of providing adequate price signals for exports while similar price signals do not exist for a customer’s consumption through the existing rate design applicable to on-site generation customers.

(1) Idaho Power's Existing Demand Response Season & Hours

For this analysis, Idaho Power leveraged the seasonal and time differentials of its Demand Response Program, which currently includes the following parameters for "On-Peak" and "Off-Peak" periods. On-Peak periods are those times when energy needs on Idaho Power's system are at their highest.

- Summer: June 15–September 15
  - On-Peak: 3 to 11 p.m., Monday through Saturday (excluding holidays), which equates to 624 hours per year
  - Off-Peak: 11 to 3 p.m., Monday through Saturday and all hours Sunday and holidays
- Non-Summer: September 16–June 14
  - Off-Peak: All hours

The On-Peak period was determined based on the Demand Response Program's contribution to the overall system reliability and are driven by the timing of the highest risk hours, or Loss of Load Probability (LOLP) hours; these hours were derived by evaluating historical data. Energy exported during highest risk hours is more valuable than energy exported during the remaining hours of the year. This is explained in more detail in Section 4.2.1.1 (ELCC Method). By choosing these same hours for the On-Peak ECR, the energy exported during times that provide the highest overall system reliability benefit are aligned with a higher energy credit.

The weighted average value is calculated by separating the exports and the corresponding hourly prices between the On-Peak and Off-Peak periods. On-Peak's weighted average energy price is computed using the 624 hours, and the remaining 8,136 hours of the year are used to calculate the weighted average Off-Peak export credit value. As a result, there are two weighted average prices calculated. Figure 4.3 summarizes the results of the seasonal time variant weighted average calculation for each of the avoided energy inputs calculated in Appendix 4.7. These values do not reflect a non-firm adjustment, which is discussed in Section 4.1.3.

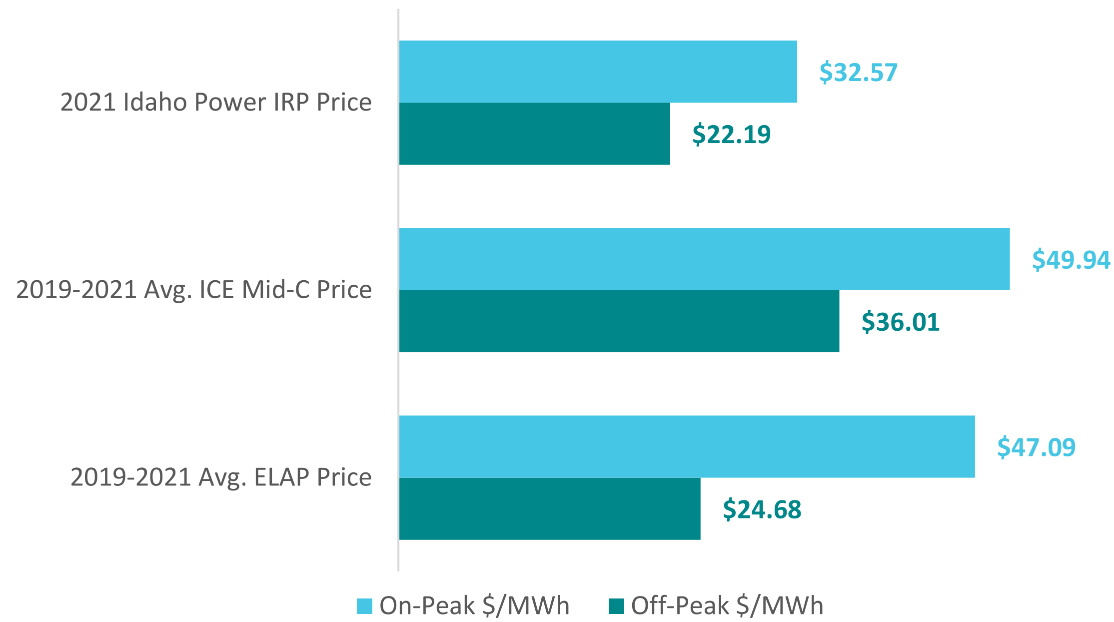


Figure 4.3
Summary results for a seasonal time variant weighted average calculation of avoided energy value with real-time 2021 customer-generator exports and demand response seasonal parameters

(2) Alternative Method for Defining Seasonal Energy Time Periods

An alternate method for defining seasonal energy time periods is to look at time windows that provide resolution for prices based on the avoided energy value. For this analysis, the study evaluated the average IRP, ICE Mid-C, and ELAP prices by hour of the day for each month of the year in Appendix 4.8. The IRP and ELAP prices provide true hourly resolution, whereas the ICE Mid-C price has large hour blocks for HL and LL, resulting in less dynamic pricing. Based on the resolution of pricing provided on an hourly basis, the ICE Mid-C is not indicative of the same level of resolution for hours of actual or anticipated high cost. Please see Figure 4.4 for a heatmap of the average hourly ELAP prices by hour and day of the month for 2021. The heatmaps for the average IRP and ICE Mid-C prices are included in Appendix 4.8.

Hour Ending (MT)	Month											
	1 January	2 February	3 March	4 April	5 May	6 June	7 July	8 August	9 September	10 October	11 November	12 December
1	$ 25.26	$ 47.26	$ 28.08	$ 26.12	$ 27.29	$ 34.64	$ 42.47	$ 43.14	$ 46.99	$ 49.05	$ 36.79	$ 39.80
2	$ 23.66	$ 39.91	$ 26.62	$ 25.82	$ 25.30	$ 31.13	$ 40.60	$ 40.54	$ 45.30	$ 48.10	$ 36.17	$ 37.23
3	$ 22.44	$ 34.65	$ 23.84	$ 24.12	$ 23.10	$ 27.09	$ 35.03	$ 35.99	$ 42.81	$ 46.61	$ 34.73	$ 35.28
4	$ 22.66	$ 35.07	$ 24.19	$ 23.46	$ 21.77	$ 25.33	$ 31.38	$ 33.66	$ 40.29	$ 45.63	$ 32.13	$ 34.52
5	$ 22.98	$ 35.56	$ 24.39	$ 24.89	$ 21.42	$ 24.56	$ 29.20	$ 32.63	$ 41.08	$ 43.54	$ 34.34	$ 35.34
6	$ 23.80	$ 42.14	$ 27.58	$ 26.39	$ 23.15	$ 24.77	$ 31.21	$ 33.47	$ 42.91	$ 46.62	$ 35.99	$ 38.07
7	$ 24.60	$ 51.30	$ 28.98	$ 26.86	$ 24.93	$ 26.66	$ 33.68	$ 34.36	$ 45.36	$ 45.30	$ 39.78	$ 42.87
8	$ 28.53	$ 73.41	$ 34.83	$ 29.86	$ 21.64	$ 25.37	$ 28.81	$ 34.66	$ 49.33	$ 47.95	$ 43.49	$ 47.63
9	$ 31.33	$ 53.09	$ 31.03	$ 26.81	$ 15.91	$ 22.23	$ 27.80	$ 31.77	$ 43.38	$ 59.47	$ 55.58	$ 52.79
10	$ 25.45	$ 33.89	$ 25.09	$ 23.26	$ 16.45	$ 23.84	$ 28.92	$ 29.85	$ 48.78	$ 57.78	$ 38.35	$ 53.12
11	$ 23.14	$ 27.53	$ 22.92	$ 21.90	$ 17.08	$ 26.29	$ 31.50	$ 31.02	$ 40.13	$ 53.45	$ 35.20	$ 47.00
12	$ 20.20	$ 22.82	$ 19.96	$ 22.22	$ 16.70	$ 27.96	$ 35.60	$ 34.89	$ 41.76	$ 55.03	$ 33.49	$ 47.34
13	$ 19.10	$ 20.62	$ 17.59	$ 22.00	$ 16.48	$ 35.55	$ 40.41	$ 40.81	$ 43.87	$ 52.10	$ 32.87	$ 42.66
14	$ 17.86	$ 18.39	$ 15.73	$ 21.14	$ 18.68	$ 37.45	$ 46.27	$ 43.53	$ 50.62	$ 52.50	$ 32.11	$ 40.99
15	$ 17.15	$ 15.17	$ 15.36	$ 20.26	$ 21.46	$ 41.83	$ 48.88	$ 50.76	$ 54.59	$ 53.79	$ 31.95	$ 40.96
16	$ 20.08	$ 15.59	$ 15.20	$ 20.90	$ 22.26	$ 42.95	$ 58.70	$ 53.83	$ 63.39	$ 55.29	$ 34.20	$ 41.55
17	$ 25.94	$ 25.30	$ 19.07	$ 21.53	$ 24.06	$ 44.33	$ 60.52	$ 54.21	$ 61.75	$ 53.78	$ 52.23	$ 49.83
18	$ 31.82	$ 56.66	$ 21.01	$ 23.00	$ 24.09	$ 45.99	$ 74.48	$ 55.12	$ 64.48	$ 57.80	$ 56.46	$ 53.47
19	$ 30.76	$ 86.09	$ 36.03	$ 29.52	$ 26.95	$ 48.27	$ 71.89	$ 63.06	$ 85.31	$ 80.26	$ 56.63	$ 62.49
20	$ 31.98	$ 100.87	$ 38.10	$ 37.70	$ 38.09	$ 56.91	$ 91.67	$ 78.77	$ 122.75	$ 69.54	$ 47.18	$ 54.47
21	$ 31.06	$ 88.53	$ 40.32	$ 41.00	$ 44.35	$ 55.47	$ 109.19	$ 75.44	$ 89.44	$ 58.34	$ 45.22	$ 52.19
22	$ 31.84	$ 76.59	$ 35.86	$ 38.45	$ 43.24	$ 53.47	$ 58.81	$ 58.71	$ 63.99	$ 58.00	$ 45.75	$ 51.50
23	$ 29.36	$ 75.28	$ 36.51	$ 40.43	$ 36.05	$ 44.54	$ 60.68	$ 54.16	$ 59.20	$ 55.96	$ 43.06	$ 50.22
24	$ 27.32	$ 60.09	$ 31.68	$ 36.59	$ 32.02	$ 43.55	$ 52.22	$ 48.49	$ 56.10	$ 55.03	$ 41.53	$ 45.93

Approximate Demand Response Time Period

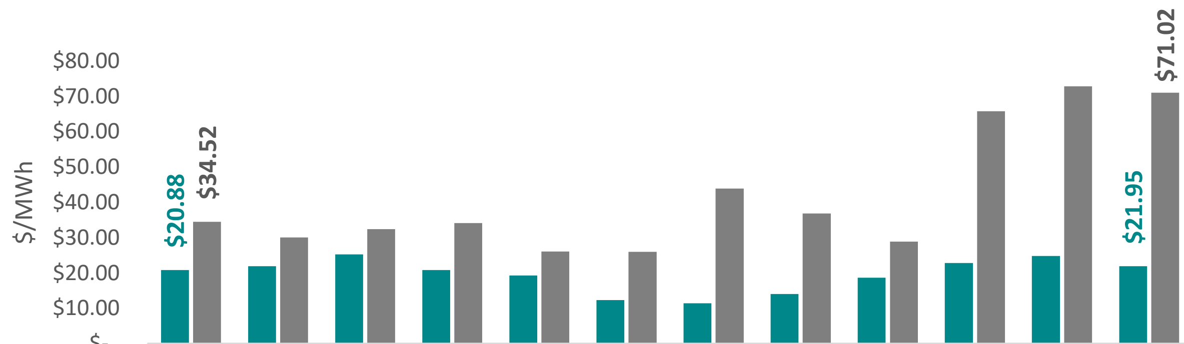
Figure 4.4
Average hourly ELAP prices for 2021 by hour of day and month

During implementation, if actual market prices are not used, stakeholders would need to evaluate if it would be appropriate to have different price signals for energy than for the capacity-related components of an ECR. Stakeholders should consider ease of understanding for customers with an ECR that relies on different on- and off-peak times for the energy value component than the capacity value components.

4.1.2.3 Energy: Weighted Average Monthly Export Credit value (Using Last 12 Months September 2022 Energy Prices)

The intent of the study is to provide an indicative sense of how prices would be calculated for an ECR. The study was drafted during 2022, so the most recent calendar year was utilized for the purposes of providing an indicative sense of how prices could be calculated. Figure 4.5 illustrates another potential method for consideration, which calculates a weighted average monthly price. For this example, the Idaho Power IRP and ELAP prices for the last 12 months, ending September 30, 2022 (i.e., October 1, 2021, through September 2022) were weighted with 2021 customer-generator exports. Each month's weighted average price is calculated by multiplying the hourly price by the real-time exports from customer-generators that were active for all of the 2021 calendar year. The supporting detail for these calculations can be found in Appendix 4.9.

Figure 4.5 illustrates the potential impact of using a price input from a forecast versus historical market prices. The forecast doesn't reflect changes in market conditions. However, while the use of historical market prices in this example values exported energy in July, August, and September higher – it is not reflective of actual market conditions. This one-year lag is a trade-off if historical prices are used instead of real-time market prices.



	Oct 21	Nov 21	Dec 21	Jan 22	Feb 22	Mar 22	Apr 22	May 22	Jun 22	Jul 22	Aug 22	Sep 22
IRP	$20.88	$21.95	$25.30	$20.87	$19.33	$12.32	$11.42	$14.08	$18.69	$22.82	$24.82	$21.95
ELAP	$34.52	$30.04	$32.44	$34.12	$26.09	$25.99	$43.94	$36.89	$28.93	$65.82	$72.86	$71.02

IRP ELAP

Figure 4.5
Summary results for flat monthly weighted average calculation of avoided energy value with real-time 2021 customer-generator exports and September 2022 last 12-month energy prices[27]

4.1.3 Evaluation of Firmness of Exported Energy

Firm energy is defined as energy that is to be scheduled, delivered, sold, received, and purchased on an uninterruptible basis. In evaluating the exported energy from customer-generators, the Commission-approved Study Framework stated that the value should reflect that energy received from on-site customer-generators is non-firm. Customer-generator exports are non-firm because there is no obligation for a customer-generator to export energy.

Schedule 86 is applicable to Qualifying Facilities (QF) that sell energy to Idaho Power on a non-firm, if, as, and when available basis. The non-firm adjustment applied to the price paid for energy provided under this service schedule is 82.4% of the monthly arithmetic average of each day's ICE daily firm Mid-C Peak average and Off-Peak average index price. The 82.4% non-firm

[27] Figure 4.5 is for illustrative purposes only and only uses 2021 exports by month, resulting in a mismatch between 2022 monthly energy prices and 2021 exports. The study elected to keep exports consistent with analysis conducted for only customer-generator exports in 2021 but recognizes that a backward-looking calculated rate might reasonably match exports and prices with the given hour, month, and year during implementation.

adjustment factor was established in Case No. IPC-E-13-25 as a result of the Dow Jones non-firm index being discontinued. Through confidential settlement discussions, parties to the case determined that applying an adjustment factor of 82.4% to a firm index price resulted in a reasonable proxy price for non-firm energy. The non-firm energy provided under Schedule 86 is further discounted by an adjustment factor of 85% to account for the transmission and transaction related costs associated with disposition of non-firm energy that is excess of Idaho Power's system needs at the time the seller delivers it to the company.

Based on analysis in Appendix 4.10, the continued use of an 82.4% adjustment factor is a reasonable basis for determining the value of non-firm energy. To evaluate a non-firm adjustment factor, the study reviewed all firm and non-firm physical energy transactions conducted between 2016 and 2021 to determine how the value of non-firm energy actually compared to the value of firm energy, and ultimately calculated a non-firm adjustment factor that could be applied to a firm energy price. The data presented in Appendix 4.10 is segmented by Schedule (A, B, and C),[28] which pertains to the firmness of the energy being transacted, and by HL and LL, which are industry standard time blocks for demand and price, and by Schedule (A, B, and C), which pertains to the firmness of the energy being transacted. Each of these designations are discussed in detail in the following paragraphs.

Generally, the demand for electricity is lower in the late evening hours, early morning hours, on weekends and on holidays than it is during daytime and early evening hours on weekdays. For this reason, the electric industry places usage periods into two primary categories: HL and LL. Idaho Power follows the North American Energy Standards Board (NAESB) definitions for HL and LL hour designations for the Western Interconnection,[29] which specifies the following in Pacific Prevailing Time:

- <u>Heavy Load Hours:</u> 7 a.m.–11 p.m. Mountain Time (MT), Monday through Saturday
- <u>Light Load Hours:</u> 11 p.m.–7 a.m. MT, Monday through Saturday, all hours on Sundays, and all hours on New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. If holidays fall on a Sunday, the following Monday

[28] These schedules are defined in the WSPP Inc. First Revised Rate Schedule FERC No. 6. WSPP Inc. administers Rate Schedule FERC No. 6, which is a multi-lateral, standardized agreement that facilitates physical transactions in capacity and/or energy between members and is available to entities (which quality for membership) throughout the entire continental United States, Canada, and Mexico. https://www.wspp.org/pages/Overview.aspx

[29] North American Energy Standards Board Wholesale Electric Quadrant Business Practice Standards, WEQ-007-A.

will be considered a Light Load Hour day. Otherwise, the Light Load Hour day will be the holiday itself.

It is industry practice for energy prices to also be segmented by HL and LL. The ICE Mid-C index and forward prices are examples, which are quoted by HL and LL periods, not by hour. Due to demand and pricing being segmented by HL and LL, the purchase and sale of energy is most commonly transacted in 16-hour (HL) and 8-hour (LL) blocks.

In Case No. IPC-E-13-25, due to the availability of daily HL/LL index prices for firm and non-firm energy, parties were able to calculate weighted average prices for all hours and determine a single non-firm adjustment factor of 82.4%. For the non-firm analysis presented in Appendix 4.10, separate non-firm adjustment factors are provided for HL and LL due to the nature of the dataset and to properly account for the difference in the value of firm and non-firm energy during these two periods. More specifically, historical non-firm energy transaction data is limited in comparison to firm energy transaction data, i.e., transactions for firm energy are much more common than transactions for non-firm energy. The dataset includes numerous days in which non-firm transactions occurred for either HL or LL hours, whereas firm transactions occurred for both HL and LL hours.

In order to make an appropriate comparison of the value of firm and non-firm energy in these instances, Idaho Power calculated a weighted average HL or LL price for firm and non-firm energy depending on the data available for non-firm transactions. As an example, on December 28, 2016, the company purchased non-firm energy for HL hours only. The company also purchased firm energy on this day, for both HL and LL hours, the prices for which were different. Calculating a weighted average price for firm energy for the day, using both HL and LL hour volumes and prices, would skew the value and ultimately the comparison of the value of firm and non-firm energy.

Absent a non-firm adjustment factor, Idaho Power’s broader customer class would effectively provide a zero-cost hedge pricing certainty to the non-firm customer-generator exports. By providing the non-firm adjustment factor, customer-generators are afforded a level of certainty and Idaho Power’s retail customer base is ensured to not pay firm energy prices for a non-firm product. The IRP forecast price and the ICE Mid-C price are both firm energy prices and should have a non-firm discount applied for the ECR calculation.

Unlike the Idaho Power IRP price and ICE Mid-C price, it is not necessary to apply a non-firm adjustment to the ELAP price. As mentioned previously, firmness relates to the ability to curtail energy in real-time. This option is established between buyers and sellers during the energy transaction process, which takes place prior to real-time. The EIM is a real-time market in which each participating entity comes to the market fully capable of meeting their own electricity demand needs in real-time, therefore, capacity has already been paid for by the participants (i.e., the market is already sufficient). Consequently, the option of firm versus non-firm is not applicable to the EIM. The ELAP price is reflective of the value of imbalance energy that occurs when supply and demand are not equal in real-time. Figure 4.6 illustrates the impact of a non-firm adjustment to the flat energy price from Figure 4.2.

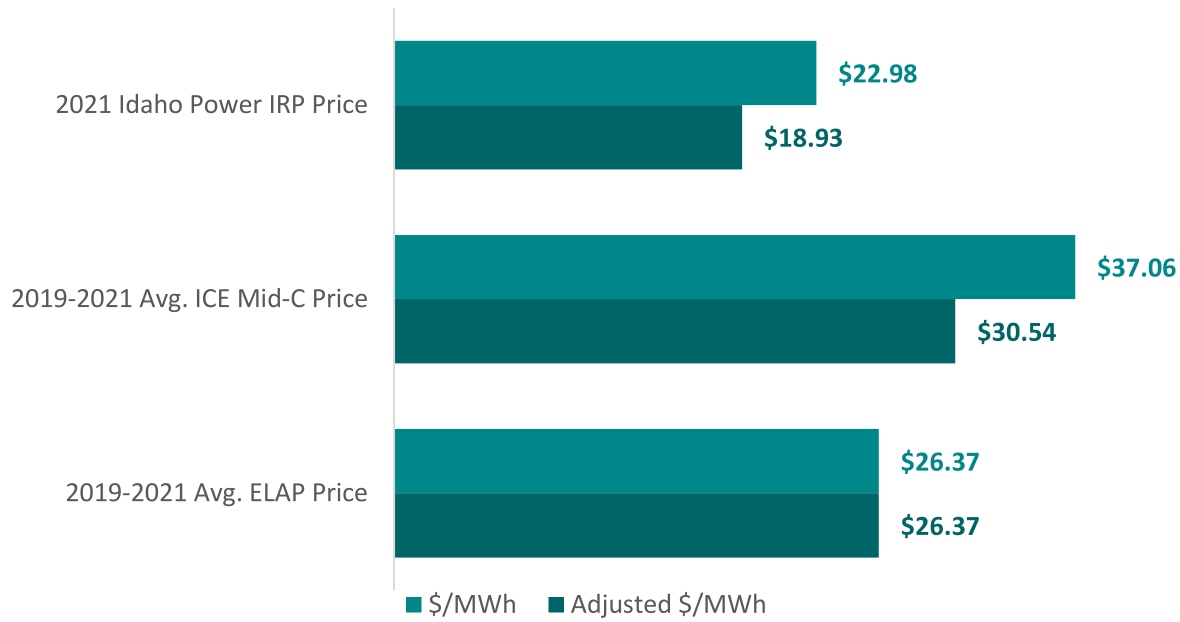


Figure 4.6
Non-firm adjustment for the flat annual weighted average calculation with real-time 2021 customer-generator exports

4.1.4 Transmission Charge or Wheeling Cost

Regardless of the method used for valuing excess net energy, it is likely exported energy from on-site generation systems will be transacted in the Energy Imbalance Market. As such, it is unlikely there will be a transmission charge or wheeling cost associated with potentially selling the DER exported energy off system, because:

1) Sales made via the EIM do not incur a wheeling expense. Sales via the EIM represent a large portion of the company's overall sales.
2) The company's merchant holds 75 MW of firm point-to-point transmission service to facilitate sales. This firm point-to-point transmission service is paid for by the merchant independent of whether the transmission is utilized, therefore, it provides yet another buffer if a sale is required but is not completed via the EIM.
3) The current level of DER penetration is relatively small, and therefore the DER peak energy exports do not result in any material amounts of energy being exported from Idaho Power's system.

The combination of the EIM, the 75 MW of transmission service already reserved for sales, and the relatively small amount of customer exports provides a significant buffer against any potential wheeling expenses associated with customer exports. For informational purposes, the company's hourly transmission wheeling rate changes on October 1 annually. Historically, the rate was $3.42 per MWh (starting October 1, 2020), and $3.56 per MWh (October 1, 2021). The company's current hourly transmission rate, as of October 1, 2022, is $3.59 per MWh.

As the penetration of on-site generation on Idaho Power's system grows, it will be important to assess whether a transmission charge or wheeling cost would be appropriately included in the ECR.

4.1.5 Fuel-Cost Hedge Benefit

The Idaho Power Energy Risk Management Standards (ERMS) adopted pursuant to the Idaho Power Energy Risk Management Policy is on file with the Commission.[30] Per Idaho Power's ERMS, hedges are transacted based on average heavy load and light load positions. Natural gas hedges or power hedges are transacted to address forecast deficit positions on an average megawatt basis in heavy load or light load periods. Natural gas hedge purchases are the most common hedging transactions, as this product can be shaped to meet a net-load profile, where less gas is consumed during low net-demand hours and gas generation is ramped up in high net-demand hours. The natural gas hedges provide price certainty for all hours, including net-peak hours, and reduce exposure to the volatile real-time spot market price.

Unlike natural gas and power purchases, which provide firm energy, customer-generation exports are intermittent and non-firm. Further, the shape of the customer-generators' exports, when they occur, does not fit the hedge profile of 16 hours of peak power, which is the profile utilized per Idaho Power's ERMS.

Considering the overall power systems needs more granularly in time (rather than heavy load and light load blocks), when energy from DERs is generated during the day there is minimal grid reliability risk regarding resource adequacy. This reduced risk is due to the penetration of solar generation across the West. When there is low resource adequacy risk, there is also minimal price risk. If there is little price risk, there is no reason for the utility to hedge to protect against run-away pricing — a primary purpose of Idaho Power's risk management policies. As shown in Figure 4.7, the highest price hours occur late in the day during the solar ramp-down period after the exports have reduced to be less than their heavy load period average (see Figure 4.7,

[30] *In the Matter of Idaho Power Company's Interim and Prospective Hedging, Resource Planning, Transaction Pricing, and IDACORP Energy Solutions (IES) Agreement*, Case No. IPC-E-01-16.

Market Price). Idaho Power has greater exposure to serving net-peak load during high price times — after solar generation hours. Figure 4.7 provides an illustrative diagram of these concepts.

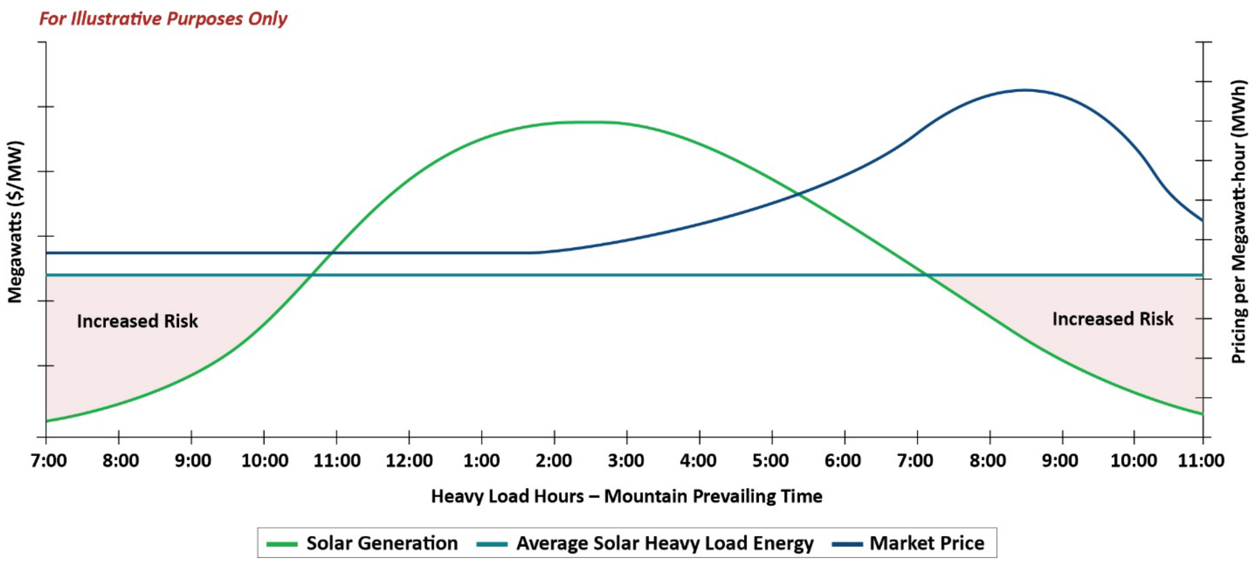


Figure 4.7
Illustrative fuel-price hedge and solar generation diagram

Exports from customer-generators do not provide a fuel-cost hedge benefit. Customer-generator exports on Idaho Power's system occur intermittently in the midday hours when it is generally less valuable, rather than on a firm basis in the highest net-peak hours, when it would be most needed — resulting in no reduction in pricing risk during the net-peak load.

Avoided Energy Costs – Supporting Appendices

Appendix 4.1
2021 Idaho Power IRP Hourly Price

Appendix 4.2
2019–2021 ICE Mid-C Hourly Price

Appendix 4.3
2019–2021 ELAP Hourly Price

Appendix 4.4
2021 Net Hourly Exports

Appendix 4.5
2021 Real-Time Exports

Appendix 4.6
Weighted Average Energy Prices (Flat)

Appendix 4.7
Weighted Average Energy Prices (Time Variant)

Appendix 4.8
2021 Hourly Price Heat Map

Appendix 4.9
September 2022 LTM Monthly Weighted Average

Appendix 4.10
Non-Firm Analysis

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

4.2 Avoided Generation Capacity Costs

This section will focus on avoided generation capacity costs Idaho Power may realize due to the exported energy from customer-generators. The electric power grid consists of three separate systems which work together to safely bring reliable energy to customers. The three systems are generation, transmission, and distribution as illustrated in Figure 4.8.

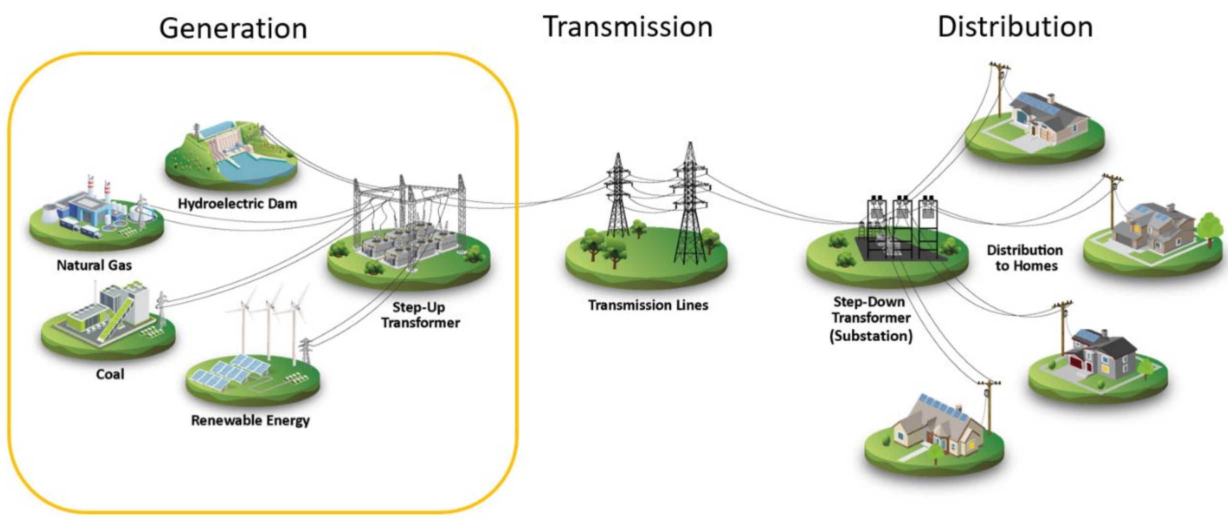


Figure 4.8
Electric grid schematic highlighting generation facilities

The generation system is designed to meet Idaho Power's system peak demand, or the most energy needed by all customers in the same instant. When forecasted peak demand exceeds the generation system capacity, additional resources are required to increase the system peak capacity. In addition, consideration is given to potential outages from individual resources in the generation system which may impact the ability to serve system load. To meet increasing peak demands, Idaho Power must purchase capacity on the market or build new resources.

The avoided generation capacity identifies the impact of customer-generators to help meet forecasted peak demand and potentially reduce the cost for additional system resources.

4.2.1 Generation Capacity Contribution Methods Overview

Depending on the type of resources installed by customers, they can either be defined as Variable Energy Resources (VER) or Energy Limited Resources (ELR). A VER refers to any renewable generation resource whose output cannot be directly stored or controlled by the facility owner or operator (e.g., wind or solar resources with hourly output that is dependent on a multitude of factors like weather and environmental conditions). An ELR refers to a resource that can be dispatched for a limited number of hours and days (e.g., energy storage).
The capacity contribution of VERs and ELRs to peak energy demand can be calculated with

various methods. The study considers two methods for evaluating the avoided generation capacity value of customer-generator exports:

1) Effective Load Carrying Capability (ELCC): Reliability-based metric used in Idaho Power's 2021 IRP.
2) National Renewable Energy Laboratory (NREL) 8,760 Hours: Method developed by NREL and used in Idaho Power's 2019 IRP.

The following two sections will describe the ELCC and NREL methods in more detail.

4.2.1.1 ELCC Method

ELCC is a reliability-based metric used to assess the contribution to peak demand of any given generation unit or power plant. ELCC determines an individual generator's contribution to the overall system reliability and is primarily driven by the timing of the highest risk hours, or Loss of Load Probability (LOLP) hours. Idaho Power transitioned from the NREL method (used in the 2019 IRP) to the ELCC method used in the 2021 IRP because it is a more robust calculation of capacity contribution of variable resources. The definitions of the key components that flow into the ELCC calculation are provided in Table 4.1 below.

Table 4.1
ELCC method — key definitions

Key Terms	Definition
EFOR	Equivalent Forced Outage Rate (EFOR) represents the number of hours a generation unit is forced off-line compared to the number of hours the unit runs. For example, an EFOR of 3% means a generator is forced off 3% of its running time.
LOLP	Loss of Load Probability (LOLP) is the likelihood of the system load exceeding the available generating capacity during a given time interval (typically an hour). The LOLP can be calculated by determining the probability that the available generation at any given hour is able to meet the net load during that same hour.
LOLE	Loss of Load Expectation (LOLE) is the expected number of days per time interval for which the available generation capacity is insufficient to serve the demand at least once per day. The LOLE can be calculated by adding the maximum LOLP from each day for a time interval (typically over one year).
Perfect Generator	Fictitious generation unit (for comparison purposes only) whose EFOR value is 0%, meaning that it is always available and never forced off-line.

The ELCC of a VER or ELR is determined by calculating the generation required to achieve a given reliability target with and without the resource being evaluated, in this case the customer exports. The ELCC will equal the difference in the size of the previously calculated generators divided by the resource's nameplate capacity. For the ELCC analysis, losses were added to the hourly customer-generator exported energy.

4.2.1.2 NREL 8,760 Hour-Based Method

The NREL methodology uses a system Load-Duration Curve (LDC) and a Net Load-Duration Curve (NLDC), representing the system net load, VER, and ELR generation, for an entire year. The LDC reflects the total system load, sorted by hour, from the highest load to the lowest load. The NLDC represents the total LDC minus the time-synchronized contribution from VER and ELR generation. The resulting net load is then sorted by hour, from the highest load to the lowest load. The capacity value of existing VER and ELR generation is the difference in the areas between the LDC (system load) and NLDC (net load) during the top 100 hours of the duration curves divided by the rated capacity of the VER and ELR generation installed. These 100 hours can be a proxy for the hours with the highest risk for loss of load. As was done for the ELCC method, losses were added to the hourly customer-generator exported energy for the NREL 8,760 hour-based analysis. More information regarding avoided losses can be found in Section 4.4.

4.2.1.3 Other Generation Capacity Evaluation Methods

The quantification of capacity contribution of solar has evolved industry-wide as well as specifically on Idaho Power's system. For example, during the 2017 IRP, Idaho Power used a variant of a method referred to as the Peak Capacity Allocation Factor (PCAF) method, which calculates the capacity contribution of solar during the top 150 load hours resulting in capacity contribution of 28.4% for a fixed-tilt system oriented due south. Recognizing that this method was limited and did not capture the impact of high solar penetration, Idaho Power's 2019 IRP transitioned to the 8,760 hour-based method developed by NREL (explained in Section 4.2.1.2). To further capture the impact of higher DER penetration levels, Idaho Power, with the support of its Integrated Resource Plan Advisory Council, adopted the best industry standard, the ELCC method (explained in Section 4.2.1.1), for the 2021 IRP.

The PCAF method concentrates value around the peak load of a utility's system, while ELCC concentrates value around periods of critical capacity need for the system. With the proliferation of VERs, there is growing divergence between the system peak load and periods of critical capacity needs. To recognize this shift, Idaho Power has adopted ELCC as the preferred method to evaluate capacity in various processes, such as the most recently filed IRP and the latest Request for Proposals (RFP).

Another alternative method to determine the avoided capacity component of the ECR is to take the levelized cost of the surrogate resource and divide it by the number of critical hours. The calculation for the alternative method is shown in Figure 4.9.

$$Avoided\ Generation\ Capacity = \frac{Levelized\ Fixed\ Cost\ of\ Avoided\ Resource}{Number\ of\ Critical\ Hours}$$

Figure 4.9
Alternative avoided generation capacity value formula[31]

This approach is similar to the NREL 8,760 hour-based method, where the number of critical hours are used as a proxy for the hours of highest risk. For comparison, the top 100 hours are used in the NREL 8,760 hour-based method. This alternative method assumes all identified critical hours are valued the same, whereas the ELCC method accounts for the hourly fluctuation in risk. Another concern with this alternative method is that it is unclear how to properly determine the number of critical hours.

The study explored several methods for quantifying the value of avoided generation capacity as discussed in this section. However, due to the limitations and deficiencies of certain methods, the study only quantifies the value of generation capacity for the ELCC and the NREL 8,760 hour-based method.

4.2.2 Generation Capacity Value: Inputs And Calculations

4.2.2.1 Generation Capacity Value: Inputs

To accurately capture the capacity contribution of customer-generator exports, available historical data for 2020 and 2021 was used and applied to the ELCC and NREL 8,760 hour-based calculations. Because these methods both typically consider a timeframe of one calendar year, the results for 2020 and 2021 were averaged to produce a singular average ELCC value and average NREL 8,760 hour-based value; this average approach is done to capture the customer-generator export contribution range resulting from the correlation between weather, load, and VER output, which can vary year to year. As more data becomes available, a three- or five-year rolling average could be used so that the capacity contribution of future customer-generator exports is not skewed by the customer resource buildout of past years. Using a three- or five-year rolling average also captures the varying weather conditions that can occur from year to year, and thus, better reflect the expected value.

Both the ELCC and NREL 8,760 hour-based methods require the following historical input data:

- The annual hourly system load data
- The annual hourly system solar data
- The annual hourly system wind data
- The annual hourly system run of river data

[31] Under this proposed method, line losses would need to be explicitly applied.

- The annual hourly system cogeneration data
- The annual hourly customer-generator export data (with losses applied)[32] and the corresponding customer-generator export nameplate capacity

However, because the ELCC risk-based metric is a statistical analysis that captures the hourly interplay between all system resources (dispatchable resources such as natural gas and hydro with storage, VERs, and ELRs), more historical input data is required to calculate the ELCC:

- The monthly capacity values of dispatchable resources and their associated EFORs

Idaho Power created a tool to implement the ELCC methodology for the 2021 IRP and maximize computational efficiency for modeling the company's existing and potential resource stack and calculate ELCCs. Dispatchable resources were modeled using a monthly outage table that was calculated using their monthly capacity and EFOR (as previously mentioned). The outage table is comprised of the components listed in Table 4.2.

Table 4.2
Outage table components for the ELCC method

LOLE Outage Table Components	Description
Capacity In:	Capacity available to serve load (MW)
Capacity Out:	Forced outage capacity (MW)
Individual Probability:	Probability that a specified event will occur
Cumulative Probability:	Cumulative distribution of the individual probabilities

For the ELCC method, the hourly VER and ELR data are subtracted from the system load to produce a net load shape that is then used in the LOLE calculations.

Table 4.3 summarizes the names and descriptions of the input and output Excel data files used to complete the capacity contribution analyses using 2020 and 2021 data.

[32]The hourly customer-generator exports utilized in the capacity contribution calculations were increased by the hourly loss factors of Table 4.9; this was done to account for the capacity contribution of loss reduction.

Table 4.3
Names and descriptions of the files and tools used to complete the capacity contribution analyses

Excel File Name	Description
Appendix 4.11 2020–2021 Real-Time & Net Hourly Customer-Generator Exports	Hourly real-time and net hourly customer-generator export energy for 2020 and 2021, with and without losses.
Appendix 4.12 2020–2021 Hourly Historical Load & VERs Data	Hourly system load, wind, solar, run of river hydro and cogeneration data for 2020 and 2021.
Appendix 4.13 2020–2021 Monthly Historical Dispatchable Data	Monthly MW capacity of the system's dispatchable resources and their associated EFOR values.
Appendix 4.14 ELCC & NREL Results	2020 and 2021 results for the ELCC and NREL 8,760 hour-based methods.

The customization functionality of the LOLE tool allows for a detailed approach to modeling Idaho Power's system; it was the selected method for Idaho Power's 2021 IRP. As system needs continue to change, new analyses such as this LOLE tool will be essential in best evaluating the Idaho Power's highest risk hours (which is of key importance because they will no longer necessarily align with the peak load hour). More information regarding both the ELCC and NREL 8,760 hour-based methods can be found in Chapter 5, section Resource Contribution to Peak of Idaho Power's 2021 IRP main report[33] and the Loss of Load Expectation section of Appendix C.[34]

4.2.3 Generation Capacity Value Calculation

Similar to the flat and seasonal time variant methods evaluated for the avoided energy value (described in sections 4.1.2.1 and 4.1.2.2), a comparable analysis can be done for the generation capacity value for both the ELCC and NREL methods. The study considers calculating the export credit value for the generation capacity input. Both the flat, or single, annual export credit value and a seasonal and time-variant export credit value are described in more detail in the following sections.

The avoided generation capacity value is calculated using the formula shown in Figure 4.10. The variables for the formula are identified in Table 4.4 and 4.5 for the flat and time variant methods, respectively.

[33] https://docs.idahopower.com/pdfs/AboutUs/PlanningforFuture/irp/2021/2021%20IRP_WEB.pdf

[34] https://docs.idahopower.com/pdfs/AboutUs/PlanningforFuture/irp/2021/2021_IRP_AppC_Technical%20Report_WEB.pdf

$$Avoided\ Generation\ Capacity\ Value = \frac{(Levelized\ Fixed\ Cost\ of\ Avoided\ Resource) \cdot (Capacity\ Contribution) \cdot (Nameplate)}{(Energy\ Exported)}$$

Figure 4.10
Avoided generation capacity value formula

Note that the avoided generation capacity value is independent of the company's identified planning reserve margin and reliability target. For information on how the planning reserve margin and reliability target are used in the company's analyses, please refer to Idaho Power's 2021 IRP.[35]

4.2.3.1 Generation Capacity: Flat Annual Export Credit Value

To evaluate a flat annual value for the avoided generation capacity, the analysis evaluates the capacity contribution of the energy exported by customer-generators for the entire year. Table 4.4 summarizes the constraints used for a flat annual generation capacity value.

Table 4.4
2021 constraints for full year analysis of a flat generation capacity value

Constraint	Value
Levelized fixed cost of avoided resource (simple cycle combustion turbine)	$128.40/kW-year
Total Customer-Generator Nameplate Capacity	64.11 MW
Total Customer-Generator Energy Exported	59,154 MWh

For avoided capacity calculations, the study relies on the least-cost selectable resource from the most recently acknowledged IRP. An August 2022, Commission order upheld this approach as reasonable, where the Commission stated: "We find it fair, just, and reasonable that the resource(s) used as a surrogate to determine avoided capacity cost be identified using the lowest-cost selectable resource from the most recently acknowledged IRP at the time of [power purchase agreement] execution." [36]

The IRP selects resources for its portfolios using an algorithm that considers both the cost of capacity and the cost of energy. For example, battery storage is not the least fixed-cost dispatchable resource that Idaho Power would consider strictly for capacity. With the objective

[35] https://docs.idahopower.com/pdfs/AboutUs/PlanningforFuture/irp/2021/2021%20IRP_WEB.pdf, pages 116–17 and 137–140

[36] *In the Matter of Idaho Power Company's Application for Approval of a Replacement Contract with Micron Technology, Inc. and a Power Purchase Agreement with Black Mesa Energy, LLC*, Case No. IPC-E-22-06, Order No. 35482 at 17 (Aug. 1, 2022).

being to identify a surrogate resource for determining the value of capacity separate from all other avoided costs, the surrogate should be based on the least-cost capacity resource, which is a single cycle combustion turbine as shown in Table 4.4 with a cost of $128.40 per kW, per year.

Figure 4.11 summarizes the NREL and ELCC results under these constraints for the value of generation capacity spread across all exports irrespective of when the export occurs during the year or time of day.

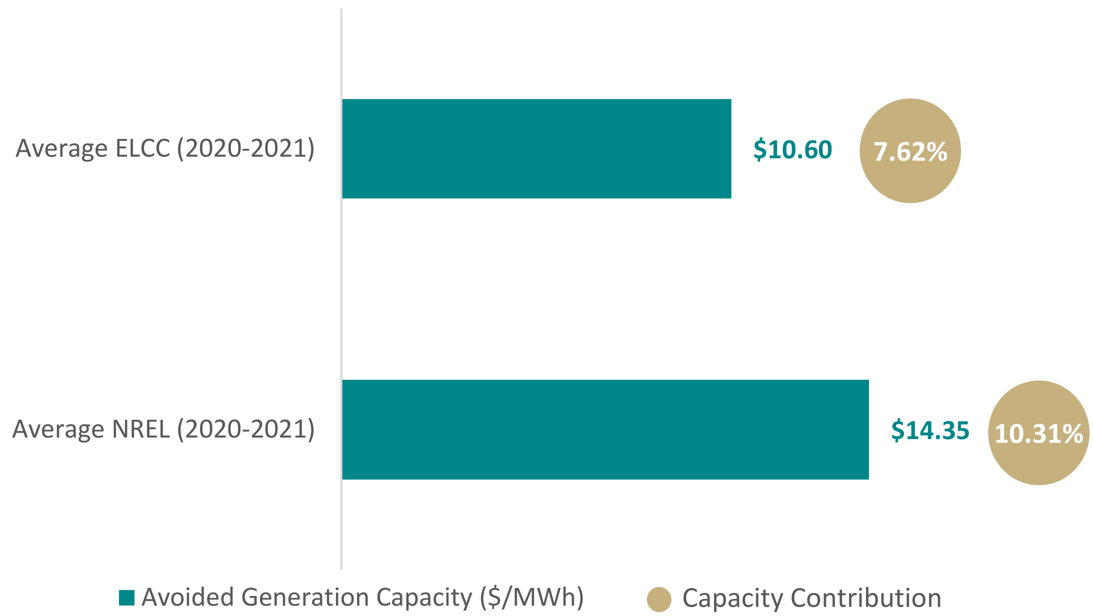


Figure 4.11
Summary results for a flat annual export credit value with real-time 2021 customer-generator exports

4.2.3.2 Generation Capacity: Seasonal Time Variant Export Credit Value

To evaluate a seasonal time variant value for the avoided generation capacity, the analysis evaluates the total energy exported by customer-generators during the On-Peak period. The On-Peak period as defined for Idaho Power's Demand Response Programs is 3 to 11 p.m., June 15 through September 15, Monday through Saturday, excluding holidays. All exports that occur outside the identified parameters are assumed to have a capacity contribution of 0%. Table 4.5 summarizes the constraints used for a seasonal time variant generation capacity value.

Table 4.5
2021 constraints for the seasonal time variant generation capacity value

Constraint	Value
Levelized fixed cost of avoided resource (simple cycle combustion turbine)	$128.40/kW-year
Total Customer-Generator Nameplate Capacity	64.11 MW
Total Customer-Generator Energy Exported	4,469 MWh

Figure 4.12 summarizes the NREL and ELCC results under these constraints for the value of generation capacity only applicable to the highest risk, or On-Peak hours.

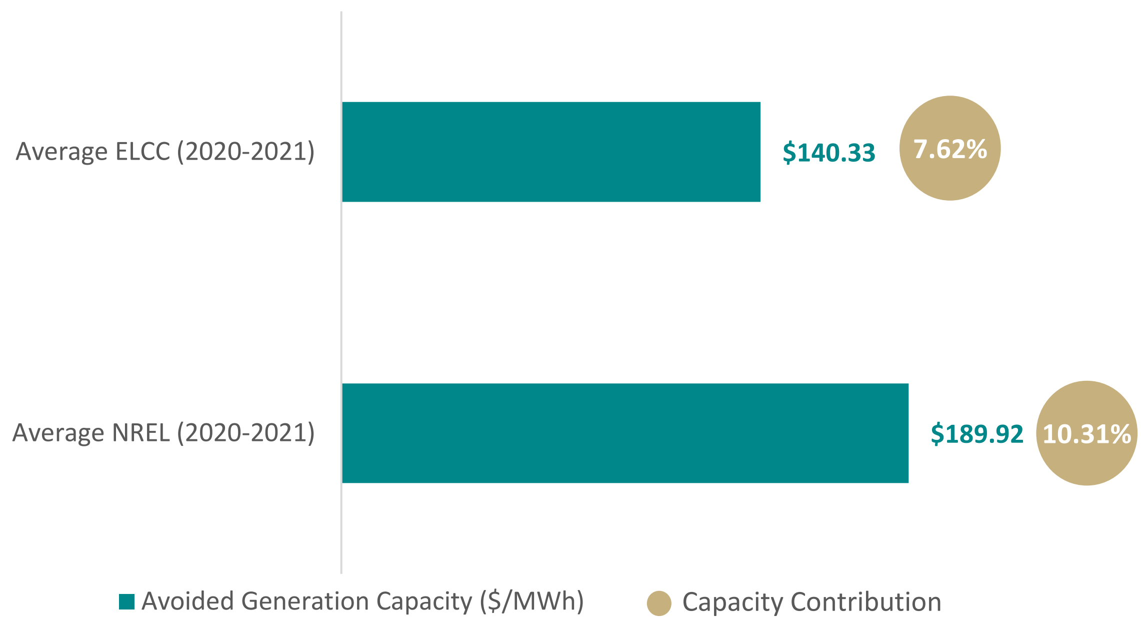


Figure 4.12
Summary results for the On-Peak credit value with real-time 2021 customer-generator exports

Avoided Generation Capacity Costs – Supporting Appendices

Appendix 4.11
2020–2021 Real-Time & Net Hourly Customer-Generator Exports

Appendix 4.12
2020–2021 Hourly Historical Load & VERs Data

Appendix 4.13
2020–2021 Monthly Historical Dispatchable Data

Appendix 4.14
ELCC & NREL Results

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

4.3 Avoided Transmission and Distribution Capacity Costs

As mentioned earlier in this study, the electric power grid consists of three separate systems which work together to safely bring reliable energy to customers. The three systems are generation, transmission, and distribution as illustrated in Figure 4.13. The avoided transmission and distribution (T&D) system costs from on-site customer-generator exports are discussed in this section.

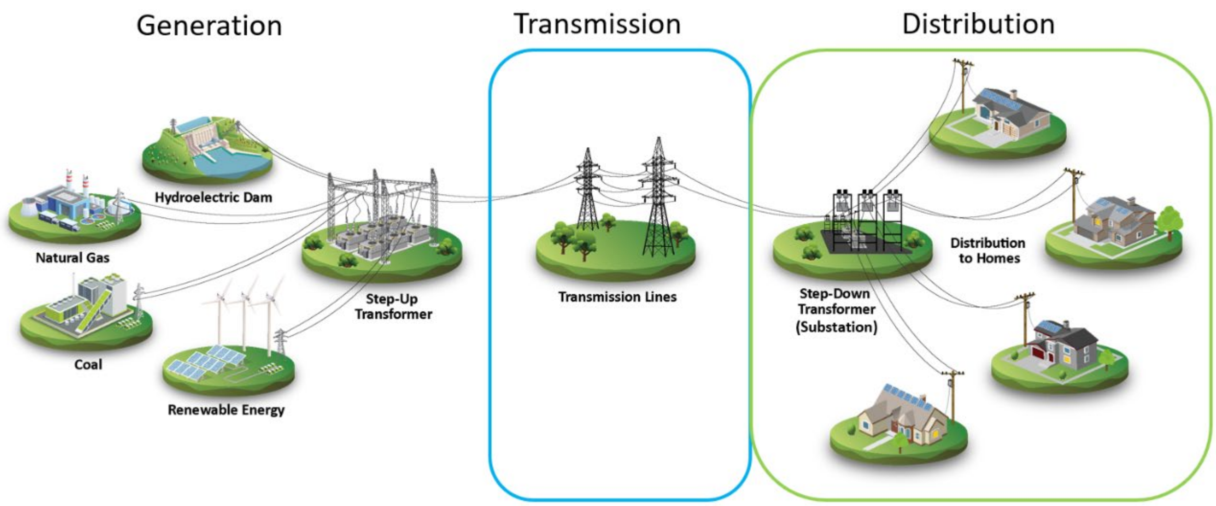


Figure 4.13
Electric grid schematic highlighting transmission and distribution facilities

The T&D system (wires, transformers, substations etc.) must be sized for the total amount of energy that could run through it at any given time (localized peak times). Idaho Power determines planning capacity limits for the T&D system. In addition, Idaho Power determines localized growth rates for the T&D system to ensure that equipment is adequately sized for the expected loads. When a part of the T&D system is identified to have loads that will exceed the planning capacity limits, a project is initiated to increase the capacity of that part of Idaho Power's system.

The addition of customer-generator exports to the T&D system has the potential to reduce the expected localized peak load. If the customer-generator exports result in localized peak reductions that are sufficient and occur at the same time as the localized peak, then the project to increase capacity may be deferred or delayed and those costs are reduced or avoided.

The illustration in Figure 4.14 depicts the distribution system where one section of the distribution system is identified as having available capacity. For this section of the distribution system, the addition of customer generation does not provide a potential to avoid a distribution project because there is no need for a project. However, a second distribution line has been identified which has limited capacity. For that limited capacity distribution line, the addition of customer generation has the potential to avoid a distribution project designed to increase capacity in a specific section of the distribution system if the generation exports.

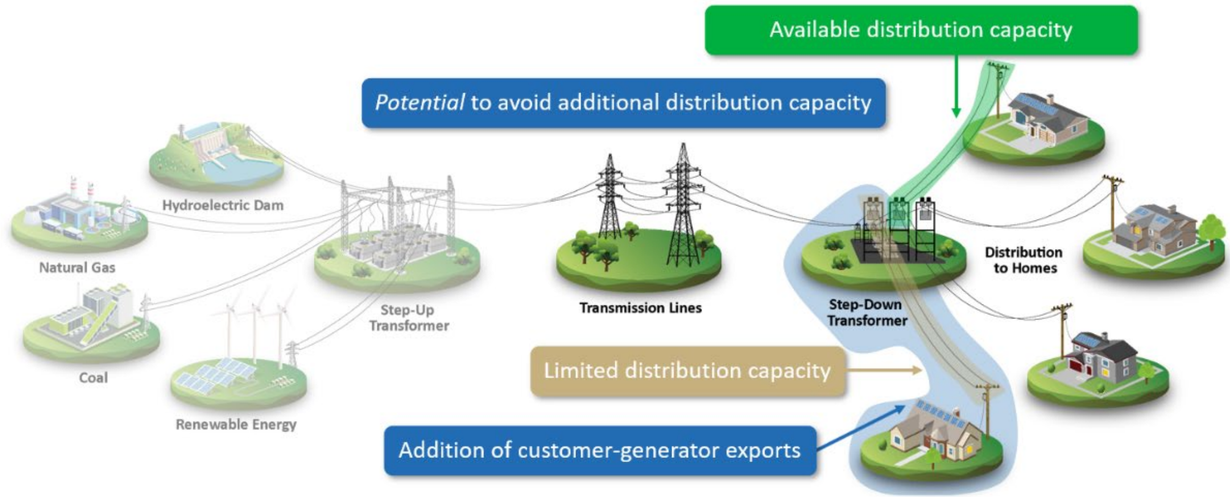


Figure 4.14
Electric grid schematic identifying localized distribution capacity

4.3.1 Transmission and Distribution Capacity Cost: Method and Assumptions

To determine the potential value of on-site generation in deferring or delaying the need for Idaho Power to build T&D resources, the study identifies coincident peak hours. Coincident peak hours are those hours when excess energy and peak hours on the T&D system overlap. The study analyzes 15 years of historical project data and five years of forecasted project data on Idaho Power's T&D system. This data identified the historical trends and projected T&D projects and the capacity need for each project.

An alternative considered was to provide an incentive to customer generation projects located in specific areas rather than based on exported energy. The potential projects would be able to defer transmission or distribution projects if they exported energy at the coincident peak hours. To that end, such an incentive would only be available *after* the project demonstrated their export energy occurred at the coincident peak times. In addition, the quantity of the export would need to be sufficient to exceed the planning capacity shortfall. This could result in some projects being installed expecting an incentive but may be dependent on additional projects being installed in a timely manner and operated such that the total export energy in a location provides a deferral value. Without the deferral value, there would not be an incentive for the installed project(s).

This alternative would not result in a guarantee of an incentive. The incentive would be dependent on sufficient coincidence exported energy by location.

4.3.1.1 Identifying Coincident Peak Hours

Customer-generator exports at the locational peak time was determined based on the number of customers for each rate class connected at each specific location. Then using the number of connected customers by rate class along with an average system size by rate class the total generation capacity available at the location is determined. As was done for the generation capacity in Section 4.2, these connected generation capacity values are increased by the expected loss savings that they provide to the system. More information regarding avoided losses can be found in Section 4.4.

Using the 2021 exported energy from customer-generators, the average hourly summer and winter exported energy is calculated as a percentage of connected customer-generator nameplate capacity. These hourly values are used to estimate the expected generation export for the coincident time of day based on the connected generation capacity. This provides the expected exports coincident with Idaho Power system peak load at that location.

4.3.2 Avoided Transmission & Distribution Value Calculation

The avoided T&D cost values of VERs can be calculated using actual and proposed capacity projects, the local area growth rates, and the local VER export values at the time of the local peak. The data used for this method includes:

1) Project costs and need dates for T&D capacity projects
2) For each capacity project in each local area:
    a) Peak capacity and peak load
    b) Growth rate
    c) Time of peak demand
3) Exported energy from VER expected at project location during peak demand time
    a) System aggregate export shape based on *real-time* energy measured in 2021
    b) System aggregate export shape based on *net-hourly* energy measured in 2021

The savings from these transmission capacity and distribution capacity projects are the basis for determining the avoided transmission and distribution value for customer-generator exports. The study analyzed historical and planned transmission and distribution capacity projects from the years 2007 through 2026.

Once coincident hours are determined, the VERs expected output at the locational peak time is subtracted from the expected peak load to get a revised peak load. The revised peak load is compared to the planning capacity. If the revised peak load is less than the planning capacity, the capacity project can be deferred.

Once a project is identified to be deferred, the deferral time is determined. The peak load is increased by the annual growth rate. For each successive year, the VERs' expected peak time exports are compared to the difference between the peak load with annual growth and planning capacity. The last year that the VER expected peak time export is greater than the difference between the peak load and planning capacity is the last year of the deferral. A project may be deferred for a single year or several years.

The project cost and the numbers of years of deferral determine the deferral value. The deferral value of all projects is summed and converted into a per year value, based on the number of years that projects were reviewed.

The annual value of deferred projects is then divided by the energy exported. This value is dependent upon either a flat or seasonal time-variant export credit value (Figure 4.15). This method is completed for transmission capacity projects to determine the transmission avoided capacity value and for distribution capacity projects to determine the distribution avoided capacity values. The constraints of this analysis are presented in Table 4.6 and the summary results are provided in Table 4.7.

Table 4.6
Transmission capacity and distribution capacity project analysis constraints

Constraint	Value
Project Years Reviewed	2007 to 2026
Count of Projects Reviewed	447
Count of Projects Deferred (% of Total)	9 (2%)

Table 4.7
Transmission capacity and distribution capacity analysis results

Line Item	Value
Distribution Capacity Projects Deferral Value	$307,263
Transmission Capacity Projects Deferral Value	$0
Total Savings	**$307,263**

The T&D analysis was completed with customer-generators 2021 exported energy for both a net hourly and real-time measurement. The deferral results and timelines were the same under both assumptions. The annual value of deferred projects must be converted to a price per kWh exported for the ECR. This calculation is dependent upon either a flat annual or seasonal time variant ECR. Additional data for this analysis is presented in Appendix 4.15.

To evaluate a flat annual value for the avoided T&D capacity, the analysis evaluates the total energy exported by customer-generators for the entire year. This structure is a simplified approach; however, does not align the value that is provided for T&D capacity with the timing or location of exports. As an alternative, the value for avoided T&D capacity costs could be applied only to exports during On-Peak hours, which better aligns the value with the timing of exports. The study did not evaluate a locational based ECR value as this is not a feasible solution within the company's billing system. Figure 4.15 summarizes the results under the above constraints for the value of avoided T&D capacity under a flat and seasonal time variant export credit rate.

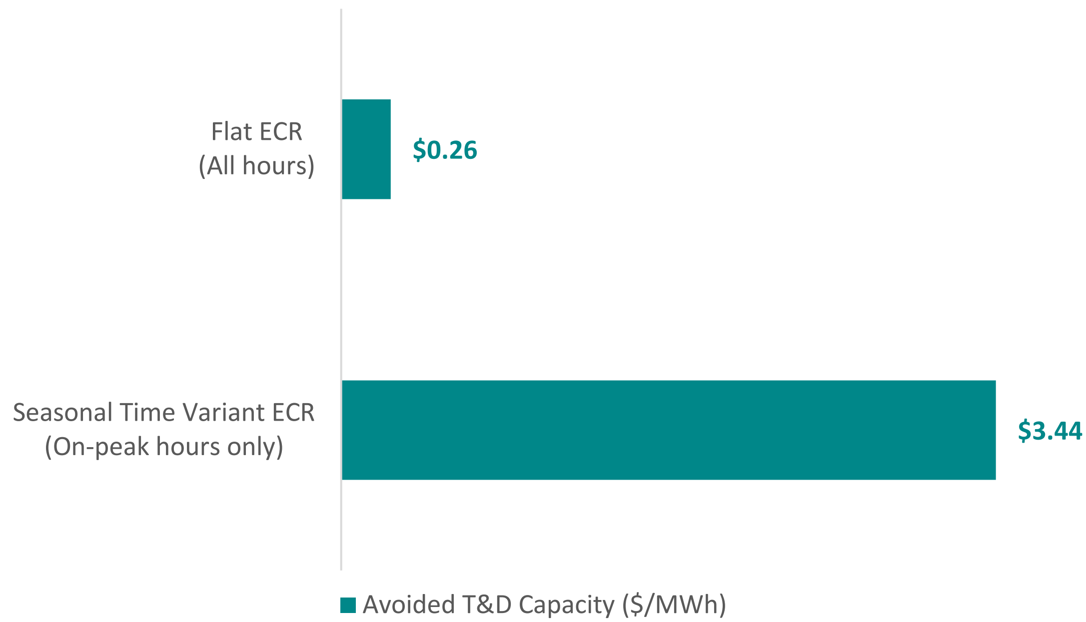


Figure 4.15
Summary results for a flat and seasonal time variant weighted average calculation of avoided transmission and distribution capacity value with real-time 2021 customer-generator exports

4.3.3 Other Avoided Transmission & Distribution Methods

Many T&D deferral approximation methods exist and, when applied appropriately, may provide a reasonable proxy for T&D deferral value when project-level data is not available.
These top-down approximation methods often rely on general utility information, like the total T&D capital spend, and ignore or make assumptions about whether T&D investments could be deferred by on-site generation. This is because T&D growth projects are location specific and depend on the local growth rates, load shapes, and equipment characteristics. These typically vary, often significantly, with the aggregated system-level information.

In some locations where there are separate distribution and transmission providers, such as Maine, the distribution utility pays a transmission tariff to the transmission provider based on a per-kW demand charge that is a function of monthly system peaks. At such locations, the DER exports may reduce the overall distribution utilities' monthly peak demands which would reduce tariff fees. This method is an approximate proxy to capture avoided transmission capacity and is not based on actual capacity projects.

When project-level data is available, as it was for this study, it is the preferred analysis method. It provides the most applicable and accurate calculation of the T&D deferral value[37] because it considers how and when T&D investments are made. Therefore, the study does not include results from less applicable approximation methods that are primarily designed for situations where project-level data is unavailable.

Avoided Transmission & Distribution Capacity – Supporting Appendices

Appendix 4.15
Transmission and Distribution Avoided Capacity

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

[37] *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 & to Implement Changes to Schedule 6, 8, and 84 Non-Legacy Systems,* Case No. IPC-E-22-22, Idaho Power Company's Reply Comments, Attachment 1 — Strunk Affidavit.

4.4 AVOIDED LINE LOSSES

As electricity moves through the system, from the generation source to the end user, some of that electricity does not reach the end user. It is lost due to heating of line wires by the current as energy moves across the line, over high-voltage transmission, and lower-voltage distribution. Figure 4.16 provides an illustrative example of lines losses that occur between the utility's generation source and the retail customer load. When energy is exported by customer-generators, Idaho Power has the potential to avoid the energy and the associated line losses.

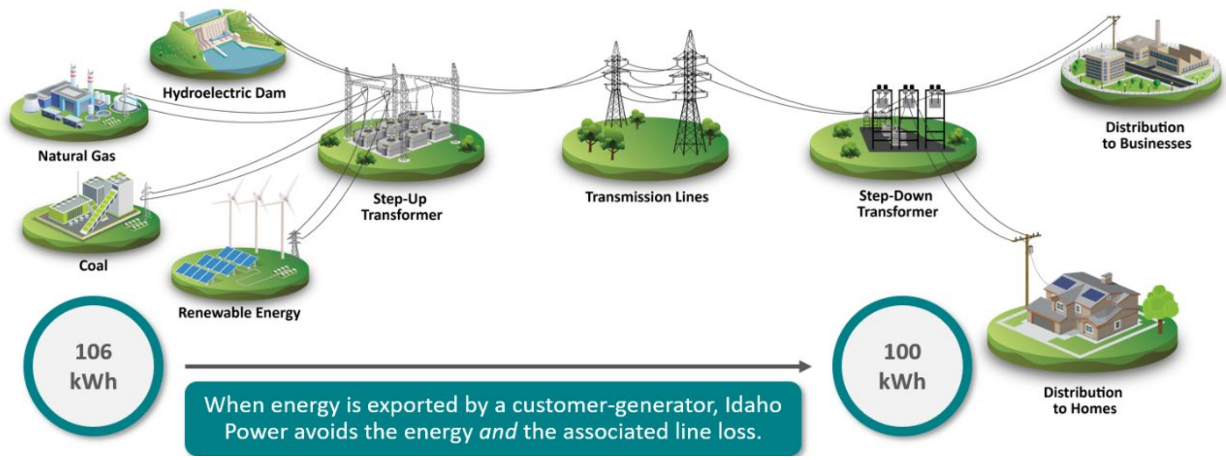


Figure 4.16
Electric grid schematic with illustrative line loss example

4.4.1 LINE LOSS VALUE: INPUTS AND ASSUMPTIONS

Line losses are proportionate to the amount of energy flow. In other words, the higher the energy flow, the higher the line losses. Line losses occur on both transmission and distribution lines. Transmission and distribution system losses increase during peak loading hours and decrease during off peak loading hours when expressed in absolute terms of energy.

Transformer losses consist of both core losses and winding losses. Transformer core losses are generated by energizing the laminated steel core of the transformer. Transformer core losses are essentially constant, meaning they do not change based on the amount of load on the transformer from no load to full load. Therefore, the existence of exports does not avoid additional transformer core losses. Transformer winding losses are generated by the flow of energy in the transformer's windings. Therefore, similar to line losses, transformer winding losses are proportionate to the amount of energy flow.

Losses can be classified as marginal losses, average line losses and peak line losses. Marginal losses are the incremental change in real system power losses caused by changes in system load and generator patterns. Average line losses are the losses that occur in the power system over a period of time; for example, over the course of a year. Peak line losses are the losses that occur during system peak load. In the company's 2012 System Loss Study, only average and peak line losses were calculated. Customer-generator energy exports are higher during the spring and fall seasons when local consumption is minimal; the exports are reduced significantly during the summer season when self-consumption increases. The study finds that using average line losses is most appropriate given the customer-generator export pattern.

Idaho Power's hourly losses are included in Appendix 4.16 and were used as the basis for evaluating an avoided line loss value for this study. Table 4.8 provides a summary of the total system losses from Idaho Power's most recent line loss study. Line losses studies are comprised of extensive analyses and are not performed often; however, line losses are expressed as percentages, which do not significantly vary through time.

Table 4.8
Idaho Power 2012 System Loss Study results, total line losses

Dates	Season	Total Losses
May–October (2–7 p.m.)	Summer On-Peak	8.6%
May–October (5 a.m.–2 p.m., 7–9 p.m.)	Summer Mid-Peak	8.5%
May–October (9 p.m.–5 a.m.)	Summer Off-Peak	8.7%
November–April (6–10 a.m., 5–8 p.m.)	Winter On-Peak	8.5%
November–April (10 a.m.–5 p.m., 8–10 p.m.)	Winter Mid-Peak	8.5%
November–April (10 p.m.–6 a.m.)	Winter Off-Peak	9.0%

As previously mentioned, only transmission and distribution primary line losses and transformer winding losses can be avoided by customer-generator exports; transformer core losses, unlike winding losses, remain near-constant and therefore are not avoidable.

The avoidable line losses are computed by adding the losses in the transmission system and the avoidable losses in the distribution system. When added as a percentage, the losses in the distribution are multiplied by a factor to consider the energy already lost in the transmission system, as seen in Figure 4.17.

$$Avoidable\ Losses = Transmission\ Losses + (1 - Transmission\ Losses) * Distribution\ Losses$$

Figure 4.17
Avoidable losses equation

The transmission losses can be computed as described in Figure 4.18.

$$Transmission\ Losses = \frac{\sum Transmission\ Line\ Losses}{Transmission\ Load + Wheeling}$$

Figure 4.18
Transmission losses equation

The avoidable distribution losses can be calculated as described in Figure 4.19.

$$Distribution\ Losses = \frac{Station\ Losses + Primary\ Losses - Transformer\ Core\ Losses}{Input\ to\ the\ substation}$$

Figure 4.19
Avoidable distribution losses equation

The hourly loss factors were grouped into six different season/time periods; the hourly values in each group were averaged to determine a loss factor for the corresponding season/time period. The different season/time periods help to capture the year-to-year variability in system load.

The isolated avoidable transmission and distribution losses are summarized by season in Table 4.9. The hourly losses for the entire year are shown in Appendix 4.16.

Table 4.9
Idaho Power 2012 System Loss Study results, transmission, and distribution losses only

Dates	Season	Transmission & Distribution Losses
May–October (2–7 p.m.)	Summer On-Peak	5.9%
May–October (5 a.m.–2 p.m., 7–9 p.m.)	Summer Mid-Peak	5.8%
May–October (9 p.m.–5 a.m.)	Summer Off-Peak	5.8%
November–April (6–10 a.m., 5-8 p.m.)	Winter On-Peak	5.7%
November–April (10 a.m.– 5 p.m., 8–10 p.m.)	Winter Mid-Peak	5.7%
November–April (10 p.m.–6 a.m.)	Winter Off-Peak	5.8%

4.4.2 2012 System Loss Study Method

To determine the impact of avoided line losses from customer-generator exports, the analysis in this study leverages the loss percentages from the 2012 System Loss Study.

The 2012 System Loss Study determined the loss percentages for the transmission system, distribution system, distribution primary voltage, and the distribution secondary voltage. The loss percentage is the ratio of the input over the output. This analysis was done for both energy losses and for peak losses. The same method was used for both loss studies, and in both cases this method for loss calculation includes the transformer core losses.

The method to determine the energy loss percentages includes the addition of all the energy inputs and all the energy outputs for each grid section. The difference between the two values is the energy losses for that grid section.

The method to determine the peak loss percentages includes the addition of all the peak inputs and all the peak outputs for each grid section. The difference between the two values is the peak losses for that grid section. The loss percentage is the ratio of the input sum over the output sum. A loss percentage flow diagram is illustrated in Figure 4.20. The illustration identifies the various energy inputs and outputs to different sections of the transmission and distribution systems that were used in loss percentage calculations. Note, the diagram shows the loss percentages corresponding to a single hour. The study uses the averages per season shown in Table 4.9 as the basis for the analysis.

Peak Hour July 12th, 2012, from 4 - 5 PM

Example Hourly Loss Percentage Calculation

Values in MWh

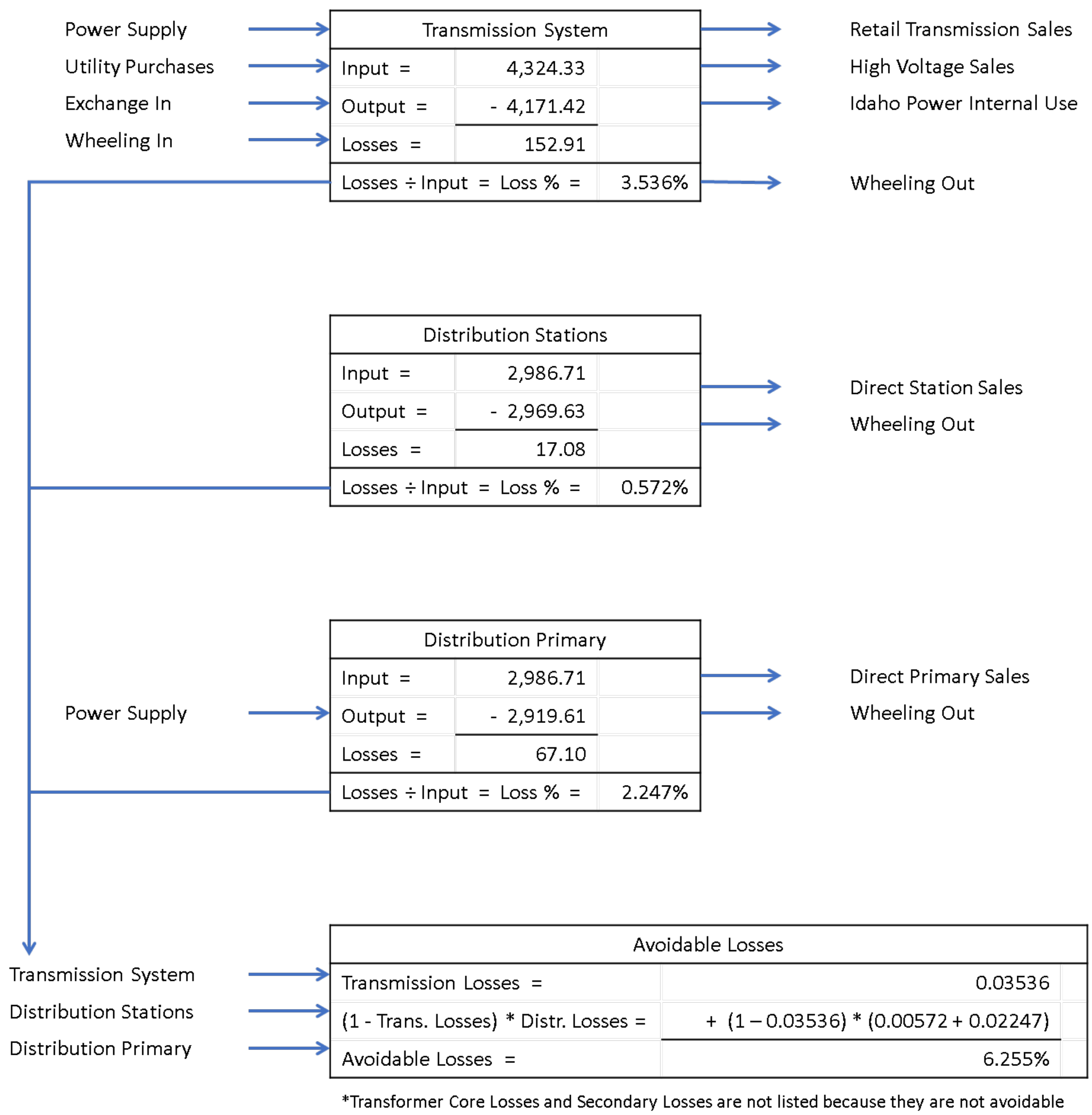


Figure 4.20
Loss percentage flow diagram (peak hour example)

The avoidable line losses are appropriately applied to both energy and capacity. The energy component of avoided losses can be valued using the same method utilized to determine the avoided energy component of the ECR. The capacity component of losses only applies to the avoided losses reduced during the system's highest risk hours.

With the line loss percentages from Table 4.9, we can determine the energy loss reduction from exported customer generation. Figure 4.21 provides the calculation of energy loss. The energy prices from Section 4.1 can be multiplied by the loss percentage to get the corresponding impact to the energy price due to losses in terms of dollars per MWh.

	2021 IRP	2019-2021 ICE Mid-C	2019-2021 ELAP
Flat Avoided Energy Price	$ 18.93	$ 30.55	$ 28.24
(x) Line Loss %	5.80%	5.80%	5.80%
Avoided Line Loss Value ($/MWh)	**$ 1.10**	**$ 1.77**	**$ 1.64**

Figure 4.21
Energy line loss calculation example for flat real-time export energy prices.

The capacity component of the avoided losses was considered when determining the avoided capacity of customer-generator exports. The capacity contribution calculations utilize integers, meaning the margin of error is +/- 1 MW. This margin of error could be significant when compared to the capacity contribution of avoided losses. The study applied the losses to the customer-generator exports to avoid considerable errors due to the margin of error of the capacity contribution calculations.

Avoided Line Losses – Supporting Appendices

Appendix 4.16
Idaho Power's Hourly Losses Report

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

4.5 Avoided Environmental Costs

Idaho Power generates or purchases energy to meet the energy needs of its customers. When there are environmental costs associated with that generated or purchased energy, then there is a potential for those costs to be avoided for customer generated exported energy. Environmental benefits that do not result in a direct savings, or an avoidable cost, are not included in this study.[38] Similarly, environmental benefits based on non-quantifiable or speculative values are not included in this study.

[38] Case No. IPC-E-21-21, Order No. 35284 at 27.

4.5.1 Environmental Costs: Inputs and Assumptions

Environmental costs that could be associated with generated or purchased energy include Renewable Energy Certificate (REC) purchases, Carbon Tax, and other costs to meet a Renewable Portfolio Standard (RPS) policy. An RPS is a regulatory mandate to increase production of energy from renewable sources such as wind, solar, biomass and other alternatives to fossil and nuclear electric generation. Most RPS's and Carbon Tax policies allow utilities to purchase RECs to meet those mandates.

Currently, Idaho Power is not subject to a Carbon Tax or an RPS policy. Idaho Power does not have a mandatory requirement to produce a set amount of renewable energy and, therefore, has no need to purchase RECs. Although customer generation from renewable resources may avoid some fossil fuel generation, thereby reducing carbon emissions, Idaho Power is not subject to a Carbon Tax and cannot monetize those emission reductions.

Idaho Power's IRP utilizes a carbon price adder in its IRP. The carbon price adders included in Idaho Power's IRP have historically been included to assess the risk of adding carbon-emitting generation to the system. However, these adders have not traditionally been included in the first several years of the IRP planning horizon to reflect the time it would take to structure and pass a carbon price adder bill into legislation and the implementation delay that would occur between the passage of the hypothetical federal legislation and the effective date of the rules once promulgated. For example, in the 2021 IRP, these price adders were not present in the first two years of the plan; and for the 2023 IRP, carbon adders were discussed with IRPAC, and it aligned with the position that the new carbon adder forecast will start in 2027 (the fifth year of the planning horizon). Finally, there are no current indications that a state or federally imposed carbon adder are imminently forthcoming. These carbon price adders are only appropriately included in an ECR if and when they materialize as actual costs impacting Idaho Power customer rates.

4.5.2 Crediting Customers for Value of Renewable Energy Credits

In most states, including Idaho, the environmental attributes of on-site generation remain with the owner. Idaho Power is not aware of any on-site generation or net metering arrangement in which a customer's export of energy back to the utility involves the transfer of the RECs or environmental attributes of those exports. Given the complexity in certifying and tracking generation in a manner that would allow for RECs to be issued for a customer's resource and the low dollar value of each individual REC (approximately $3–8 per MW), it is unlikely that customers would be sophisticated enough or financially incentivized to certify their own RECs. In order for Idaho Power to do so on a customer's behalf, the current registration process would require that the customer legally transfer the environmental attributes of the on-site generation, and, in order to prevent double counting of those attributes, the customer would no longer be able to claim the clean nature of the energy used to power their home or business.

Additionally, Idaho does not have any mechanisms that allow for the exchange of on-site generation RECs—Idaho does not have a Renewable Portfolio Standard with a distributed generation carve out, a Solar Renewable Energy Certificate market, or any legislation that establishes specific treatment of on-site generation RECs. As a result, the environmental attributes of on-site generation (in the form of RECs) are not certifiable for the purpose of utility buy back.

4.5.2.1 Requirements to Obtain and Track Renewable Energy Credits

It may be logistically possible for Idaho Power to aggregate and certify RECs from customer-generators, but there are several hurdles: 1) to register each customer-generator resource with WREGIS, at a minimum the customer would need to legally transfer ownership of the environmental attributes of their resource to Idaho Power and would be prevented from claiming the clean nature of the energy from the resource going forward; 2) Idaho Power would need to implement detailed recording and tracking of generation data; and 3) the company would need to pay a small monthly fee. The typical value of a REC ranges between $3–8 per MW, and based upon the administrative burden and the impact on the customer's ability to claim the environmental attributes of the generation, such an approach seems unlikely to be well received by customer-generators. As a result, the study has not included a value associated with on-site generation RECs.

WREGIS has specific and detailed requirements and protocols for approving the creation of RECs, or WREGIS Certificates. The study references relevant portions of WREGIS's operating rules,[39] but notes that the rules are extensive, and the study does not represent a full record of WREGIS rules or approval processes.

WREGIS does not "certify" generation but rather has a process for approving generating units[40] which may earn WRGIS Certificates for tracking within the WREGIS system, if approved.

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[39] WREGIS's Operating Rules, last published January 4, 2021.

[40] WREGIS defines a renewable generating unit as including any generation facility that is "defined as renewable by and of the states or provinces in [the Wester Energy Coordinating Council]." WREGIS Operating Rules at 10.

With respect to customer-generators and the creation of WREGIS Certificates, the entity must follow the instructions provided by WREGIS and be approved by WREGIS.

WREGIS also has requirements specific to "On-Site Load" — the category under which Idaho Power's customer-generators would likely be defined. An entity with On-Site Load must meet requirements related to metering, communication, and verification of dynamic data before WREGIS Certificates may be earned. According to WREGIS Operating Rules 9.6.1:

> For On-Site Load to contribute to Certificates, the Generating Unit must have sufficient metering in place to measure, either directly or through a process of netting, the On-Site Load. If a netting process is used, it must be designed to exclude Station Service. If On-Site Load is metered directly, the Generating Unit must have two separate meters, one to meter the On-Site Load and one to meter generation that is supplied to the grid and each meter must be registered separately with WREGIS. If On-Site Load is measured through a netting process, both the meter measuring generation supplied to the grid and the other meters involved in the netting process may be registered separately with WREGIS.
> The method of metering to be used and the netting process, if applicable, must be reviewed and approved by WREGIS staff prior to the On-Site Load being registered and reported in WREGIS. (at 35)

WREGIS does not certify, but rather has a process for approving Generating Units which, if approved, may earn WREGIS certificates. WREGIS Operating Rules Section 5 addresses the requirements for transferring a Generating Unit from one WREGIS account holder to another. The assignment of registration rights will give the Generator Agent (an entity designated by the Generator Owner via a legal assignment to act on the Generator Owner's behalf with WREGIS, e.g., Idaho Power) full and sole permissions and authority over the transactions and activities related to the Generating Unit and any WREGIS Certificates.

4.6 Integration Costs

Idaho Power must plan for intermittent production from VERs (e.g., solar and wind). Integration costs reflect the incremental costs associated with accommodating variable resources on the system. Idaho Power periodically conducts integration studies based on the number of variable resources on its system. The most recent Idaho Power integration study was completed in 2020 and reflected the then-current level of intermittent generation on the system. The integration study determined the costs to integrate additional variable resources, including customer generation.

4.6.1 Integration Costs: Inputs and Assumptions

For the 2020 VER Integration Study, Idaho Power worked in conjunction with a technical review committee and retained Energy and Environmental Economics, Inc. (E3) to perform the study. Through the analysis, E3 calculated VER integration costs and regulation reserve requirements for various VER addition scenarios for a 2023 model year.

Improving on the 2018 VER Integration Study to model Idaho Power's new participation in the Western EIM, E3's analysis utilized Energy Exemplar's PLEXOS software to allow for modeling the system in four stages: day ahead, hour ahead, 15-minute, and 5-minute markets. Idaho Power joined the EIM in the second quarter of 2018. The addition of the EIM market allows for balancing of forecast errors in real time.

The 2020 VER Integration Study derived integration costs for utility scale resources are also representative for customer-generator integration costs due to their highly correlated variability and non-dispatchability.

4.6.2 Study Methods and Results

The 2020 VER Integration Study is Appendix 4.17. The 2020 VER Integration Study identifies an applicable solar integration rate in the Base 2023 Case of $2.93 per MWh, or $0.00293 per kWh as shown in Table 4.10. This integration cost is the calculated incremental cost for adding 251 MW of additional solar beyond the 310 MW of solar on Idaho Power's system in 2020. The integration cost for Case 2, 3, 9, and 10 is the calculated incremental integration cost for the given scenario modeled. Case 1 best represents Idaho Power's current system. The company does expect to add 131 MW of storage in 2023 — the incremental storage and other incremental resources could be factored into the next VER Integration Study and could inform future updates to the ECR.

Table 4.10
Integration costs from 2020 VER study, 2023 base year (reproduction of Table ES1 from the 2020 VER Integration Study)

Tier	VER Study Case Number	Assumptions	Integration Costs ($/MWh)
Base (One Bridger Unit Retired)	1	One Bridger Unit Retired; 131 MW of unspecified Solar contracts and 120 MW from the planned Jackpot Solar facility Added on top of existing Solar	$2.93
Base (Bridger Online)	2	All Bridger Units Online; 131 MW of unspecified Solar contracts and 120 MW from the planned Jackpot Solar facility Added on top of existing Solar	$3.61
Higher Solar Penetration	3	Same as VER Study Case 1 + 794 MW of New Solar	$3.86
Higher Solar Penetration + 0.25 Storage	9	Same as Higher Solar Penetration VER Case 3 + 200 MW Storage (2.5 MW Storage for every 10 MW of Solar)	$0.64
Higher Solar Penetration + 0.50 Storage	10	Same as Higher Solar Penetration VER Case 3 + 400 MW Storage (5 MW Storage for every 10 MW of Solar)	$0.93

The integration rate in the 2020 VER Integration Study reflects Idaho Power's incremental costs incurred when accommodating the uncertainty associated with variable resources on the system. Idaho Power incurs integration costs due to reduced flexible resource optimization, caused by variable resource uncertainty, when planning operations ahead of real time (day-ahead, and hours ahead of real time), and in the 15-minute, and 5-minute markets. The 2020 VER Integration Study determined the integration cost of accommodating additional solar; however, the solar generation considered was utility scale solar.

The key question for this study is, can the utility scale solar be utilized as a proxy for Idaho Power retail customer exports to determine integration costs? If yes, the 2020 VER Integration Study can be used to determine the integration cost component of the ECR. If not, another integration study may be required before including the integration cost component in the ECR.

To answer the 'can utility scale solar be utilized as a proxy for Idaho Power retail customer exports' question, the study analyzed day-ahead and hour-ahead real time uncertainty. Figure 4.22 depicts customer exports compared to the company's utility scale solar, with both outputs normalized based on their peaks for the first week of the four quarters of 2021. This data shows that the shapes are comparable and highly correlated. The variation appears to be driven by the same variability in weather. These figures support utility scale solar as a good proxy for customer-generator exports for the purposes of studying integration costs, as they relate to the day-ahead and hour-ahead uncertainty — which partially drives the integration cost.

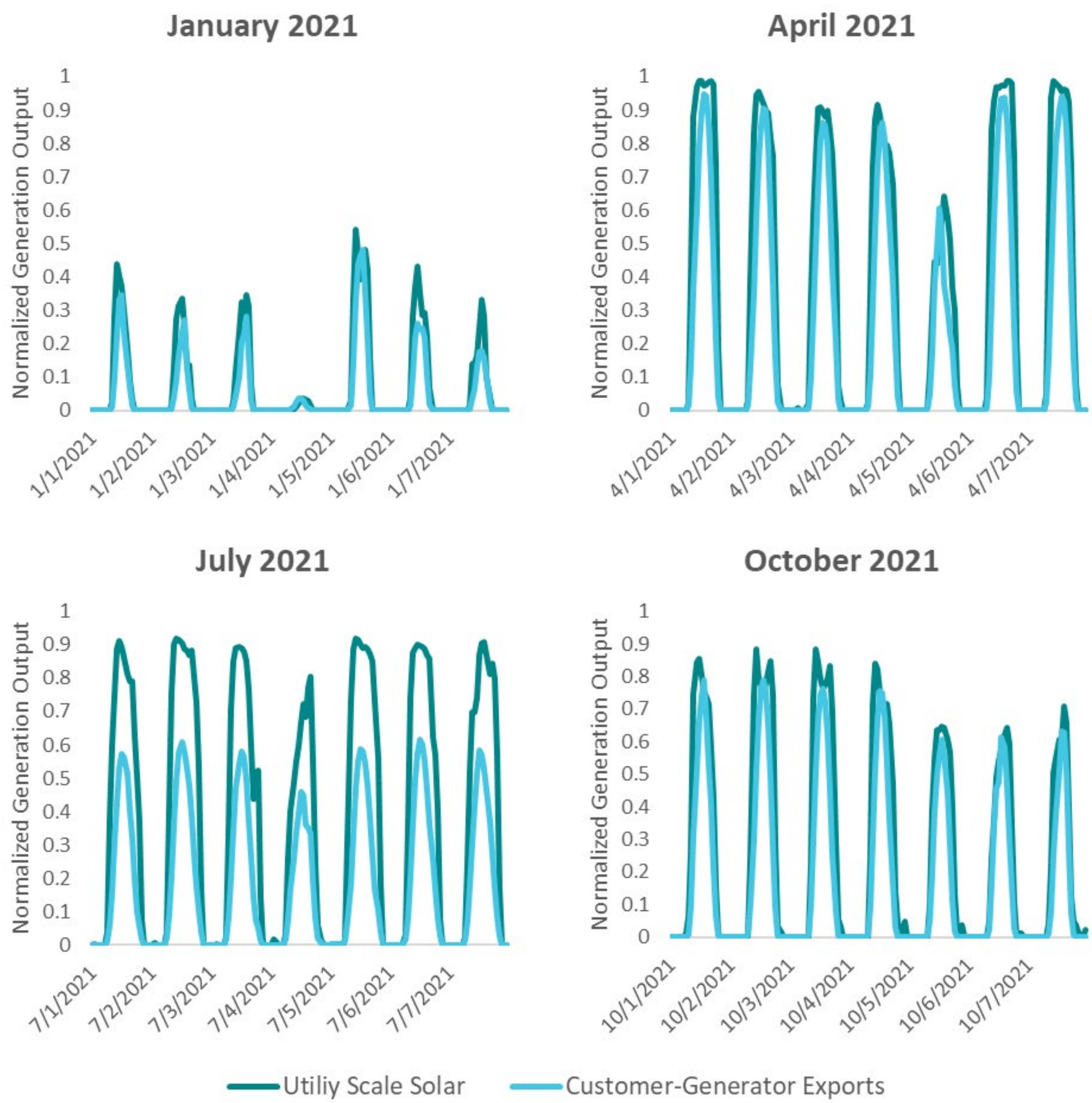

Figure 4.22
Customer-generator and utility scale solar generation 2021 output normalized for peak generation output

Integration costs are also caused by uncertainty in the 15-minute and 5-minute timeframes. Idaho Power does not collect customer data on these timeframes; therefore, it is challenging to directly compare customer exports and utility scale solar. On-site customer-generator systems are geographically diversified across southern Idaho and eastern Oregon. That diversity likely reduces the 15-minute and 5-minute variability. Idaho Power's utility scale solar is also highly diversified with 17 projects totaling approximately 315 MW spread across southern Idaho and eastern Oregon.

The benefits of utility scale solar, that reduces its 15-minute and 5-minute variability, is how it is designed. It is industry practice for a utility scale solar project to "overbuild" the solar panels on the direct-current (DC) side of the inverter with 20% or more additional DC capacity.[41] The capacity necessary to export energy onto the grid is limited by the inverter, which converts DC to alternating-current (AC). Therefore, the DC capacity can be oversized relative to the AC capacity. This DC overbuild, depicted in Figure 4.23, provides several benefits to a utility scale project. The primary benefit related to resource variability and uncertainty is that a cloud can often cover a portion of a utility scale project, and result in no reduction in output from the project because the inverter may already be "clipping" part of the DC output. Therefore, utility scale projects typically have a built-in short-term variability buffer. Customer projects have no such buffer — when a cloud shades the project, the utility will see a reduction in customer-generator exports, or an increase in demand if the customer is not exporting. Therefore, utility scale solar is a reasonable and conservative proxy for customer-generator exports as they relate to 15- and 5-minute uncertainty — the remaining timeframes reflected in the integration cost.

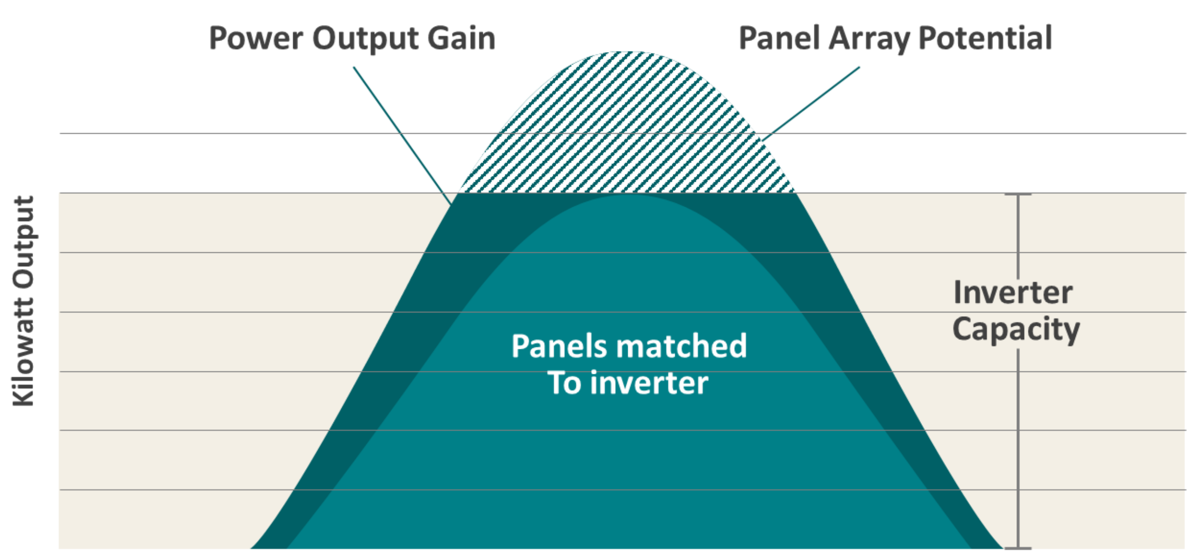

Figure 4.23
Advantages of higher DC/AC ratio illustration

[41] https://pv-magazine-usa.com/2018/03/19/u-s-solar-module-to-inverter-ratio-settles-in-around-1-25/

The utility scale solar integration costs derived in the 2020 VER Integration Study provide a reasonable proxy for the integration costs associated with customer exports. From the 2020 VER Integration Study, the applicable solar integration rate is identified in the Base 2023 Case in Table ES1: $2.93 per MWh or $0.00293 per kWh. This integration rate could be utilized until Idaho Power completes its next integration study and integration costs for customer-generators could be evaluated directly.

Integration Costs – Supporting Appendices

Appendix 4.17
Idaho Power's 2020 VER Integration Study

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

4.7 Summary of Conclusions

Sections 4.1 through 4.6 evaluate the components of the Export Credit Rate as identified in the Study Framework. There are several variables and combinations that can result in a range of Export Credit Rate values. For many of the components, the study evaluates more than one method. Each method can result in a different value depending on if calculated with exports measured under a net hourly or real-time interval. For purposes of the study, the summary Export Credit Rates, or ECRs, are shown in Figures 4.24 and 4.25 under the three different energy prices, real-time measurement interval, and a generation capacity value under the ELCC method (described in Section 4.2). Appendix 4.18 shows ECR values under both a real-time and hourly measurement interval.

Real-Time Export Credit Rate

$/MWh	(1) 2021 Idaho Power IRP	(2) 2019-2021 Average ICE-Mid-C	(3) 2019-2021 Average ELAP
Flat Export Credit Rate			
Avoided Energy	$ 18.93	$ 30.54	$ 26.37
Plus: Avoided Generation Capacity (ELCC)	10.60	10.60	10.60
Plus: T&D Deferral	0.26	0.26	0.26
Plus: Avoided Line Loss	1.10	1.77	1.53
Plus: Avoided Environmental Costs	-	-	-
Less: Integration Costs	(2.93)	(2.93)	(2.93)
Flat ECR	**$ 27.96**	**$ 40.25**	**$ 35.84**

Note: Non-firm adjustment applied to the avoided energy value for Column 1 (IRP) and Column 2 (ICE Mid-C).

Figure 4.24
Flat Export Credit Rate with real-time exports and ELCC generation capacity value

Real-Time Export Credit Rate

$/MWh	(1) 2021 Idaho Power IRP	(2) 2019-2021 Average ICE-Mid-C	(3) 2019-2021 Average ELAP
Time Variant Export Credit Rate			
Off-Peak			
Avoided Energy	$ 18.29	$ 29.67	$ 24.68
Plus: Avoided Generation Capacity (ELCC)	-	-	-
Plus: T&D Deferral	-	-	-
Plus: Avoided Line Loss	1.06	1.72	1.43
Plus: Avoided Environmental Costs	-	-	-
Less: Integration Costs	(2.93)	(2.93)	(2.93)
Off-Peak ECR	**$ 16.42**	**$ 28.46**	**$ 23.18**
Summer On-Peak (Demand Response Hours: 3-11pm, M-Sat)			
Avoided Energy	$ 26.84	$ 41.15	$ 47.09
Plus: Avoided Generation Capacity (ELCC)	140.33	140.33	140.33
Plus: T&D Deferral	3.44	3.44	3.44
Plus: Avoided Line Loss	1.56	2.39	2.73
Plus: Avoided Environmental Costs	-	-	-
Less: Integration Costs	(2.93)	(2.93)	(2.93)
On-Peak ECR	**$ 169.23**	**$ 184.38**	**$ 190.66**

Note: Non-firm adjustment applied to the avoided energy value for Column 1 (IRP) and Column 2 (ICE Mid-C).

Figure 4.25
Time variant Export Credit Rate with real-time exports and ELCC generation capacity value

Export Credit Rate Summary – Supporting Appendices

Appendix 4.18
Export Credit Rate Summary

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

5. Frequency of Export Credit Rate Updates

A consideration for implementing a new compensation structure is the frequency of updates to the components of the Export Credit Rate, or the ECR. The study addresses data inputs to an ECR and criteria for determining when updates should occur. The study also considers potential customer impacts from the frequency of updates to the ECR. It is essential to balance the customer-generators need for stability with the need for regular updates to ensure an appropriate and up to date ECR.

5.1 Energy Price Inputs

The study evaluates three energy prices for the avoided energy cost of the ECR. These three values fall into two different types of inputs that would create unique considerations for the frequency and need for an update. Each input type is explained below.

Forecasted Energy Price: Idaho Power's energy price from the IRP is a forecasted hourly input. A forecasted value could remain constant until the Commission acknowledges the next IRP. The inputs could be as granular as the forecasted hourly pricing or could be weighted from a recent year's exports (as explained in Sections 4.1) to provide a more stable, predictive price for customers to plan for through the upcoming year. If an IRP-driven input was selected for implementation, the energy input would be updated every other year along with or directly after receiving acknowledgment of an IRP.

Actual Market Price: The ICE Mid-C and ELAP energy prices represent actual market prices. As a result, the energy input would not remain constant like the price from the IRP. Instead, Idaho Power's billing system could apply actual market prices for the given hour that the customer-generator's export occurs (i.e., a unique value would be applied for all 8,760 hours of the year based on the actual market price in that given hour). The energy input would continually use the actual ICE Mid-C or ELAP price to value exports in the billing period. This energy market price would result in the energy input not requiring an "update" because Idaho Power would compensate customers at those actual market values. Another option would be for avoided energy to be based on actuals, but to be updated based on a less granular cadence. For example, they could be based on the most recent year or an average over multiple years.

Idaho Power, stakeholders, and ultimately the Commission, must evaluate the benefits and potential impacts of leveraging a forecasted energy price or an actual market price. Both approaches have merit as a representative proxy for the value provided for avoided energy attributed to customer-generator exports. Stakeholders could have a range of opinions on the weight of each method's benefits. Forecasted energy prices offer stability and may be easier to understand. A forecast provides stability but may not maximize value for the customer-generator when market prices are higher than forecasted. However, a forecast also mitigates a drop in market prices, which could be lower than the forecasted price.

5.2 Avoided Generation Capacity

The study evaluates two methods for valuing the capacity contribution of customer-generator exports, which are then used to determine the avoided generation capacity cost of the ECR. The avoided generation capacity value calculation considers 1) capacity contribution, 2) levelized fixed cost of the avoided resource, and 3) annual exported energy from customer-generators. The three inputs are individually evaluated for frequency of updates to the avoided generation capacity value of the ECR.

Capacity Contribution: Both the ELCC and NREL methods discussed in Section 4.2 typically consider a timeframe of one calendar year. Both methods require the following historical input data:

1) Annual hourly system load data
2) Annual hourly system solar data
3) Annual hourly customer-generator export data
4) Customer-generator nameplate capacity

These values could be updated on an annual basis or updated every other year to align with IRP updates. Section 4.2.2.1 contemplates a three- or five-year rolling average to further mitigate volatility from year to year due to changes to capacity additions and weather conditions.

The ELCC risk-based metric is a statistical analysis that captures the hourly interplay between all system resources. Additional historical input data is required to calculate the ELCC: 1) hourly system wind, run of river hydro, and cogeneration data; 2) monthly capacity values of dispatchable resources and their associated EFORs. As previously mentioned, these additional inputs could be updated annually or aligned with IRP timing.

Levelized Fixed Cost of Avoided Resource: The levelized fixed cost of the avoided resource is determined in Idaho Power's IRP. Therefore, it would be reasonable to expect this input only to be updated every other year.

Annual Exported Energy: The amount of energy exported from customer-generators could be updated annually or every other year. Continued growth in customer generation would suggest that it would be appropriate to update annually; this includes the addition of the latest data available if a three- or five-year rolling average method is applied for the capacity contribution calculations. Whichever period is selected for updating the supporting data for the capacity contribution would also need to be applied to the annual exported energy to ensure there is no mismatch between the quantity of energy exported and the associated nameplate capacity.

Capacity Deficiency Year: Order No. 35284 directed the study to evaluate the use of first deficit year. PURPA projects only receive a capacity value starting the year of the company's first deficiency. If a similar approach was applied to customer-generators, it could be reasonable to align with the timing of the company's IRP. Stakeholders would need to consider advantages and disadvantages with this type of approach. For example, PURPA projects are contractually obligated to deliver energy, whereas customer-generators are not. The company would be required to track the vintage of customer-generator systems, resulting in customer-generators having differing rates by vintage of system, which could be difficult to understand for customers and would add administrative complexities.

5.3 Avoided Transmission and Distribution Capacity

The method for identifying avoided transmission and distribution capacity looks at 15 years of actual data and five years of forecasted data on Idaho Power's system. Due to the size and amount of capacity added by a transmission or distribution project, this particular input is less sensitive to changes until a large enough increase in capacity occurs. For consistency, this input could be updated every other year in coordination with other ECR updates. Alternatively, Idaho Power could update the avoided transmission and distribution capacity analysis when a total nameplate capacity installed amount is reached and update this value component in the subsequent ECR update process.

5.4 Avoided Line Losses

Line losses studies are comprised of extensive analyses and are not performed often; however, line losses are expressed as percentages, which do not significantly vary through time. Given the relatively small value this contributes to the ECR, it would be reasonable to not propose an update schedule, rather, this component could be updated as new loss studies are completed.

5.5 Avoided Environmental Costs

Idaho Power could evaluate the avoided environmental costs on an annual or biennial basis to see if such costs can be avoided that are quantifiable and affect rates. Alternatively, the Commission could require Idaho Power to file an update within a specific time after a Carbon Tax or an RPS policy is enacted to update the ECR value to reflect the change.

5.6 Integration Costs

Idaho Power's last VER Integration Study was completed in 2020. The company has completed a total of seven VER integration studies, including the first VER integration study completed in

2007. While VER integration studies are not completed at set intervals, history has shown that Idaho Power completes the Integration Study regularly.

As VER penetration increases on the system, which Idaho Power forecasts to continue at an increasing rate, Idaho Power will continue to refresh the integration study and also evaluate the integration costs of customer generation in future studies. The company expects to undertake its next VER Integration Study following completion of its 2023 IRP or 2025 IRP. This VER Integration Study input could be updated as part of subsequent updates as more recent integration studies are available.

6. Compensation Structure

The *compensation structure* is the metering and billing arrangement for customer-generators with exporting systems. This study evaluates two types of compensation structures: 1) Net Energy Metering (NEM), and 2) Net Billing. The *measurement interval*, which is discussed in more detail in Section 3 of this study, refers to the metering and billing arrangements that define how the electricity flows are measured and billed for both energy consumption and energy generation. The study evaluates three measurement intervals 1) monthly, 2) hourly, and 3) real-time or instantaneous.

In this context, *consumption* refers only to energy the customer used from Idaho Power's electricity supply, and *generation* refers only to excess energy the customer exported to Idaho Power's grid. It does not include the on-site energy generated and consumed immediately by the customer-generator.

As described in Section 3, the study uses Net Energy Metering with a monthly measurement interval as the base case, as this is the existing compensation structure and measurement interval for Idaho Power's on-site customer-generators. In accordance with the Study Framework approved by the Commission, the study will evaluate and compare the base case against an hourly and real-time measurement under a Net Billing compensation structure.

6.1 Average Residential Customer Bill Impact Analysis

As discussed in Section 3, the average residential customer has an average monthly consumption of approximately 1,000 kWh per month or 12,000 kWh per year. This average residential customer has an average monthly bill of $88.94 before installing on-site generation. To illustrate the impacts on a customer's bill under each of the compensation structures, the same illustrative example of an average residential customer was evaluated under varying system sizes to provide a reasonable range: 1) annual energy generation approximately equal to annual energy consumption (8.5 kW system); and 2) annual energy generation equal to approximately 50% of annual energy consumption (4.25 kW system).

Figure 6.1 illustrates the average residential customer's average monthly bill under a monthly, hourly, and real-time measurement interval with an 8.5 kW solar system installed. Export Credit Rate values from the study are summarized in Appendix 4.18. For the purposes of this analysis, the Net Billing impact analysis used a flat Export Credit Rate of $0.03781 per kWh, which utilizes the ELAP energy price (it was roughly in between the high and low ECR energy values) and the ELCC generation capacity value (the ELCC method has been used in the most recently filed IRP). Appendix 3.1, 3.2, and 3.3 provide a toggle to evaluate impacts under varying flat Export Credit Rate values.

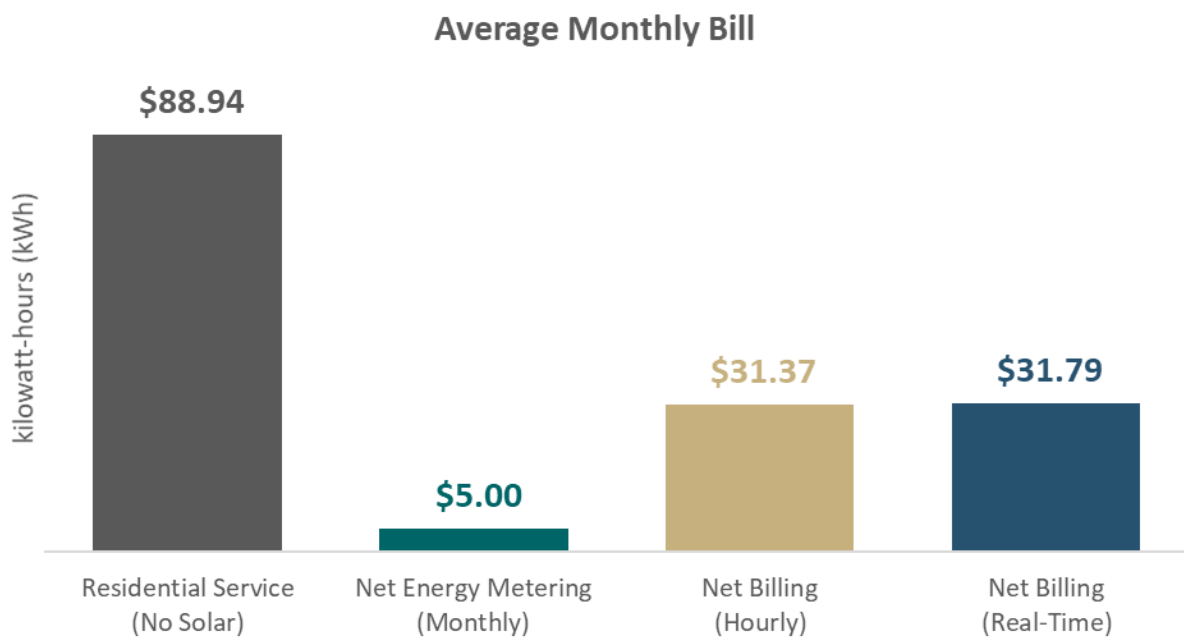

Figure 6.1
Average monthly bill for average residential customer with 8.5 kW solar system installed

In Figure 6.1, the customer has installed a solar system that generates enough energy that slightly exceeds the total annual energy consumption. Therefore, on an average monthly basis, the customer's monthly bill under the Net Energy Metering compensation structure is equal to the fixed service charge of $5 per month — the fixed service charge is not offset by kWh credits.[42] When changing the measurement interval from monthly to hourly the meter measures a monthly average of 615 kWh consumed (shown in Figure 3.5) and 616 kWh exported (shown in Figure 3.6). When the retail rate is applied against the energy consumed and a $0.03781 Export Credit Rate is applied to the energy exported on a net hourly basis, the result is an average monthly bill of $31.37. Similarly, the real-time measurement results in average monthly energy measured for consumption of 639 kWh (shown in Figure 3.5), average monthly energy exported of 659 kWh (shown in Figure 3.6), and an average monthly bill of $31.79. For an existing customer taking service under Net Energy Metering, moving from a monthly to real-time measurement results in an average monthly bill increase of approximately $27; however, the customer will still realize an average monthly reduction of over $57 per month compared to having no solar installed.

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[42] *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 9-10 (July 3, 2013).

Figure 6.2 illustrates the average residential customer's average monthly bill under a monthly, hourly, and real-time measurement interval with a 4.25 kW solar system installed. For the hourly and real-time Net Billing compensation structure the export credit rate used is $0.03781 per kWh.

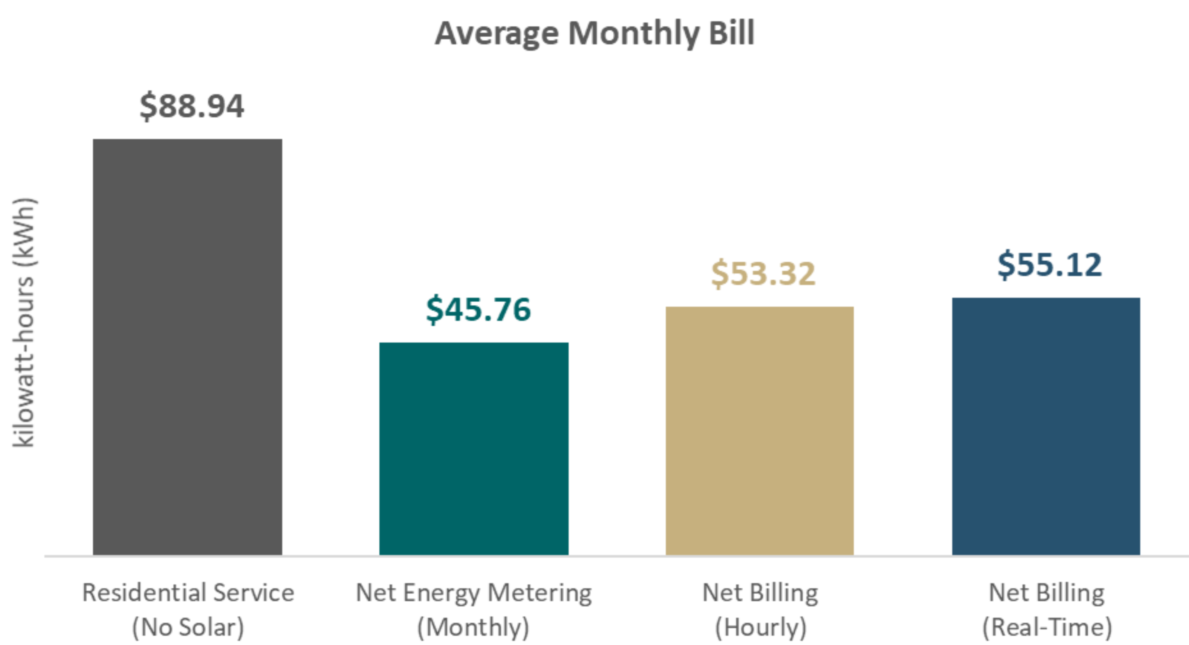

Figure 6.2
Average monthly bill for average residential customer with 4.25 kW solar system installed

In this scenario, the customer has installed a solar system that generates approximately 50% of the annual energy consumption. On an average monthly basis, the customer's monthly bill under the Net Energy Metering compensation structure reflects average monthly energy measured for consumption of 504 kWh (shown in Figure 3.7) and an average monthly bill of $45.76 per month. When changing the measurement interval from monthly to hourly, the meter measures a monthly average of 678 kWh consumed (shown in Figure 3.7) and 174 kWh exported (shown in Figure 3.8). When the retail rate is applied against the energy consumed and the Export Credit Rate is applied to the energy exported, the result is an average monthly bill of $53.32. Similarly, the real-time measurement results in average monthly energy measured for consumption of 705 kWh (shown in Figure 3.7), an average monthly energy exported of 186 kWh (shown in Figure 3.8), and an average monthly bill of $55.12. For an existing customer taking service under Net Energy Metering, moving from a monthly to real-time measurement results in an average monthly bill increase of approximately $10; however, this is an average monthly reduction of almost $34 per month compared to having no solar installed.

6.2 Schedule 6 (Residential) Customer-Generator Bill Impact Analysis

The study also evaluated the different measurement intervals and compensation structures for all residential customer-generators with 12 months of data in 2021. The total population for this analysis was 6,425 residential customer-generators. Appendix 3.2 includes all supporting data and the ability to select or remove legacy systems from the summary analysis discussed in this study.

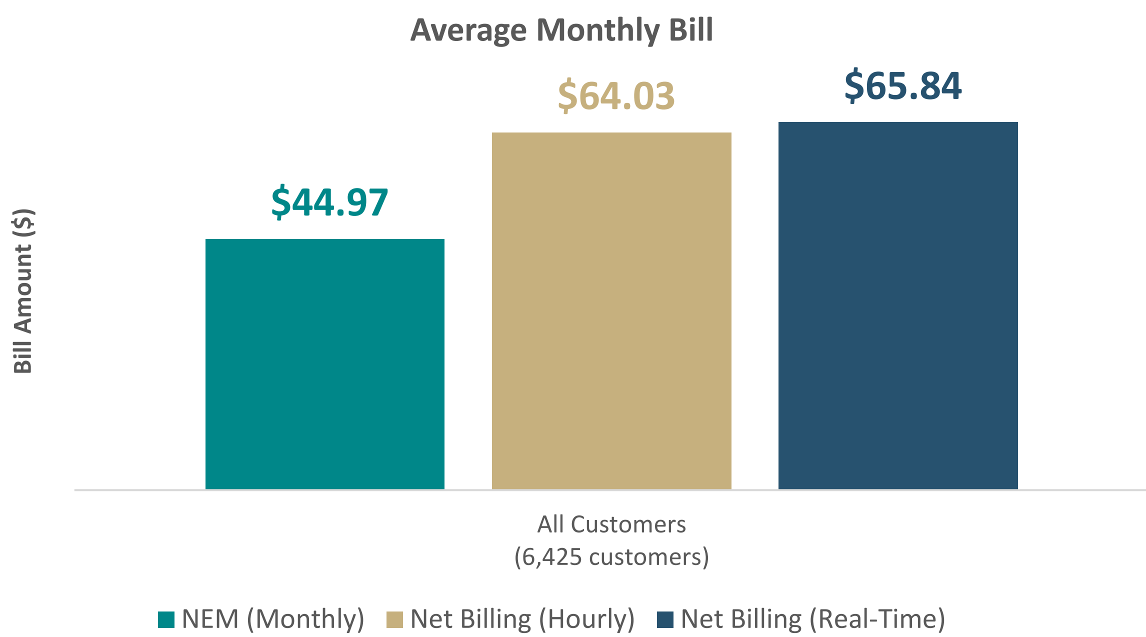

Figure 6.3
Average monthly bill for all residential customer-generators in 2021

The analysis first calculated the energy measured for consumption and export under each of the three measurement intervals and respective compensation structures for each customer from the 2021 data set. Consistent with other analysis in this section, the bill impact for Net Billing assumes a flat Export Credit Rate of $0.03781.

Figure 6.3 summarizes the average monthly bill for residential customer-generators with Exporting Systems active for all of 2021. On an average monthly basis, residential customer-generators average net monthly energy measured for consumption of 463 kWh (shown in Figure 3.9) and an average monthly bill of $44.97. Moving from a monthly to hourly measurement interval results in average monthly energy measured for consumption of 896 kWh (shown in Figure 3.9) and an average monthly bill of $64.03. The real-time measurement results in average monthly energy measured for consumption of 932 kWh (shown in Figure 3.9) and an average monthly bill of $65.84. Moving from a monthly to real-time measurement results in an average monthly bill increase of approximately $21; however, this does not reflect the average monthly reduction compared to no solar installed (as illustrated in Figure 6.1 and 6.2).

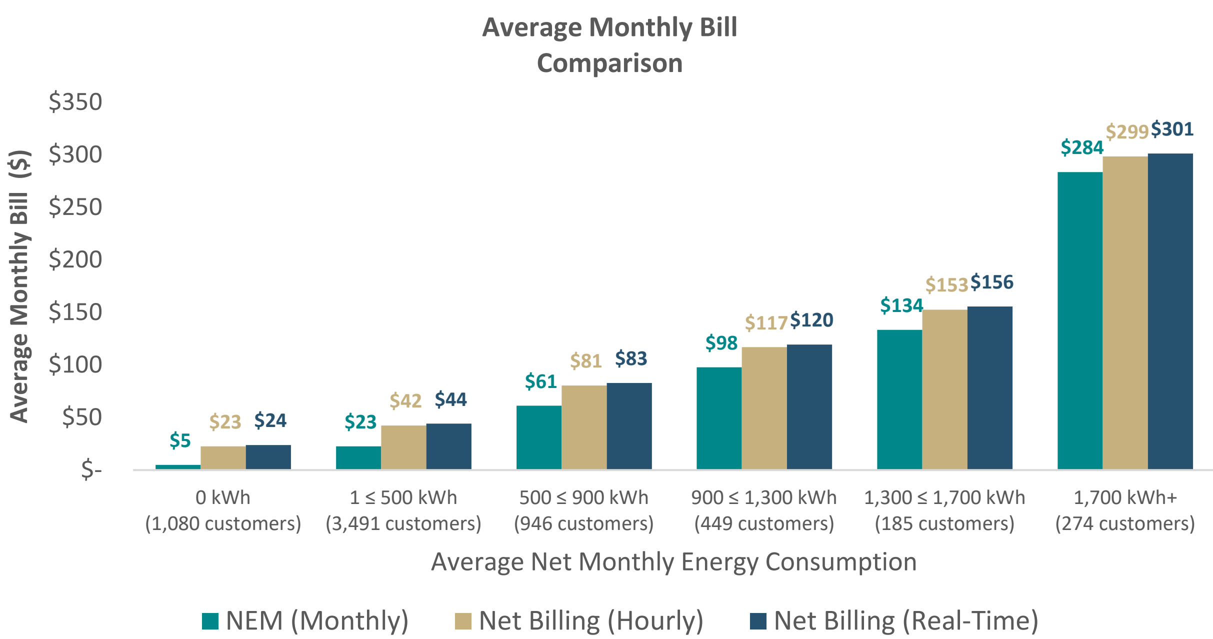

Figure 6.4
Average monthly bill for each compensation structure and measurement interval for all residential customer-generators in 2021, by average net monthly energy use

Figure 6.4 separates the customer-generators by their average monthly energy consumption in 2021 under a monthly measurement interval. The residential customer-generators have been grouped into six categories to evaluate the average magnitude of bill impacts within each group of customers. Figure 6.4 does not account for the residential customer-generators average monthly bill before solar was installed. The average monthly bill before solar was installed would be higher than the real-time Net Billing average monthly bill shown in Figure 6.4.

6.3 Schedule 8 (Small General) Customer-Generator Bill Impact Analysis

The study evaluated an identical bill impact analysis for the different measurement intervals and compensation structures for all small general customer-generators with 12 months of data in 2021. The total population for this analysis was 52 customers. Appendix 3.3 includes all supporting data from the summary analysis discussed in this study.

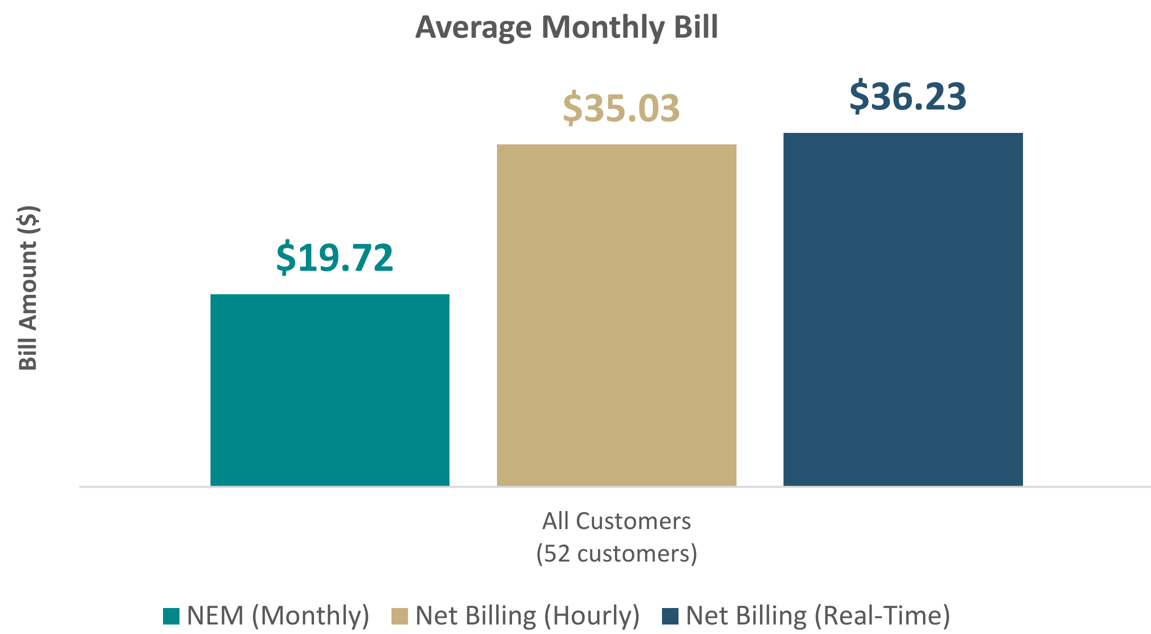

Figure 6.5
Average monthly bill for all small general customer-generators in 2021

Figure 6.5 summarizes the average monthly bill for small general customer-generators with Exporting Systems active for all of 2021. Similar to the analysis in Section 6.2, the analysis uses an Export Credit Rate of $0.03781. On an average monthly basis, small general customer-generators calculated average monthly bill is $19.72 under Net Energy Metering and a monthly measurement interval. Moving from a monthly to hourly measurement interval results in an average monthly bill of $35.03. The real-time measurement results in an average monthly bill of $36.23. Moving from a monthly to real-time measurement results in an average monthly bill increase of approximately $16. However, this does not reflect the average monthly reduction compared to no solar installed.

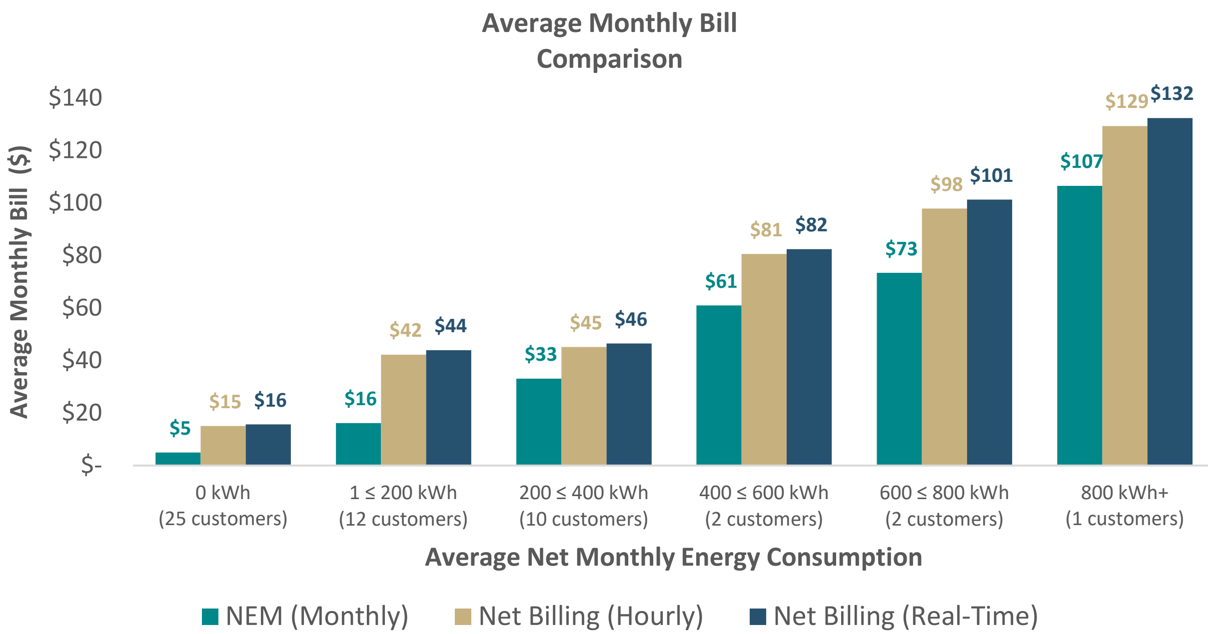

Figure 6.6
Average monthly bill for each compensation structure and measurement interval for all small general customer-generators in 2021, by average net monthly energy use

Similar to Figure 6.4 for residential customer-generators, Figure 6.6 separates the small general customer-generators by their average monthly energy consumption in 2021 under a monthly measurement interval. The small general customer-generators have been grouped into six categories to evaluate the average magnitude of bill impacts within each group of customers. Figure 6.6 does not account for the small general customer-generators average monthly bill before solar was installed. The average monthly bill before solar was installed would be higher than the real-time Net Billing average monthly bill shown in Figure 6.6.

6.4 Schedule 84 Customer-Generator Bill Impact Analysis

The study includes similar data for Schedule 84 customer-generators with 12 months of data in 2021. However, these customer-generators with legacy systems have a different interconnection configuration than residential and small general customers. Legacy systems have a two-meter interconnection and non-legacy systems have a single-meter interconnection. The additional meter for these legacy systems separately meters generation and consumption. As a result, a similar analysis for Net Billing with a real-time interval would measure all generation as exports. For this reason, the study did not consider the same analysis as conducted for existing Schedule 6 and Schedule 8 single-meter customers.

However, the study has evaluated Schedule 84 customers under the following three scenarios: (1) no solar (i.e., grid only service); (2) monthly net energy metering; and (3) hourly net billing.

The hourly data for these customers is made available in Appendix 3.4. The first scenario (no solar grid only service) is possible to evaluate due to the unique two-meter interconnection because the consumption is separately metered. The second and third scenario are similar to the analysis in Section 6.2 and Section 6.3 for residential and small general customer-generators. The real-time scenario is not analyzed because the real-time netting does not occur with two separate meter configurations; therefore, such an analysis would not account for the difference in configuration.

The analysis of Schedule 84 systems is for illustrative purposes only and any conclusions reached should consider the significance of the sample size as well as the fact that all customers evaluated with 12 months of data in 2021 were legacy two-meter systems that would not be subject to changes in the on-site customer generation offering. If the project eligibility cap (discussed in Section 9) were to be modified, it could have an impact on any trends in the analysis of existing Schedule 84 customers. The detailed supporting analysis for the bill impact analysis for existing Schedule 84 commercial and irrigation customers is provided in Appendix 3.5 and 3.6.

6.4.1 Commercial Customer-Generator Bill Impact Analysis

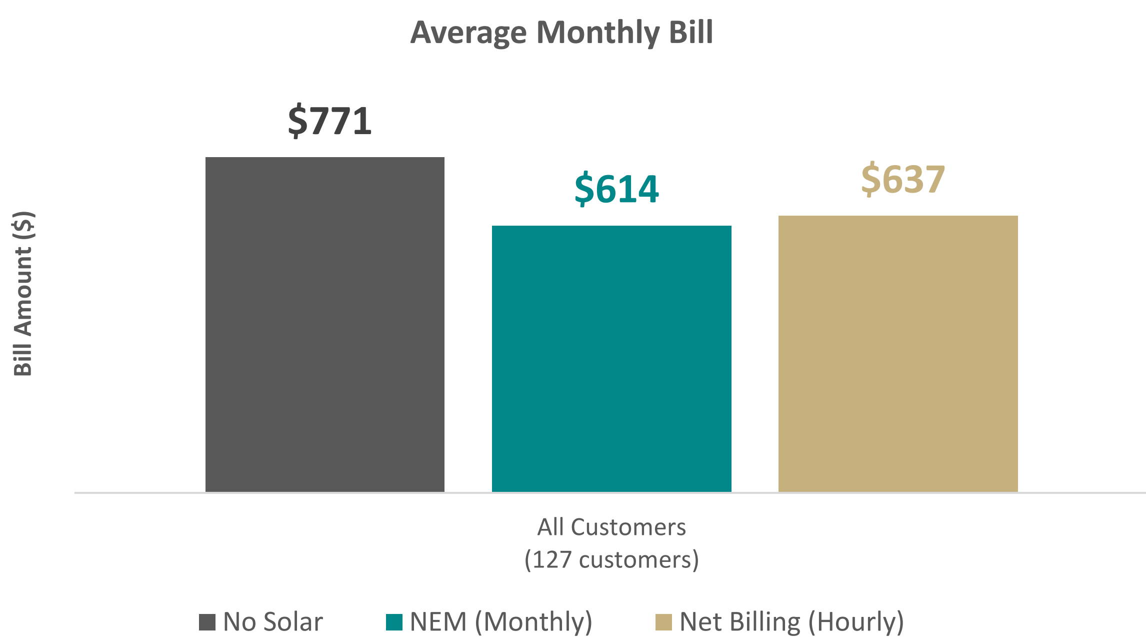

Figure 6.7
Average monthly bill for all commercial customer-generators in 2021

Figure 6.7 summarizes the average monthly bill for commercial customer-generators with Exporting Systems active for all of 2021. Similar to the analysis in Section 6.2 and Section 6.3, the analysis uses an Export Credit Rate of $0.03781. On an average monthly basis, commercial customer-generators calculated average monthly bill was $771 before solar and $614 under Net Energy Metering and a monthly measurement interval. Moving from a monthly to hourly measurement interval results in an average monthly bill of $637. Moving from a monthly to hourly measurement results in an average monthly bill increase of approximately $23 or 4%.

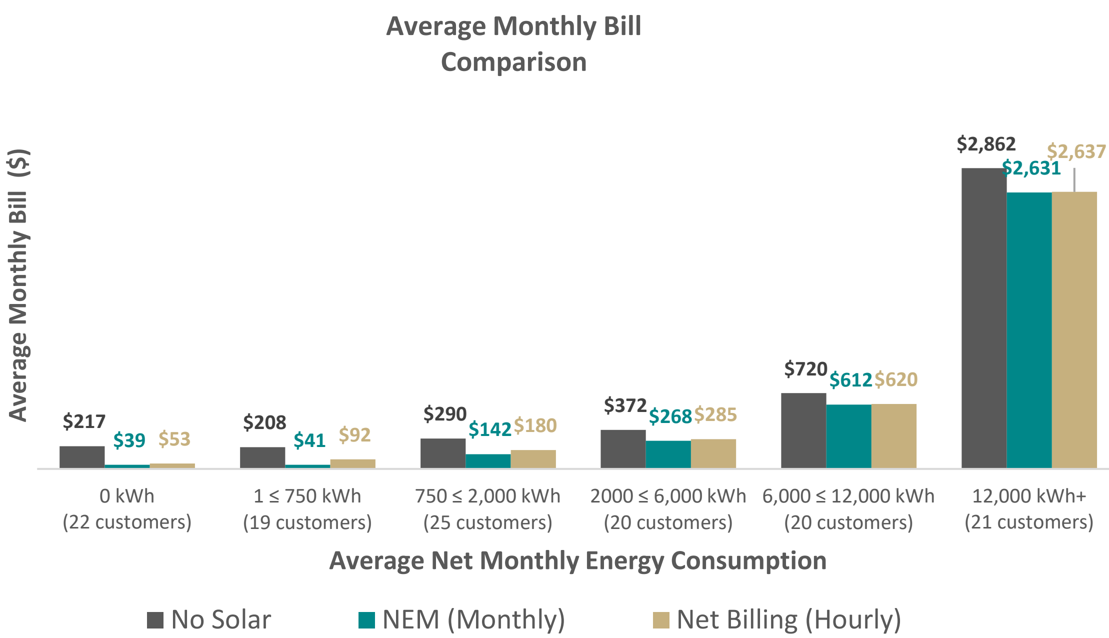

Figure 6.8
Average monthly bill for each compensation structure and measurement interval for all commercial customer-generators in 2021, by average net monthly energy use

Figure 6.8 separates the commercial customer-generators by their average monthly energy consumption in 2021 under a monthly measurement interval. The commercial customer-generators have been grouped into six categories to evaluate the average magnitude of bill impacts within each group of customers. Figure 6.6 compares the commercial customer-generators average monthly bill before solar was installed.

6.4.2 IRRIGATION CUSTOMER-GENERATOR BILL IMPACT ANALYSIS

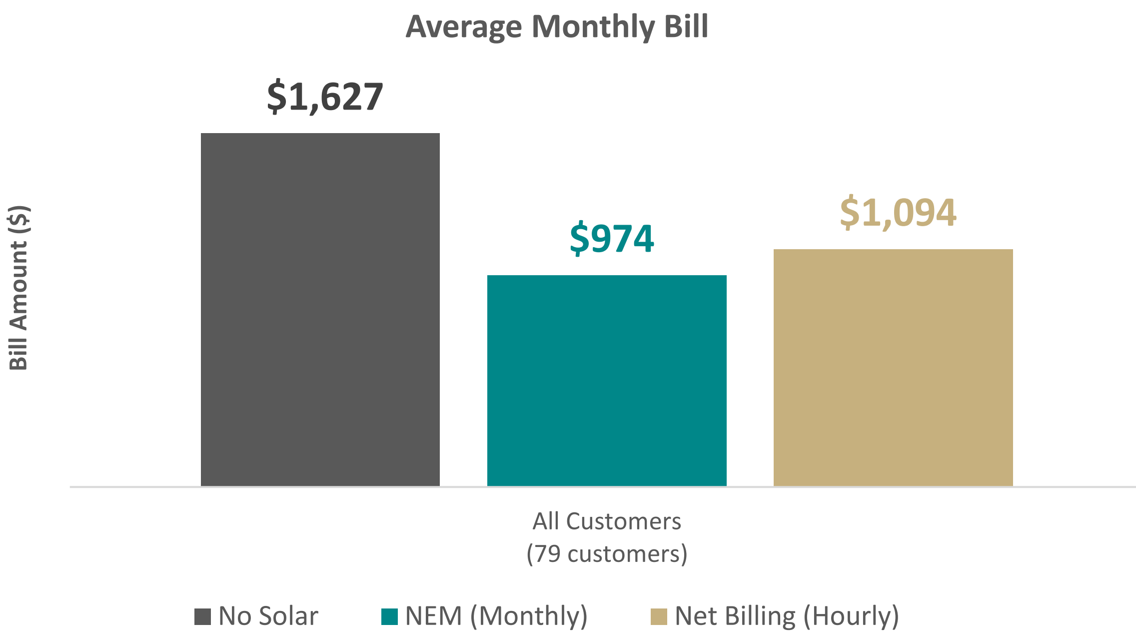

Figure 6.9
Average monthly bill for all irrigation customer-generators in 2021

Figure 6.9 summarizes the average monthly bill for irrigation customer-generators with Exporting Systems active for all of 2021. Similar to the analysis in Section 6.2 and Section 6.3, the analysis uses an Export Credit Rate of $0.03781. On an average monthly basis, irrigation customer-generators calculated average monthly bill was $1,627 before solar and $974 under Net Energy Metering and a monthly measurement interval. Moving from a monthly to hourly measurement interval results in an average monthly bill of $1,094. Moving from a monthly to hourly measurement results in an average monthly bill increase of approximately $120 or 12%.

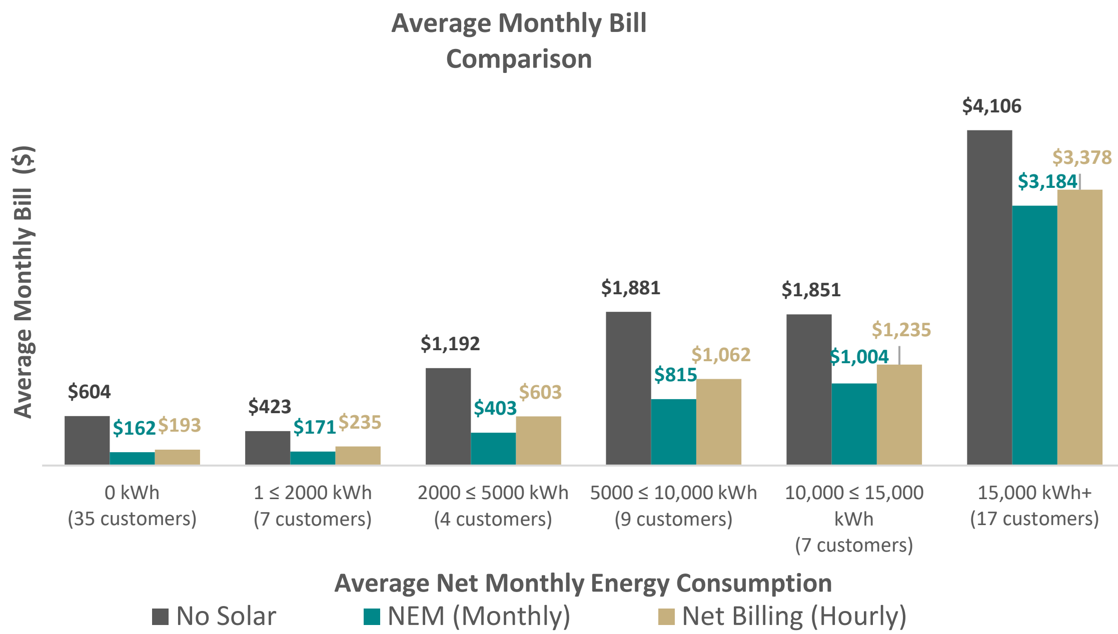

Figure 6.10
Average monthly bill for each compensation structure and measurement interval for all irrigation customer-generators in 2021, by average net monthly energy use

Figure 6.10 separates the irrigation customer-generators by their average monthly energy consumption in 2021 under a monthly measurement interval. The irrigation customer-generators have been grouped into six categories to evaluate the average magnitude of bill impacts within each group of customers. Figure 6.10 compares the irrigation customer-generators average monthly bill before solar was installed.

Compensation Structure – Supporting Appendices

Appendix 3.1
2021 Measurement Interval and Bill Impact — Average Residential

Appendix 3.2
2021 Measurement Interval and Bill Impact — Schedule 6

Appendix 3.3
2021 Measurement Interval and Bill Impact — Schedule 8

Appendix 3.4
2021 Metering Data — Schedule 84

Appendix 3.5
2021 Measurement Interval and Bill Impact – Schedule 84 (Commercial)

Appendix 3.6
2021 Measurement Interval and Bill Impact – Schedule 84 (Irrigation)

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

7. Class Cost-of-Service

A Class Cost-Of-Service study (CCOS) is used to assign or allocate a fair share of the utility's revenue requirement to the various customer rate classes or schedules; the output of the CCOS is the cost of service or revenue requirement for each rate class or schedule. The CCOS is developed through a three-step process that recognizes the way the utility's costs are incurred by relating these costs to the way in which the utility is operated to provide electrical service. The process consists of an Idaho service area test year required revenue that is: 1) categorized by electric system functions of generating, transmitting, or distributing energy (functionalization), 2) classified based on the utility service being provided (classification), and 3) allocated to customer classes (allocation).

The CCOS informs how a change in billing measurement interval from the current "monthly" Net Energy Metering compensation structure to either hourly or real-time Net Billing impacts not only cost assignment to Schedule 6 and 8, but also if either of those compensation structures may result in collection of revenue from those customers in excess of the baseline requirement identified by the CCOS. In determining the scope of the study, the Commission, as part of Order No. 35284, declined to order a full cost-of-service evaluation be completed as part of this study. The Commission stated that "*updates* to current cost-of-service, new rate designs, and transitional rates be *implemented* in a general rate case" (a regulatory proceeding where the company's overall costs and allocations to customer classes are reviewed by the Commission), but also acknowledged "*these issues are studied within this process [the on-site generation study]."*[43] As the Commission noted, CCOS is studied within the process of evaluating on-site customer-generator class billing changes, and Idaho Power approaches the CCOS baseline as a necessary data point to measure impacts of potential changes to compensation structure for customer-generators.

CCOS is evaluated for each separate rate class, and the Commission in Case No. IPC-E-17-13 found it reasonable to separate Residential and Small General Service customers into separate schedules, as well as noting "analysis of the history of company's on-site generation program reveals an unfairness in how current and future on-site generation customers avoid fixed costs." [44] CCOS evaluation for the separate classes helps identify that independent baseline of fixed cost allocation to Schedules 6 and 8.

Schedule 84 on-site generation customers have not been authorized by the Commission to be separate classes. Thus, commercial, industrial, and irrigation on-site generation customers

[43] Case No. IPC-E-21-21, Order No. 35284 at 24 (emphasis added).

[44] Case No. IPC-E-17-13, Order No. 34046 at 16.

continue to take service, and have CCOS evaluated, under their respective Schedule 9, 19, or 24 "parent" class. In development of CCOS inputs, Schedule 84 customers are not included in the customer sample for Schedule 9, 19, or 24, so the impact from a change in measurement interval is not a factor for cost assignment to these classes as it is for Schedule 6 and 8.
The relative precision sample statistic of the Schedule 9, 19, and 24 customer samples is within an acceptable tolerance limit above 90%. That relative precision sample statistic coupled with the limited proportion of Schedule 84 customer in the parent class as listed in Table 7.1 implies a strong statistical significance of the samples as currently designed. Over time the samples will continue to be evaluated as the customer groups potentially evolve.

Even if Schedule 84 customers were included in the parent class sample, Schedule 84 customers make up a small portion of the parent class as listed in the table below, and the impact to CCOS would be de minimis.

Finally, it should be noted that legacy customers make up the overwhelming majority of Schedule 84 customers, and any proposed change in measurement interval would not be applicable.

Table 7.1
CCOS Idaho Schedule 84 customers by Parent Class as of December 2021

Schedule	Schedule Customer Count	Legacy Schedule 84 Count in Parent Class	Non-Legacy Schedule 84 Count in Parent Class
Schedule 9S (Small Commercial)	36,757	155	10
Schedule 9P (Large Commercial)	279	1	1
Schedule 19P (Industrial)	114	1	0
Schedule 24 (Irrigation)	18,795	198	0
Total	**55,945**	**355**	**11**

7.1 Development of the 2021 CCOS

To develop the 2021 CCOS, Idaho Power first prepared a report of system costs, the 2021 Results of Operations (ROO), based on 12-months ending December 31, 2021, using a methodology similar to that which is used to develop a historical test year in a General Rate Case (GRC). While this process included standard regulatory adjustments including normalizing and annualizing adjustments, no financial data was grown or forecasted, and the ROO does not contemplate a change in rate of return as compared to actual 2021 results. The results of the ROO were input into a Jurisdictional Separation Study (JSS) to determine the Idaho jurisdictional ROO (Idaho ROO). A detailed explanation of the process used to develop the Idaho ROO is included as Appendix 7.1, and the Idaho ROO is included as Appendix 7.2.

After the 2021 Idaho ROO was determined, the company used a methodology consistent with that approved by the Commission in the 2008 GRC and the same method filed by Idaho Power in the 2011 GRC[45] to complete the 2021 CCOS. Some modifications were necessary to incorporate new Schedules 6 and 8, and to develop an allocation methodology for Idaho Power generation resources added since the 2011 GRC. Appendix 7.3 is a detailed overview of the company's CCOS process and describes the existing methodology and necessary adjustments[46] in greater detail. Because CCOS is not under evaluation as part of this study and Idaho Power is not seeking changes to its authorized revenue requirement on a system basis, the 2021 CCOS was completed based on the overall rate of return achieved by the normalized 2021 actual results (5.40%), not at the most recent Commission-authorized overall rate of return (7.86%). The study presents the results to inform the Commission of the impact to CCOS under each of the proposed measurement intervals.

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[45] The company's most recent general rate case was Case No. IPC-E-11-08, which was settled without Commission approval of cost-of-service methodology. The Commission most recently approved the company's cost-of-service methodology in the last fully litigated general rate case, Case No. IPC-E-08-10.

[46] The company believes the adjustments made to incorporate Schedules 6 and 8 result in reasonable allocation of system costs and are similar to the adjustments presented to the Commission in Case No. IPC-E-18-16, *In the Matter of the Application of Idaho Power Company to Study Fixed Costs of Providing Electric Service to Customers.*

CUSTOMER RATE COMPONENTS AND COLLECTION OF SYSTEM COSTS

The results from the CCOS can be compared to the current customer class revenue collection to identify if the total amount of CCOS costs is collected from the customer class, and if the revenue component collection aligned with the way system costs are incurred as identified by the CCOS.

If customer rates are developed matching CCOS cost allocation perfectly, customer-classified costs (e.g., meters, customer service costs) would be collected through the service charge, energy-classified variable costs (e.g., fuel) would be collected from the energy charge, and demand-classified fixed costs (e.g., generation, transmission, and distribution plant) would be collected from a demand charge.

Idaho Power currently collects the revenue requirement from Schedule 6 and 8 customers through two billing components: 1) a fixed monthly service charge, and 2) a volumetric energy rate. Because Schedule 6 and 8 do not include a demand charge in their billing structure, nearly all of the fixed costs to serve these customers are instead collected in the volumetric energy rate.

7.2 2021 CCOS Results

The primary purpose of the CCOS prepared for this study is to highlight the impact on cost-allocation between the studied measurement intervals. To accomplish this, two CCOS were completed with differing underlying data for cost allocation based on the two measurement intervals studied: one relied on hourly data and the second relied on real-time data. The CCOS is prepared through two modules, the Assign Module, and the Functional Cost Module. Both modules for each of the two CCOS are provided as appendices 7.4 through 7.7, with each Functional Cost Module appendix also including a summary of the CCOS results by customer class.

To quantify the improvement in revenue collection that results from a shorter measurement interval for consumption against the baseline CCOS revenue requirement, the study evaluated the effectiveness of the current rates under an hourly and real-time structure versus the current billing structure (monthly metering). Under the hourly billing structure, the measurement interval of consumption and exports is shortened from measuring net consumption or exports over the course of a billing month to measuring net consumption or exports that occur on a net hourly basis, which ties to the underlying cost-allocation method utilized in the CCOS. Under this type of a billing structure, the customer’s generation will offset up to 100% of the customer’s usage within each hour, but any excess hourly production cannot be used to offset kWh consumption in another hour. Rather, excess energy not used within the hour would be converted to a bill credit.

Figure 7.1 includes both the current level of revenue collection through monthly metering as compared to CCOS identified required revenue, as well as the composition of that revenue collection compared to CCOS informed allocation. Additionally, Figure 7.1 provides a secondary comparison for the change in revenue collection by moving from monthly metering to hourly billing for all customers in Schedule 6 and 8. The CCOS analysis informs that while net hourly billing may reduce the revenue requirement deficiency by approximately 49% and 53% for Schedule 6 and 8 customers, respectively; the existing pricing[47] structure does not align with the underlying cost structure.

[47] In Order No. 35284, the Commission acknowledged a full cost-of-service analysis is due to be completed along with an in-depth study of rate design options, but declined to order the full process to be completed as part of this study.

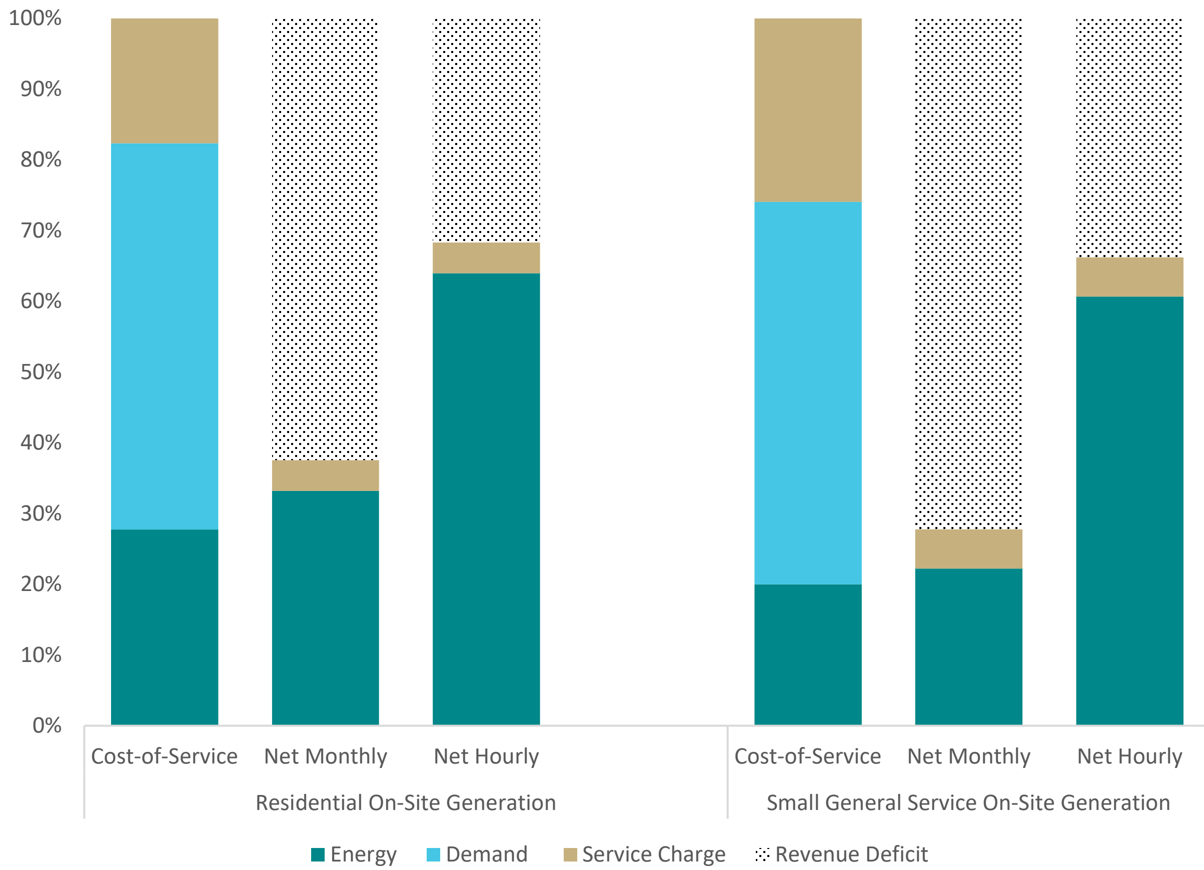

Figure 7.1
On-site generation monthly billing vs. hourly billing all customers

In recognition that approximately 80% of Schedule 6 customers, and approximately 90% of Schedule 8 customers evaluated in this study have legacy systems under the monthly metering billing structure, Figure 7.2 provides a comparison for revenue deficiency improvement moving from monthly metered to hourly billing for the remaining customers with non-legacy systems. Revenue deficiency improvement is only 9% and 7% for Schedule 6 and 8, respectively, when customers with legacy systems remain on the monthly metering structure.

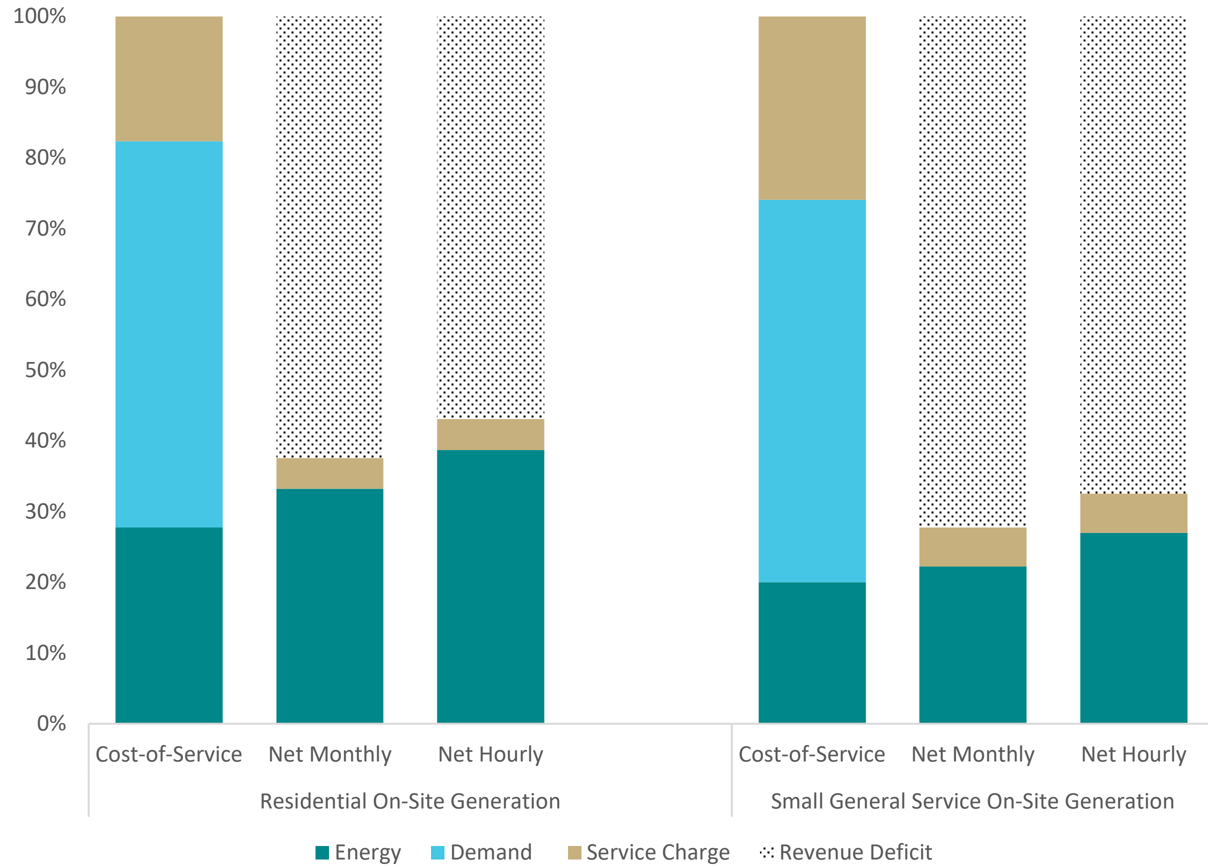

Figure 7.2
On-site generation monthly billing vs. hourly billing for non-legacy systems

In the second CCOS, the company utilized the meter's actual delivered channel to perform cost allocation under the real-time structure. As shown in Figure 7.3, while real-time delivered compensation structure for all customers may reduce the revenue requirement deficiency by approximately 51% and 54% for Schedule 6 and 8 customers, respectively; the existing pricing[48] structure does not align with the underlying cost structure.

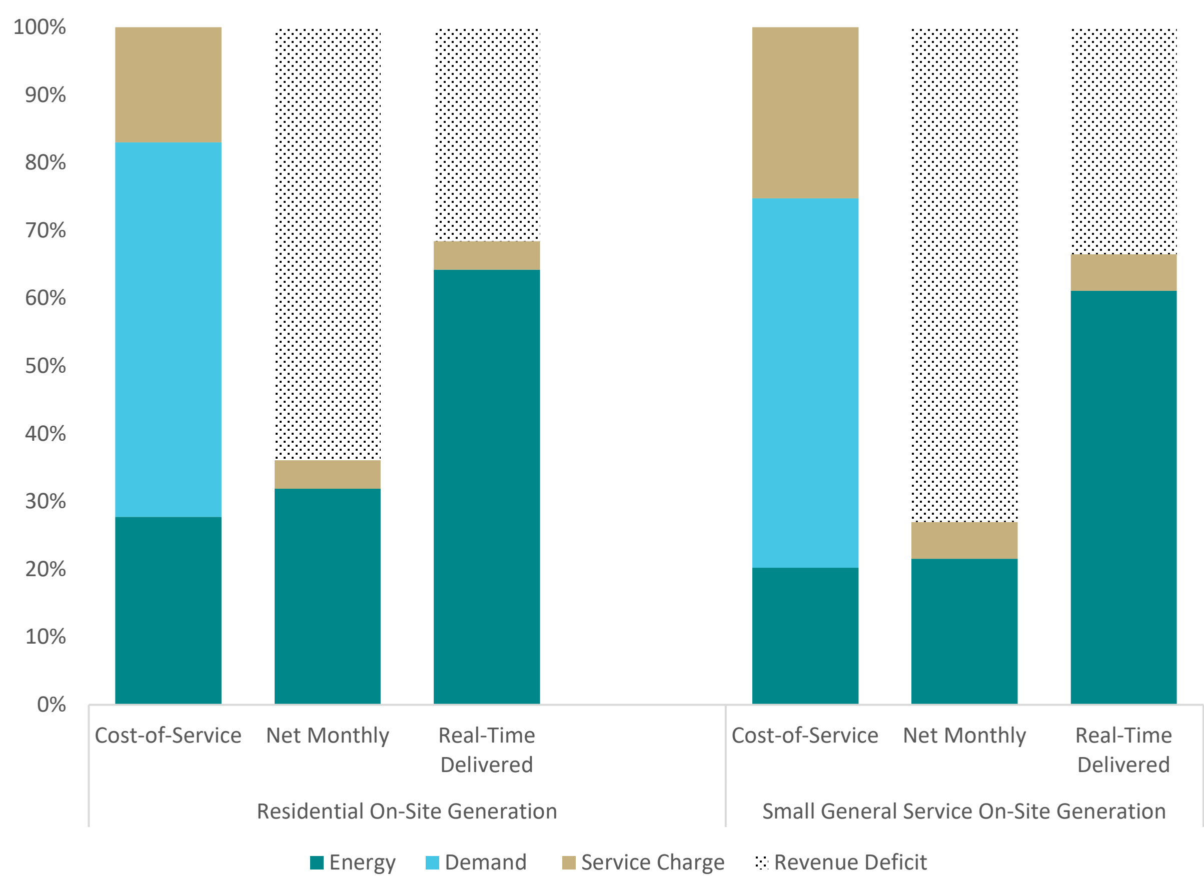

Figure 7.3
On-site generation monthly billing vs. real-time billing for all customers

[48] In Order No. 35284, the Commission acknowledged a full cost-of-service analysis is due to be completed along with an in-depth study of rate design options, but declined to order the full process to be completed as part of this study.

Idaho Power completed the same comparison for real-time billing with respect to holding Schedule 6 and 8 customers with legacy systems under the existing monthly metering structure, and improvement to the revenue requirement deficiency is reduced to 16% and 7%, respectively, as shown in Figure 7.4.

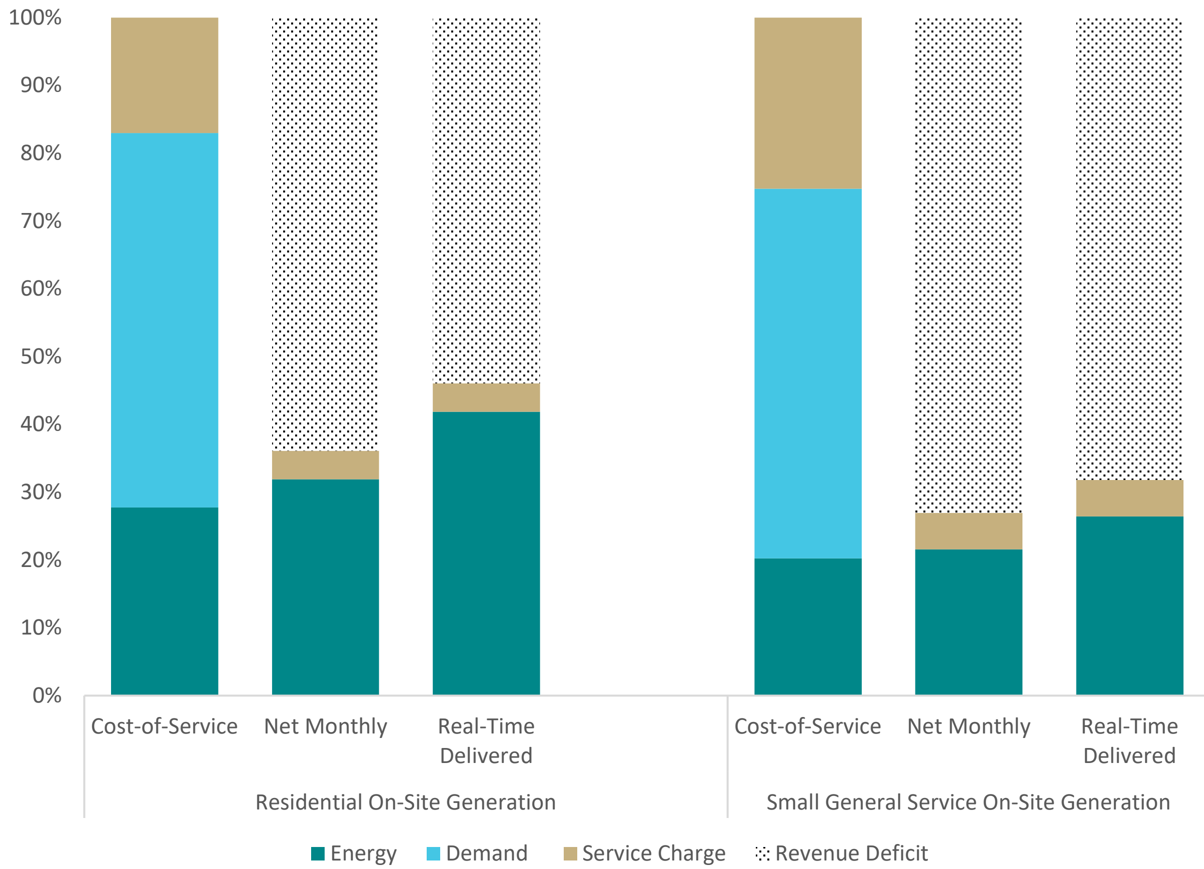

Figure 7.4
On-site generation monthly billing vs. real-time billing for non-legacy systems

Class Cost-of-Service – Supporting Appendices

Appendix 7.1
Idaho ROO Process Guide

Appendix 7.2
Idaho ROO

Appendix 7.3
Class COS Process Guide

Appendix 7.4
CCOS — Hourly Netting Assign Module

Appendix 7.5
CCOS — Hourly Netting Summary and Functional Cost Module

Appendix 7.6
CCOS — Real-time Assign Module

Appendix 7.7
CCOS — Real-time Summary and Functional Cost Module

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

8. Recovering Export Credit Rate Expenditures

This section addresses the accounting structure for and quantifies the impact of payments to customers for excess energy delivered to Idaho Power. Idaho Power is subject to the Code of Federal Regulations (CFR) Uniform System of Accounts, which prescribes how and where transactions should be recorded in its financial statements. Per the CFR, it is appropriate for the payment for net excess energy credits to be recorded in FERC account 555 Purchased Power because it is energy that the company is purchasing for the benefit of its customers.[49] Figure 8.1 below provides the CFR instructions for recording purchased power expenses to FERC account 555.

555 Purchased power.

A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, etc. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.

B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt-hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract.

Figure 8.1
Code of Federal regulations operating expense instructions, definition of CFR 555 purchased power

8.1 Method Evaluated

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. Prior to this change, payments were recorded to FERC account 555 Purchased Power and were subject to recovery through the Power Cost Adjustment (PCA).[50] In subsequent PCA filings these costs were

[49] 18 CFR 1.101 Uniform system of accounts prescribed for public utilities and licensees subject to the provisions of the Federal Power Act.

[50] *In the Matter of the Application of Idaho Power Company for Amendments to Schedule 84 – Net Metering*, Case No. IPC-E-02-04, Order No. 29094 at 7 (August 21, 2002).

included with *Public Utility Regulatory Policies Act of 1978* (PURPA) Qualifying Facilities (QF) costs and were not subject to sharing by the company.[51]

WHAT IS THE POWER COST ADJSUTMENT MECHANISM?

On March 29, 1993, by Order No. 24806, the Commission approved the implementation of an annual power cost adjustment procedure to provide consistency and stability to rates. The PCA is a rate mechanism that quantifies and tracks annual differences between actual net power supply expenses (NPSE) and the normalized or “base level” of NPSE recovered in the company’s base rates for recovery or credit through an annual rate change on June 1. The PCA includes FERC account 555 Purchased Power. FERC Account 555 includes the costs of both PURPA and non-PURPA (market) purchases.

The PCA includes a 95%/5% sharing mechanism between customers and the company. This mechanism allows the company to pass through to Idaho customers 95% of the annual differences in actual NPSE as compared to the base level NPSE, whether positive or negative. The exceptions to this are PURPA QF expenses and demand response incentive costs, which are not subject to the 95%/5% sharing mechanism and instead are passed through the PCA at 100%.

Export credit costs should be treated as an NPSE subject to recovery though the PCA. Like the previous treatment of financial credits for net excess energy, these costs should not be subject to the 95%/5% sharing mechanism. Similar to PURPA QFs, customer generation is a must-take resource provided to the company on a non-firm basis. The export credit costs should be recovered in a manner similar to expenses incurred to purchase energy from PURPA QFs.

The PCA is applicable to the energy delivered to all Idaho retail customers. For the base, forecast, and true-up components, all customers pay the same PCA rate.

Appendix 8.1 quantifies the annual cost of net exports under both hourly and real time measurement intervals and priced at various ECRs. The lowest cost is $309,933 and is based on an hourly measurement interval using the 2021 Idaho Power IRP ECR from Appendix 4.16

[51] *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.* IPC-E-03-05, Said Exhibit No. 3.

($22.74/MWh). The highest cost is $590,947 and is based on a real-time measurement interval using the 2019–2021 Average ICE Mid-C ECR from Appendix 4.16 ($40.26/MWh).

Appendix 8.2 quantifies the impact on the 2021/2022 PCA deferral of each interval and export credit rate studied.

8.2 Customer Classes Impacted

As stated in Order No. 35284, "the direct costs [of net excess generation] should be linked with the associated benefits." Excess energy purchased from onsite generation customers benefits the entire system, not unlike energy purchased on the market, from Power Purchase Agreements (PPAs), or from PURPA QFs. Market purchases, PPAs, and PURPA energy are recovered from all customer classes via base rates and the PCA. Therefore, export credit costs should be treated consistently and be recovered as NPSE by all customers classes in base rates (updated periodically in a general rate case or single item proceeding)[52] and PCA rates (updated annually). Appendix 8.3 provides the revenue impact by rate class for each interval and export credit rate studied assuming 100% recovery through the 2022 PCA.

The costs of administering Idaho Power's net metering service[53] are collected through base rates like other administrative costs. Idaho Power has not identified significant, incremental costs associated with administering its net metering service that should be directly assigned to on-site generation net metering customers. Idaho Power will continue to monitor the costs of administering its net metering service and if it determines that there are significant, incremental costs that should be directly assigned to these customers, it will bring that to the Commission's attention through a filing.

[52] *In the Matter of the Application of Idaho Power Company for Authority to Establish a New Base Level of Net Power Supply Expense*, Case No. IPC-E-13-20, Order No. 33000 (March 21, 2014).

[53] I.P.U.C. No. 29, Tariff No. 101 Schedule 6 Residential Service On-Site Generation, Schedule 8 Small General Service On-Site Generation, Schedule 84 Customer Energy Production Net Metering Service.

Recovering Export Credit Rate Expenditures – Supporting Appendices

Appendix 8.1
Value 2021 Net Export kWhs at ECRs

Appendix 8.2
2021–2022 PCA Model with ECRs Expense

Appendix 8.3
2022 PCA Revenue Impact by Rate Class

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

9. Project Eligibility Cap

9.1 Evaluation of Existing Cap

The existing project eligibility cap varies by customer type. Residential and small general customers' project eligibility cap is 25 kW and commercial, industrial, and irrigation customers' project eligibility cap is 100 kW.

The rationale for a cap for individual installations was, in part, to limit the amount that other customers subsidize some of the costs of net metering customers. In Case No. IPC-E-01-39, Commission Staff stated,

> For the Commission to accept a net metering tariff where customer generation is credited at full retail rates, it must be willing to accept the fact that Idaho Power may not recover its full costs of providing service from net metering customers. Those costs that are uncollected must either come from Idaho Power through its shareholders or from other customers collectively.[54]

When directing Idaho Power to expand its net metering proposal to include customer classes other than residential and small general service, the Commission set a 2.9 MW cumulative generation nameplate capacity cap at which point it would review subsidization by non-participants and noted that 100 to 125 kW was a more reasonable capacity limit for commercial, industrial, and irrigation customers that aligned with the Federal Energy Regulatory Commission minimum qualifying facility size of 100 kW.[55]

Commercial, industrial, and irrigation customers that elect to interconnect a Non-Exporting System are not limited to the project eligibility cap. Alternatively, a customer can choose to sell their renewable energy as a Qualified Facility to Idaho Power under Schedule 86 for Exporting Systems larger than 100 kW.

Residential customer generation projects are typically sized significantly below the maximum allowed 25 kW cap. Approximately 2% of residential systems are larger than 20 kW and 93% are less than 15 kW. The current 25 kW cap is higher than Idaho Power's planning load for residential lots of 13 kW.

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[54] *In the Matter of the Application of Idaho Power Company for Approval of a New Schedule 84 -Net Metering Tariff*, Case No. IPC-E-01-39, Staff Comments at 3.

[55] Case No. IPC-E-01-39, Order No. 38951 at 11-12.

It is important to note that Idaho Power administers each of its tariffs for retail service — including the on-site generation tariffs — according to service points (a service point is akin to the point of delivery, or meter). The information included in this study and the following figures should not be interpreted to suggest a one-to-one relationship between service point and a customer or business entity. For example, a single customer may have multiple service points, but the company is precluded from aggregating those meter reads for any purpose other than determining whether a customer's total power requirements exceed the threshold for standard tariff service.[56]

Figure 9.1 is a histogram of non-solar residential service points. This information is based on billing data over calendar year 2021, and excludes mobile home parks, RV parks, and large master metered customers. The non-solar residential service points with demand 25 kW and greater represents 2.1% of non-solar residential service points.

[56] Rule C of Idaho Power's Commission-approved tariff states, "Where separate Points of Delivery exist for supplying service to a Customer at a single Premises or separate meters are maintained for measurement of service to a Customer at a single Premises, the meter readings will not be combined or aggregated for any purpose except for determining if the Customer's total power requirements exceed 20,000 kW."

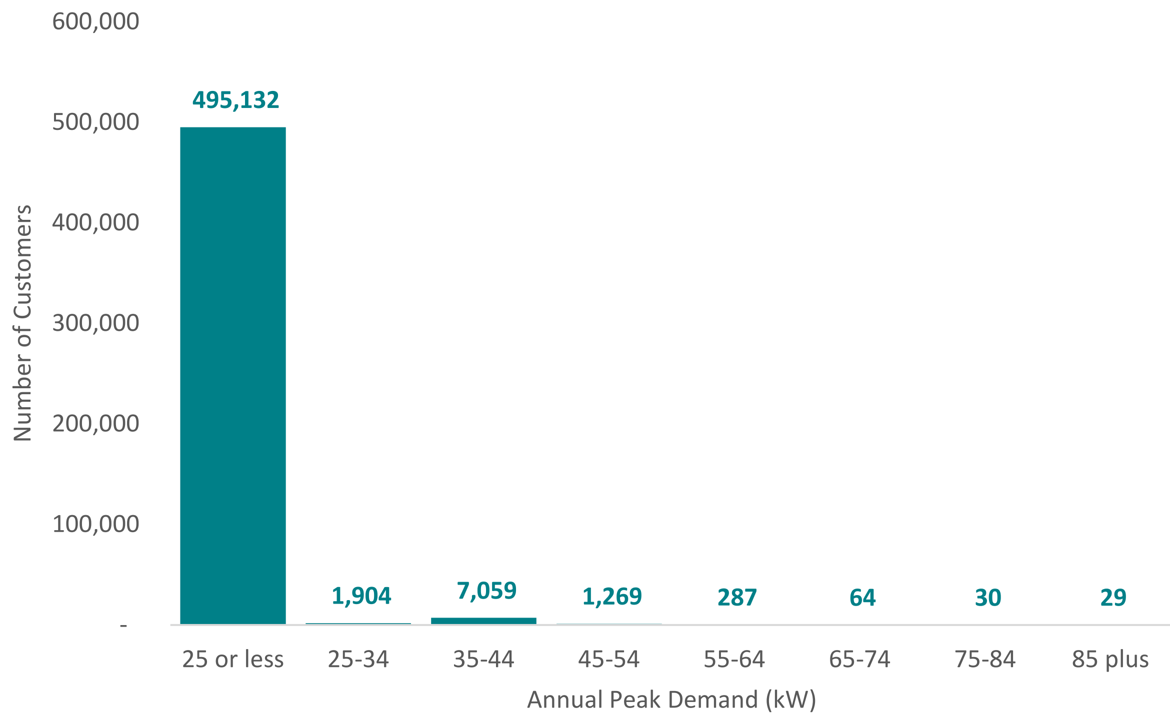

Figure 9.1
Non-solar residential customer service point histogram

Figure 9.2 is a histogram of non-solar commercial and industrial service points. This information is based on billing data over calendar year 2021. The non-solar commercial and industrial service points with demand 100 kW and greater represents 3.9% of non-solar commercial and industrial service points.

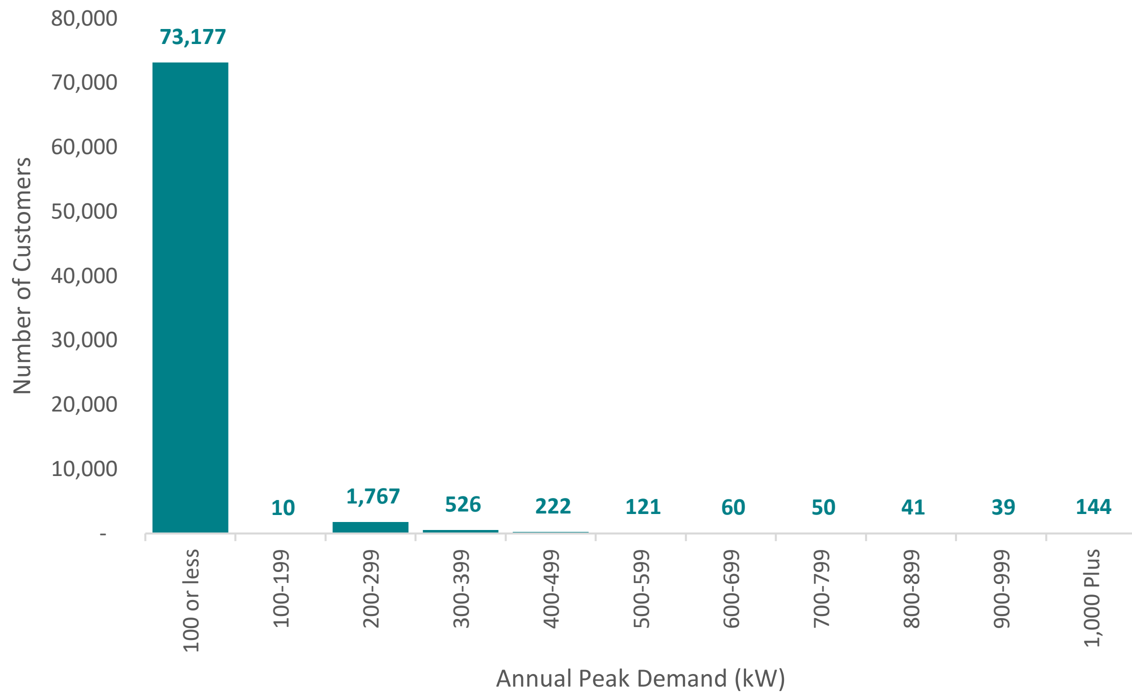

Figure 9.2
Non-solar commercial and industrial service point histogram

Figure 9.3 is a histogram of non-solar irrigation service points. This information is based on billing data over calendar year 2021. The non-solar irrigation service points with demand 100 kW and greater represents 14.3% of non-solar commercial and industrial service points.

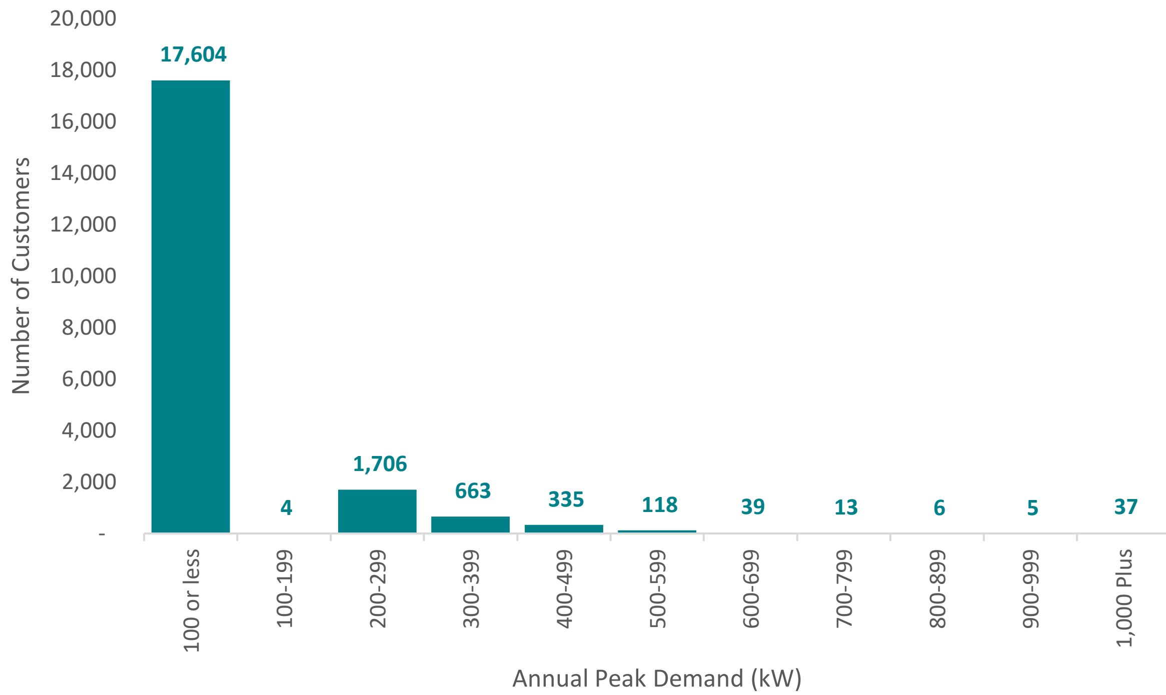

Figure 9.3
Non-solar irrigation service point histogram

As of May 31, 2022, irrigation customer generation systems accounted for 2% of the total systems (242 of 12,322 systems) and 19% of the nameplate capacity (22.00 of 118.04 MW). Approximately 85% of irrigation systems are greater than 95 kW. Table 9.1 provides a summary of active and pending Exporting Systems in Idaho Power's service area as of May 31, 2022.

Table 9.1
Active and pending Exporting Systems count, total capacity (MW), and average system size (kW) as of May 31, 2022

Customer Type	Count	Total Capacity (MW)	Average Size (kW)	Project Cap (kW)	Average Size as % of Cap
Residential	11,807	88.92	7.53	25	30%
Small General	73	0.57	7.77	25	31%
Commercial & Industrial	200	6.56	32.80	100	33%
Irrigation	242	22.00	90.89	100	91%
Total	**12,322**	**118.04**	**9.58**	**–**	**35%**

Note: Numbers may not add up due to rounding.

9.2 Evaluation of Modified Cap

9.2.1 Technological Improvements and Standardization

In Order No. 28951, the Commission highlighted the importance of considering safety, service quality, and grid reliability when determining the appropriate project eligibility cap. The following background provides an overview of technological improvements and standardization of equipment that have occurred.

The IEEE Standards Board approved the IEEE 1547 standard in 2003 and the *Energy Policy Act of 2005* established IEEE 1547 as the national standard for the interconnection of distributed generation resources in the United States of America. Prior to the established standard, there was no way for an electric utility to have any certainty as to the performance of a proposed customer generation project. Many project characteristics were unknown: response to fault conditions; power output range; voltage output range and response; harmonic contributions; islanding detection; outage return to service process. Each project required significant detailed design information and associated analysis to determine if it could be safely connected.

Once the IEEE standard was defined and adopted, equipment manufacturers began designing their equipment to operate within the standard’s requirements. At that time Underwriter Laboratories (UL) prepared testing procedures to certify equipment to meet IEEE 1547. The UL certification for this equipment was designated as UL 1741. Within a few years, the standard was included in the Energy Policy Act, and several vendors offered UL 1741 certified equipment for customers to purchase and install for their on-site customer generation projects.

With the IEEE 1547 standard and UL certification, the operating performance of distributed generation resources was defined and many of the risks have been reduced but not eliminated. For the equipment to receive the UL certification, it is tested to verify that it will operate within the allowed parameters that include power quality limits, voltage limits, power limits, island detection, fault detection, automated shut down requirements, and delay in returning to service after an outage to minimize impact to the local grid and safety to line workers. In addition, IEEE continues to review the standard and has provided updates to address lessons learned from field experience and identified new features of the more sophisticated equipment that is now available.

The latest update to the standard, IEEE 1547-2018, incorporates several operational features to allow for higher penetration of distribution connected generation without negatively impacting the grid. These features include allowing for volt-amp reactive operation and watt reduction operation to support local system voltage, automatic shutoff due to voltage excursions outside of set parameters, low voltage ride-through settings to support system voltage during a system disturbance. The latest standard also includes a requirement for communication connection standard. The communication presence will allow for remote control setting confirmation and for remote control setting changes. The control setting changes are designed to modify performance including temporary production curtailment to adjust to system needs and to allow higher penetration of connected generation.

9.2.2 Modified Cap Impact

The Commission-approved Study Framework included an analysis of a modification to the project eligibility cap set at 100% and 125% of a customer's demand. The study considered the merits of a project eligibility cap set relative to a customer's demand. From a system perspective, the interconnection considerations related to a generator will be evaluated independently from a customer's demand (whether it is set at 100% or 125% won't result in differing interconnection requirements). In other words, during an hour without customer load (for example, when an irrigation pump isn't running), a generator sized at 125% of a customer's 100 kW load (125 kW generator) would behave the same as a generator sized at 100% of a 125-kW load (125 kW generator).

A customer's demand, irrespective of the definition or criteria used, is not a technical factor that will define a project eligibility cap to ensure that the company's system remains safe and reliable. Developing the appropriate review and study processes and defining the necessary interconnection requirements are the factors that will ensure the company's system remains safe and reliable as larger DERs are interconnected. Modifications to the project eligibility cap would require an evaluation of the interconnection requirements and consider specific rules to ensure that Idaho Power is able to administer its customer generation offering that is consistent for all customers with a project eligibility cap set at a percentage of a customer's demand.

9.2.2.1 Interconnection Requirements

The wide adoption of IEEE 1547 has reduced safety, service quality, and reliability risks associated with interconnection of distributed generation resources. However, potential risks are still associated with increasing the project eligibility cap for on-site customer-generators. The concentration of distributed generation at a single connection point could require additional studies similar to what is necessary for PURPA generation facilities if the project eligibility cap is increased from 100 kW to 100% to 125% of the customer's demand.

For comparison, several screening factors for PURPA generation facilities are evaluated to determine if a project requires more detailed studies before interconnection. For example, a more detailed study is needed if a project is larger than 2 MW and/or exceeds 15% of the distribution line section load. The additional generation studies evaluate various system impacts, including but not limited to the following:

- Distribution voltage and line equipment impacts
- Voltage flicker from generation output variability
- Deadline reclosing
- Ground fault current contribution limits
- Other system upgrades

Study costs for PURPA projects typically range between $1,000 and $3,000. If a more detailed study is required for these projects over 2 MW and/or greater than 15% of the distribution line section, PURPA projects must deposit $1,000 to apply toward study costs. If a project meets all screening criteria, it has the potential to waive the study requirement, but a (preliminary review) is still conducted, and a $500 application fee is required. This review process is more labor-intensive than on-site generation projects 100 kW or less.

PURPA generation facilities must execute a Generation Interconnection Agreement with Idaho Power. If the Commission ultimately approved a modified project eligibility cap for customer-generators to a customer's demand, the Schedule 68 interconnection requirements would need to be evaluated for modification for larger systems that might require more extensive interconnection facilities similar to those applicable to PURPA generation facilities, outlined in Schedule 72.

9.2.2.2 Distribution System Operations

In managing its distribution system, Idaho Power will periodically change connections to its distribution line sections by closing and opening distribution switches. The switching operation moves customer load from one distribution line section to another. Distribution line switching can restore service after an outage or de-energize a portion of the system to perform maintenance, particularly during light load times.

During restoration, customer-generator systems may begin to generate and export energy after sections of the distribution line have been energized for more than five minutes. Under certain circumstances, the customer-generator exports could exceed the equipment capacity of the switched distribution section. For example, an area of distribution line with a large quantity of customer generation associated with seasonal loads could start exporting all generated energy to Idaho Power’s system. Under the current 100 kW cap for non-residential customers, there is an opportunity to limit the number of customer-generator systems switched at a time. However, increasing the cap to a customer’s demand could negatively impact the switching process during seasons or certain times with low customer load.

PURPA projects are typically remotely curtailed during the distribution switching operations and left off until the system is returned to normal operation status. Without a similar means to switch off the larger customer generation systems, the distribution system operations will be limited, or it will require a site visit for someone to switch the project offline manually. Several factors could be used to determine the need for a remote switch for an individual project. The remote switch in most cases could be a device that connects to the projects electrical panel, like a relay device. Examples for factors to evaluate could include but are not limited to: (1) the relationship of the project to switching devices; (2) the size of the generator; (3) the load characteristics of the feeder; (4) the specific distribution line segment where the project interconnects; and (5) other generation systems on the distribution feeder.

One solution to this would be a requirement for identified larger customer-generator systems to include a communications connection to allow remote curtailment by Idaho Power. A relay would need to be installed at an electrical location on the customer-generator side of the company’s retail metering point to allow complete isolation of the DER and interconnection facilities from the customer’s electrical load and service. The equipment cost depends on the rating required for the specific generation project at each location, in addition to communications requirements. Assuming the device would be similar to the disconnect devices used in the company’s irrigation peak rewards demand response program, the device would cost about $180.

An alternative solution would be implementing a Distributed Energy Resource Management System (DERMS). Implementation of a DERMS would require a communication connection to each customer-generator system and major software deployment for Idaho Power. This would allow the remote curtailment of the customer-generator system when the load is significantly reduced (e.g., during the off-season for seasonal loads).

9.2.2.3 Implementation and Operational Considerations

During the study design phase, Idaho Power received feedback from stakeholders and the public that the 100-kW cap for commercial, industrial, and irrigation customers was arbitrary. As characterized by stakeholders, a system cap equal to (i.e., 100%) or slightly greater than (i.e., 125%) a customer’s demand, attempts to better align with their ability to generate for some of their energy needs. The study evaluates the following considerations related to a cap tied to a customer’s demand:

1) Should a demand-based system size cap apply to all customer-generators or only commercial, industrial, and irrigation customers?
2) What is the definition of a customer’s demand for purposes of a system size cap?

3) How will a demand-based system cap be defined for a customer without historical usage data?
4) How do changes in system ownership that result in considerable changes in customer demand impact a customer-specific and demand-related cap?

Table 9.1 highlights that residential and small general customer-generators average system size is roughly 30% of the 25-kW cap. It does not appear that the 25-kW cap limits these customer segments. Additionally, due to the relative size of residential and small general customers and the higher likelihood of customer turnover, it would be more challenging to manage a system cap that is unique to customer load. For these reasons, retaining the 25-kW cap for residential and small general customers could be reasonable.

A customer's demand can be defined in a variety of ways. For example, it could state a customer's demand in terms of their maximum monthly demand over a given number of months (e.g., last 12 months). A customer can also have a higher 15-minute demand than their hourly demand in the same hour. Demand charges are calculated based on a customer's 15-minute demand rather than their hourly demand.

For new customers, a demand project cap based on their demand could create administrative difficulties that would have to be evaluated. Customers could be incentivized to overestimate their demand to maximize the system size installed under a demand-related cap. It is common for industrial and commercial customers to overestimate rather than underestimate their energy and demand requirements.

Customer demand can increase or decrease over time. For example, a business owner could have a 50-kW maximum hourly demand over the last 12 billing months when they install a generation system. For example, if a new customer purchases the building and only operates with a maximum hourly demand of 25 kW, they would have a generation system equal to 200% of their demand. Such a dynamic and customer-specific demand could create administrative difficulties that would need to be evaluated. These implementation considerations are more fully addressed in Section 11.

Another consideration regarding the project eligibility cap is the overlap between PURPA and customer-generation. Because customer generation projects could be implemented as PURPA and vice versa, gaming could occur — especially if PURPA rates, terms, and requirements are different than those for customer-generators — thus providing an incentive for customer-generators or PURPA projects to manipulate the rules to achieve more favorable rates or terms.

For example, this type of gaming historically occurred in Idaho when large PURPA solar and wind projects that should have qualified as IRP-based projects disaggregated into smaller published rate projects in order to receive higher rates. This was resolved by lowering the published rate eligibility cap from ten average-megawatt to 100 kW.[57] Potential gaming considerations should be evaluated as parties advocate for recommended changes to the project eligibility cap.

[57] Order No. 32697 at 13-14.

10. Other Areas of Study

10.1 Billing Structure

Other areas of the study that will help inform decisions for implementing a new service offering for customer-generators include billing structure and access to data for prospective customer-generators.

After evaluating the measurement interval, Export Credit Rate, compensation structure, and the recovery of export credit expenditures, Section 10.1.1 evaluates the billing components that a customer-generator could offset with the implementation of Net Billing under either an hourly or real-time measurement. Section 10.1.2 reviews how accumulated kWh credits might expire or be compensated as a financial credit. Section 10.1.3 explores how financial credits could be transferred or retired upon customer relocation or discontinued service.

Section 10.2 concludes the study by reviewing data that Idaho Power makes available to its customers to help them make informed decisions before investing in on-site generation facilities. Additionally, the study confirms that customers have the data needed to understand the impacts of a change in compensation structure and measurement interval.

10.1.1 Evaluation of Bill Components

Idaho Power's existing Commission-approved net metering service offering limits the credit to only offsetting energy usage. According to the applicable standard service schedule, customer-generators are billed for all applicable non-energy charges for the Billing Period. The study includes an evaluation of the bill components that a customer-generator would be able to offset under a Net Billing compensation structure.

Under a Net Billing compensation structure, customer-generators would be compensated for excess energy with a financial credit equal to the Export Credit Rate. As described in Section 8.1, these payments for excess energy would be subject to recovery through the PCA. Providing a financial credit under a Net Billing compensation structure, rather than a kWh (energy) offset, would create the ability for customer-generators to apply their credit for excess energy to offset any portion of their bill — not just the energy charges.

10.1.2 Review of Accumulated kWh Credits & Expiration

10.1.2.1 Review of Accumulated kWh Credits

After the implementation of the kwh crediting for excess net energy authorized by the Commission in Order Nos. 32845 and 32872 in January 2014, the company has accumulated significant unused kWh credit balances. The excess net energy credit balance in 2014 was approximately 0.5 million, increasing to over 17.1 million kWh credits in 2021. The compound annual growth rate for the accumulated unused excess net energy credits from 2014 to 2021 was 66%. Figure 10.1 shows the accumulated excess net energy credit balance for 2014 through 2021.

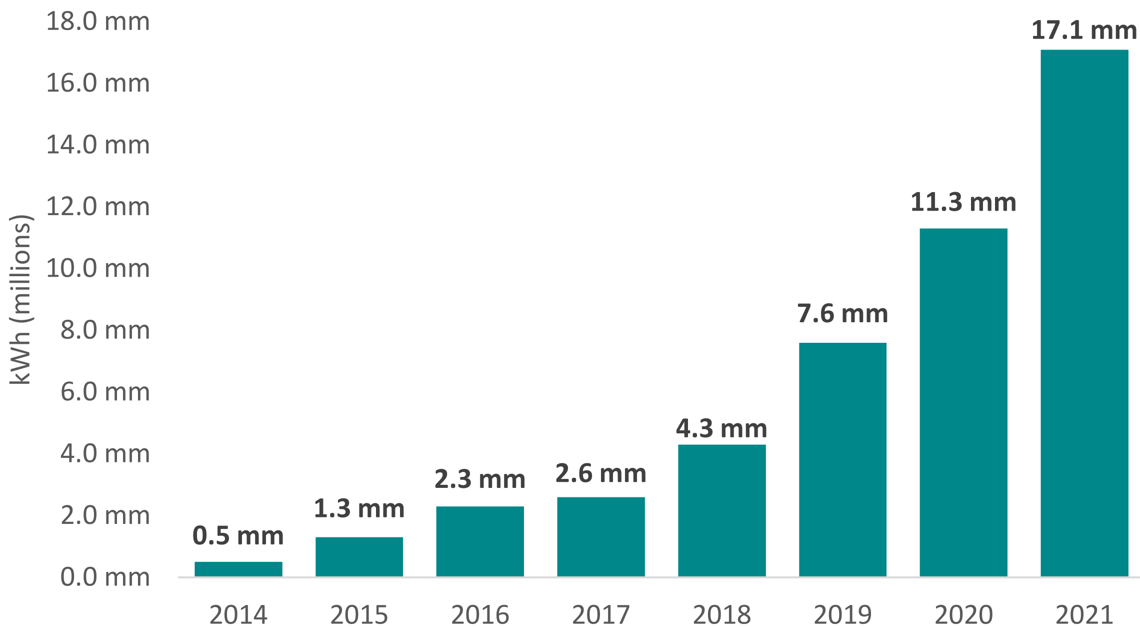

Figure 10.1
Accumulated excess net energy credit balance 2014–2021

In this section, the company presents a methodology that could be used to calculate a monetary value associated with accumulated kWh credits. Other methodologies could be evaluated.

Appendix 10.1 provides an analysis of accumulated excess kWh credits and a methodology that could be used to quantify a monetary value associated with the accumulated kWh credit balance as of December 31, 2021.

To calculate a monetary value on the accumulated excess kWh credits requires a determination of the following: 1) How many of the kWh's are likely to be used and thus have value to the holder of the credits; and 2) What is the monetary value of each kWh?

The methodology used to estimate how many of the kWh's are likely to be used was to first look at the percent of accumulated kWh's that were aggregated and transferred over a historical three-year period (2018–2020) by customer class.

Using a three-year average, residential customers aggregated and transferred 14.98% of their accumulated kWh's; commercial customers aggregated and transferred 30.79% of their accumulated kWh's and irrigation customers aggregated and transferred 100% of their accumulated kWh's.

These percentages were then applied to the December 31, 2021, accumulated excess kWh credit balances by customer class and, in total, an estimated 7.5 million kWh's are likely to be used and have value to the holder of the credits.

To calculate the monetary value of each kWh, the result was multiplied by each customer class's average energy rate. The average energy rate was selected because the accumulated kWh credits can only be used to offset the energy components of a customer bill. Using this methodology results in monetary value to the customers holding the credits of $548,675.
It should be noted that when these excess kWh credits are used there is a reduction in customer usage which results in costs to other customers through the Fixed Cost Adjustment (FCA) and the Sales Based Adjustment Rate (SBA). Under this methodology there is a calculated cost to other customers of $290,116 if 7.5 million accumulated excess kWh's were used.

10.1.2.2 Review of Expiration of Accumulated kWh Credits

As can be seen on Appendix 10.1, of the 17.1 million accumulated excess kWh's, 2.1 million are from non-legacy systems. To facilitate the transition from a one-for-one kWh credit approach to a financial credit approach for non-legacy systems, these accumulated excess kWh credits could be exchanged for financial credit. The kWh credits could expire at the time the customer holding the credits is moved to a financial credit compensation structure and in exchange the customer could receive a financial credit.

Other methods could be considered for implementation, such as not exchanging the accumulated excess kWh credits for non-legacy systems. Rather, they could continue to be used to offset net consumption until they are exhausted.

Additionally, legacy systems or non-legacy systems could be provided the option to exchange their accumulated kWh credits for financial credits. This could be beneficial for customers that may not be able to utilize all of their accumulated kWh credits.

In this section, the company presents a methodology that could be used to calculate a monetary value, benefit to other customers and benefit to Idaho Power assuming the

2.1 million non-legacy accumulated kWh credits are exchanged for financial credits.
Other methodologies could be evaluated.

In recognition that excess accumulated kWh's benefitted the system at the time they were created, the accumulated kWh's could be compensated at the Export Credit Rate and recovered through the PCA similar to how the study anticipates the cost of export credits would be recovered (see section 8.1). Because Idaho Power does not have information that is granular enough to determine if excess kWh's were accumulated during on peak or off-peak periods the use of non-time variant export credit rates is appropriate. Using the same flat ECR value as Section 6 of $0.03781 per kWh, results in a cost to the PCA of $77,823. Appendix 10.1 also shows the PCA cost using other ECR values from Appendix 4.16.

Benefit to Other Customers

Other customers would pay this cost through the PCA. However, because the excess kWh credits would not be used as a reduction in customer usage, the cost would be offset by a reduction in the FCA and SBA (as more fully described in Section 10.1.2.1). Appendix 10.1 calculates a net benefit to other customers of $76,759 if the non-legacy systems accumulated excess kWh's were expired and compensated at a flat ECR.

Benefit to Idaho Power

If the excess kWh credits were expired and not used to offset customer usage, Idaho Power would benefit by collecting the average energy rate for the usage not offset. However, this benefit would be reduced by less FCA, and SBA amounts being collected. Appendix 10.1 calculates a net benefit to the company of $45,433.

10.1.3 Review of Financial Credits Transfer & Expiration

Under the current offering, customers are allowed to transfer accumulated excess kWh credits annually, so long as they meet certain requirements[58] and the account subject to offset is held by the customer. Accumulated excess kWh credits are non-transferrable in the event the customer relocates and/or discontinues service at the point of delivery associated with the Exporting System. Any unused credits expire at the time the final bill is prepared.

For customers with non-legacy systems that would receive financial credit, the financial credit could be transferred annually to any account(s) held by the customer. Customers could submit requests to transfer financial credits between January 1 and January 31 of each year. Consistent with current practice, requests would need to be received by Idaho Power by midnight, Mountain Standard Time, on January 31. Requested transfers would be executed by

[58] I.P.U.C No. 29, Tariff No. 101 Schedule 84 Customer Energy Production Net Metering Service

the company no later than March 31. Financial credits should also 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.

10.2 Access to Data

Idaho Power currently provides information to help customers make informed decisions with regards to on-site generation, including access to data needed to evaluate the economics of an onsite generation system. As illustrated below, customers have access to hourly data for their account that would allow them to evaluate a potential system under the existing Net Energy Metering with a monthly measurement interval, as well as under a Net Billing compensation structure as illustrated in Section 6 and Appendix 3.2.

Information is located at idahopower.com/customergeneration, which is accessed thousands of times each year.

2021 Webpage Total Views:

- Investing in Solar — Idaho Power: 3,763
- Understanding Customer Generation — Idaho Power: 6,290
- Frequently Asked Questions — Idaho Power: 4,556
- Pick the Right Solar Installer — Idaho Power: 2,576
- Apply to Connect Your System — Idaho Power: 3,753
- Beware of Misinformation and Scams — Idaho Power: 1,362

Customers can also access information through customer facing employees who are available to answer questions by phone, email and in-person.

Information includes:

Customer Energy Usage: Through MyAccount, customers can access monthly usage data and download one year of hourly usage information. Customers can also print bills which include meter numbers, current rate schedules and monthly billing demand.

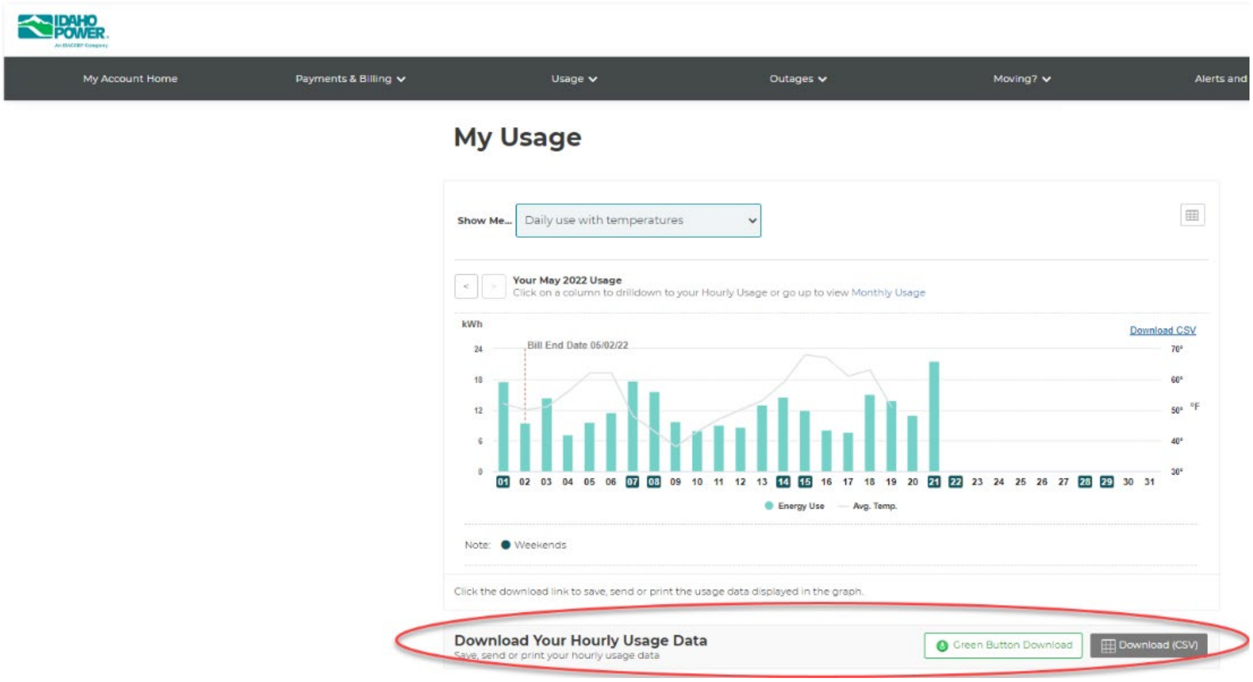

Figure 10.2
Idaho Power MyAccount webpage example for downloading hourly usage data

Rates: Current utility rate schedules are available at Rates and Regulatory — Idaho Power. Estimated annual fuel prices increases are published in the Integrated Resource Plan and is also shared in the Customer Generation-Frequently Asked Questions.

Solar Energy Information: Idaho Power cites technological data that may be helpful to customers on idahopower.com/customergeneration including typical solar PV system degradation rates, O&M costs and asset life. Data cited is sourced from the National Renewable Energy Lab and U.S. Department of Energy and embedded in the Frequently Asked Questions portion of the site.

Hourly Energy Production: Idaho Power's website includes links to PV Watts, a free tool by the National Renewable Energy Laboratory, that customers or installers can use to estimate total monthly or hourly solar generation based on a customer's unique set up factoring in system size, module type, and configuration.

Sample Payback: In addition, Idaho Power provides an example of a typical home's potential payback on a net monthly and net hourly scenario. Assumptions for this calculation are posted at Frequently Asked Questions — Idaho Power under the question, "What data and assumptions are used for the two solar payback examples?"

Interconnection Requirements: Idaho Power provides details such as technical specifications, application process, forms and timelines and tariff schedules. This information can be found at

[Understanding Customer Generation — Idaho Power](). Information also includes updates on open cases that may affect the on-site generation tariffs and pricing.

Pricing for Customers with On-site Generation

At the direction of the Idaho Public Utilities Commission (IPUC), Idaho Power is performing a study of the costs and benefits of on-site generation on Idaho Power's system. The study is expected to be complete in 2022. The Commission-approved study will inform proposed modifications to the pricing structure for customers with on-site generation during the implementation phase of the process. Case documents are available on the IPUC website (IPC-E-21-21).

Idaho Power's on-site generation tariffs, as with all other tariffs, are not contracts and are subject to change at any time upon order of the IPUC. Changes to the on-site generation tariffs in the future may include, but are not limited to, modifications to rates, billing components, billing structure, compensation structure, and the value for excess energy produced by the customer's on-site generation system (and thus, the amount a customer would be compensated). This is consistent with the Idaho Residential Energy System Disclosure Act, which requires solar retailers to provide a disclosure reminding potential customers that legislative or regulatory actions can affect or eliminate one's ability to sell or get credit for any excess power generated by the system and may affect the price or value of that power.

Figure 10.3
Idaho Power webpage 'Understanding Customer Generation'

Other Areas of Study – Supporting Appendices

Appendix 10.1
Net Metering Excess kWh Valuation and Expiration Scenarios

Note: All appendices can be accessed at www.puc.idaho.gov under Case No. IPC-E-22-22.

11. Implementation Considerations

11.1 Transitional Rates

As part of the study review and implementation phase, the public, stakeholders, and the Commission will have an opportunity to review the study and assess the impact of changes to the on-site customer-generator service offering. The study does not propose a specific proposal for implementation. Instead, the company anticipates stakeholders will use the data contained in the study to present methods for the Commission's consideration for implementation. Included with proposed implementation methods for non-legacy customer-generator systems, the Commission could direct proposals to address transitional rates. For example, the Commission could evaluate if it should cap the average customer impact. If so, the Commission could assess proposals for transitional rates over a given number of years to transition non-legacy systems from the retail rate to a Commission-approved ECR under Net Billing.

11.2 Administrative Updates and Communication Materials

As discussed in further detail throughout the study, there are several modifications that may be appropriate to the on-site customer generation offering. Ultimately, the Commission will evaluate what changes could be implemented in the near-term and what changes might be more fully explored in a future general rate case or other proceeding. While the Commission will ultimately determine what the appropriate timing and scope of future changes will be, the study outlines several considerations below that will need to be addressed in advance of the effective date of those changes. After authorization of any changes to the on-site customer generation offering, an implementation schedule would allow for the following activities to be completed.

11.2.1 System Changes

Idaho Power’s existing meters are capable of measuring consumption and excess net energy on a net hourly or a real-time basis. As such, there are no changes required to the metering infrastructure if the Commission determines a Net Billing compensation structure is appropriate. Idaho Power’s billing system is capable of performing Net Billing (either hourly or real-time); however, some configuration would be required to implement that functionality. For example, if a real-time actual market price is selected for the avoided energy component of the ECR, Idaho Power would need to ensure adequate testing of system changes to compensate customer-generators for real-time actual market prices. Idaho Power would also need to re-design the bill and ensure customers have access to billing data via the company’s online portal, My Account.

11.2.2 Tariff Changes

Idaho Power anticipates changes to Schedules 6, 8, 68, and 84 may be required as a result of a Commission order directing modifications to the on-site customer generation offering.
For example, changes to the measurement interval and compensation structure will require changes to Schedules 6, 8, and 84, and may necessitate a new tariff schedule that could contain the various components of the Export Credit Rate authorized to be applied against all excess net energy exported to the grid. As described in more detail in Section 9, modifications to the project eligibility cap would require changes to Schedule 68, which may include expanded interconnection study requirements.

Idaho Power would likely endeavor to hold technical workshops with Commission Staff, installers, and other interested stakeholders to discuss proposed interconnection requirements prior to submitting tariff changes for the Commission's review and approval in advance of an ordered effective date.

11.2.3 Customer Communication

Robust customer communication will be necessary prior to implementing any modifications to the on-site customer generation offering. Idaho Power would ensure customer service and other customer-facing employees are adequately trained to respond to customer inquiries in advance of when customer communications detailing the changes are distributed. Idaho Power would communicate with all customers with existing non-legacy systems to inform them of the changes and provide information about how they will be impacted by the changes.

The materials contained on Idaho Power's website would be updated to describe any changes to the on-site generation offering and any educational tools or materials will be created.

11.2.4 Installer Communication

Idaho Power has more than 50 installers known to be operating in its service area and communication to those installers is critical to ensure they know how Idaho Power's customers will be impacted by changes to the on-site customer generation offering. Idaho Power would develop written communication and host educational workshops with the installers to communicate information related to changes to the on-site customer generation offering.