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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO IMPLEMENT CHANGES TO THE COMPENSATION STRUCTURE APPLICABLE TO CUSTOMER ON-SITE GENERATION UNDER SCHEDULES 6, 8, AND 84 AND TO ESTABLISH AN EXPORT CREDIT RATE	)	**CASE NO. IPC-E-23-14** **COMMENTS OF THE COMMISSION STAFF**

COMMISSION STAFF ("STAFF") OF the Idaho Public Utilities Commission ("Commission"), by and through its Attorney of record, Chris Burdin, Deputy Attorney General, submits the following comments.

BACKGROUND

On July 27, 2017, in Case No. IPC-E-17-13, Idaho Power Company ("Company") filed an application with the Commission for authority to establish new schedules for residential and small general service customers with on-site generation. In that case, the Commission separated on-site generation customers as distinct rate classes; recognized the need to address the costs, benefits, rates, rate design, and compensation of on-site generation customers; reasoned that it is unfair for on-site generation customers to be able to avoid paying their share of fixed costs; and ordered the Company to prepare and file a credible and fair study on the costs and benefits of on-site generation to the Company's system, as well as proper rates and rate design, transitional rates, and related issues of compensation for net excess energy provided as a resource to the Company. Order No. 34046.

On December 20, 2019, in Case No. IPC-E-18-15, the Commission denied a settlement proposed by the Company, Staff and intervenors. In its reasoning, the Commission reiterated that the Company must submit a comprehensive study before proposing changes to the Net Energy Metering ("NEM") programs.[1] The Commission directed that the study: (l) must use the most current data possible and must be readily available to the public, and in the Commission's decision-making record; (2) must be designed in coordination with the parties and the public, and the Commission will determine the final scope of the study; and (3) the study must be written so it is understandable to an average customer, but its analysis must be able to withstand expert scrutiny. Order No. 34509 at 9. Additionally, the Commission established Grandfather Status for customer generators with existing on-site generation systems and those that complete their systems within one year of the service date of Order No. 34509. *Id.* at 14.

On June 28, 2021, in Case No. IPC-E-21-21, the Company filed an application with the Commission to initiate a multi-phase process for the study of costs, benefits, and compensation of net excess energy associated with on-site customer generation, in its application the Company included a proposed study scope. In that case, the Commission received public comments and multiple rounds of comments from the Company, Staff, and intervening parties on different elements to be included in the study scope. Based on the input of the diverse parties, the Commission provided additional direction and specific requirements for each element to be included in the study. Order No. 35284.

On June 30, 2022, the Company submitted an application with the Commission to Complete the Study Review Phase of the Comprehensive Study of Costs and Benefits of On-Site Customer Generation and for Authority to Implement Changes to Schedules 6, 8, and 84. Included in the application was the completed Value of Distributed Energy Resources ("VODER") study and its supporting appendices. In that case, the Commission found that the Company had completed a fair and credible study in accordance with previous orders and

[1] NEM is the current compensation structure where customer-generators receive a kWh credit for excess energy delivered to the grid. The kWh credit can be applied to offset energy consumption within the current billing cycle or future billing cycles. NEM requires a single bi-directional meter read for the billing period.

acknowledged that the Company filed its completed VODER study. Order No. 35631. The Commission then directed the Company to file a new case requesting changes to its NEM program. *Id.*

On May 1, 2023, the Company filed an application ("Application") with the Commission proposing changes to the Company's on-site and self-generation tariffs. The Company requests that the Commission authorize: (1) real-time net billing with an avoided cost-based financial credit rate for exported energy; (2) a methodology for determining annual updates to the Export Credit Rate ("ECR"); (3) a modified project eligibility cap for Commercial, Industrial, and Irrigation ("CI&I") customers; (4) related changes to the accounting for and transferability of excess net energy financial credits, and (5) updated tariff schedules necessary to administer the modified on-site generation offering. The Company requests an effective date of January 1, 2024.

The Company represents that its recommendations are guided by the following objectives: (1) recommend a compensation structure that will accurately measure a customer-generator's use of the system – both in recording exported energy and usage; (2) apply methods that will result in a fair and accurate valuation of customers' exported energy; (3) implement a repeatable method for updating the ECR that will ensure timely recognition of changing conditions on Idaho Power's system and the broader power markets which may warrant changes to the ECR; (4) balance accuracy with customer understandability. Application at 15-16.

The Company represents that the proposed changes to the on-site generation service offerings would only apply to non-legacy customers taking service under Schedules 6, 8, and 84. Customers with legacy systems will continue to take service under the rules of monthly NEM until legacy status terminates on December 20, 2045, also known as Grandfather Status. *Id.* at 16.

The Company is proposing a real-time net billing with an avoided cost-based financial credit rate for exported energy. The Company states that the customer-generator will first consume any of their generation on-site, and any generation they are not consuming will be metered and exported to the grid at a defined ECR. The Company represents that customers will generate financial credit, based on the product of measured exported energy and the ECR, which can be monetized to offset current or future charges associated with utility provided service. *Id.* at 17-18.

The Company is proposing a seasonal and time variant ECR to compensate for energy and other elements associated with avoided capacity, line losses, and integration costs. The proposed On-Peak season and time variance is between June 15 and September 15, 3pm to 11pm, excluding Sundays and holidays, with all other hours considered Off-Peak. The Company valued its ECR using a series of costs avoided or deferred by the Company through the existence of on-site generation exports on the Company's system. These avoided costs include energy, generation capacity, transmission and distribution, and line losses offset by an integration cost. The Company's proposal extends only to non-legacy systems. *Id.* at 19-20. "Legacy" systems for Schedules 6 and 8 are systems that were installed or purchased by December 20, 2019, and that meet other eligibility requirements. Order Nos. 34509 and 34546. "Legacy" systems for Schedule 84 are systems that were installed or purchased by December 1, 2020, and that meet other eligibility requirements. Order No. 34854.

The Company is also seeking a change in how the project eligibility cap is defined for Schedule 84 customers. The Company proposes that, if the net billing compensation structure is approved, the project eligibility cap be set at the greater of 100 kW or 100% of demand at the service point for Schedule 84 customers. If the net billing compensation structure is not approved, the Company does not propose modifying the existing project eligibility cap, because it serves to mitigate cost-shifting under the current net metering compensation structure. *Id.* at 20-21. The Company does not propose any modification to the 25kW project eligibility cap for Schedule 6 and Schedule 8 customers. For Schedule 6,8, and 84, the Company proposes that energy storage devices are not used to calculate the nameplate capacity of on-site generation facilities for Schedule 6, Schedule 8, and Schedule 84 customers.

The Company represents that for purposes of administering the cap, the Company proposes using the maximum billing demand from the last 12 months, measured when the customer generation application is submitted. *Id.* at 22. The Company states that for irrigation customers without a full in-season billing history, a conversion factor related to the horsepower of the customers' pump(s) at the service point would determine the maximum demand. *Id.*

The Company represents that for customers with non-legacy systems, the Company proposes to treat ECR expenditures as a Net Power Supply Expense ("NPSE") subject to 100% recovery through the Company's Power Cost Adjustment ("PCA"). *Id.* at 23-24.

The Company proposes that financial credits may offset all billing components of the bill, not just the energy-related portion of a customer bill. *Id.* at 24.

The Company represents that customers with non-legacy systems will be able to transfer financial credits to another account held in their name for their own usage, which will be administered similar to the Company's current NEM service offering for customers transferring kilowatt hour ("kWh") credits; however, the Company is not proposing to change the transferability of kWh credits for legacy customers. *Id.*

The Company proposes that accumulated kWh credits held at service points with non-legacy systems will be converted to financial credits one year after the effective date of a Commission-authorized change in compensation structure. *Id.* at 25.

The Company represents it will issue a news release and will directly notify its customers of the Application with a bill insert included with their next billing cycle. Id. at 26-27. The Company will also send direct-mail letters to all existing and pending on-site generation customers and will have information regarding its proposals on its website. *Id.* at 27.

STAFF ANALYSIS

Based on the analysis presented in the sections below, Staff recommends that the Commission issue an order to:

1. Implement Staffs proposals for a real-time net billing with an avoided cost based, seasonal, time-variant, ECR, with the following recommendations:
    a. Adjust the On-Peak *season* to align with the summer season proposed in the GRC. Direct that updates to the *season* be part of future general rate case filings;
    b. Accept the On-Peak *hours*, as proposed by the Company, but direct that if future IRP analysis indicates a need to update the *hours* of highest risk, the Company should file a separate docket;
    c. Distribute the avoided energy value in alignment with the summer and non-summer seasons, as determined in the GRC;
    d. Use the *most current* levelized capacity cost for the least-cost dispatchable resource from the 2023 IRP;
    e. Use a *five-year* rolling average of the ELCC percentage to determine the avoided capacity value;

f. Calculate the ELCC and avoided capacity values *without* the line loss gross up, and *subsequently apply* the line loss gross up to that result;
g. Include *all* customer exports in the calculation of each year's ELCC;
h. Use the industry-typical line loss calculations. Apply the annual energy line losses to the energy value, and the peak hour line losses to the capacity value.

2. Direct the Company to update all proposed components of the ECR except the hours of highest risk in an annual filing beginning April 1, 2025.
3. Direct the Company to update the hours of highest risk in a separate filing on an as-needed basis.
4. Maintain the current Schedule 6 and Schedule 8 eligibility caps but monitor when the cap becomes limiting and consider changes to the cap if warranted.
5. Approve the proposed eligibility cap for Schedule 84 customers: the greater of 100 kW and 100% of demand and:
   a. Incorporate into Schedule 84 the Company's proposed methods used to determine a customer's demand relative to the Schedule 84 cap.
   b. Direct the Company to play a more active role to verify the need for a professional engineer to conduct an analysis to determine a new customer's demand requirements.
   c. Direct that the cost of such analysis should be charged to the on-site generation customer.
   d. Incorporate into Schedule 84 the description of the Company's proposed treatment when a customer's demand changes; and
   e. Clarify in Schedule 84 that an expanded system is still subject to the project eligibility cap, which is the greater of 100 kW or 100%of demand at the service point.
6. Incorporate the Company's additional proposed interconnection requirements in Schedule 68 due to the increase of the project eligibility cap for Schedule 84.
7. Approve the Company's proposal to exclude energy storage and only include the nameplate capacity of generation to enforce the eligibility cap for Schedules 6, 8, and 84; and to require the customer to pay all upfront and ongoing costs of system upgrades through a surcharge, if upgrades are needed.

8. Approve the Company's request to recover ECR expenditures as a net power supply expense subject to 100% recovery through the PCA.
9. Approve the Company's proposals on the use and transferability of financial credits.
10. Approve the Company's proposal to convert accumulated kWh credits to financial credits using a blended average retail energy rate on December 31, 2024, and:
    a. Direct the Company to notify each non-legacy customer that has excess kWh credits as of December 31, 2024 of how their excess credits will be converted, at what rate, and how it will be displayed on their next bill.
11. Direct the Company to transfer or refund any accumulated financial credits in the event a customer relocates or discontinues service.
12. Authorize the integration rates from the 2020 Variable Energy Resource ("VER") study as proposed for purposes of the ECR rates in this filing, and:
    a. Direct the Company file an update to Schedule 87 rates and integration costs from the 2020 VER study for Commission approval to be used in future ratemaking that requires it, including updates to Clean Energy Your Way ("CEYW") and ECR-related rates.
    b. Direct the Company to file all future VER studies and integration costs for Commission authorization, if integration cost have materially changed from those authorized.
13. Direct the Company to adjust the language of Tariff Schedules 6, 8, and 84 according to all recommendations presented above in a compliance filing.

Case History & Introduction

As a basis for its analysis, Staff used established Commission language on the necessity of an updated rate for the Company's on-site generation programs. Order No. 34046 established the need to create the rate classes based on evidence of cost-shifting and the increasing feasibility and penetration of on-site generation technology; and established the need to study the costs, benefits, proper rates and rate design, and other issues.

On the topic of cost shifting, the Commission stated that: "Our analysis of the history of the Company's on-site generation program reveals an unfairness in how current and future on-site generation customers avoid fixed costs. The ability these customers have to 'net out' or net to zero their electricity use causes them to underpay their share of the Company's fixed costs to serve customers, and this inequity will only increase as more customers choose on-site generation." Order No. 34046 at 16. The stated ability of customers to net out their fixed costs is a product of the technological limitation of bi-directional meters common in place at the time of when the Company began offering NEM in 1983. Those meters only had a single channel meaning it would simply spin backwards when a customer exported power, banking the export until the next unit of consumption rolled the meter forward. This limitation meant that a customer could potentially use a kWh exported during the day to offset load during the night. Since the time of the original NEM offering, the Company has installed Advance Metering Infrastructure ("AMI") meters that are capable of tracking imports and exports as separate channels.

When paired with the Company's rate structure, the current NEM leads to the on-site generation customers not paying their share of associated fixed costs. Under the Company's current rates, energy rates have fixed costs embedded into them. Any time an on-site generation customer uses a banked export to offset consumption the Company is not recovering the fixed or variable costs incurred to serve that customer, thus driving a difference between the actual and expected recovery for the Company. The difference between the fixed and variable costs incurred and not recovered is reflected in the Fixed Cost Adjustment ("FCA")[2] and PCA [3] mechanisms. In both mechanisms, the difference is captured and passed on to all customers in the form of an increased surcharge to the PCA and FCA; thus, shifting costs to non-generating customers.

In Case No. IPC-E-17-13, Staff and intervenors attempted to quantify the subsidy created from this situation. The Commission stated that "we need not quantify a cost shift in either direction to make our decision." *Id.* at 17. From review of the Company's current rate structure and consistent with the Commission language, Staff believes it is necessary to change the Company's current net energy credit offering to a financial based ECR. If a change does not occur, the increasing penetration of on-site generation will in turn increase the subsidy to on-site

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[2] The FCA accounts for the difference between the expected recovery of the fixed cost components embedded in variable rates and the actual amount that the Company received. The FCA is calculated using the difference between actual collections and an approved recovery amount based on the most recent rate case.
[3] The PCA is a mechanism that the Company uses to account for the variable costs incurred to supply power for its customers. At a high level, the PCA is calculated using the difference between the actual NPSE and the revenue collection based on expected usage.

generation customers. In 2017, the Company identified 1,468 active and pending on-site generators on its system. IPC-E-17-13, application at 6. As of June 2023, this number has grown to 17,098 systems. *See* Response to Production Request No. 21. As federal policy, environmental considerations, and economic drivers increase the implementation of on-site generation systems, it remains important to address the identified cost shift to protect all customers by moving forward with an ECR from the current one-to-one energy credit offering for non-legacy customer in Schedule 6, 8, and 84.

Staff Proposed ECR

Staff believes that, in general, the Company's proposals are reasonable and well supported by the extensive case history. However, Staff disagrees with some of the Company's proposals, and Staff has prepared an alternate proposal recommending changes to the summer season, allocation of energy value, and line losses. A summary of Staff's proposed ECR design and comparison to the Company's proposed ECR is presented in Table 1 below.

Table 1 – Comparison of Company and Staff proposed ECR's

ECR by Component (cents/kWh)	**Staff Proposed**		**Company Proposed**	
	Season	**ECR**	**Season**	**ECR**
Energy	Summer	5.66 ¢	On-Peak	8.59 ¢
Including integration and losses	Non-Summer	4.84 ¢	Off-Peak	4.91 ¢
Generation Capacity	On-Peak	9.18 ¢	On-Peak	11.59 ¢
	Off-Peak	0.00 ¢	Off-Peak	0.00 ¢
Transmission & Distribution Capacity	On-Peak	0.18 ¢	On-Peak	0.25 ¢
	Off-Peak	0.00 ¢	Off-Peak	0.00 ¢
Total	**Summer On-Peak**	**15.06 ¢**	**On-Peak**	**20.42 ¢**
	Summer Off-Peak	**5.66 ¢**	**Off-Peak**	**4.91 ¢**
	Non-Summer	**4.84 ¢**		

For its analysis of each of the ECR components, Staff considered the criteria identified in Case No. IPC-E-22-22: understandability, transparency, accuracy, and stability. Although understandability, transparency, and stability are criteria that are uniquely important to customer generators, the accuracy of the ECR is not only important to customer generators so they receive an accurate value for their exports, but also important to all other ratepayers who consume and are being charged for customer-generator's exports.

Staff utilized the principles of avoided cost to determine the accuracy of avoided cost values in the ECR and to identify the components that should be included. Using avoided cost to accurately determine the ECR will ensure that customers who consume exported power from customer generators are "indifferent" as to whether the Company receives its power from the Company's existing resources or from customer generators.[4]

Finally, Staff evaluated the Companies analysis for differentiating rates based on the value of exports using the levels of reliability risk in the Company's system during different time periods.

<u>Measurement Interval</u>

The current NEM structure uses a monthly netting interval which allows the exporting customer to "bank" exports, in the form of energy credits, for use during hours when the customer was a net consumer. This allows a customer to use any excess kWh credits from exports to offset their consumption when they are not exporting.

For the measurement interval of the ECR, Staff considered both a real-time, and hourly, netting interval consistent with Commission Order No. 35631. Staff did not consider any interval larger than hourly (i.e., daily, weekly, monthly, etc) because the longer the interval, the less accurate the measurement becomes.

Real-Time Interval

Based on its analysis of the measurement interval, Staff believes that a real-time interval presents many advantages in terms of accuracy, understandability, and malleability of the ECR. A real-time or instantaneous measurement interval takes advantage of the AMI meter's

[4] The Commission has used avoided cost principles to evaluate and set rates for resources that provide power and benefits to the Company's system for Public Utilities Regulatory Power Act ("PURPA") projects, Demand-Side Management ("DSM") resources, and special-contract customer-generation projects through the Company's Clean Energy Your Way program. The basis of avoided cost is well documented in *Indep. Energy Producers Ass'n, Inc. v. Cal. Pub. Utils. Comm'n*, 36 F.3d 848, 858 (9th Cir. 1994) ("If purchase rates are set at the utility's avoided cost, consumers are not forced to subsidize QFs because they are paying the same amount they would have paid if the utility had generated energy itself or purchased energy elsewhere.")

capability to track imports and exports separately. Under this measurement interval, energy that customer generators are exporting to the system is tracked through the meter in the same way as consumption. Because the export is counted at the moment it is exported, a real-time interval is the most accurate interval available, limited only by how often the Company collects data and aggregates it for analysis. In its Response to Production Request No. 6, the Company stated that under the proposed real-time measurement interval, data would be pulled from the AMI meter on an hourly basis. Although the data is gathered on an hourly basis, the data is still based on energy counted at the moment of export.

By using the proposed real-time measurement interval, exports would be tracked in a manner consistent with imported power. Imports and exports would each have their own meter channel, using data collected on the same time schedule and with each having its own associated rate. Staff believes that having consistency between exports and billing will increase customer understandability and transparency.

Under a real-time interval, the Company and customer generators would have both the import and export data for every hour. [5] This interval matches the hourly resolution of the proposed ELAP market prices and the granularity of other Company analysis and programs such as TOU consumption billing. Staff believes aligning the measurement interval with the resolution of other data will increase the potential options for future optional rate structures.

Staff recognizes that implementing a real-time measurement interval will likely increase the bills for on-site generation customers; however, Staff is confident that this impact will be caused strictly from increasing the accuracy of tracking exports and will reduce cost shifting to non-customer generators.

Hourly Netting Interval

Based on its analysis of the measurement interval, Staff believes that a net hourly interval is less accurate, does not present real benefits, and is less understandable than a real-time interval. Similar to the current monthly netting, an hourly netting interval allows a customer to bank and consume exported energy within the netting period (i.e., hourly). By shortening the netting interval from a monthly interval to a more granular hourly interval, the ability to offset

[5] Customer generators will be able to access their imports and exports for their meter through their My Account information that is available to a customer through the Company's website or app.

imports is reduced. The Company demonstrates this in the VODER study by showing that the inaccuracy of an hourly net billing structure yields a quantifiable difference when compared to a real-time net billing structure. *See* October VODER study, p.21, Figure 3.5-3.16.

From the perspective of a customer-generator, an hourly netting interval has the effect of slightly extending the one-to-one kWh offset benefit that the customer experiences behind the meter as generation offsets load. However, this "benefit" is due to the inaccuracy of the netting interval and is not associated with an actual reduction in consumption. For all other customers on the Company's system, the inaccuracy of the netting translates to an expense paid to exporters for energy that is not actually provided to the Company's system.

Regardless of using real-time or hourly netting, the Company would continue to collect import and export data on an hourly basis. *See* Response to Production Request No. 6. Consequently, under an hourly netting interval, the Company would still use the same input data as the real-time interval to calculate the hourly net exports for each customer.

The Company affirms that data will be available to customers at the hourly level. *See* Response to Production Request No. 9. However, Staff believes that under an hourly netting interval there will be an apparent inconsistency for those unfamiliar with the netting calculation. This additional calculation and separation from the raw data reduces understandability by complicating customer's bills. Additionally, because the Company will be using real-time interval data to determine the net hourly interval imports and exports, the Company will incur additional cost with no additional benefit over implementing a real-time measurement interval. *See* Supplemental Response to Production Request No. 8.

From the analysis presented above, Staff believes that a real-time measurement interval is more accurate, more understandable, and more malleable than a net hourly interval. Staff recommends that the Commission order the Company to implement a real-time measurement interval for its ECR.

<u>Time Period Rate-Differentiation based on System Reliability Risk</u>

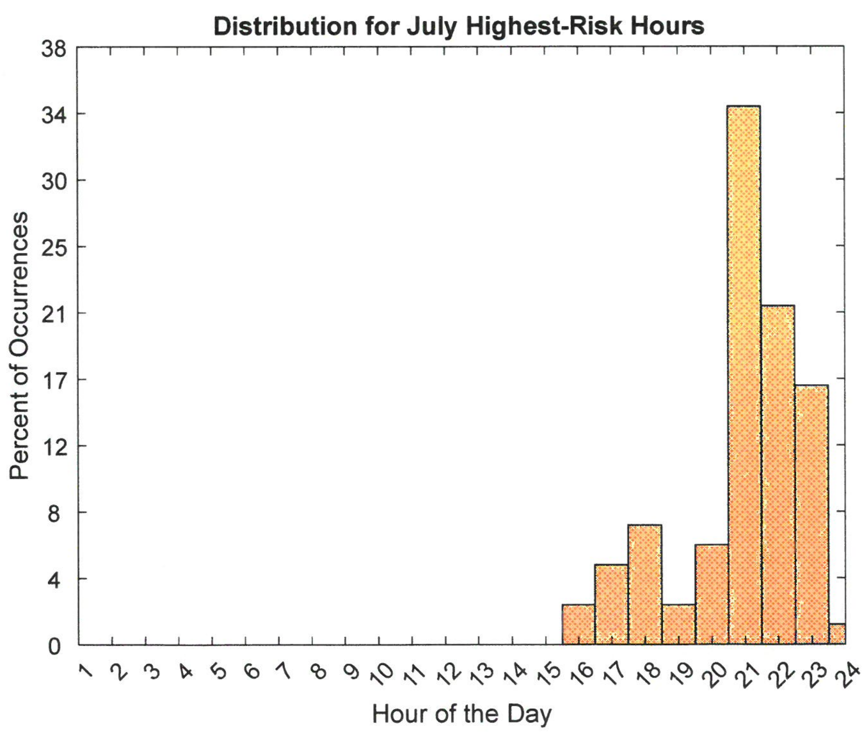
The Company's proposal for the ECR is a seasonal time-variant rate structure. This type of rate design structure creates higher rates in the proposed "On-Peak" summer season of June 15 to September 15 between the highest risk hours of 3pm to 11pm. Support for these hours is based in the 2021 Integrated Resource Plan ("IRP") analysis of the highest risk hours and seasons on the Company's system presented in its filing to modify the seasons of its Demand Response ("DR") programs in Case No. IPC-E-21-32.

In contrast to the time periods proposed for the ECR, the Company maintains an optional TOU consumption rate schedule that charges higher rates during higher risk hours. For residential customers under Schedule 5 the TOU rates have a seasonal "On/Off-Peak" structure corresponding to only the highest risk hours. For Schedule 9, 19, and 20 customers, the TOU hours include Mid-Peak pricing. In the Company's concurrent General Rate Case ("GRC") filing, Case No. IPC-E-23-11, the Company is proposing to change the TOU peak hours for Schedule 5 customers to occur between 7pm and 11pm. For TOU schedules with Mid-Peak pricing, the Company is proposing to change the timing of Mid-Peak pricing to 3pm to 7pm and 11pm to 12am with On-Peak pricing from 7pm to 11pm. Additionally, the Company is proposing to extend its summer season one month to span from June 1 to September 30. As described in the testimony of Connie Aschenbrenner filed in the GRC, the proposals for TOU hours and extending the summer season are based on preliminary analysis performed for the Company's 2023 IRP that have shown an increasing trend of high-risk later in the summer season and in the later hours of the day. The Company's GRC was filed on June 1, 2023, and at that time the Company requested an extension from the Commission to extend the file date of its IRP to the last business day of September 2023. *See* Case No. IPC-E-23-17 and Order No, 35837.

The difference in the proposals for the ECR and TOU rates can be attributed to the timing of the 2023 IRP highest risk analysis, which was not completed in time to be used for the ECR filing. In both filings, support for the proposals was provided by the same type of "Highest Risk" analysis. This analysis is based out of the Company's Reliability and Capacity Assessment Tool ("RCAT"). The RCAT is a computing tool that uses hourly load and generation data inputs to calculate a Loss of Load Probability ("LOLP") or risk that the combination of all the resources on the Company's system will be unable to meet load for each hour of the year. The Company uses the hourly LOLP values to determine hours and seasons of highest risk. Hours of highest risk are determined directly from the LOLPs for each month. The analysis considers the hours of the top ranked LOLPs that correspond to 50% of all the risk within the month.

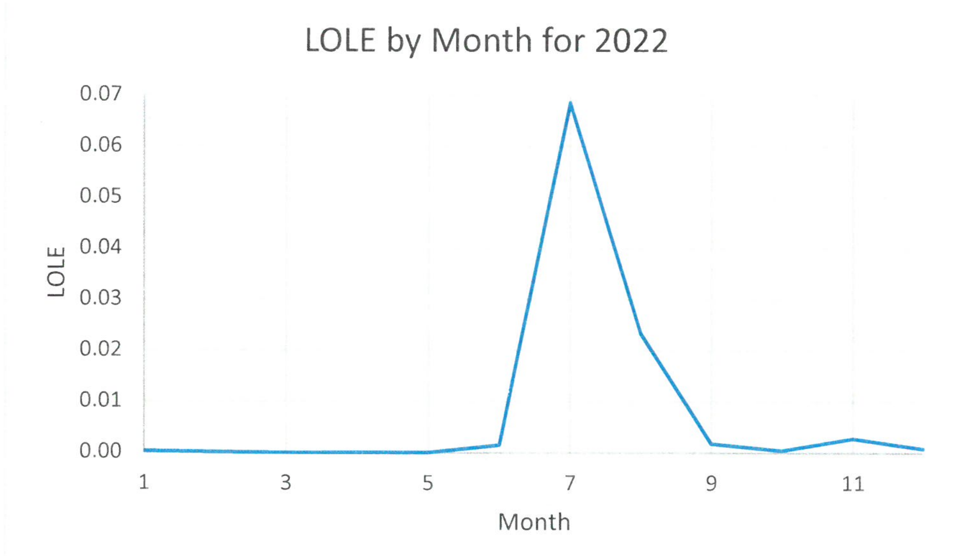
In Response to Production Request No. 96 in IPC-E-23-11, the Company's highest risk analysis shows that the highest risk hours are between 3pm and 12am with the most risk concentrated in a consecutive block between 7pm to 11pm. The Company's proposals define the 7pm to 11pm consecutive block as "On-Peak", the remaining high-risk hours as "Mid-Peak" and all other hours as "Off-Peak". Additionally, the Company used the same analysis to define the summer season (June 1 through September 30). Staff notes that the Company did not include its Battery Energy Storage Systems ("BESS") in its analysis of the hours of highest risk. Staff is concerned that by excluding BESS resources from the model, the analysis does not accurately reflect the actual risk seen by the system. However, this resource type is a recent addition to the Company's system and Staff will review this analysis as part of the Company's 2023 IRP and future filings by the Company. Figure 1 below demonstrates that for the month of July, 50% of all risk is contained between the hours 4pm and 12am

Figure 1: example of the LOLP distribution used to determine the highest risk hours for the month of July



When defining seasons of highest risk, the analysis aggregates the hourly LOLP to a monthly perspective. This is done using a Loss of Load Expectation ("LOLE") or the expectation that that Company will suffer a loss of load in a given month. LOLE is calculated by taking the sum of the highest LOLP for each day in a month. Figure 2 shows the LOLE for each month of a load and resource year of 2025 using a 2022 historical year. Consistent with the proposed high-risk season, the vast majority of the loss of load expectation is captured between the months of June and September.

Figure 2 – Example of the LOLE for each month of 2022.



The Company uses its identified seasons and hours of highest risk to inform its CEYW construction projects, DR programs, Demand Side Management ("DSM") avoided costs, TOU consumption rates, and the proposed ECR. Of these programs, the CEYW, DR programs, and DSM avoided costs are noted to have significant differences that separate them from the other offerings, despite being informed by the same analysis. For the CEYW construction projects, after the analysis is complete, the highest risk timing is locked in and does not receive updates. DSM avoided costs are used to estimate the value of programmatic offerings. Finally, and most notably, DR programs have additional analysis conducted that maximizes the effectiveness of the programs given the limitations of their dispatch parameters. Despite similar analysis, Staff believes that it is inappropriate use the same DR season (June 15 to September 15) for the ECR and that the method for determining these seasons is not directly comparable. Accounting for these end uses leaves the TOU consumption rates and the proposed ECR for direct comparison. Both rates are based on the same type of analysis presented in the Company's IRP filings and both share an intended purpose of using price signals to encourage behavior that benefits the Company's system. Because of the similarities between these offerings, Staff believes that it is inappropriate to have a misalignment between the timing of the export credit and TOU rates price signals.

Staff recommends that the Company align the summer seasons of the ECR to match the summer season of June 1 to September 30 presented in the concurrent GRC. Staff notes that this recommendation is to align the ECR seasons with those presented in the GRC and is based on the Company's preliminary analysis presented in Response to Production Request No. 96 in Case No. IPC-E-23-11. Staff recommends that the seasons of highest risk for all rates be updated as part of future general rate case filings as informed by the most recently filed IRP. Additionally, Staff believes that, as proposed by the Company, a misalignment of the summer season for all Schedules in the GRC and the ECR summer season will cause customer confusion. Staff received numerous questions, comments, and concerns regarding this in Staff's Workshop and through public comments regarding the misalignment of TOU and export credit rates. Staff notes that this proposal interacts with the Company's proposal for On-Peak hours. If accepted by the Commission, Staff's proposed summer season would have the effect of shifting some value from the On-Peak rates to the Off-Peak rates and extending the On-Peak hours. Staff believes this favors on-site generation customers by providing more value in accessible times. More detailed analysis on these impacts is presented in the relevant sections below.

Based on analysis provided in Response to Production Request No. 96 of Case No. IPC-E-23-11, the combined Mid-Peak and On-Peak risk hours used to define the TOU rates span a similar window as the proposed ECR, 3pm to 12am and 3pm to 11pm, respectively. Due to this similarity, Staff is comfortable with the Company's proposed On-Peak ECR hours of 3pm to 11pm for the summer season of June 1 to September 30. However, this does not negate the need for continued alignment between the TOU and ECR highest risk hours. Staff recommends that, as IRP analysis indicates a need to update hours of highest risk, the Company file a separate docket to update the highest risk hours for both the ECR and TOU rates.

Avoided Energy

Determination of Value

Staff agrees with the Company's proposed method for valuing avoided energy based on ELAP pricing. The Company proposes that the value of avoided energy be determined by the hourly prices from the Energy Imbalance Market ("EIM"), the western region's real-time energy market. Since EIM prices vary from location to location, the Company proposes using the EIM Load Aggregation Point ("ELAP") pricing, which is independently determined on an hourly basis by the California Independent System Operator ("CAISO"). The Company proposes to use the 12 months of market data ending December 31 of each year. Under the Company's proposal, the avoided energy component of the ECR is calculated by multiplying the ELAP hourly price, given in dollars per megawatt-hour ("MWh") of energy, by the total MWhs exported by customer-generators each hour, yielding a total dollar value for all energy exported that hour. The hourly values can then be summed up and distributed according to a method discussed in the next section.

Staff believes that the use of hourly ELAP prices is reasonable because they reflect the true market value of energy in the Company's service area in each hour. The price represents the market value of *non-firm* energy, which Staff believes is the correct classification of customer-generator exports. Given the challenge of fairly adjusting the value of energy downward if it is non-firm, Staff believes this aspect of ELAP pricing is a significant advantage. Lastly, ELAP pricing is publicly available information through CAISO, which makes the use of ELAP values transparent and verifiable.

Staff believes that using historic pricing data is reasonable. Historic pricing is less accurate than real-time pricing as it creates a delay or lag between the current energy price and when those prices are reflected in the value of the ECR, but it provides rate stability and transparency for the customers. Staff believes it is more important to provide customers a fixed set of published energy values for a year, than to assign an unknown and highly variable real-time price to each unit of exported energy. If the proposed ECR were to use a shorter historical data set or a real-time market price, the resulting rates would fluctuate often and offer no stability for customers to plan their investments. Additionally, to keep the value of energy as accurate as possible, Staff agrees with the Company's proposal to use the most recent year's pricing data, and not to incorporate multiple years of pricing data via some type of rolling average.

Distribution of Value

Staff disagrees with the Company's proposed method to distribute the value of avoided energy and recommends that the value of avoided energy be allocated between the Summer and Non-Summer seasons and the definition of Summer and Non-Summer for the ECR be aligned with the Summer and Non-Summer seasons for the corresponding consumptive tariffs proposed in the Company's GRC. The Company proposes to distribute the energy value between an On-Peak time window and all other hours, called the Off-Peak window. The Company claims that the On-Peak hours are "currently identified as the hours of the Company's greatest system need for energy and capacity." Ellsworth at 9.

Staff believes that the On-Peak time window is determined primarily by capacity considerations, not energy considerations, as described in further detail in the System Reliability Risk section above. Staff believes that it is inappropriate to distribute the energy value using a time window defined by capacity. As the capacity-based hours span into the evening when solar production is unavailable, the energy value assigned to those times would be unattainable by most customer generators.

A better proposal is to assign the energy value in accordance with energy-defined seasons. Staff proposes to distribute the energy value between the Summer and non-Summer seasons that are established in the tariffed consumption rates. The Summer season has higher volumetric consumption rates primarily because energy costs are higher in that season. It is conceptually consistent, and therefore more accurate, to allocate the ECR avoided energy costs in the same manner. This proposal also partly resolves public comments that noted the inconsistent times and seasons between consumption rates and ECR rates. Staff believes its proposal is fairer to exporting customers because it allocates all the avoided energy value only to seasons, and not to specific hours of each day (especially hours after dark), so the full energy value is obtainable by all exporting customers.

A downside of having differing time periods between Energy and Capacity components is that the combined ECR could have as many as four different values. The Company's proposal would only have two ECR values, an On-Peak value and an Off-Peak value, because it defines the times and seasons to be the same for Energy and Capacity. If the Summer season is extended to September 30, as supported by Staff in the Company's general rate case, Staff's proposal would produce three ECR values: Non-Summer, Summer Off-Peak, and Summer On-Peak. This incremental complexity is not unusual in the Company's optional Schedules. Staff believes this small additional complexity is worth the benefits.

Comparison of Value

If the Commission accepts Staff's proposal and the definition of the Summer season of June 1 to September 30, Staff calculated what the ECR energy rates would be and compared them to the Company's proposed On- and Off-Peak energy rates in Table 2 below:

*Table 2 –ECR Energy Value Comparison**

Company Proposal	Cents/kWh		**Staff Proposal**	Cents/kWh
On-Peak Jun 15 – Sep 15, 3pm-11pm, excluding Sundays & Holidays	8.59		*Summer* *Jun 1 – Sep 30, all hours*	5.66
Off-Peak All other days and hours	4.91		*Non-Summer* *Oct 1 – May 31, all hours*	4.84

* Based on the Company's 2022 data and inclusive of the Company's proposed line losses and integration costs.

Although the Summer energy rate is less than the On-Peak rate, Staff believes that the longer season and more inclusive hours will return the energy value more fairly to customers within each class. The Company's proposal would favor customers whose systems could export late in the day, such as systems with battery storage and west-oriented systems.

<u>Avoided Generation Capacity</u>

Determination of Value

Staff believes that the Company's proposed method for valuing avoided generation capacity of exports is reasonable. However, to increase the stability, accuracy, and transparency of the proposals, Staff recommends that the Company implement the following:

1. Using a 5-year rolling window instead of a 3-year rolling window to estimate Effective Load Carrying Capability ("ELCC") values;
2. Modifying the method used to incorporate line losses in calculating capacity value; and
3. Using all exports from customer generators in its calculation of the ELCC.

The Company proposes to determine the capacity contribution of all customer generation (measured in total kilowatts) and multiply it by the levelized capacity cost of the least expensive dispatchable resource (measured in $ per kilowatt per year).

Staff agrees with the Company's proposal to use the levelized capacity cost of the least expensive dispatchable resource as determined in the most recently filed IRP. The Company has used this convention to value capacity costs in other cases and it is consistent to continue this practice. In the 2021 IRP, the least-cost resource is the Simple Cycle Combustion Turbine ("SCCT"), valued at $131.60 per kilowatt per year. However, on September 30, 2023, the Company filed the 2023 IRP. In this edition, the least expensive dispatchable resource is still the SCCT, with a levelized cost of $145.94 per kilowatt per year. Staff recommends that this updated value be used to determine the avoided capacity value because it is more current and therefore more accurate.

To determine the capacity contribution of customer-generators, the Company proposes multiplying a rolling 3-year average of the ELCC percentage by the hour of maximum exports, thereby yielding the equivalent megawatts of perfect generation. Staff believes the ELCC is a reasonable method to determine a resource's capacity contribution. Electric utilities are beginning to adopt methods similar to the Company's ELCC method because it measures a resource's contribution during the hours of highest risk, which are often different from the hours of highest system load. The true value of avoided capacity occurs during the hours of highest risk, so the ELCC is a more accurate means of assigning value. Older capacity methods such as the National Renewable Energy Laboratory ("NREL") 8,760-hour method, or the Peak Capacity Allocation Factor ("PCAF") method assess a resource's contribution during the hours of highest system load, not necessarily during the hours of highest risk, and are therefore less accurate.

Although the Company proposes a 3-year rolling average of ELCC values, Staff recommends increasing the ELCC to a 5-year rolling average. This is because Staff is concerned the ELCC will trend down as solar penetration increases. Utility-scale solar generators can lock in their ELCC percentage through a contract with the Company, but this is not practical for a class of customers with customers who enter and exit the class on an ongoing basis. Staff believes a reasonable workaround is to extend the duration of the rolling average so the ELCC values of early years can continue contributing to the overall capacity value for a longer period. The year 2020 was the first year ELCCs could be accurately determined for customer exports, so a full 5-year average would not be attainable until the end of 2024. Therefore, if the Commission accepts Staff's recommendation, the rolling average would incorporate each year's result as it became available through 2024.

Staff proposes a modification to how the Company incorporates line losses into the calculation of capacity value. The Company marks up the customer exports and feeds the marked-up values into its MATLAB scripts that calculate the ELCC. In theory, the grossed-up exports yield a slightly higher ELCC result than if the unmodified values were used. However, Staff believes that the ELCC algorithms do not have the resolution to account for the small line loss increases, thus line losses are effectively nullified. Because the Company performs these calculations using complicated MATLAB scripts, verification by Staff is extremely difficult. Staff therefore proposes that the Company account for line losses for capacity in the same manner as it does for energy, by applying the line loss gross up *after* the ELCC and avoided capacity values are determined. This approach is simpler and more transparent to all parties and will likely produce more accurate results.

Staff disagrees with one of the Company's ELCC calculation steps. In its response to Production Request No. 2, the Company disclosed that it zeroes out all customer exports except the ones that occur during the On-Peak hours, and inputs that modified export profile into the ELCC algorithm. Even though most of the contributions to capacity occur during the On-Peak hours, Staff believes that some contributions to capacity may occur outside those hours. Therefore, the Company should include *all* exports in its calculation of the ELCC. The Company should be calculating the full value of avoided capacity value throughout the entire year, not just the avoided capacity value during the On-Peak hours. The subsequent distribution of that value is discussed in the section below.

Distribution of Value

Staff believes the Company's proposal to distribute all the generation capacity value to the On-Peak hours is reasonable. The Company proposed to distribute the value of avoided generation capacity to its On-Peak hours. The On-Peak hours correspond to the hours of highest risk discussed at length in the preceding section on Rate Design Structure.

Staff agrees with the Company's assertion that "The procurement of capacity resources is driven by the identified hours of highest risk…." Ellsworth Direct at 17. This means that customer exports that occur during the hours of highest risk are principally responsible for avoiding the need and cost for additional capacity. Therefore, the value of avoided generation capacity should be distributed during those periods when capacity costs are avoided, which occur during the hours of highest risk. This has the added advantage of sending a price signal to incentivize customers to export energy during these hours. Details of Staff's analysis of the definition of On-Peak hours can be found in the Time Period Rate-Differentiation Based on System Reliability Risk section above.

Comparison of Values

Table 3 below compares the On-Peak capacity values using the 2021 avoided resource value and the 2023 avoided resource value.

*Table 3 – ECR Capacity Value Comparison**

	Units	**2021 IRP**	**2023 IRP**
Levelized Fixed Cost of Avoided Resource	$/kW-year	$131.60	$145.94
On-Peak Avoided Generation Capacity Value	cents/kWh	11.59	12.85

* All calculations use the Company's original line loss value and method for applying the line losses. Proposed changes to the line loss rate and ELCC calculations are not captured.

<u>Avoided Transmission and Distribution Capacity ("T&D")</u>

Determination of Value

The Company compares T&D capacity shortfalls throughout its system and overlays customer exports to determine how long it can delay projects that increase T&D capacity. The value is determined based on the cost of capital of the project investment and the length of time a project can be delayed. Staff believes the Company's proposed method of project-by-project deferral assessments is reasonable and agrees that assessing every T&D capacity project over a 20-year time span is sufficiently comprehensive.

Staff recognizes the validity of the Company's long-established process to identify future T&D capacity shortfalls by forecasting local load growth and comparing it to T&D capacity limits. However, Staff has concern about the auditability of the final step, the overlay of customer exports and the identification of capacity deferrals. Because the total value of T&D

project deferrals is less than 1% of the overall ECR value, Staff concludes that the risk is low and the proposed approach is reasonable.

Distribution of Value

The distribution of value for avoided T&D capacity follows the same reasoning as the distribution of value for avoided generation capacity, as discussed in the preceding section. In short, the avoided capacity value should be distributed only to exports during the hours of highest risk because those are the hours when the value is truly earned. Staff believes the Company's proposal to distribute all the T&D deferred capacity value to the On-Peak hours is reasonable.

<u>Avoided Line Losses</u>

In its Application the Company opted to update the line loss analysis using 2022 data included as Exhibit No. 4, rather than line loss data from a 2012 study utilized in the VODER Study. The Company's data shows overall losses declined from 9.7% in 2012 to 7.6% in 2022. Both values are higher than the nationwide average of 5%.[6]

Staff reviewed the report and the underlying calculations and concluded that the analysis is reasonably accurate but disagrees with the Company's proposed coefficients.

Determination of Value

The electric utility industry typically calculates line losses in two ways.[7] The first way calculates the system losses over the entire year, and the second way calculates the system losses during the peak hour of the year. The Company performed both calculations as part of its study but attempted to calculate the losses during the On-Peak and Off-Peak periods. To do this, the Company used hourly data from its 138-kV system to serve as a proxy to modify the peak and energy calculations. Staff believes this approach embeds too many assumptions, obfuscates the calculations, and jeopardizes accuracy. Also, it is inappropriate to apply a capacity-based loss rate to the ECR energy value.

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[6] U.S. Energy Information Administration estimate of annual T&D losses in the United States 2017-2021.
[7] Distribution System Losses Evaluation by Electric Power Research Institute, December 2008; Chapter 3.

Staff recommends that the ECR utilize the industry-typical loss calculations, not the Company's unique extrapolation of those losses. The avoided energy value should be grossed up by the standard annual energy loss coefficient and the avoided capacity value should be grossed up by the standard peak hour loss coefficient. This more accurately aligns the loss measurements with each of the avoided values. It also streamlines any future studies by only using the industry-typical calculations. Overall, Staff believes this approach is more accurate and more transparent.

Comparison of Value

Table 4 below compares the proposed loss coefficient values:

Table 4 – ECR Line Loss Coefficient Comparison

Company Proposal	Staff Proposal
On-Peak = 1.050	Capacity = 1.053
Off-Peak = 1.044	Energy = 1.044

Avoided Environmental Costs

The Company has not proposed to include any avoided environmental benefits. For its analysis, Staff considered a national carbon tax, an Idaho Renewable Portfolio Standard ("RPS") policy, social health, and RECs as options that could be used to provide a value of an environmental benefit.

There are currently no mandated Carbon Tax, RPS policy, or other environmental costs to the Company on a state or federal level. Outside of a mandate there is no other identified environmental benefit that has a direct and quantifiable impact on the Company's rates. Commission Order No. 35631 at 28. Regarding Renewable Energy Credits ("RECs"), ownership remains with the owner of the on-site generation system absent an RPS or other legislation. Until a state or federal legislation mandates a quantifiable environmental cost or adder to the Company's rates, it is not appropriate to include any associated environmental benefits in the ECR.

Integration Costs

The Company proposes to use its 2020 VER integration study to provide an integration cost of $0.00293/kWh to be accounted as a reduction to the proposed ECR. An integration study is a study that is periodically conducted by the Company to quantify the cost of regulating variable, non-firm energy sources into the Company's system such as those used by customer-generators. Due to the scope of the Company's integrations studies, Staff does not expect that changes to the NEM will not directly affect the forecasts or validity of the 2020 study's estimation of integration costs. In its Response to Production Request No. 35, the Company stated that the previous integration study considered VER penetration levels beyond what is currently on the Company's system. Staff agrees with the Company's basis for and inclusion of the $0.00293/kWh integration cost in the ECR.

While the proposed integration costs have been thoroughly reviewed through the IRP and are well supported for inclusion in the ECR, Staff believes that the Company should be using integration costs authorized by the Commission for ratemaking purposes. In the past, after a new study is completed, the Company has filed an update to Schedule 87 (intermittent Generation Integration Charges) and once authorized, it is used to determine avoided cost rates for PURPA. The last time Schedule 87 was updated was in July of 2016, even though subsequent VER studies have been conducted. Staff recommends that the Commission: (1) authorize the integration rates for purposes of the ECR rates in this filing; (2) direct the Company to file the 2020 VER study for Commission authorization to update Schedule 87 and to be used in future ratemaking that requires it including future updates to CEYW and ECR-related rates; and (3) direct the Company to file all future VER studies and integration costs for Commission authorization, if integration cost have materially changed from those authorized.

Billing Impacts of Proposed ECR Rates:

Most on-site generation customers will experience the largest impact of the change to the ECR in their bills. Under the Company's proposal, non-legacy customer generators will no longer be able to bank energy credits (NEM) to offset their consumption usage and customers will now receive a financial credit (ECR) for their exports which can then be used to pay any part of their bill. The Company estimates the average non-legacy customer bill to increase approximately $12 for Schedule 6, $15 for Schedule 8, and $12 for Schedule 84. This rate can vary significantly for each customer usage and export patterns, but in general customers that tend to consume higher amounts of energy will experience the greatest financial impact.

Table 5 - Schedule 6 Average Bill Impact[8]

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

Table 6 - Schedule 8 Average Bill Impact[9]

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

Table 7 - Schedule 84 Average Bill Impact [10]

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

[8] See Response to Staff Production Request No. 1, Attachment 1 – Response to Staff Request No. 1 – Residential
[9] See Response to Staff Production Request No. 1, Attachment 2 – Response to Staff Request No. 1 – Small General
[10] See Response to Staff Production Request No. 1, Attachment 3 – Response to Staff Request No. 1 – Large General

All Customers	**8**	**$ 61.64**	**$ 73.94**

Bill Impacts under Staff Proposal

Under Staff's proposal, while the summer On-Peak rate is slightly reduced from the Company's On-Peak rate, customers will have a greater period of time to earn a higher value for exports to the Company's system. For On-Peak summers hours, customers would have a total of 824 hours to receive the higher ECR versus the Company's proposed season for On-Peak hours of 634 hours. In the summer Off-Peak hours, customers will receive a higher value for exports than they would have under the Company's proposal, $0.0569 per kWh versus $0.0491. As displayed in Table 8 below, on-site generators will have a greater amount of exports fall under an increased ECR.

Table 8 – Company vs Staff Proposed On-site Generators Exports[11] by Season

Schedule 6		**Schedule 8**		**Schedule 84**	
Company	**Staff**	**Company**	**Staff**	**Company**	**Staff**
On-Peak Exports	Summer On-Peak Exports	On-Peak Exports	Summer On-Peak Exports	On-Peak Exports	Summer On-Peak Exports
3,983,767	5,564,344	37,646	49,883	2,233,620	3,138,484
Off-Peak Exports	Summer Off-Peak Exports	Off-Peak Exports	Summer Off-Peak Exports	Off-Peak Exports	Summer Off-Peak Exports
54,566,619	19,472,826	382,060	138,049	30,872,551	7,719,923
	Non-Summer Exports		Non-Summer Exports		Non-Summer Exports
-	33,513,216		231,774	-	22,247,763
Total Exports (kWh)	58,550,387	Total Exports (kWh)	419,706	Total Exports (kWh)	33,106,171

Staff estimates that under its proposed ECR, residential customer generators could see an average net bill of approximately $46, an increase of approximately $9. However, this value can change significantly based on an individual customer generator's export and consumption profiles. Staff believes that under its proposed ECR, customer generators will ultimately have more opportunity to maximize their exports during the summer season; thus, increasing their

[11] Total Exports are based on Legacy and Non-legacy customer generators.

ability to control the financial impact of changing from the current NEM rate structure to an ECR and providing exports to the system during the Company's highest risk months and hours.

Combined billing Impacts of Proposed ECR and General Rate Case:

Concurrent to this filing the Company filed a GRC. The Company requested an overall rate increase of 8.61% with an effective date of January 1, 2024. If the Company's proposed changes in the GRC are accepted, on-site generation customers could face additional bill impacts from the overall rate increase and from changes in the Company's monthly service charges. Notably, the Company has proposed to increase the residential service charge from $5 to $35 over a 3-year transition period. If approved, this could increase customer fixed charges by $30, this will likely result in a significant increase to a customer generator's net bill in any given month. Additionally, the Company has proposed to offer TOU to Schedule 6. Staff notes that the offering of TOU rates for Schedule 6 customers provides customers with further opportunity to maximize exports and the financial impact of the ECR and GRC, if they are approved.

Updates to ECR

Table 10 below details the Company's proposal to update the various inputs that inform the ECR. The Company proposes to file updates annually on April 1, to be effective June 1. This timeline is consistent with the Company's other annual update filings also referred to as spring filings.

Table 9 - Company proposal for ECR component updates.

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

Under the Company's proposal, the real-time exports, ELAP hourly market prices, contribution capacity – ELCC, and peak annual exports component inputs are updated annually based on historical export and market data. As described in the section on the determination of the avoided energy value, using historical data provides some stability to the ECR. Under the Company's proposal, Staff believes updating these inputs on an annual basis is a reasonable amount of time between updates to help ensure that rates closely resemble market conditions while balancing the need for rate stability for customer generators. Additionally, while there is an inaccuracy in current market conditions created by the lag, by regularly updating the ECR, the value of past rate years is captured across the life of the system with each subsequent update to the ECR. Staff agrees with the Company's proposal to file updates to the real-time exports, ELAP hourly market prices, and peak annual exports annually on April 1. Additionally, Staff agrees with updating the contribution capacity – ELCC with the addition of Staff's recommendation to move to a 5-year rolling average. In its Response to Production Request No. 40, the Company states that the timing of the annual filing is driven in large part by ELAP market data, which is not fully reconciled until 70 business days after the last day of the historical year. Data from the Company's system is available as early as March. Staff recommends that the Company be prepared to respond to audit requests on this information before the filing date.

For the remaining inputs, the Company has proposed to update them on a routine basis. These inputs are based on various other Company filings that are completed on a consistent cycle. Each of the inputs listed in Table 9 except for the Hours of Capacity Need are related to updating the input data used to calculate the ECR. The Hours of Capacity Need is the only input that would update the structure of the ECR and change the methodology for how the ECR is calculated. In comparison, all of the Company's spring filing updates are limited to updating the input data behind the calculation for the filing's respective adjustment. None of these filings update the methodology or change the way these calculations are performed. Because Staff's analysis in these filings is limited to verifying the updates to data inputs and not fundamental changes to the methodology, it is possible for these cases to operate on the accelerated timeline of being filed in April and going into effect on June 1. If the Company were to update the hours of capacity needed as part of a condensed filing timeline, Staff would not be able to complete a thorough review of the proposed changes and their supporting documentation. Staff agrees with the Company's proposal to update the levelized cost of avoided resource, transmission & distribution deferral, line loss, and variable energy resource integration cost inputs on a routine basis specific to each input as proposed in the table above. However, Staff disagrees with the Company's proposal to update the Hours of Capacity Need input for On-Peak hours in the proposed April filing. Staff recommends that the Commission order the Company to update the Hours of Capacity Need component of the ECR in a separate filing. This filing should be submitted by the Company on an as needed basis as informed by analysis provided in the Company's IRP planning process. Any changes to the structure of the ECR (i.e., season length, hours, how credits are applied, etc.) should trigger a new case with ample time for all parties to review and provide input.

Finally, The Company proposes to file its first update April 1, 2024. Staff believes that under the Company's proposal, Customers will not have had sufficient time to adjust to the new rate. From the proposed ECR effective date of January 1, 2024, on-site generation customers would only receive three bills showing the impact of the ECR before the Company files its first update. Staff believes this may cause customer confusion and recommends that the Company delay the first update to the ECR until June 1, 2025. Staff believes that the Company can use this "acclimation period" to provide educational materials and for customers to adjust to the updated ECR billing structure.

Modifications to Project Eligibility Cap

Staff's evaluation of the project eligibility cap is based on three criteria: (1) eligibility caps should be set to help minimize cost impacts to other non-participating customers; (2) eligibility caps should be set to ensure the safety and reliability of the Company's system; and (3) eligibility caps should be set to align with the program's intent, which is to allow customers to offset their own consumption. In its evaluation, Staff agrees with the Company's eligibility cap proposals for Schedule 84 customers, Schedule 6 and 8 customers, and customer generators under all three schedules with energy storage. However, Staff has identified additional recommendations beyond the Company's proposals.

<u>Project Eligibility Cap for Schedule 6 and Schedule 8 Customers</u>

The Company does not propose any change to the eligibility cap for Schedule 6 and Schedule 8 customers because the Company believes that the current cap of 25 kW is not limiting for these customers. Anderson Direct at 5. For example, the average residential customer service point maximum annual hourly demand is approximately 6 to 7 kW, and the most commonly installed residential system is about 7.5 kW, or 30% of the 25 kW cap. Anderson Direct at 5.

The Company believes that Schedule 6 and Schedule 8 customers are dissimilar to Schedule 84 customers in two ways. First, a higher percentage of customer service points registered an annual demand in excess of the existing cap for Schedule 84 customers. Nearly 8% of non-solar commercial and industrial customers and 13% of non-solar irrigation customers registered an annual peak demand of over 100 kW. *See* Responses to Staff Production Request Nos. 16 and 20. However, only 2% of Schedule 6 and Schedule 8 service points registered an annual peak demand in excess of the existing cap. *See* Response to Staff Production Request No. 17. Second, there are Schedule 84 customers with larger demands who desire to install larger on-site generation systems. Those customers have installed smaller, disaggregated 100 kW systems and transferred kWh credits annually to qualifying service points under the existing "meter aggregation rules". Application at 21-22.

Staff agrees with the Company's reasoning, and Staff recommends maintaining the current Schedule 6 and Schedule 8 eligibility caps but monitor when the cap becomes limiting and consider changes to the cap if warranted.

Project Eligibility Cap for Schedule 84 Customers

In its Application, the Company proposes modifying the Schedule 84 Project eligibility cap to 100kW or 100% of demand. The Company's Revised Study Framework in Case No. IPC-E-21-21 includes analysis of 100% and 125% of a customer's demand for determining the project eligibility cap. However, the Company proposes 100% of the customer's demand, instead of 125% of the demand. The Company provides the following rationale:

First, the Company believes that a cap larger than 100% of the demand cannot be implemented without system upgrades, which will require all customers to pay for the ongoing cost associated with the upgrades, even though the initial cost is paid for by the on-site generation customer. Second, the Company does not routinely install facilities larger than customer demand in any other situation. Third, 100% of the demand can ensure the Company does not have oversized distribution equipment on its system. Fourth, 100% of the demand aligns well with the intent of allowing a customer to offset their energy usage behind the meter. *See* Response to Staff Production Request No. 15. Lastly, customers who desire to install an on-site generation system larger than 100% of demand can do so by becoming a Qualifying Facility under Schedule 86 (non-firm energy) or Schedule 73 (firm energy), or choosing the non-exporting option. *See* Response to Staff Production Request No. 45.

Staff agrees with the Company's reasoning, and Staff recommends approval of the Company's proposed eligibility cap for Schedule 84 customers, which is the greater of 100 kW or 100% of demand.

How Demand is Determined for Schedule 84 Customers

The Company proposes different methods for determining a Schedule 84 customer's demand for purposes of conforming to the 100% eligibility cap, depending on the following circumstances:

- A: For customers with at least 12 months of historical billing data, the maximum billing demand from the last 12 months is used.

- B: For new customers or those without at least 12 months of historical billing of their own, the Company will evaluate and rely on available historical billing data at that service point. If customers believe their demand will exceed that of the past customer, the Company proposes requiring an analysis of the facility's power needs performed by a professional engineer and paid by the customer.
- C: For new customers or those who neither have at least 12 months of historical billing of their own nor have historical billing data at the service point, the Company proposes requiring an analysis of the facility's power needs performed by a professional engineer.
- D: For irrigation customers without a full in-season billing history, a conversion factor related to the horsepower of their pumps at the service point will be used to determine the maximum demand.

Application at 22 and Anderson Direct at 9.

Staff mostly agrees with the Company's proposal; however, Staff is concerned with Scenario B as described above, because the Company would only require an analysis be performed by a professional engineer when a customer "believes" their demand will exceed that of a past customer.

Staff assumes that the Company intends to have the on-site customer pay for the analysis, which will prevent cost shifts to other customers. However, Staff believes that it may discourage customers from wanting to incur the additional cost and bias their beliefs, resulting in an inadequately sized interconnection that could affect reliability. Although this may not affect the Company's system, Staff believes the Company should play a more active role and verify the need for the analysis rather than relying on the customer's beliefs. In all cases of additional analysis, Staff believes the cost should always be charged to the on-site customer.

Staff recommends the Company play a more active role in determining whether a needs analysis needs to be conducted, ensure the analysis is paid by the customer, and incorporate into the Schedule 84 language the Company's proposed methods used to determine a customer's demand relative to the Schedule 84 cap.

Demand Changes After Installation for Schedule 84 Customers

The Company proposes to maintain a customer's current system size if a customer's demand decreases or if a new customer takes over the premises with a lower power requirement. If a customer's demand increases after the initial installation, an expansion can be conducted pursuant to Schedule 68 by applying for a system modification. Application at 22-23 and Anderson Direct at 9-10.

Staff agrees with this proposal but recommends that the description of the treatment be incorporated in Schedule 84 language. Staff also recommends the description should clarify that an expanded system is still subject to the project eligibility cap, which is the greater of 100 kW or 100% of demand at the service point.

Additional Interconnection Requirements for Schedule 84 Customers

The Company proposes the following additional interconnection requirements in Schedule 68 to accommodate the increase of the project eligibility cap for Schedule 84.

- Inverter-based generation of 100 kW and greater will provide documentation to validate inverter settings.
- A power plant controller or a properly configured inverter will be installed on the customer's side of the point of delivery for systems 500 kW and greater.
- The existing uniform interconnection agreement and requirements applicable to non-exporting systems larger than 3 MW will apply to systems 3MW and greater.

Ellsworth Direct at 31.

Staff recommends approval of these changes in Schedule 68 necessary to interconnect exporting systems larger than 100 kW safely and reliably due to the increase of the project eligibility cap for Schedule 84.

Project Eligibility Caps for Systems with Energy Storage

The Company proposes that for systems with energy storage devices,[12] only the amount of generation nameplate capacity be used to determine whether the cap is exceeded for Schedules

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[12] Energy storage devices can share an inverter with the generation facility ("DC coupled") or connect to a stand-alone inverter ("AC coupled"). Staff believes this proposal only applies to AC-coupled energy storage devices, not DC-coupled energy storage devices because Idaho Power only collects the information of nameplate capacity of the

6, 8 and 84. Anderson Direct at 13. If the sum of generation capacity and storage capacity is exceeded, the Company allows upgrades to the system as long as the customer pays the upfront cost.[13] However, Staff is concerned with incremental "ongoing" costs of system upgrades beyond the upfront costs that can shift to other customers. For these reasons, Staff has considered three options to address the potential additional cost:

Option 1: Accept the Company's proposal and allow ongoing costs associated with system upgrades to be spread to all customers, if the costs are minimal;

Option 2: Accept the Company's proposal but apply a surcharge for ongoing operation and maintenance costs ("O&M") to customers who require system upgrades;

Option 3: Reject the Company's proposal and maintain the status quo where the capacity of energy storage is included in the calculation of the total nameplate capacity of the on-site customer's system subject to the respective eligibility caps.

Under the current Schedule 6, Schedule 8, and Schedule 84, when a customer seeks to add energy storage devices, and if the combined capacity of the generating resource and the energy storage devices exceeds the project eligibility cap, the Company must deny the customer's interconnection application. *See* Response to Staff Production Request No. 25 (a). For example, if a residential customer has a solar generation system of 22 kW paired with an AC-coupled energy storage device of 4 kW, the total nameplate capacity is 26 kW, which exceeds the project eligibility cap of 25 kW for Schedule 6 customers. *See* Response to Staff Production Request No. 25 (c). If the solar generation system and the AC-coupled energy storage device export energy simultaneously, the capacity being delivered to the Company's system would be 26 kW. *See* Response to Staff Production Request No. 26. Under the current eligibility caps, the Company must deny the customer's interconnection application.

The Company proposes to exclude the capacity of energy storage in the calculation of the nameplate capacity of the on-site generation facilities for determining whether the nameplate capacity exceeds the project eligibility cap but will consider the capacity of energy storage in the

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inverters, and only the capacity size of AC-coupled energy storage devices is known. Response to Staff Production Request No. 37.

[13] Staff obtained this information through a conference call with the Company on September 5, 2023.

feasibility review process. *See* Response to Staff Production Request No. 25 (b). The Company's proposal will allow all on-site generation customers (Schedule 6, Schedule 8, and Schedule 84) to install generation capacity up to their respective project eligibility caps, while allowing them to add additional energy storage capacity. *See* Response to Staff Production Request No. 25 (b).

The Company believes the feasibility review will verify whether the interconnection of the combined system will be sufficient and will not jeopardize the safety or reliability of the Company's system. *See* Response to Staff Production Request No. 25 (b). After the review, if the Company believes the customer's combined system will require a system upgrade, the customer will be required to pay all of the upfront costs. However, the Company's proposal does not require incremental on-going O&M costs be paid by the customer and these costs could be shifted to non-generating customers.[14]

Through its evaluation, Staff considered the magnitude of the ongoing costs. If these costs are minimal, accepting the Company's proposal and allowing ongoing costs associated with system upgrades to be spread to all customers may be reasonable. However, if the costs are not minimal, Option 2, accepting the Company's proposal but applying a surcharge to customers who require system upgrades, would be preferred. Staff rejected Option 3, the status quo, because it does not accommodate customers that currently have large amounts of generation capacity close to the current cap who desire to install a battery to offset their consumption. Staff also believes Option 3 should be rejected because systems with storage can provide significant benefits to the Company's system by reducing the Company's net peak loads, especially if the cost impact to other non-exporting customers is minimal.

Staff's final recommendation is Option 2 because the Company could not provide the amount of ongoing cost of system upgrades to determine if the costs were minimal. *See* Response to Staff Production Request No. 53. Staff expects this Option to protect other customers from cost shifts, meet customers' needs, and increase the amount of storage capacity beneficial to the Company's system. Furthermore, the Company believes a surcharge could be

[14] An example of an ongoing O&M cost would be the replacement of a larger and more costly failed transformer required by the system upgrade. Staff obtained this information through a conference call with the Company on September 5, 2023.

implemented similar to the Facilities Charge in Schedule 68 that requires customers with non-exporting system of three megavolt-ampere or larger to pay for ongoing maintenance costs. *Id.*

Staff recommends approving the Company's proposal to exclude the capacity of energy storage and only include the nameplate capacity of generation to enforce the eligibility cap but if a customer requires a system upgrade, the customer be required to pay all upfront costs and ongoing costs through a surcharge.

Other Implementation Considerations

Recovery of ECR Expenditures

The Company recommends recovery of ECR expenditures as a net power supply expense subject to 100% recovery through the PCA. The recommendation is similar to the VODER Study presented in IPC-E-22-22, which Staff maintains is appropriate.

Staff agrees with the Company that the energy purchased from self-generators is a must-take resource and should be recovered through the PCA. Application at 23. Like PURPA, Staff believes the Company has no choice whether it can take Schedule 6, 8, and 84 customer exports as a matter of policy and should be recovered at 100% through the PCA without customer sharing. Order No. 35607 at 12.

Financial Credit Use and Transferability

In the Application, the Company is proposing two recommendations for future use and transferability of accumulated financial credits. The Company has recommended that non-legacy customers be allowed to pass financial credits to other accounts in the customer's name. The second request is to allow the financial credits to be applied to all billing components, including customer service charge, energy-related portion, riders, and other components. Implementing an ECR and allowing customers to use the financial credit to be applied to all billing components may incentivize non-legacy customers and future customers to maximize their solar systems during peak hours, which may be to the benefit of all customers. Staff does not take issue with this request. As such, Staff recommends that non-legacy customers be allowed to transfer financial credits to other accounts in their name.

Financial Credit Expiration

In its proposed tariff language for Schedules 6, 8, and 84, the Company added the following under the conditions of purchase and sale for net billing.

> Credits are non-transferrable in the event that a customer relocates and/or discontinues service at the Point of Delivery associated with the Exporting System. Any unused credits will expire at the time the final bill is prepared.

While the language is consistent with the net metering section in the tariffs, Staff believes there should be a distinction between the non-transferability of kWh credits under legacy net Metering, and the financial credits under the proposed Net Billing structure. Under the proposed language, when a customer relocates to another location on the Company's system or discontinues service with the Company, any financial credits that the customer has earned by exporting energy to the Company's system will expire. For kWh credits, this methodology appears reasonable as the Company is unable to transfer a unit of energy within its system or to another utility's system. However, for financial credits under the proposed net billing, this will result with customer on-site generators being uncompensated for energy that they provided to the Company. Staff believes that the Company's reasoning provided in Response to Production Request No. 54 is insufficient to support denying an on-site generation customer's compensation for exported energy that has a quantifiable benefit to the Company.

Staff recommends that the Commission order the Company to transfer financial credits to the customers new meter when a customer relocates within the Company's system or refund the amount of accumulated financial credits to the customer in the event they relocate outside the Company's system and to adjust the tariff language in a compliance filing.

Accumulated kWh Conversion Rate and Timeframe

Company witness Grant Anderson's testimony outlines that any accumulated kWh credits will be converted to a financial figure after one year, or after December 31, 2024. Anderson Direct at 21-22. The Company anticipates using a blended average retail energy rate as of December 31, 2023, to convert any excess kWh credits.

The formula to calculate a blended average retail energy rate for each non-legacy customer class is to sum charges for energy, the FCA, and the PCA, then divide by the total kWh consumed.[15]

Staff recommends approval of the Company's use of a blended average retail energy rate to convert excess accumulated kWh credits at the end of 2024. Staff is unaware of how customers may be notified of this conversion. Therefore, Staff recommends the Company notify each non-legacy customer that has excess kWh credits as of December 31, 2024, of how their excess credits will be converted, at what rate, and how it will be displayed on their next bill. Regarding the conversion to a financial credit, Staff supports the Company's proposal that the conversion of accumulated kWh credits to a financial credit be recovered through the FCA for Residential and Small General Service customers and the PCA for Commercial, Irrigators and Industrial customers.

Transition Period

The Company, the Commission, and several intervening parties have been involved in changing the NEM program since 2017 through a multitude of dockets summarized earlier in these comments. Staff believes the processing of these dockets has provided customers with enough notice of potential changes that additional transition to an ECR is not necessary.

For these reasons, Staff does not recommend any transition period. Staff believes that allowing current non-legacy customers to use accumulated kWh credits over the 2024 calendar year will provide enough transition and opportunity for current NEM customers to learn the new program.

However, as indicated earlier in the ECR Update Section, Staff proposes the first update to the ECR to begin in 2025 rather than 2024. Staff believes an acclimation period is necessary for customers to adjust to the ECR billing structure without having the ECR billing rate change in the first 6 months of a new program.

[15] Company Responses to Staff Production Request Nos. 51 and 52.

STAKEHOLDER AND CUSTOMER COMMUNICATION

Public Workshops

On August 15, 2023, the Commission issued a press release announcing two virtual public workshops. The first IPUC workshop was held the evening of September 6, 2023, and the second was held on the afternoon of September 7, 2023. Among the topics discussed at the workshop were the VODER study, history of the case, and grandfathering. Where appropriate, Staff attempted to address customers' comments and concerns in these areas. The workshops were well attended with approximately 106 customers that participated in the September 6, 2023 evening workshop and approximately 42 customers participated in the September 7, 2023 afternoon workshop.

Customer Comments

As of October 11, 2023, 231 public comments have been filed in this case. Of the 234 customers who offered comments, 108 customers (47%), identified as non-legacy customers, while only 7 (3%) clearly identified themselves as legacy customers. There were another 68 customers (30%) who have net-generation system but did not identify their status, whether legacy or non-legacy.

Previous Orders

Customers continued to express concerns regarding grandfathering with 94 customers (41%) stating that all current net generations customers should be granted legacy status. Another 46 customers (20%) claimed they were not aware of possible changes to the program at the time they had their systems installed. These customers stated they would not have gone forward had they known the rates would change.

There were 58 customers (25%) who disagreed with the outcome of IPC-E-22-22, including 34 customers (15%) who challenged the objectivity of the VODER study, and 24 customers (10%) who suggested that the Commission failed to consider third party studies and the concerns of interested parties. There were 83 customers (36%) who urged further consideration of environmental benefits.

Structure and Compensation

Regarding any change to compensation, 153 customers (67%) wanted no change to the structure of the program, and 136 customers (59%) wanted to keep monthly net metering versus real time metering. Regarding the accrued kwh credits accumulated by both legacy and non-legacy customers, 41 customers (18%) expressed concern about the future value and traceability of accumulated credits as well as advocated for customer options for the applicability of those credits.

Regarding financial credits under the proposed changes, 33 customers (14%) worried about the accountability of those financial credits and the value of those credits. Of the 21 customers (2%) who offered comments on the ECR, 13 customers (1%) wanted the ECR tied to retail rates, and 8 customers (1%) expressed a desire for an unbiased annual review of ECR rates.

There were 45 customers (20%) who offered comments regarding compensation for peak versus non-peak hours, time-of-day versus peak and non-peak hours, seasonal demand versus customer peak hours and use of a single rate versus peak and non-peak hours. Peak hours compensation extends into the evening even as generation declines and suggested that compensation for peak hours should start earlier in the day.

Incentives

There were 79 customers (34%) who said the Company needs to provide more incentives to customers to encourage net generation.

STAFF RECOMMENDATION

Staff Recommends the Commission:

1. Implement Staffs proposals for a real-time net billing with an avoided cost based, seasonal, time-variant, ECR, with the following recommendations:
    a. Adjust the On-Peak *season* to align with the summer season proposed in the GRC. Direct that updates to the *season* be part of future general rate case filings;
    b. Accept the On-Peak *hours*, as proposed by the Company, but direct that if future IRP analysis indicates a need to update the *hours* of highest risk, the Company should file a separate docket;

c. Distribute the avoided energy value in alignment with the summer and non-summer seasons, as determined in the GRC;
d. Use the *most current* levelized capacity cost for the least-cost dispatchable resource from the 2023 IRP;
e. Use a *five-year* rolling average of the ELCC percentage to determine the avoided capacity value;
f. Calculate the ELCC and avoided capacity values *without* the line loss gross up, and *subsequently apply* the line loss gross up to that result;
g. Include *all* customer exports in the calculation of each year's ELCC;
h. Use the industry-typical line loss calculations. Apply the annual energy line losses to the energy value, and the peak hour line losses to the capacity value.

2. Direct the Company to update all proposed components of the ECR except the hours of highest risk in an annual filing beginning April 1, 2025.
3. Direct the Company to update the hours of highest risk in a separate filing on an as-needed basis.
4. Maintain the current Schedule 6 and Schedule 8 eligibility caps but monitor when the cap becomes limiting and consider changes to the cap if warranted.
5. Approve the proposed eligibility cap for Schedule 84 customers: the greater of 100 kW and 100% of demand and:
    a. Incorporate into Schedule 84 the Company's proposed methods used to determine a customer's demand relative to the Schedule 84 cap.
    b. Direct the Company to play a more active role to verify the need for a professional engineer to conduct an analysis to determine a new customer's demand requirements.
    c. Direct that the cost of such analysis should be charged to the on-site generation customer.
    d. Incorporate into Schedule 84 the description of the Company's proposed treatment when a customer's demand changes; and
    e. Clarify in Schedule 84 that an expanded system is still subject to the project eligibility cap, which is the greater of 100 kW or 100%of demand at the service point.

6. Incorporate the Company's additional proposed interconnection requirements in Schedule 68 due to the increase of the project eligibility cap for Schedule 84.
7. Approve the Company's proposal to exclude energy storage and only include the nameplate capacity of generation to enforce the eligibility cap for Schedules 6, 8, and 84; and to require the customer to pay all upfront and ongoing costs of system upgrades through a surcharge, if upgrades are needed.
8. Approve the Company's request to recover ECR expenditures as a net power supply expense subject to 100% recovery through the PCA.
9. Approve the Company's proposals on the use and transferability of financial credits.
10. Approve the Company's proposal to convert accumulated kWh credits to financial credits using a blended average retail energy rate on December 31, 2024, and:
    a. Direct the Company to notify each non-legacy customer that has excess kWh credits as of December 31, 2024 of how their excess credits will be converted, at what rate, and how it will be displayed on their next bill.
11. Direct the Company to transfer or refund any accumulated financial credits in the event a customer relocates or discontinues service.
12. Authorize the integration rates from the 2020 Variable Energy Resource ("VER") study as proposed for purposes of the ECR rates in this filing, and:
    c. Direct the Company file an update to Schedule 87 rates and integration costs from the 2020 VER study for Commission approval to be used in future ratemaking that requires it, including updates to Clean Energy Your Way ("CEYW") and ECR-related rates.
    d. Direct the Company to file all future VER studies and integration costs for Commission authorization, if integration cost have materially changed from those authorized.
13. Direct the Company to adjust the language of Tariff Schedules 6, 8, and 84 according to all recommendations presented above in a compliance filing.

Respectfully submitted this 12th day of October 2023.

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i:umisc/comments/ ipce23.14jjtmsmltncchjbdm comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 12th DAY OF OCTOBER 2023, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF TO IDAHO POWER,** IN CASE NO. IPC-E-23-14, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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