Attachment No. 1

Rocky Mountain Power's On-Site Generation Study

Rocky Mountain Power | Pacific Power

ROCKY MOUNTAIN POWER'S ON-SITE GENERATION STUDY

PAC-E-19-08 Net Metering IPUC Order No. 34753

June 2023

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ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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Item Number	Subject	Order No. 34753 – Attachment A: Scope of Rocky Mountain Power's On-Site Generation Study	Location in Study
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Item Number	Subject	Order No. 34753 – Attachment A: Scope of Rocky Mountain Power's On-Site Generation Study	Location in Study
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Item Number	Subject	Order No. 34753 – Attachment A: Scope of Rocky Mountain Power's On-Site Generation Study	Location in Study
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Glossary

90/110 performance band – A PURPA generator’s energy deliveries plus or minus 10% from its forecasted performance.

Automated Meter Infrastructure (AMI) – Integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers.

Distributed Energy Resource (DER) – A small-scale supply or demand resource that is usually situated near sites of electricity use.

Energy Imbalance Market (“EIM”) – The EIM automatically balances demand every five minutes with the lowest cost energy available across the participating grids.

Export Credit Rate (ECR) – The total credit to the customer once a customer’s generation is netted by either real-time billing or interval netting.

Flexible Reserve Study (FRS) – Estimates the regulation reserve required to maintain PacifiCorp’s system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards as well as the incremental cost of this regulation reserve.

Instantaneous Billing – Method of calculating customer-generator billing where the customer’s financial credit for exports and the customer’s retail charges are calculated separately and the net result is either charged or credited to the customer.

Integrated Resource Plan (IRP) – The IRP is a comprehensive decision support tool and roadmap for meeting the company's objective of providing reliable and least-cost electric service to all our customers. Developed with involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders the IRP focuses on the first 10 years of a 20-year planning period and includes the preferred portfolio of supply-side and demand-side resources to meet this need. PacifiCorp prepares its integrated resource plan on a biennial schedule, filing its plan with state utility commissions during each odd numbered year.

Integration Costs – The additional expense when variable energy resources are added to a portfolio. Typically includes costs related to the uncertainty and variation in variable energy resource output from moment to moment. For distributed resources, integration costs could potentially include equipment and/or operational changes to manage impacts on the distribution system.

Interval Netting – Method of calculating customer billing where the total electricity consumed and generated is calculated for a given interval and the output of that calculation is included on a customer’s bill.

Line Losses – Loss of electricity due to the resistance of the conductor, or line, against the flow of the current, or electricity.

Loss of Load Probability ("LOLP") – Likelihood of a risk of loss of load event where system load and/or reserve obligations could not be met with available resources.

Net Billing – As defined by Electric Service Schedule 136, charges for all electricity supplied by the Company and netted by the export credit for the electricity generated by an eligible customer and fed back to the electric grid over the applicable billing period. Net billing differs from net metering because net billing customers do not get a credit in kWh but instead all net energy exports are credited to the customer at the exported customer-generated energy credit rate.

Net Metering – As defined by Electric Service Schedule 135, the difference between the electricity supplied by the Company and the electricity generated by an eligible customer and fed back to the grid over the applicable billing period. Net metering may also refer to on-site generation or a distributed energy resource in general.

The Public Utility Regulatory Policies Act of 1978 ("PURPA") – Enacted following the energy crisis of the 1970s to encourage cogeneration and renewable resources and promote competition for electric generation.

Qualifying Facility ("QF") – a generation facility that meets certain ownership, operating, and other criteria established by the Federal Energy Regulatory Commission ("FERC") according to the Public Utility Regulatory Policies Act of 1978 ("PURPA")

Renewable Energy Certificates ("RECs") – The property rights to the environmental, social, and other non-power attributes of renewable electricity generation. RECs are issued when one megawatt-hour (MWh) of electricity is generated and delivered to the electricity grid from a renewable energy resource.

Surrogate Avoided Resource ("SAR") Methodology – Method for determining avoided costs for standard qualifying facility resources up to at least 100 kW in nameplate capacity. Under the SAR Methodology, avoided energy costs reflect forecast prices for natural gas and the assumed heat rate of a combined cycle combustion turbine. Monthly weighting factors are used to differentiate avoided costs by month, and an adjustment of 85 percent is applied to non-firm resources.

1.0 Executive Summary

Rocky Mountain Power, a division of PacifiCorp ("PacifiCorp" or the "Company") presents this study ("Study") to evaluate methods, inputs, and assumptions for valuing on-site generation that is exported to the grid. The Idaho Public Utilities Commission ("Commission") approved the scope of this study ("Study Scope") of on-site generation on August 26, 2020.[1]

The Study provides the Commission and stakeholders with the information needed to evaluate changes to the export credit rate ("ECR") for on-site customer generators in the future. The purpose of this Study is not to propose a specific ECR at this time but to initiate a review and obtain feedback on potential considerations for valuing an ECR.

The Study gives a snapshot of its current approximately 2,200 on-site customer generation customers in Idaho. Data for modeling different components of the ECR was based on proxy Utah customers in the same climate zone as Idaho customers.

The effects of netting imports monthly, hourly, and instantaneously were analyzed to show the revenue requirement impact for each scenario. As guided by the Commission's Study Scope, the avoided cost of exported energy was calculated using the same price assumptions as the Company's most recently acknowledged integrated resource plan ("IRP") and the capacity value of exported energy was analyzed using the loss of load probability ("LOLP") study. The avoided capacity value of on-site generators was modeled during PacifiCorp's highest risk-of-loss-of-load-event hours to evaluate potential contribution of on-site generation during the grid's most strained hours. Different export credit scenarios were analyzed to show the annual export costs at various ECRs. The Study concludes by looking at the different implementation issues for an ECR including how different customers would be affected by expired credits and the effects of updating the ECR at different frequencies.

2.0 Introduction

2.1 Current Net Metering Summary

As of December 31, 2022, there are 2,196 on-site generating customers connected to PacifiCorp's system in Idaho. The majority of those customers are residential using solar photovoltaic ("PV") systems. There are also 61 wind generation customers and five customers with a mix of electricity sources or with hydro generators.

[1] *In the Matter of the Application of Rocky Mountain Power to Close the Net Metering Program to New Service & Implement a Net Billing Program to Compensate Customer-Generators for Exported Generation.* Case No. PAC-E-19-08, Order No. 34753.

Table 2.1: Idaho On-Site Generation Customer Count as of 12/31/2022

Customer Type	Solar PV	Wind	Mixed/ Other	Total
Residential	2,055	54	5	2,114
Small Commercial	63	5	-	68
Large Commercial	8	2	-	10
Irrigation	4	-	-	4
Total	**2,130**	**61**	**5**	**2,196**

Net metering customers participate in the Company's customer generation programs through Schedules 135 or 136. Residential and general service customers taking service on Schedules 1, 23, 23A, or 36 must not have a generating capacity greater than 25 kilowatts (kV). All other customers are limited to a generating capacity of 100 kW. Schedule 135 closed to new applicants as of October 2, 2020. The average size of a residential customer's solar PV system is 8.1 kW, as of December 31, 2022.[2]

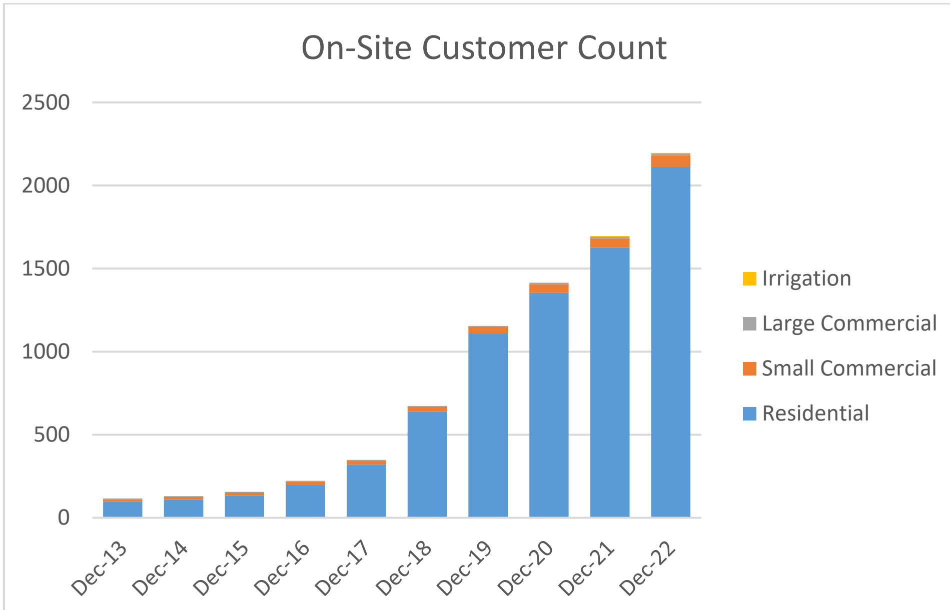
Table 2.2: Average Size of On-Site Generation Customer's System

Customer Type	Solar PV kW (average)	Wind kW (average)	Mixed/Other kW (average)
Residential	8.1	3.75	12.35
Small Commercial	16.95	9.44	-
Large Commercial	44.74	2.4	-
Irrigation	21.58	-	-
Weighted Average	**8.51**	**4.17**	**12.35**

On-site generation customer growth has increased steadily over the last 10 years with an annual average growth rate of 40%. While customer growth has moderated slightly during the last 3 years in percentage terms, 2022 saw the most on-site customers connecting to the system with a total of 500 new customers added.

[2] For more detail on the customer size, generation type, and customer system size, see the system size tab of Appendix 11.2: Idaho Expired Credit Analysis 2012-2022.

Figure 2.1: On-Site Generation Customer Adoption



2.2 Regulatory History

PacifiCorp began offering Electric Service Schedule 135 - Net Metering Service, in 2003, as approved by Order No. 29260 in Case No. PAC-E-03-4. The case was initiated following a petition by the NW Energy Coalition which requested a net metering schedule in Idaho following approval of net metering schedules for Idaho Power Company and Avista. In that case, PacifiCorp proposed Schedule 135, which was patterned from Idaho Power's net metering Schedule 84.

Schedule 135, as approved by Order No. 29260, limited participation on Schedule 135 to no more than 25 kilowatts for customers taking service on Schedules 1, 36, 23, or 23A and to 100 kilowatts for all other customers. Customers taking service on Schedules 1, 36, 23 or 23A were to be credited for excess net energy at the customer's standard service rate and all other customers would be credited net excess energy at a rate that equals 85 percent of the monthly weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Electricity Price Index (Dow Jones Mid-C Index).

On June 14, 2019, PacifiCorp submitted an application to close Electric Service Schedule 135 and to implement a net billing program to compensate customer-generators for exported generation.[3] On August 26, 2020, the Idaho Public Utilities Commission issued Order No. 34753 which required this on-site generation study to be completed. On October 2, 2020, the Idaho Public Utilities Commission issued Order No. 34798 initiating Electric Service Schedule 136 - Net

[3] *See In the Matter of the Application of Rocky Mountain Power to Close the Net Metering Program to New Service & Implement a Net Billing Program to Compensate Customer-Generators for Exported Generation.* Case No. PAC-E-19-08.

Billing Service. Order No. 34798 also adopted Order No. 34752, which granted existing Electric Service Schedule 135 customers grandfathered status for a period of 25 years.

3.0 Netting Period

3.1 Summary of Instantaneous, Monthly, and Hourly Billing

There are three different methods of "netting" that may be used to calculate the amount of electricity that a customer consumes and exports: instantaneous, hourly, and monthly. In a "real time" or "instantaneous" calculation, the meter exports and consumption are measured separately. With instantaneous netting, all of the consumption from the electric grid is measured and charged the retail rate and all exports to the electric grid are also measured and credited to the customer.

Interval netting, on the other hand, does not calculate instantaneously but instead calculates the total net electricity consumed or generated over the specified interval. While on first look it may appear that instantaneous and interval netting would result in similar outcomes, this is not the case. To the extent a customer was consuming power from the electric grid during part of an hour, and exporting during the rest of an hour, hourly netting would result in an equal reduction to both consumption and exports, relative to instantaneous netting. With monthly netting, even larger amounts of consumption and exports can be offset, as the customer's consumption may be days or weeks earlier or later than their exports.

Using an interval over which exports and imports are netted masks the intertemporal reality of the service that Rocky Mountain Power provides. One benefit of a net billing program without interval netting is that it sends a price signal for customer-generators to align their usage with their generation output. This can benefit other non-participating customers by accurately accounting for the load that the customers with generation draw from the system. Netting over an interval period, such as 15 minutes or an hour, sends a weaker price signal for customer-generators to match usage with generation. With the scale of customer generation that has been adopted in the Company' service territory, encouraging alignment of loads with intermittent generation has never been more important. When a cloud rolls by an area where extensive customer generation is present, their energy production will suddenly drop, and the Company must provide the power demanded. Indeed, every fraction of a second the Company must serve the load requirements of its customers as loads fluctuate in real time. Sending a robust price signal to match customer generation with load as in the net billing program provides a greater opportunity for customer-generators to benefit the system.

3.2 Class Revenue Requirement

The tables and analysis below address Study Scope Item 1.

Study Scope Item 1

Calculate the class revenue requirement if each of the existing customer-generators netted their energy exports: a. Monthly b. Hourly c. Instantaneously

To estimate the revenue requirement for each of the netting regimes listed for the Study, the Company analyzed the monthly billing and metering data from customer-generators in 2022 from which the Company could determine values for the monthly netting and instantaneous netting scenarios. The Company did not include irrigation customer-generators, because there were only two irrigation customers with on-site generation, and they did not have a full 12 months of revenue in 2022.

Automated meter infrastructure ("AMI") installations are being finalized during the second quarter of 2023 and the Company does yet not have enough hourly profile data available for customer-generators in Idaho for hourly loads. Instead, the Company used proxy profile data from its customer-generators in northern Utah which are in the same climate zone as the Company's Idaho service territory. To estimate hourly netting values, the monthly percentage differences in hourly as compared to instantaneous netting from the Northern Utah dataset were applied to metered data from Idaho customer-generators. The following table 3.1 shows the exported energy volumes under each netting scenario in total and also expressed as a percentage of generation:

Table 3.1: Comparison of Generation to Exports under Different Netting Scenarios

Export and Generation (kWh)	a. Monthly Netting	b. Hourly Netting	c. Instantaneous Netting	d. Generation
Residential Sch 1	2,111,780	8,062,620	8,554,724	16,422,970
Residential Sch 36	551,492	2,058,027	2,182,649	4,124,398
General Service Sch 23	244,599	534,099	565,335	1,512,638
General Service Sch 6	58,760	116,414	123,320	522,963
Total	**2,966,631**	**10,771,161**	**11,426,028**	**22,582,969**

Export % of Generation	a. Monthly Netting	b. Hourly Netting	c. Instantaneous Netting	d. Generation
Residential Sch 1	13%	49%	52%	100%
Residential Sch 36	13%	50%	53%	100%
General Service Sch 23	16%	35%	37%	100%
General Service Sch 6	11%	22%	24%	100%
Total	**13%**	**48%**	**51%**	**100%**

To estimate the revenue requirement impact by class of different netting scenarios, the Company estimated the change in revenue from traditional net metering. Increased revenue from the class lowers the overall revenue requirement. Assuming a generic 3¢ per kWh export credit, the Company estimates the following revenue requirement changes from traditional net metering (increased net revenue from customer generation participants) for the different netting scenarios:

Table 3.2: Revenue Requirement Changes from Traditional Net Metering

Revenue	a. Monthly Netting	b. Hourly Netting	c. Instantaneous Netting	d. Traditional Net Metering
Residential Sch 1	$1,253,784	$1,716,364	$1,756,739	$1,090,937
Residential Sch 36	$384,917	$462,434	$468,933	$333,476
General Service Sch 23	$156,402	$172,883	$174,728	$141,635
General Service Sch 6	$296,204	$296,925	$297,011	$295,469
Total	$2,091,307	$2,648,606	$2,697,411	$1,861,517
Revenue Requirement (Δ from Traditional Net Metering)	-$229,791	-$787,089	-$835,895	-

Based on Table 3.2 above, monthly netting would result in $230k reduction in the revenue requirement when compared with traditional net metering, meaning that an additional $230k is recovered from customer generators and not required from other customers. Hourly netting would see a larger $787k reduction and instantaneous netting would see a $836k reduction in the revenue requirement when compared with traditional net metering.

3.3 Class Export Payment

In addition to the class revenue requirement, the Study Scope required the Company to calculate the export credits for each class at different intervals.

Study Scope Item 2

Calculate the total class export credit payments if each of the existing customer-generators net their energy exports:

a. Monthly
b. Hourly
c. Instantaneously

Using the same assumptions as the revenue requirement analysis above, the Company estimates the following class export payments for the different netting scenarios.

Table 3.3: Export Payments by Class

Export Credit Payments	a. Monthly Netting	b. Hourly Netting	c. Instantaneous Netting
Residential Sch 1	$63,353	$241,879	$256,642
Residential Sch 36	$16,545	$61,741	$65,479
General Service Sch 23	$7,338	$16,023	$16,960
General Service Sch 6	$1,763	$3,492	$3,700
Total	**$88,999**	**$323,135**	**$342,781**

3.4 Bill Impacts

The Study Scope required the Company to calculate the bill impacts to existing customer-generators.

Study Scope Item 3

Analyze bill impacts to existing customer-generators, stratified by usage, if energy exports are netted:

a. Monthly
b. Hourly
c. Instantaneously

Using the same assumptions from the previous sections, the Company estimates the following average bills for the different netting scenarios.

Table 3.4: Bill Impacts by Class

Average Bill	a. Monthly Netting	b. Hourly Netting	c. Instantaneous Netting	d. Traditional Net Metering
0 - 500 kWh	$14.49	$44.44	$47.28	-$2.66
501 - 1,000 kWh	$77.92	$97.97	$99.38	$77.49
1,000 - 1,500 kWh	$128.66	$144.73	$145.83	$128.55
1,500 - 2,000 kWh	$179.33	$193.98	$194.99	$179.33
2,000 - 3,000 kWh	$247.76	$261.38	$262.37	$247.76
3,000 - 5,000 kWh	$372.39	$383.30	$384.07	$372.39
5,000 kWh - 10,000 kWh	$624.67	$632.67	$633.28	$624.67
10,001 kWh+	$2,553.63	$2,559.70	$2,560.04	$2,553.63
Average	**$91.18**	**$115.48**	**$117.61**	**$81.16**

3. 5 Administrative Costs

Instantaneous billing provides administrative benefits compared to interval netting. Using the meters for exported and delivered energy instead of relying upon profile data to bill customers is less administratively burdensome for the Company. Without netting, the Company's meters simply record energy delivered and energy exported and send those registers to the Company's billing system to calculate a bill for the customer. While the Company has automated much of the process for billing customers taking service on Schedule 136 , based upon 15-minute intervals, there still is some backend manual work that is required to accurately bill customers. 15-minute interval netting requires profile data for each meter which on average includes 2,920 reads for each monthly billing period. Most of the time, there are no issues with this data, but when there is, Company employees must resolve it. Some of the issues that may require intervention include:

- Meter aggregations require manual calculation using a billing calculation sheet. The Company estimates 0.25 – 0.50 hours per month aggregating meter data depending on number of meters involved.
- Interval data issues such as from gaps in data or when meters are exchanged also require manual reconciliation. It is hard to quantify the time spent on missing data as it only occasionally happens and now AMI exchanges are mostly complete in Idaho. Going forward, meter exchanges will happen less frequently. Assuming a one percent failure of billings each year and 0.5-1.0 hours to resolve for each 100 customers in net billing, then the following time requirement is estimated:

    100 customers x 12 billings = 1200 x 1% = 12 accounts x 0.5 – 1.0 hour = 6 - 12 hours annually

At the current volume of 2,200 customer-generators, this would scale to a 132 to 264 hours of activity per year for the Company. In addition, using total exported energy and total delivered energy in the billing calculation is a simpler concept to explain to customers than netting over each 15-minute or hour interval. It is much easier for someone to understand that all energy sent to the grid will get a certain export price and all energy delivered to the customer will be billed at standard tariff rates than to describe how energy is netted in every interval period.

4.0 Export Credit Rate

The ECR determines the total credit to the customer once a customer's generation is netted by either real-time billing or interval netting. The ECR is established through a method that looks at the costs the Company avoids as a result of the exported energy. These costs are broken into five parts:

- Avoided Energy Costs
- Avoided Capacity or Generation Costs
- Avoided Fuel Risk Costs
- Avoided Transmission and Distribution Costs
- Avoided Line Losses

Once all the costs from the parts listed above are combined, they are adjusted to account for the costs incurred by integrating the customers into the system. A summary of these costs by component is provided in table 4.1 below, and descriptions of each component are provided in the following sections. Note that these values have not been adjusted to reflect the reduced value of non-firm deliveries, as discussed in Section 4.3.2.

Table 4.1: Summary of Export Credit Costs

¢/kWh Year	IRP Energy Value (Forecast)	*EIM Energy Value (Actual)*	Risk Value	LOLP Gen Capacity	LOLP Trans Capacity	LOLP Dist Capacity	Line Losses	Integration Cost	Total Export Credit
2021	4.08	*2.83*	0.00	0.00	0.03	0.07	0.29	-0.02	4.44
2022	3.38	*4.35*	0.71	0.00	0.03	0.07	0.29	-0.02	4.46
2023	3.25		0.51	0.00	0.03	0.07	0.27	-0.61	3.53
2024	1.99		0.08	0.00	0.03	0.07	0.15	-0.19	2.14
2025	2.03		0.03	0.00	0.03	0.07	0.15	-0.12	2.19
2026	2.01		0.02	0.40	0.03	0.08	0.18	-0.09	2.62
2027	2.12		0.02	0.40	0.03	0.08	0.19	-0.24	2.60
2028	2.34		0.03	0.41	0.03	0.08	0.21	-0.23	2.86
2029	2.84		0.02	0.41	0.03	0.08	0.24	-0.04	3.58
2030	2.99		0.02	0.42	0.03	0.08	0.25	-0.05	3.74
2031	3.07		0.02	0.42	0.03	0.08	0.26	-0.02	3.86
2032	3.16		0.02	0.43	0.03	0.09	0.27	-0.03	3.97
2033	3.18		0.02	0.43	0.03	0.09	0.27	-0.01	4.01
2034	3.34		0.02	0.44	0.03	0.09	0.28	-0.01	4.19
2035	3.47		0.02	0.44	0.03	0.09	0.29	-0.01	4.34
2036	3.80		0.02	0.45	0.03	0.09	0.31	-0.01	4.70
2037	4.43		0.03	0.45	0.04	0.10	0.36	-0.005	5.40
2038	5.22		0.10	0.46	0.04	0.10	0.42	-0.005	6.33
2039	5.68		0.09	0.46	0.04	0.10	0.45	-0.005	6.82
2040	5.53		0.11	0.47	0.04	0.10	0.44	-0.03	6.66

4.1 Modeled Data as a Proxy for Actual Customer Export Data

In relation to using modeled data as a proxy for actual customer data, the Study Scope asked for a date when a full year of hourly AMI export data will be available.

Study Scope Item 4

Confirm when a full year of hourly AMI export data will be available for customer-generators.

As of April 27, 2023, deployment of AMI meters in Idaho is 97 percent complete. A full year of hourly AMI export data for Idaho customers for nearly all customer-generators will be available one year from this date.

4.2 Model Validation Method

The Study Scope required the Company to explain its method for verifying and validating the accuracy of its model and modeled customer data.

Study Scope Item 5

Explain the Company's method for verifying and validating the accuracy of its model and modeled customer export data.

As detailed in the discussion of the netting period, the export profiles were derived from a total census of customer-generators taking service on Schedule 136 in northern Utah that are in the same climate zone as the Company's Idaho service territory.

While the Company maintains a load research sample for Idaho customer-generators, the profile derived from Utah customers in northern Utah is more suited for this Study for several reasons. First, the Idaho customer generation load research sample was implemented in 2014 and sampled from a very different mix of customers than what we see today. Roughly one-half of the generation systems in the 2014 Idaho sample were wind; however, most customer-generator systems are now operating solar PV. Second, the Idaho customer generation load research sample consists of 44 sites and is subject to sampling uncertainty. A sample this size produces estimates with sampling errors of 10 to 20 percent. Estimates derived from a census of northern Utah customers are not subject to sampling error. Finally, the Company's northern Utah and Idaho service territories have similar climates and geographic characteristics. The Company used the International Energy Conservation Code (IECC) climate zone map to identify Utah customers in climates similar to that of the Company's Idaho service territory.[4] Nearly all Idaho customers are in climate zone 6B. The Company identified Utah customers taking service on Schedule 136 also in climate zone 6B and calculated an average export profile from these customers ("Northern Utah Customers").

To validate the accuracy of export profiles derived from a census of the Company's Northern Utah Customers, the Company first reviewed sources of statistical error and bias. Sampling and measurement error are two major sources of statistical error. By definition, estimates derived from a census are not subject to sampling error. Measurement errors are small—the Company purchases meters with accuracy certified by the manufacturer to be in compliance with the American National Standard Code for Electricity Metering (ANSI C12.1).

The Company also examined sources of bias. Estimates are biased if the population of interest is systematically different from the proxy used to represent that population. Possible systematic differences and sources of bias between these two groups include:

[4] See the 2021 International Energy Conservation Code (IECC) "Section C301 Climate Zones" for a map and a list of climate zones for each county. Counties in the Company's Idaho service territory are in climate zone 6B (cold and dry). https://codes.iccsafe.org/content/IECC2021P1/chapter-3-ce-general-requirements#IECC2021P1_CE_Ch03_SecC301

Differences in photovoltaic system sizes: If customer demand were otherwise equal, a larger photovoltaic system size would result in a greater portion of the total production of the system being exported, and smaller portion consumed onsite.

Differences in actual monthly exports and deliveries: Building size and the mixture of end uses can contribute to differences in total customer demand, which would contribute to a difference in actual monthly exports and deliveries. Higher full requirements consumption, with equal production, would result in lower exports.

Different amounts of solar irradiance and PV production in the two regions: Idaho customer-generators are concentrated primarily in counties surrounding Idaho Falls. This is 150 miles north of Logan, Utah, where most of the Northern Utah Customers are concentrated. Geographic differences could produce different levels of solar irradiance and PV production.

The Company first compared the installed capacity of customer generation systems of Northern Utah Customers and Idaho to determine if there was a systematic difference in system sizes. The Company found a small difference in system sizes—the installed capacity of Idaho customers' systems is 5.2 percent lower than the capacities of Northern Utah Customers. Table 4.2 presents the mean installed capacity for each of these groups.

Table 4.2: Northern Utah Customers and Idaho System Size (Installed Capacity)[5]

Population	Installed Capacity (kW)
Average Northern Utah Customers	9.0
Average Idaho	8.5
Percent Difference	***-5.2%***

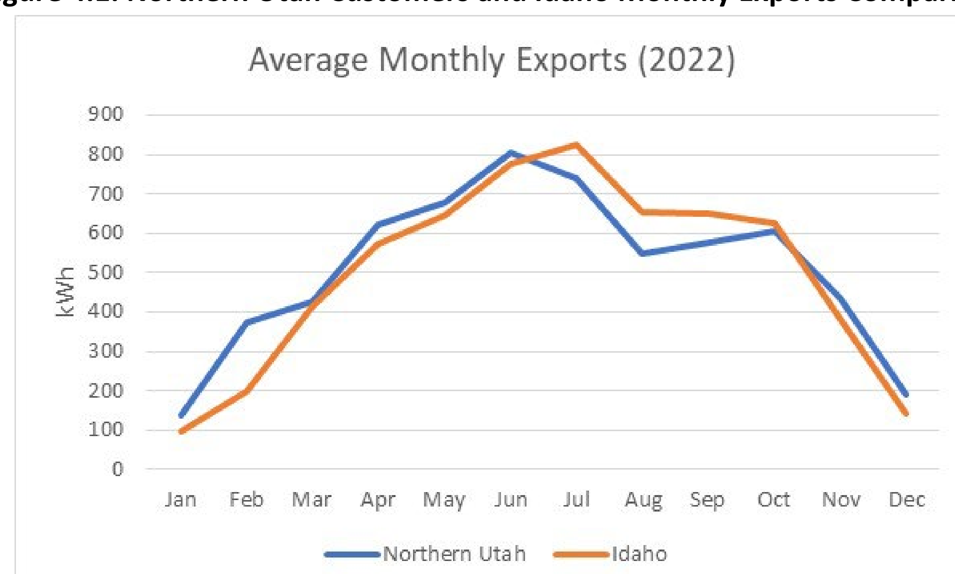
Next, the Company compared actual average monthly deliveries and exports from Idaho customer-generators against Northern Utah Customers in 2022. The distribution of exports across months for Idaho and Northern Utah Customers is similar as shown in Table 4.3 and Figure 4.1.[6]

[5] Supporting data provided in Appendix 4.4: Idaho Export Profile Validation Avg Capacity.
[6] Supporting data for Table 4.3 and Figure 4.1 provided in Appendix 4.5: ID Export Profile Validation Monthly Exports.

Table 4.3: Northern Utah Customers and Idaho Average 2022 Monthly Exports

Month	Average Exports (kWh)		12-Month Shape	
	Northern Utah	Idaho	Northern Utah	Idaho
Jan	139	95	2%	2%
Feb	375	199	6%	3%
Mar	426	412	7%	7%
Apr	621	572	10%	10%
May	677	644	11%	11%
Jun	804	776	13%	13%
Jul	741	824	12%	14%
Aug	549	655	9%	11%
Sep	575	651	9%	11%
Oct	607	625	10%	10%
Nov	434	383	7%	6%
Dec	189	143	3%	2%
Total	**6,136**	**5,980**	**100%**	**100%**

Figure 4.1. Northern Utah Customers and Idaho Monthly Exports Comparison



The Company found that Idaho customers exported slightly less than Utah customers in winter and shoulder months, while exporting more in summer months. The weighted average absolute difference in monthly exports between Idaho and Northern Utah Customers is approximately 11 percent (weighted by monthly exports).

Finally, the Company used PV production models to compare the hourly shape of systems in Idaho against those customers located in Utah climate zone 6B. This involved first determining the geographic concentration of customer-generators in Utah climate zone 6B and Idaho. Sixtynine percent of all the customer generation capacity in Idaho is concentrated in the counties surrounding Idaho Falls including Bonneville (37 percent), Jefferson (20 percent), and Madison (12 percent) counties. In Utah climate zone 6B, counties near Logan; Cache (33 percent), Summit (28 percent), and Box Elder (20 percent), account for 82 percent of the installed capacity.

The Company used the National Renewable Energy Laboratory's PVWatts[7] calculator to estimate the hourly solar PV production for a typical system located in Idaho Falls, ID and Logan, UT. PVWatts is a publicly available online calculator that estimates the amount of electricity produced by a typical PV system. It uses solar irradiance data and assumptions for latitude, longitude, array type, tilt, azimuth, and weather to estimate PV system output.

For each location, the Company estimated the hourly output of an 8 kW, south-facing, fixed array, standard crystalline silicon PV system with a 20-degree tilt. The Company then calculated each location's distribution of solar PV production across the year and within each month. The Company then summarized these profiles into 12-month by 24-hour shapes and calculated the Weighted Mean Absolute Percentage Error ("wMAPE") between the Idaho and Utah production profiles for each time interval. To understand the total difference across months and the hourly difference within months, two versions of wMAPES were calculated:

> **Monthly Weighted Mean Absolute Error**: This statistic captures differences in the total Utah and Idaho monthly across months. If one location produces more than another in a specific month, this wMAPE will be higher for that month.
>
> **Hourly Weighted Mean Absolute Error:** This statistic measures the difference between Idaho and Utah hourly production profiles within months. It compares the average 24-hour shape for each month, ignoring differences in production across months. If PV systems in one location produce more later in the day than the other, these wMAPEs will be higher.

Table 4.4 shows the wMAPES for each month from the monthly and hourly perspectives. Months with higher monthly wMAPEs have a larger difference in both total PV production for the month *and* across hours within the month. Months with higher hourly wMAPEs exhibit differences in 24-hour shapes (ignoring differences across months).

Winter months exhibit the greatest mean absolute percentage errors, which reflect both differences in latitude and the number of sunny days. This finding is consistent with the prior comparison of monthly exports. Overall, the wMAPEs are 7.9% across the year and 5.4% within months.

[7] See https://pvwatts.nrel.gov/

Table 4.4: Solar Production Difference - Weighted Mean Absolute Percentage Errors[8]

Month	Monthly Mean Absolute Percentage error	Hourly Mean Absolute Percentage Error
January	18.7%	14.0%
February	8.7%	9.5%
March	4.6%	4.7%
April	7.7%	3.9%
May	8.3%	7.4%
June	7.5%	3.5%
July	5.0%	2.4%
August	5.7%	4.7%
September	5.2%	3.9%
October	5.3%	3.9%
November	14.8%	8.3%
December	26.5%	13.8%
Weighted Annual Average	**7.9%**	**5.4%**

The Company concludes from this analysis:

- System sizes for Idaho customer-generators are like those of Northern Utah Customers. The Company found that the Idaho systems have installed capacities that are approximately 5 percent lower than northern Utah systems.
- Both models and actual monthly data indicate that winter months exhibit a larger difference in total PV production (greater than 10 percent wMAPE).
- Within months and across hours, the difference between the Logan and Idaho Falls production profiles is small—mostly less than 10 percent, on average.

The Company expects that differences in hourly export profiles between Northern Utah Customers and Idaho will be like the differences found in the Logan and Idaho Falls production profiles. While the Company expects a greater difference in exports in the winter months and a smaller difference in the summer months, its analysis indicates that the overall difference will be small.

4.3 Avoided Energy Value

To evaluate the best method for calculating the avoided energy value, the Study Scope requested the avoided energy value be calculated using the energy price assumptions in the Company's most recently acknowledged IRP.

[8] Supporting data provided in Appendix 4.6: ID Export Profile Validation PV Watts Production.

Study Scope Item 6

Calculate the avoided cost of exported energy using the energy price assumptions in the Company's most recently acknowledged Integrated Resource Plan ("IRP").

The Commission acknowledged the Company's 2021 IRP in August 2022. The 2021 IRP included a variety of price and policy scenarios, with the main scenario including a medium gas price forecast and medium greenhouse gas costs. These assumptions are embodied in hourly market price forecasts, based on input assumptions used in the Company's September 2020 official forward price curve. Within the IRP models, energy value varies by location because of transmission constraints and the balance of supply and demand. As a result, energy value in the Company's Idaho service territory will vary from the price at distant market points. With that in mind, for the purpose of calculating the energy value and cost-effectiveness of energy efficiency measures, the Company uses hourly marginal resource costs reported by its IRP models.

The Company notes that energy price assumptions in the 2021 IRP will be three years out of date in September 2023. The Commission's acknowledgment of the 2021 IRP does not touch upon these assumptions, so there is little basis to conclude that relying upon the outdated assumptions in the 2021 IRP is more aligned with Commission direction than a more recent forecast or actual historical results would be.

The Company also notes that there is an important relationship between customer generation exports and the Company's marginal costs that is not captured by the forward price curve. Specifically, customer generation exports will tend to be lower when customer load is high because a greater portion of the customer's production can be devoted to the customer's own needs under those conditions. If, for example, the customer's load is high because of effects that impact the system as a whole, such as regional weather conditions, this would manifest as lower exports when demand and energy costs are highest. This relationship between exports and system conditions is not reflected in the forecast modeled using 2021 IRP results, but it is present in historical data. Specifically, by weighting actual Energy Imbalance Market ("EIM") prices by the actual customer generation export volumes in each interval, an accurate representation of energy value can be identified. Because EIM prices are public, do not require complicated modeling assumptions, and more accurately capture the relationship between customer exports and system conditions, they are a strong candidate for identifying energy value. Energy values based on 2021 IRP results and historical EIM prices are presented in Table 4.1.

4.3.1 Supporting Documentation for Avoided Energy Value

The Study Scope requested the supporting documentation for the Company's avoided energy value calculation.

Study Scope Item 6(a)

Provide supporting documentation.

The 2021 IRP energy values shown in Table 4.1: Summary of Export Credit Costs reflect the value of customer exports using the hourly marginal energy prices for the Goshen location from the Company's 2021 IRP preferred portfolio results, which were also used for the Idaho energy efficiency cost-effectiveness evaluation. The EIM energy values shown in Table 4.1 reflect the value of customer exports using hourly average of historical EIM prices in the Real-Time Pre-Dispatch market (15-minute market) for the PacifiCorp East Load Aggregation Point location (a weighted average for load points in PacifiCorp's East Balancing Authority Area).

4.3.2 Supporting Documentation for Non-Firm Energy

The Study Scope requested the Company provide calculations and documentation showing why the avoided cost of exported energy produced by customer-generators should be valued at 85% of the total avoided energy value.

Study Scope Item 7

Provide the calculations and documentation showing why the avoided cost of exported energy produced by customer-generators should only be valued at 85% of the total avoided energy value.

Customer-generators are non-firm energy and should be valued at 85% of the total avoided energy value in line with the commission practices for pricing qualifying facilities ("QF"). Because customer-generators make no commitment to export particular volumes to the system, they are considered non-firm energy. An 85 percent adjustment is similar to current practices for both the surrogate avoided resource ("SAR") methodology when pricing qualifying facilities and for the customer generation net billing credit for PacifiCorp customers taking service on Schedule 135.[9]

However, the SAR Methodology does have some limitations since it does not have hourly detail. Based on this limitation, the Company recommends using EIM prices for the avoided energy value because it is available in a higher granularity and can be used to value the particular pattern of customer exports. Because EIM prices are set shortly before delivery, they do not have the same risk as firm delivery commitments made in advance and may not require as large of a non-firm adjustment as would be appropriate for a forward market product. EIM prices are

[9] In addition to the 85 percent adjustment made for non-firm energy under the SAR Methodology, Schedule 135's Net Metering Rate Credit for non-residential customers is calculated at 85 percent of the monthly weighted average of the daily on-peak and off-peak Mid-Columbia Intercontinental Exchange Electricity Price Index (Mid-C ICE Index) prices for non-firm energy.

also public, which allows for greater transparency, and reflect actual relationships between exports and prices, which can be difficult to assess in a forecast.

Idaho Regulatory History of SAR Methodology and Non-Firm Energy Pricing

The Commission has approved the SAR Methodology for determining avoided costs for standard qualifying facility resources up to at least 100 kW in nameplate capacity. Under the SAR Methodology, avoided energy costs reflect forecast prices for natural gas and the assumed heat rate of a combined cycle combustion turbine. [10]

In Order No. 29632, the Commission found that energy "delivered outside of the 90/110 performance band (i.e., non-conforming energy) would be priced at 85 percent of the *non-firm* market price or the contract price, whichever is less."[11] The non-firm market price has been found by the Commission to equal to the 82.4 percent of the firm market price.[12] Based on the foregoing, the formula for non-firm energy delivered outside the performance band can be expressed as:

*Non-firm market price outside of performance band = 85% * non-firm market price; where*

*Non-firm market price = 82.4% * firm market price*

The Company agrees with a non-firm market price adjustment and will explain why non-firm energy is less valuable than firm energy in more detail below.

Firm Energy and Non-Firm Energy Characteristics

To better understand how the customer-generators differ from firm market transactions, it is helpful to understand some key aspects of firm market transactions. At present, most firm market transactions reflect a limited set of market products such as:

- Blocks of hours at a constant volume, typically Heavy Load Hours (HLH), Light Load Hours (LLH), or all hours.[13]
- Monthly products (covering every day in a month) are available prior to the start of a month, while transactions for individual days are only available a day or two before delivery.
- Typically traded in increments of 25 MW.

[10] *In the Matter of the Commission's Review of PURPA QF Contract Provisions Including the Surrogate Avoided Resource and Integrated Resource Planning Methodologies for Calculating Avoided Cost Rates*, Case No. GNR-E-Il-03, Order No. 32697 at 7-8 (Dec. 18, 2012).
[11] *In the Matter of Rocky Mountain Power's Application for Approval of Power Purchase Agreement between PacifiCorp and Birch Hydro Company*, Case No. PAC-E-20-07, Order No. 34889 at 2 (Jan. 14, 2021).
[12] *In the Matter of Rocky Mountain Power's Application for Approval of Power Purchase Agreement between PacifiCorp and Birch Hydro Company*, Case No. PAC-E-20-07, Order No. 34889 at 2 (Jan. 14, 2021).
[13] HLH is 6:00 a.m. to 10:00 p.m. (Pacific Prevailing Time) Monday through Saturday, excluding certain holidays. LLH is all other hours, namely 10:00 p.m. to 6:00 a.m. nightly, and all day on Sundays and holidays.

- Only a few locations have many market participants, such as Mid-Columbia or Palo Verde. Few entities are available at most delivery points, and they may not have interest in transacting for a given product.
- Such market products are considered firm because the seller is subject to costs for damages if it fails to provide deliveries as agreed.

Exports from customer-generators vary significantly from market products. Customer-generators exports:

- Vary from moment to moment
- Are not committed in advance
- Are not delivered to liquid market locations
- Provide no commitment to deliver. A customer may not have excess power to sell back to the utility, either because its generation is low or because its own needs are high.

A utility must instantaneously dispatch sufficient resources to equal its customer load at all times. Both resources and loads are uncertain, as wind and solar output varies, load varies, and traditional resources experience unplanned outages. Under nearly all conditions, a utility must have sufficient resources to balance its loads with enough extra energy to meet its reliability obligations, such as contingency reserve requirements.

Since exported volumes may not actually be delivered as expected, a utility must maintain adequate resources to serve load. Such resources cannot support firm market transactions if exported volumes are delivered as expected, because such transactions would have to have been finalized at least a day in advance, if not longer. In addition, if resources are only available for a few hours, they may not be able to support the entire duration and quantity of a market product.

The differential between firm market transactions and as-delivered energy varies based on a variety of factors, including the as-delivered energy profile, the supply and demand expectations of market participants, and the uncertainty in supply and demand, along with market participant’s next best alternatives. Such factors can only be measured indirectly, and it is difficult to distinguish expectations due to uncertainty and risk from actual outcomes.

With the advent of EIM, significantly more market data is available that better aligns with export profiles. EIM prices reflect:

- Individual intervals (five or fifteen minutes).
- Delivery begins a few minutes after a dispatch instruction is received.
- No minimum quantity.
- Location-specific values for utility-scale resources, or aggregate values specific to PacifiCorp loads.

While no single market price can reflect the intertwined month-ahead, day-ahead, hour-ahead, and intra-hour planning and operations used to balance PacifiCorp's load and resources, EIM prices are the most direct representation of the actual value of customer exports. The Company stands by the EIM as the best source for exported energy credit; however, the Company would also consider using the SAR methodology with adjustments made for non-firm energy consistent with prior QF filings.

4.4 Avoided Capacity Value

The Study Scope requested the Company analyze the capacity value of exported energy provided by customer-generators using either the LOLP study or by evaluating the amount of power exported to the grid by customer-generators during the top 100 peaking events in the last 10 years.

Study Scope Item 8

8. Analyze the capacity value of exported energy provided by customer-generators on a class basis using one of two methods:

a. Loss of Load Probability Study, or

b. Determine the power that is reliably exported to the grid by net metering during peaking events. Use the top 100 peaking events from each of the past 10 years (1,000 peaking events). Use a reliability threshold of 99.5%. If, for example, the study determines that customer-generators provide no less than 1.5 MW of power during 99.5% of the peaking events, then use 1.5 MW as the basis for determining the capacity avoided by the customer-generator class.

The Company has analyzed the capacity value of energy using the LOLP study from its IRP. The Company also looked at the top 100 peaking events from the past two years.

4.4.1 Loss of Load Probability Study

The Company's LOLP study from its 2021 IRP, is used to estimate the generation capacity contribution of customer generation exports. The study is discussed in the 2021 IRP in Volume II, Appendix K: Capacity Contribution[14], and reflects a 2030 test period including resource additions from PacifiCorp's 2021 IRP preferred portfolio which were projected to be in service by that time.

The capacity factor approximation methodology described as the "CF Method" in Appendix K of the 2021 IRP can be used to translate LOLP results for the PacifiCorp system into a generation capacity contribution that is specific to a particular hourly generation profile (or export profile in this instance). The CF Method calculates a capacity contribution based on a resource's

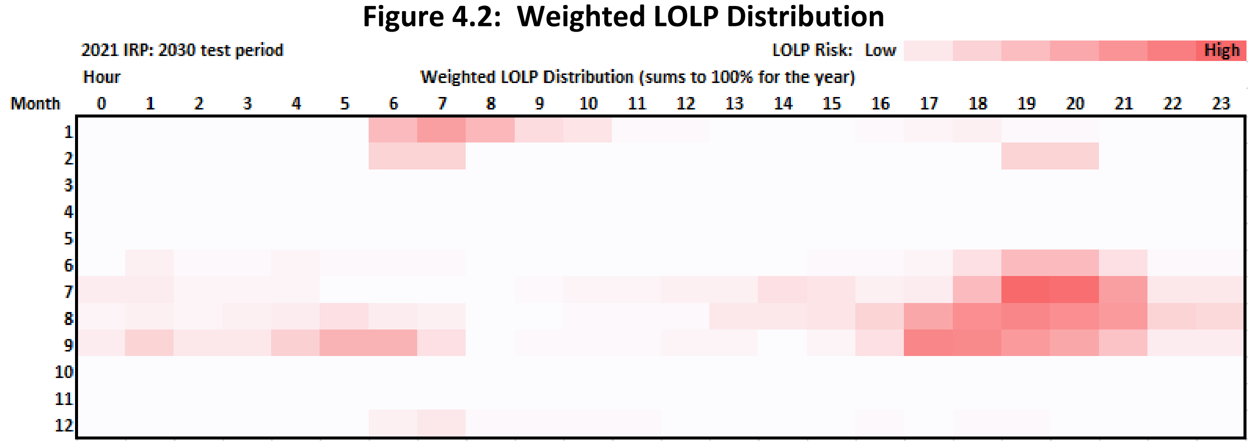
[14] Included with this Study as Appendix 4.7: Appendix K - Capacity Contribution - 2021 IRP.

expected availability during periods when the risk of loss of load events is highest, based on the LOLP in each hour.

An important aspect of the capacity factor approximation methodology is that the LOLP results reasonably reflect the relationship between periods of high demand, and periods with low resources, as these are most likely to lead to loss of load conditions. For accurate capacity contribution values, this relationship also must be maintained within a resource profile being evaluated. Many of these relationships are broadly a result of weather, but weather is complex and multi-faceted, so it is difficult to align the weather conditions underlying historical exports with the forecasted weather conditions within PacifiCorp's 2021 IRP, as manifested in the load forecast and renewable resource generation profiles. In general, peak-producing weather conditions would be expected to increase customer demand, reducing the amount available for export, but the effect of weather on customer generation production, system demand, and renewable supply could also influence LOLP.

In the absence of better data on the influence of weather on exports relative to system supply and demand, PacifiCorp opted to calculate a capacity contribution based on average exports in the last two years (2021-2022) by month and hour (a "12x24 profile"), i.e. assuming that customer exports were neither higher, nor lower, than average during hours with LOLP. The hours with higher LOLP are shown shaded in red below.

Figure 4.2: Weighted LOLP Distribution



As shown on LOLP tab of CONF Appendix 4.2: ID EE Cost-Effectiveness, this results in a capacity contribution for customer generation exports equal to 3.0% of their nameplate capacity, prior to accounting for avoided line losses. By comparison, the 2021 IRP identified an annual capacity contribution of 13% for utility-scale solar resources in Idaho. The results are not directly comparable because customer generation exports are net of a customer's onsite demand and the utility-scale solar reflects a profile incorporating tracking technology, which increases its output in the morning and evening when LOLP is higher.

4.4.2 Historical Peak Conditions

PacifiCorp has compared evaluated historical customer generation exports and the top 10 percent load conditions over the past two years, spanning 2021-2022. During all hours in the top 10 percent of annual Idaho load, exports provided an average capacity factor of 12.7 percent, while during all hours in the top 10 percent of annual system load, exports provided an average capacity factor of 14.4 percent. Many of the top hours have significantly lower exports, as shown in Table 4.5 below. At a 99.5 percent exceedance level, exports are well below a 1 percent capacity factor.[15]

Table 4.5: Customer Generation Exports During Peak Loads

Top 10%	Exceedance During Peak Load Hours, % Nameplate (by Percentile)							
Load	50%	60%	70%	80%	90%	95%	99.5%	100%
Idaho	4.73%	0.58%	0.0387%	0.0097%	0.0020%	0.0013%	0.0005%	0.0002%
System	9.98%	4.29%	0.9985%	0.0460%	0.0110%	0.0042%	0.0012%	0.0005%

Note that these load-based results do not account for reliability and risk related to resource supply. The 2021 IRP results account for periods when loads are high and resource availability is low. The resource availability aspect is particularly important as solar resources are becoming a greater share of PacifiCorp's portfolio, and the incremental reliability benefits from customer exports (which are primarily solar) are reduced as a result.

4.4.3 Time-Differentiated Capacity Values

The Study Scope requested the Company provide hourly time-differentiated capacity values

Study Scope Item 9

Provide hourly time-differentiated capacity values.

PacifiCorp has prepared hourly generation, transmission, and distribution capacity values (in $/MWh) based on the 2021 IRP LOLP capacity analysis described above and provided them in CONF Appendix 4.2: ID EE Cost-Effectiveness. Hourly capacity values are proportionate with the weighted LOLP by month and time of day shown in Figure 4.2. Capacity and reliability are probabilistic and involve discrete resource commitments. For instance, the addition of a simple cycle combustion turbine, which impacts many hours at once, cannot be acquired for select hours. While it is reasonable to spread capacity compensation across the hours with capacity shortfalls, it should be recognized that this is more of a rate design exercise than a true representation of hourly capacity values. The portfolio as a whole must have sufficient resources in each and every hour despite resources increasing or decreasing reliability based on their availability in particular hours.

[15] Data for analysis provided in Appendix 4.1: Export Profile Jan21-Dec22.

4.5 Avoided Risk

The Study Scope requested the Company to evaluate avoided risk by analyzing whether there is a fuel price guarantee value provided by on-site generators as a class.

Study Scope Item 10

Analyze whether there is a fuel price guarantee value provided by on-site generators as a class.

PacifiCorp's 2021 IRP included stochastic analysis, which evaluated portfolio costs considering variations in load, hydro output, electricity and natural gas prices, and thermal unit forced outages. PacifiCorp's calculation of the energy value and cost-effectiveness of energy efficiency measures used these stochastic results to identify the incremental value associated with these risks, and PacifiCorp has calculated the avoided risk associated with customer exports using the same risk values applied to energy efficiency. Over the 2021 IRP horizon, this increases the energy value of customer exports by 3.9 percent, or $1.24/MWh as shown on summary tab of CONF Appendix 4.2: ID EE Cost-Effectiveness.

5.0 Project Eligibility Cap

An evaluation of the pros and cons of setting a customer's project eligibility cap at different predetermined caps and demand levels was requested by the Study Scope.

Study Scope Item 11

Analyze the pros and cons of setting a customer's project eligibility cap according to a customer's demand as opposed to predetermined caps of 25 kW and 100 kW. a. Analyze at 100% of demand. b. Analyze at 125% of demand.

Per the load research information used in the Company's last general rate case[16], the estimated maximum non-coincident peak is 8.4 kW for the typical residential customer taking service on Schedule 1 and 11.5 kW for the typical residential customer taking service on Schedule 1. At 25 kW, the current cap is well above 125 percent of the typical customer's demand. Setting a capacity level that is based upon an individual customer's demand could be administratively burdensome and could create frustration for smaller customers who want to install a larger facility. It could also create a perverse incentive by encouraging customers to have a higher peak load before they request to interconnect an onsite generation system. The complications of setting a capacity level based on the individual customer's demand would be the same at 100% of demand and at 125% of demand.

[16] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations.* Case No. PAC-E-21-07.

6.0 Avoided Transmission and Distribution Costs

The Study Scope requested the Company to calculate the value of transmission and distribution costs that could be avoided by customer-generator exports to the grid.

Study Scope Item 12

Quantify the value of transmission and distribution costs that could be avoided by energy exported to the grid by net metering customers using the methodology for calculating the avoided transmission and distribution costs provided by energy efficiency programs.

PacifiCorp's evaluation of energy efficiency measures includes assumed deferral of local transmission and distribution upgrades. Unlike system LOLP, where a variety of resources may be used to ensure reliable operation in different times of day and seasons of the year, the local electrical grid needs to be capable of delivering the maximum demand after accounting for energy efficiency and customer generation. As a result, the capacity contribution for transmission and distribution system deferral is likely to differ from the generation capacity contribution based on system LOLP and may be specific to a particular circuit or transmission system element.

When the Company provides electric service to a new subdivision it utilizes standard system designs based on the number and size of expected homes in the new subdivision. It does not assume any level of self-generation because doing so would risk under-sizing the equipment.

In the absence of specific information about transmission and distribution capacity needs and their relationship with expected customer exports, PacifiCorp has estimated the potential avoided transmission and distribution costs using the system LOLP-based generation capacity contribution value of 3.0 percent, as previously discussed. Using the same avoided transmission and distribution upgrade costs applied in PacifiCorp's calculation of the energy value and cost-effectiveness of energy efficiency measures based on the 2021 IRP results in a value of $1.10/MWh for the 2021 IRP horizon.

7.0 Avoided Line Losses

The Study Scope requested the Company the avoided line loss calculations at a level that an average customer could understand.

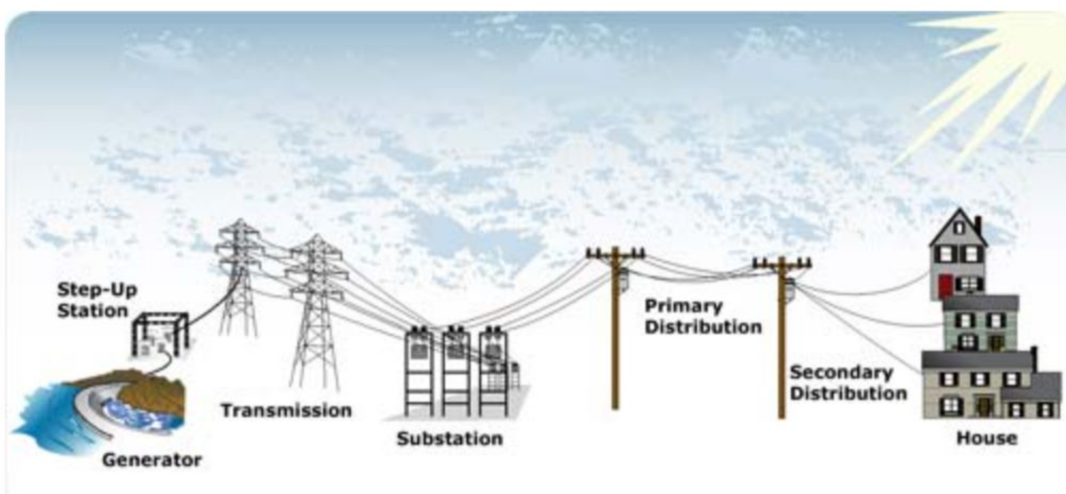
Study Scope Item 13

Explain the avoided line loss calculations at a level that an average customer can understand.

All electrical lines have impedance or constraint against conducting electricity, due to the conducting material, air temperature, and distance. Electricity is converted to heat while trying to overcome these constraints, and this loss of energy is referred to as line losses. The primary cause of transmission and distribution line losses are due to the resistance of the conductor, or line, against the flow of the current, or electricity. This resistance results in heat produced in the conductor increasing the temperature of the conductor making it less efficient to transfer electricity. The heat is generated on the microscale when electrons collide with and transfer energy to the conductor's atoms.

Line losses are calculated as the difference between the total generation injected into the grid and the total metered volume at customer sites. The line losses are separated into three categories: transmission, primary and secondary. Transmission line losses account for those line losses that occur over the transmission system. Primary line losses include those losses that occur on distribution voltages in the range from 2.2kV to 34.5 kV with most circuits at 12.4 kV. Secondary line losses include those losses that occur on distribution systems that are low voltage in the 120V to 480V range.

Figure 7.1: Transmission, Primary, and Secondary Components of an Electrical System[17]



The line losses incorporated in the Company's current rates are from its 2018 Line Loss study. That study identified "Demand" loss factors, based on losses during peak conditions, as well as "Energy" loss factors, based on loss averaged over all conditions. The 2018 Line Loss Study identified line losses in Idaho specific to the following interconnection levels:

Table 7.1: Idaho 2018 Demand and Energy Loss Summary

Voltage Class	Demand Loss Factor	Energy Loss Factor
Transmission	3.816%	3.503%
Primary	8.121%	7.082%
Secondary	9.834%	9.061%

[17] Transmission Line FAQ, GATEWAY WEST Transmission Line Project, http://www.gatewaywestproject.com/faq_general_transmission.aspx (last visited Feb. 20, 2023).

For customer-generators, the Company expects to apply the export credit to resources interconnected at secondary voltage levels, and to meter the exports before they go onto the secondary distribution system. The energy exported from the customer-generators will then incur some line losses traveling across the secondary distribution system to other customers, so it will not avoid the entire line losses associated with serving load on the secondary distribution system. Therefore, the Company proposes crediting exports for avoiding line losses on the transmission and primary distribution systems. If customer exports and customer generation exceeded the load on a particular distribution circuit, electricity could potential be transferred back up to higher voltages and could incur higher losses. For distribution capacity, avoided line losses are measured relative to losses at the transmission demand level, as losses incurred on the transmission system would not have been transferred across the distribution system.

8.0 Integration Costs

Integration costs refer to the additional expense when variable energy resources are added to a portfolio. Integration typically includes costs related to the uncertainty and variation in variable energy resource output from moment to moment, and these system impacts have been estimated in the 2021 IRP as described in more detail below. For distributed resources, integration costs could potentially include equipment and/or operational changes to manage impacts on the distribution system, particularly at high penetration levels, but the Company has not identified any specific costs associated with distribution system impacts from customer-generators in Idaho.

The Study Scope requested the Company to calculate the dollar impact of deferring a study of the integration charges for net metering customer until AMI data is available.

Study Scope Item 14

Study other methods for determining the integration costs of net metering customers as a class. Calculate the dollar impact of deferring a study of the integration charges for net metering customers until AMI data is available, and if different, calculate the dollar value of using a zero placeholder until AMI data is available.

The 2021 IRP includes an analysis of wind and solar integration costs in its Flexible Reserve Study (“FRS”) which is included in this Study as Appendix 8.1: Appendix F – Flexible Reserve Study- 2021 IRP. That analysis estimates the regulation reserve required to maintain PacifiCorp’s system reliability and comply with North American Electric Reliability Corporation ("NERC”) reliability standards as well as the incremental cost of this regulation reserve.

On April 23, 2007, Rocky Mountain Power filed an application requesting Commission approval of utility-specific wind integration adjustment to the published avoided costs rates. The Commission reviewed the facts and the settlement stipulation of the case and determined that a utility-specific wind integration cost adjustment to that utility's published avoided costs, among other adjustments, was appropriate.[18] With respect to the cost of integrating wind generation into existing utility systems, the Commission found in Order No. 29839, Case No. IPC-E-05-22 that the supply characteristics of wind generation and related integration costs could provide a basis for adjustment of the published avoided cost rates.[19] Since then, the Company has continued to refine the FRS to accurately capture the cost of integrating renewable resources into the grid in light of changes in available data, resource mix, and reliability standards.

On August 28, 2017, the Company filed Case No. PAC-E-17-11 to update the wind integration rate and implement an integration rate for solar. The Commission determined that there is a cost to integrate variable resources in Order No. 33937 where integration rates for both wind and solar were approved.

Regulation reserves must compensate for two aspects of supply and demand: changes within an hour, where some periods are higher and some periods are lower, and changes from forecast, where generation does not reach the level forecasted roughly an hour prior. The FRS accounts for these factors by using the hour-ahead resource-specific forecasts from actual operations, and actual deviations from those forecasts, at a five-minute granularity.

PacifiCorp does not have a real-time forecast of customer generation exports that could be used to identify specific integration requirements, but it is possible to measure deviations within each hour, relative to the hourly average. During 2021-2022, the historical customer export data has a mean average percent error ("MAPE") of 8.6 percent, when comparing 15-minute values to the hourly averages. By comparison, the utility-scale solar in the FRS had a lower MAPE of 7.2 percent, indicating the utility-scale has a proportionately smaller contribution to regulation reserve requirements than customer exports. Note that this does not necessarily indicate that customer generation production has higher variability than utility-scale production. A significant portion of the customer generation production is used behind the customer meter, but to the extent production exceeds onsite demand throughout an hour, all of the variability is exported to the electric grid. That variation is thus higher as a percentage of customer generation exports and would be lower as a percentage of customer generation production. Customer load generally does not respond to changes in onsite production (e.g., decrease consumption when customer generation production falls) and exports may have even more variability as a result of changes in a customer's demand.

Because the variation in customer generation exports exceeds that of utility-scale generation, it is reasonable to expect integration costs for customer generation exports to be higher. In light

[18] *In the Matter of the Petition of Rocky Mountain Power for an Order Revising Certain Obligations to Enter into Contracts to Purchase Energy Generated by Wind-Powered Small Power Generation Qualifying Facilities.* Case No. PAC-E-07-07, Order No. 30497.
[19] *In the Matter of the Petition of Idaho Power Company for an Order Temporarily Suspending Idaho Power's PURPA Obligation to Enter into Contracts to Purchase Energy Generated by Wind-Powered Small Power Production Facilities.* Case No. IPC-E-05-22, Order No. 29839 at p. 8.

of this, the use of the utility-scale solar integration costs likely understates the actual cost but is reasonable. Using the latest utility-scale solar integration costs approved in Order No. 34966 in PAC-E-20-14, the solar integration costs for 2023 is currently $0.24/MWh[20]. Assuming an average annual exports of 5,000 kWh per customer, the dollar impact of using a zero placeholder for integration costs until AMI data is available is $1.20 per customer per year.

9.0 Avoided Environmental Costs and Other Benefits

9.1 Grid Stability, Resiliency, and Cybersecurity

The Study Scope requested the Company to quantify the value of grid stability, resiliency, and cybersecurity provided by on-site generators.

Study Scope Item 15

Quantify the potential value of grid stability, resiliency, and cybersecurity protection provided by on-site generators as a class and different penetration levels.

The Federal Energy Regulatory Commission ("FERC") defines resilience as "the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and /or rapidly recover from such an event". To achieve any resiliency or grid stability benefits as defined above, on-site generation must be paired with storage since on-site generators, on their own, are susceptible to and can even enhance disruptive events.

Without storage, on-site generation does not provide grid benefits because in the event of an outage, systems are designed to power down for safety at any penetration level of on-site generation. The Company has also found that on-site generation does not provide cybersecurity benefits and can create additional cybersecurity risk because on-site generation creates more potential access points to the grid.

9.1.1 Grid Benefits of On-Site Generation with Storage

The grid *can* benefit from on-site generation when it is paired with solar. Battery management programs, like Wattsmart Batteries, provide four primary grid service benefits: 1) frequency regulation services 2) peak load management 3) circuit congestion relief, and 4) backup power.

In 2019, the Company was part of a partnership that developed a 600-unit all-electric residential community in Utah, where each apartment was outfitted with batteries paired with rooftop solar. The project provides 12.6 MWh of storage that is dispatchable by RMP through the Distributed Battery Grid Management System. An evaluation of this project identified the four primary grid service benefits listed above.

[20] See Appendix 8.2: Wind and Solar Integration Charges Approved in Order No. 34966.

Without battery storage, on-site customer generation does not provide either frequency regulation services, peak load management, circuit congestion relief or backup power.

9.1.2 Community Resiliency Benefits of Customer Generation with Storage

When a catastrophic disaster strikes, backup power paired with storage can ensure emergency services, such as fire, medical, and shelter services, continue to operate. On-site generation with storage provides value to the community from avoided property damage, injuries, fatalities, and lost productivity. While there is no standard method for determining the community resiliency value of customer generation some tools can help determine the value for individual sites.

An evaluation of Pacific Power's Community Resiliency Pilot used the Federal Emergency Management Agency's ("FEMA") benefit-cost analysis tool to determine the potential resiliency value for customer generation and batteries at specific sites that provide vital services—fire stations, data centers and designated shelters. FEMA's calculator determines the value of maintaining these services based on the type of emergency and the facility category. For example, analysis for a fire station considers the probability of property loss, the dollar value of the loss, and the number of fire incident prior to and during the outage. The tool also determines avoided injuries and deaths from maintaining fire service. The resiliency benefits can vary significantly from site-to-site depending on the unique characteristics of the facility, the community the facility serves, and the type of disaster.

None of the community resiliency benefits outlined above is possible without battery and storage paired together since battery storage provides the backup power required during a disaster. Also, the benefits outlined above are not relevant to the purposes of this Study, which is focused on the benefits of on-site generators connected to the grid, *as a whole,* and not any one site and the benefits it might give to a community in the event of a disaster. Further, those benefits are unquantifiable and do not accrue specifically to customers of the utility in their capacity as consumers of energy.

9.1.3 Customer Generation and Cybersecurity Protection

Cyber-attacks are potential resiliency events. Thus, the cybersecurity protection benefits of customer generation with storage are the same as those described above. In the event of a catastrophic cyberattack, customer generation and storage could provide sustained power to vital services.

However, increasing penetration of customer generation could increase cybersecurity risks. The U.S. DOE's report on "Cybersecurity Consideration for Distributed Energy Resources on the U.S.

Electric Grid" identifies several cybersecurity risks from distributed energy resources.[21] When a customer-generator connects to the grid, it creates a new access point, which adds incremental risk for cyberattacks. Most customer generation systems use solid-state inverters to produce output and sync with the grid. These inverters are software-driven and digitally controlled. The improper application of this software—such as through a cyberattack—could affect reliability and grid stability.

9.2 Public Health and Safety

The Study Scope requested the Company to quantify the value to local public health and safety from reduced local impacts of global warming.

Study Scope Item 16

Quantify the value to local public health and safety from reduced local impacts of global warming such as reduced extreme temperatures, reduced snowpack variation, reduced wildfire risk, and other impacts that can have direct impacts on Rocky Mountain Power customers.

The value of customer generation exports with respect to global warming harm reduction is difficult to quantify. The greenhouse gas costs in the 2021 IRP represent possible federal policy that would impact the dispatch of emitting resources, and do not represent local impacts, which are much more complex. Some of the referenced global warming impacts, including impacts on retail load and hydropower production, directly impact PacifiCorp's loads and resources, and climate-related effects on these inputs have been incorporated in PacifiCorp's 2023 IRP.

Though it is imperfect for identifying local impacts, PacifiCorp's avoided energy value, addressed in section 4.3 of this Study, includes the impact of assumed medium greenhouse gas costs, consistent with assumptions from the 2021 IRP. Medium greenhouse gas costs are reflected in market prices, as well as in the dispatch cost of PacifiCorp's coal and natural gas-fired resources, but it is not possible to differentiate greenhouse gas costs from energy and other variable costs within the reported hourly energy value. PacifiCorp's 2021 IRP also included analysis using a social cost of greenhouse gases ("SCGHG"); however, this represents global public health and safety impacts, rather than local impacts.

Another possible value of customer generation exports is via Renewable Energy Certificates ("RECs"), which are addressed in section 9.4 of this Study below.

[21] *Cybersecurity Considerations for Distributed Energy Resources on the U.S. Electric Grid*, U.S. DOE Office of Cybersecurity, Energy Security, and Emergency Response and the Office of Energy Efficiency and Renewable Energy, October 2022. https://www.energy.gov/sites/default/files/2022-10/Cybersecurity%20Considerations%20for%20Distributed%20Energy%20Resources%20on%20the%20U.S.%20Electric%20Grid.pdf

9.3 Economic Benefits

The Study Scope requested the Company to quantify the value to local economic benefits from on-site customer generation.

Study Scope Item 17

Quantify local economic benefits, including local job creation and increased economic activity in the immediate service territory.

Quantifying local economic benefits of increased economic activity is difficult, if not impossible, to quantify with a degree of certainty. In addition, the Company's generation, transmission, and distribution activities in its current service territories provide economic benefits. However, the Company does not charge customers for these benefits in electric rates. Allowing difficult-to-quantify economic benefits in the ECR would not be fair to non-participating customers.

9.4 Possible Net Value of Renewable Energy Credits

The Study Scope requested the Company to quantify the net value of RECs sales from on-site generation.

Study Scope Item 18

Quantify the possible net value of Renewable Energy Credit sales produced by net metering exported energy.

Currently, Idaho does not have a renewable portfolio standard ("RPS"), so the benefits of RECs would come from REC sales. Only renewable output delivered to the electric grid can qualify for RECs, and there are administrative requirements to certify renewable resources and assign RECs to their production.

To create RECs, the renewable energy generator must be registered with the Western Electricity Coordinating Council ("WECC") and the Western Renewable Energy Generating Information System ("WREGIS"). Renewable energy cannot be monetized through REC sales without this process in the WECC region. Coordinating the certification and tracking of the RECs would be an administrative complex and could require a full-time employee to administer. The Company expects the administrative costs would exceed any revenues generated from REC sales.

At present, PacifiCorp does not sell all the RECs it generates on behalf of its Idaho retail customers, as the market for RECs is limited. To the extent that there were other parties interested in purchasing RECs from Idaho customer-generator exports, a $1/MWh REC price would equate to approximately $5 per year in incremental export credit value for an Idaho customer-generator, assuming 5,000 kWh of exports annually, which represents approximately half of their annual production.

9.5 Reduced Risk from End-of-Life Disposal

The Study Scope requested the Company to quantify the reduced risk from end-of-life disposal concerns for the Company compared to fossil-fueled resources.

Study Scope Item 19

Quantify the reduced risk from end-of-life disposal concerns for the Company compared to fossil-fueled resources.

Investment in utility scale resources considers end-of-life closure costs to determine least cost resources. To the extent capacity benefits displace a new generation resource, this potential benefit is already captured in that category.

10.0 Recovering Export Credit Rates in the ECAM

10.1 Current Export Credit Recovery

To better understand how export credit rates may be recovered in the Energy Cost Adjustment Mechanism ("ECAM"), the Study Scope asked the Company to explain the method currently used to record net metering bill credit costs.

Study Scope Item 20

Explain the method currently used to record net metering bill credit costs.

Currently, bill credits for net metering are used to reduce the energy charges that are paid to the Company. These net metering bill credits therefore reduce the Company's retail revenue.

10.2 Recovery Allocation

The Study Scope asked the Company to quantify the current amount of net metering costs allocated to each class.

Study Scope Item 21

Quantify the current annual amount of the net metering costs allocated to each class.

Table 10.1 below shows the reduction in revenue for each class attributable to exported energy that is valued at retail energy charges:

Table 10.1: Net Metering Reduction in Revenue by Class

	Residential Sch 1	Residential Sch 36	General Service Sch 23	General Service Sch 6	Total
Exported Energy (MWh)	8,555	2,183	565	123	11,426
Value at Retail Rate	$916,330	$269,067	$51,091	$5,242	$1,241,731

The Study Scope required the Company to explain how these costs have been allocated and recovered between rate classes for the past five years.

Study Scope Item 22

Present and explain how these costs have been allocated and recovered between rate classes for the past five years.

In between rate cases, the Company absorbs the cost of reduced revenue from net metering. In 2021, the Company filed a rate case that updated class revenues and that took effect January 1, 2022. The rate case before the 2021 rate case occurred ten years before and took effect on January 10, 2012, with a second-year price change that took effect on January 1, 2013. During that timeframe, onsite generation adoption was still in its infancy and was a small portion of retail revenue situs directly assigned to each customer class. Exported energy from on-site customer-generators reduces net power cost ("NPC") by reducing purchases or fuel costs. While these cost savings reduce NPC which is captured in the ECAM, the cost of paying for exported energy that is above what is built into the revenue for a general rate case is absorbed by the Company. The cost of the ECAM is allocated to customer classes on the basis of energy sales adjusted for line losses.

10.3 Export Credit Price Scenarios

The Study Scope asked the Company to quantify the annual export costs for each customer class and different assumed export rates.

Study Scope Item 23

Quantify these annual costs under the assumptions that the Export Credit Rate is the retail rate, 7.4 cents/kWh, 5 cents/kWh, or 2.23 cents/kWh.

Assuming an instantaneous netting regime, the export credit payments by class are show in Table 10.2 for the different specified levels of export credit price

Table 10.2: Annual Export Costs by Rate

	Residential Sch 1	Residential Sch 36	General Service Sch 23	General Service Sch 6	Total
Exported Energy (MWh)	8,555	2,183	565	123	11,426
Value at Retail Rate	$916,330	$269,067	$51,091	$5,242	$1,241,731
Value at 7.4¢/kWh	$633,050	$161,516	$41,835	$9,126	$845,526
Value at 5.0¢/kWh	$427,736	$109,132	$28,267	$6,166	$571,301
Value at 2.23¢/kWh	$190,770	$48,673	$12,607	$2,750	$254,800

The Study Scope called for an analysis how these costs would be allocated and recovered by each rate class through the Company's ECAM.

Study Scope Item 24

Analyze how these costs would be allocated and recovered by rate class through the Company's proposed ECAM method going forward.

Going forward, the Company recommends that the export credits paid to customer-generators on the net billing program would be recorded as a purchased power expense and tracked in the ECAM like all other energy purchases. This would align the cost to acquire this energy with any reductions to net power costs by avoided purchases or reduced fuel expense. The Company recommends that the cost of export credits would be allocated on energy sales adjusted for line losses, which is consistent with how other ECAM costs are treated.

11.0 Schedule 136 Implementation Issues

The Study Scope asks the Company to consider several implementation issues such as billing structure for on-site generators, export credit expiration scenarios, and the frequency of export credit updates.

11.1 Billing Structure

11.1.1 Time-of Delivery Pricing

The Study Scope requested an explanation of how seasonal and time-of-delivery prices differences will be used to help align customer generated exported energy with the Company's needs and how using more granular time periods for differentiating energy and capacity credits could be used to align customer-generated exports more closely with the Company's system needs.

Study Scope Item 25

Explain if and how seasonal and time-of-delivery price differences will be used to help align customer generated exported energy with the Company's system needs.

Study Scope Item 26

Explain if and how using more granular time periods for differentiating energy and capacity credits could be used to more closely align customer-generated exports with the Company's system needs.

The Company recommends a seasonal export credit price that is not of time-of-use differentiated. The difference in time of use periods can be confusing for customers with most of the Company's customers not currently enrolled in a time varying pricing option. The differential between an on-peak versus an off-peak export credit is not as significant as the difference in the retail price versus the export credit. All customers in Idaho, however, are subject to seasonal pricing and consistency with an export credit will send appropriate price signals to customers. To best align export credit pricing to the highest cost period of the year, the Company proposes a summer period of June through September. Winter months would include October through May. These seasons are consistent with seasonal pricing for almost all rate schedules. Presently for Schedule 36, the summer season includes May. The Company recommends that the seasons for export credit pricing would align with the seasons in Schedule 36 for participating net billing customers served under that schedule, until such time as the seasons for Schedule 36 are updated.

11.1.2 Economic Evaluation for Customer-Generators and On-Site Generation System Installers

The Study Scope requested an explanation of how potential customer-generators and on-site generation system installers can have accurate and adequate data and information to make informed choices about the economics of on-site generation systems over the expected life of the system.

Study Scope Item 27

Explain how potential customer-generators and on-site generation system installers will have accurate and adequate data and information to make informed choices about the economics of on-site generation systems over the expected life of the system.

The purpose of customer generation programs like net metering or net billing is to offset part or all the Customer's own electrical requirements and not to enable customers to become an independent power producer. If the customer's intent is to offset its own usage, then customer-generators and system installers have the same customer usage information and pricing to make informed choices about the economics of on-site generation systems as they do to make decisions about other energy investments like conservation focused measures such as more efficient windows or air conditioning equipment. Under net billing, customer-generators would be incentivized to align their usage with generation. This can be done behaviorally through actions such as running appliances like dishwashers during the middle of the day, sizing their systems at levels that reduce exports, or installing onsite storage. With the installation of AMI, customers will be able to view their hourly usage online which should allow determined customers to analyze their usage patterns.

11.1.3 Residential Solar Energy Disclosure Act

The Study Scope requested an explanation of how on-site generation system installers will be able to comply with the Residential Solar Energy Disclosure Act if hourly or instantaneous netting and/or granular time-differentiated export rates are adopted and updated annually.

Study Scope Item 28

Explain how on-site generation system installers will be able to comply with the Residential Solar Energy Disclosure Act if hourly or instantaneous netting and/or granular time-differentiated export rates are adopted and updated annually.

As explained in response to Study Scope item 27, the intent of net metering or net billing is not for customers to become developers of qualifying renewable generation resources or to get into the business of selling energy to the Company. The purpose is to offset the customer's own usage. Inasmuch, as net billing customers use the generation they produce onsite, they will avoid paying the retail price for energy. When customer-generators on bet billing export energy to the utility grid, they will be compensated at the export credit price which would update periodically. The value of exported energy could change over time. Before committing to install onsite generation, customer-generators should take note that all investments including rooftop solar have risks. While under net billing, a customer-generator will save on their utility bill from producing energy, those savings may go up or down with time. In many ways installing onsite generation is like choosing to purchase a hybrid or electric vehicle. An individual who makes this choice would save on gasoline over time, but those savings levels fluctuate with the changing price of gasoline. Under the Residential Solar Energy Disclosure Act, installers will need to document for their potential customers the assumptions used in their projection of savings for the system.

11.2 Export Credit Expiration

To evaluate different scenarios for export credit expiration, the Study first evaluated the current magnitude of accumulated export credits and generation. Then, the effects of different expiration periods were analyzed to see how customers would be affected. Finally, the Study looked at how the Company and non-participating customers are impacted by expired credits.

11.2.1 Accumulated Export Credits

The Study Scope requested the magnitude, duration, and value of accumulated export credits as of August 1, 2020, be quantified.

Study Scope Item 29

Quantify the magnitude, duration, and value of accumulated export credits as of August 1, 2020.

As of August 1, 2020, there was a total of 4,530,405 kWh in excess generation for all customers as detailed in Table 10.1 below

Table 11.1: Excess kWh Total as of 8/1/2020

Customer Class	2013	2014	2015	2016	2017	2018	2019	2020	Total
Residential	21,729	46,758	59,349	140,598	215,748	631,720	1,141,045	1,226,213	3,483,160
Small Commercial	41,462	70,153	61,235	92,809	158,167	245,993	195,306	163,280	1,028,405
Large Commercial	-	80	240	440	320	1,040	2,560	14,160	18,840
Irrigation	-	-	-	-	-	-	-	-	-
Total	63,191	116,991	120,824	233,847	374,235	878,753	1,338,911	1,403,653	4,530,405

To better understand the magnitude, duration, and value of the excess generation, the Company valued each year's excess generation by customer class and rate. In addition to the table above, the Company evaluated expired generation from August 1, 2020, to December 31, 2022, to provide a more current portrait of expired credits. The detail of this analysis is provided on the summary tab of Appendix 11.2: Idaho Expired Credit Analysis 2012-2022. The estimated value of all excess generation is $325,386.06 for all 2,196 net metering customers from 2012 to 2022.

11.2.2 Impact to Customers over Various Expiration Periods

The Study Scope requested the impact to customers of a 2-year, 5-year, and 10-year expiration periods be quantified.

Study Scope Item 30

Quantify the impact to customers of a 2-year, 5-year, and 10-year expiration periods.

The impact to customers for credits expiring at either 2-years, 5-years, and 10-years, will vary depending on each customer's load and system size. Customers with systems that consistently overproduce, will be most affected by expiring credits. As shown on the Table 11.2 below, 14 percent of on-site generation systems overproduced in 2022.[22]

Table 11.2: Percentage of Customers Overproducing Annually

Year Ending	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Residential	2	8	10	21	29	59	122	212	215	281
Small Commercial	4	4	4	5	5	9	12	19	23	16
Large Commercial	-	-	-	-	-	-	-	1	-	-
Irrigation	-	-	-	-	-	-	-	-	-	2
Totals	**6**	**12**	**14**	**26**	**34**	**68**	**134**	**232**	**238**	**299**
Percentage	5%	9%	9%	12%	10%	10%	12%	16%	14%	14%

The average annual compensation for net overproducers has been $294 over the last 5 years.[23] A breakdown of the weighted average for each customer class for the last 5 years is included in Table 11.3 below. The net value of overproduction for each of the overproducers is provided in detail in Appendix 11.1: Weighted Average Overproduction.

[22] Additional analysis included on the customer count tab of Appendix 11.2: Idaho Expired Credit Analysis 2012-2022.
[23] See summary tab of Appendix 11.1: Weighted Average Overproduction.

Table 11.3: Weighted Average of Customer Overproduction

Year Ending	2018	2019	2020	2021	2022
Residential Count	59	122	212	215	281
Avg Annual Compensation/Customer	$276.02	$209.22	$196.26	$207.12	$200.37
Small Commercial Count	9	12	19	23	16
Avg Annual Compensation/Customer	$1,937.71	$875.56	$785.77	$499.72	$615.28
Large Commercial Count	-	-	1	-	-
Avg Annual Compensation/Customer	-	-	$842.27	-	-
Irrigation Count	-	-	-	-	2
Avg Annual Compensation/Customer	-	-	-	-	$54.08
Total Customer Count	68	134	232	238	299
Weighted Avg Annual Compensation/Customer	$495.95	$268.89	$247.33	$235.40	$221.60

To better understand how the overproducing customers would be impacted by different expiration periods, the Company took a sample of the overproducing customers and calculated the value of credits that could be subject to expiration over the different time periods. The results of this analysis can be seen on Appendix 11.3: Customer Impact at 2-, 5-, and 10-Year Expiration.

As shown on the residential tab of Appendix 11.3, only two customers overproduced for the year in 2013. At the end of the 10-year period, those two customers would have $1,177.5 in combined credits that would begin to expire, on a rolling basis.

For the 5-year analysis, the two customers from the 10-year analysis were analyzed again along with the largest overproducer in 2018. The overproducing site was selected to show how customers with both large and small amounts of overproduction would be affected by expired credits. As shown on the residential tab of Appendix 11.3, two of the customers would not have any expired credits when looking at the last five years, however the largest overproducer would have $9,927.32 in credits that would begin to expire on a rolling basis of approximately $2k annually. While the impact to this customer could potentially be significant, most customers would not be heavily impacted by the expiration of credits over a 5-year period.

For the 2-year analysis, the customers from the 5-year analysis were included and added a customer that was at the median range for overproducers to analyze the impact to the broadest possible range of overproducers. The average annual credit of the four selected customers was $82 that would expire on a rolling basis.

In summary, over 85 percent customers will not be affected by expiring credits. For those overproducers with credits at risk of expiration, the impact will vary depending on system size and load. The most over-sized customer could see credits valued at approximately $2k expiring annually. In contrast, the average overproducer would not have more than $100 in credits expire on an annual average basis.

11.2.3 Export Credit Expiration Policy

The Study Scope requested an explanation of the need for credits to expire.

Study Scope Item 30

Explain the need for credits to expire. a. Show how the Company does or does not benefit from the expiration of customer export credits. b. Show how non net bill customers are harmed or benefited from the expiration of customers export credits.

Customer generation programs are intended for customers to offset some or all of their energy bill with onsite generation and not for a customer to become a power producer. To encourage customers to appropriately size their generation systems to match actual usage at the site of the system, the Company recommends that export credits may be rolled over until March of each year for most customers and until October for irrigation customers. This would allow customers a reasonable opportunity to accumulate and use credits to offset actual energy use at the location of the customer generation system.

The Company's recommendation is for expired export credits to go to a qualified charitable organization. There is no benefit to the Company.

When establishing net metering the Commission confirmed that: "The purpose of net metering is not to encourage excess generation. Developers of qualifying renewable generation resources who wish to get into the business of selling energy to the Company should, under PURPA, request firm or non-firm energy purchase contracts."[24] The net metering rate is not intended to encourage participants to become independent power producers. If the ECR is not set at a level that holds other customers economically indifferent from paying for the exports or another comparable source of energy, other customers are harmed by having to pay an unreasonable rate.

[24] *In the Matter of the Petition of NW Energy Coalition and Renewable Northwest Project to Establish Net Metering Schedules for PacifiCorp.* Case No. PAC-E-03-4, Order No. 29260 at p. 6.

11.3 SAR Energy Rates Updates and IRP Cycle Impact to Export Credit Updates

The Study Scope requested the impact of biennial updates, as compared to annual updates of the ECR, by comparing the changes in the SAR energy rate, line losses, and integration costs using historical data over one year, one IRP cycle and two IRP cycles be quantified.

Study Scope Item 32

Quantify the impact of biennial updates as compared to annual updates of the Export Credit Rate by comparing the changes in the SAR energy rate, line losses, and integration costs using historical data over one year, one IRP cycle (two years), and two IRP cycles (four years).

Assuming the ECR is updated based upon non-levelized annual prices, the Company analyzed how compensation would vary for a customer-generator who exports 5,000 kWh per year under different update scenarios – annual, biennial, and every 4 years. The chart below in figure 11.1 shows how the price would have varied under these cycles starting with the prices effective around June 1, 2012, for a ten-year period:

Figure 11.1: Frequency of Export Credit Updates[25]

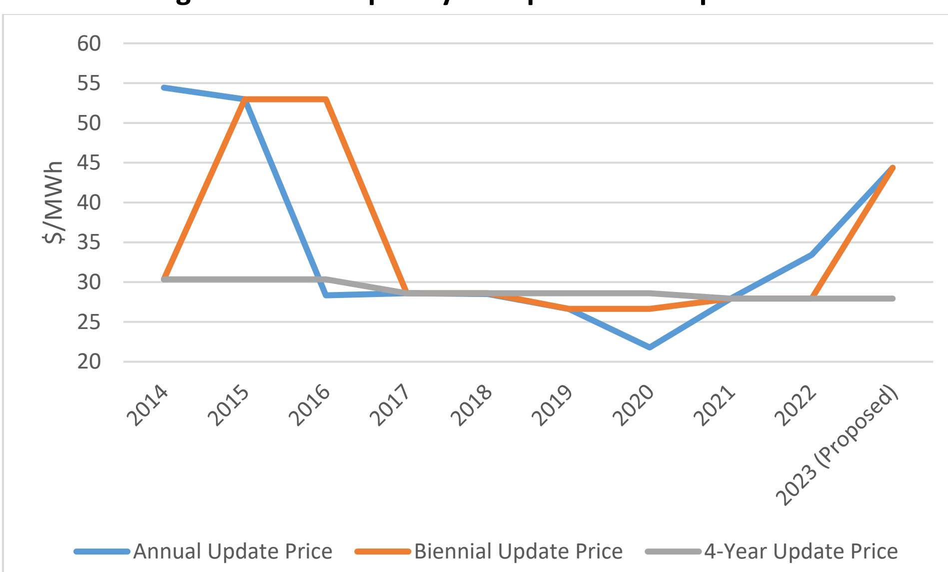


Table 11.4 shows how compensation for an annual 5 MWh of exports over this ten-year period would have compared for the different update cycle scenarios:

[25] See Appendix 11.4: SAR Export Credit Analysis for calculation.

Table 11.4: Impact of Different Update Cycles

Annual Update Price	Biennial Update Price	4-Year Update Price
$1,735	$1,735	$1,446

The results for the annual update and the biennial update are nearly identical. The 4-year update is lower primarily, because it misses capturing higher prices that occurred in 2014 and 2015 that get picked up in annual and biennial updates. Depending upon when updates begin could make a large difference for multi-year updates in the future. The Company recommends the ECR be updated annually, which would provide customer-generators with more accurate compensation.

12.0 Smart Inverter Study

The Study Scope requested an explanation of the Company's Utah smart inverter policy and a quantification of the benefits of applying that policy to its Idaho service territory.

Study Scope Item 33

Explain the key aspects of the Company's Utah smart inverter policy and quantify the benefits of applying that policy in its Idaho service territory, in particular, the potential benefits of reactive power control.

In 2017, Rocky Mountain Power took part in a Smart Inverter Project as part of the Utah Sustainable Transportation and Energy Plan ("STEP") to investigate the capabilities and impacts of smart inverters on the Company's distribution system. The Company's project partners included the Electric Power Research Institute and Utah State University and resulted in the study of: (1) IEEE 1547 smart inverter standards and policy, (2) laboratory selection and testing, (3) hosting capacity results, with and without smart inverters, (4) settings determination, (5) deployment best practices, and (6) Technical Policy 138, interconnection standard updates. The Smart Inverter Study was produced from the efforts of the STEP project in Utah docket 19-035-17 and is included with this Study as Appendix 12.0: Utah STEP - Smart Inverter Study.

This research produced the smart inverter policy that the Company has implemented for its Utah customers. That policy was considered in a Utah Public Service Commission proceeding to determine how the value provided by customer smart inverters should be included in the ECR, Utah Docket No. 17-035-61, and no specific export credit value was applied to account for the benefits of smart inverter technology.

While smart inverters are not expected to impact export credit rates, including minimum requirements for inverter technology can ensure the hosting capacity and power quality of the distribution system do not deteriorate as customer generation is added.

The following Appendices are voluminous and provided in their native format via Box:

Appendix 3.1 - ID NEM Class Production.xlsx

Appendix 4.1 - Export Profile Jan21-Dec22.xlsx

CONF Appendix 4.2 - ID EE Cost-Effectiveness.xlsb

CONF Appendix 4.3 - ID Export Credit Calculations.xlsb

Appendix 4.4 - Idaho Export Profile Validation Avg Capacity .xlsx

Appendix 4.5- ID Export Profile Validation Monthly Exports.xlsx

Appendix 4.6 - ID Export Profile Validation PV Watts Production.xlsx

Appendix 4.7 - Appendix K - Capacity Contribution - 2021 IRP.pdf

Appendix 8.1 - Appendix F - Flexible Reserve Study - 2021 IRP.pdf

Appendix 8.2 - Wind and Solar Integration Charges Approved in Order No. 34966.pdf

Appendix 11.1 - Weighted Average Overproduction.xlsx

Appendix 11.2 - Idaho Expired Credit Analysis 2012-2022.xlsx

Appendix 11.3 - Customer Impact at 2-, 5-, and 10-Year Expiration.xlsx

Appendix 11.4 - SAR Export Credit Analysis.xlsx

Appendix 12.0 - Utah STEP - Smart Inverter Study.pdf