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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION TO COMPLETE THE STUDY REVIEW PHASE OF THE COMPREHENSIVE STUDY OF COSTS AND BENEFITS OF ON-SITE CUSTOMER GENERATION & FOR AUTHORITY TO IMPLEMENT CHANGES TO SCHEDULES 6, 8, AND 84	)	**CASE NO. IPC-E-22-22** **COMMENTS OF THE COMMISSION STAFF**

Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Riley Newton, Deputy Attorney General, and submits the following comments.

BACKGROUND

Idaho Power ("Company" or "Idaho Power") offers net energy metering ("NEM") programs under which customers can generate electricity to meet their own demand and export any excess electricity back to the Company's grid in exchange for an energy credit that can offset the customer's monthly energy consumption. Currently, customers who wish to install on-site generation can interconnect an exporting system under the terms of Schedule 6 – Residential Service On-Site Generation ("Schedule 6"), Schedule 8 – Small General Service On-Site Generation ("Schedule 8"), and Schedule 84 – Commercial, Industrial, and Irrigation ("Schedule 84").

On May 9, 2018, in Case No. IPC-E-17-13, the Commission 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 at 31.

On December 20, 2019, in Case No. IPC-E-18-15, the Commission clarified that the study: (1) 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.

On December 30, 2021, in Case No. IPC-E-21-21, the Company filed an application to initiate a multi-phase process for the study of costs, benefits, and compensation of net excess energy associated with customer on-site generation. Included in the application was a proposed study scope and a study design schedule including time for public workshops. In that case, the Commission received intervening party and public comments on the different elements included in the scope. Based on those comments, 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 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 ("Application"). These comments are a result of Staff's review of the Application, which included the Value of Distributed Energy Resource Study ("VODER Study" or "Study") and supplemental information included in the filing.

STAFF REVIEW

The purpose of Staff's review is to analyze whether the VODER Study complies with the Commission's decisions relative to the Study Scope in Order No. 35284. In that Order, the Commission directed what components related to valuing the export of customer generation to the Company's system should be included in the Study. Below is a summary of Staff's conclusions on whether each component was sufficiently addressed:

1. Measurement Interval – The Study complied.
2. Export Credit Rate ("ECR").
    a. Avoided Energy Value – The Study complied in part but Staff recommends that the Company submit an amendment to the Study that provides additional explanation and data for two issues outlined below.
    b. Avoided Capacity Value – The Study complied, with two exceptions that should be addressed by an amendment to the Study.
    c. Avoided Transmission and Distribution Costs – The Study complied.
    d. Avoided Line Losses – The Study complied, with exceptions regarding transformer line losses and adjustments to avoided cost of capacity that should be addressed by an amendment to the Study.
    e. Integration Costs – The Study complied.
    f. Avoided Risk – The Study complied.
    g. Environmental and Other Benefits – The Study complied, but Staff recommends that the Company submit an amendment to the Study that provides additional explanation for one issue.
3. Frequency of ECR Updates – The Study Complied. Participating customer-generators' need for stability, and accurate rates, should be balanced with the need for regular updates to accurately track avoided costs.
4. Compensation Structure – Under scenarios, moving from current NEM program to a net billing program, customer-generators will see lower generator export bill credits and will see higher electric bills.
5. Class Cost of Service ("CCOS") and Rate Design – The Study complied. However, the Company is not collecting its full share of revenue requirement from Schedule 6 and Schedule 8 customer-generators. Future studies of CCOS and rate design must be evaluated and implemented in the Company's next general rate case.
6. Recovering ECR Expenditures – The Study complied.
7. Project Eligibility Cap – The Study complied with Order Nos. 35284, 34046, and 34509, but Staff recommends that the Company submit an amendment to the Study that provides the following: (1) the Study be supplemented with

information received through discovery; (2) the policy factors identified be considered in setting the cap; and (3) an evaluation of potential gaming and manipulation between Public Utilities Regulatory Policies Act of 1978 ("PURPA") and customer-generation be conducted.

8. Other Areas to Consider – The Study complied.
9. Implementation Considerations – The Company did not offer any transition guidelines and Staff will present recommendations in any implementation process for a new program.
10. Public Input – Customer comments for the most part offered thoughts and opinions, and most did not offer separate findings they wanted introduced for consideration.

In determining these conclusions, Staff weighed the sufficiency of the Study based on criteria provided in Order Nos. 34046, 34509, and 35284, which included elements of transparency, inclusion of public input, and ability to be comprehended by the public but able to withstand expert scrutiny, etc. Staff also considered the tradeoff between accuracy and rate stability of the ECR.

If the ECR is not accurately developed and maintained at the Company's avoided cost, exports will shift costs to the Company's non-generating customer classes, or compensation for customer exports will not be commensurate with the value provided to the system. Alternatively, Staff and customer-generators believe that predictability and rate stability is important, even if it comes at the expense of accuracy.

The principle of cost causation entails that customers pay for the costs incurred by the Company in delivering benefits to the customer. For consumption of electricity, the allocation of the Company's costs to individual customer classes and the rates for each class are generally based on the costs caused by the customers in each class.

Staff believes that these cost causation principles also apply to customers who export electricity, who should be compensated for the benefits they provide to the system based on the costs they avoid for the system. The cost of customer exports through an ECR should be included in net power costs ("NPC") that are allocated to all customers through the Company's Power Cost Adjustment ("PCA"). However, if the ECR is not accurately developed and maintained at the Company's avoided cost, one of two results will likely occur: (1) other customers will be harmed due to an allocation of cost higher than what they would have paid without the existence of customer exports if the ECR is set above the Company's avoided cost; or (2) customer-generators will be undercompensated for the value they provide to the system if the ECR is set below the Company's avoided cost. The Federal Energy Regulatory Commission ("FERC") used these same principles when propagating rules used to establish avoided cost rates for PURPA qualifying facilities ("QF").[1]

Measurement Intervals

The information presented in the VODER Study complies with Order No. 35284. The data provided is transparent, understandable, and the Company presented its findings of the monthly, hourly, and real-time measurement intervals for customer-generators as directed by the Commission.

In the VODER Study, the Company evaluated the length of time between meter reads (measurement intervals) to measure the energy delivered and received by: (1) hourly, and (2) real-time. The Company evaluated the class revenue requirement and considered revenue collection for existing customer generators under each proposed measurement interval. The Company also conducted a bill impact analysis which compares how each measurement interval impacts existing and future customers with on-site generation.

Net Billing

Net billing is an alternative compensation method to the current NEM program and does not allow banking of kilowatt-hour(s) ("kWh(s)"). Instead, net billing calculates the difference between energy exported and consumed in each hour and applies an applicable rate for any net energy exported. The VODER Study outlines that each kWh will have a monetary value applied. For energy exported, net billing applies a credit at an ECR. Similarly, for each kWh

[1] Avoided costs under PURPA means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source. *See* l8 C.F.R. $ 292. l0l (bX6). Order No. 25884 states that "[r]atepayers should be indifferent to whether a resource serving them was constructed by a utility or an independent developer. The cost and quality of service provided by either should be the same. Ratepayers should not be asked to subsidize the QF industry through the establishment of avoided cost rates that exceed utility costs that would result from an effective least cost planning process." Order No. 32262 states that "PURPA entitles QFs to a rate equivalent to the utility's avoided cost, a rate that holds utility customers harmless - not a rate at which a project may be viable."

consumed, net billing applies the applicable customers retail rate (i.e., Schedule 1 rates for Residential customers).

When evaluating hourly and real-time measurement intervals, the Company outlines the key differences between the measurement intervals. For hourly measurement intervals, a customer would be billed for net energy consumption or credited a dollar amount for net exports during each hour. For example, in a one-hour timeframe, if a customer-generator exports more kWh than they consume, they may be credited an ECR. The measurement on a real-time basis is more accurate than on a hourly basis.

Unfortunately, the hourly measurement and real-time interval comparison could not be applied to Schedule 84 customer-generators because most Schedule 84 customer-generators do not have a single meter like Schedule 6 customers. All legacy[2] Schedule 84 customers have two meters; one meter reads all energy consumed and the second meter reads all energy exported. In Order No. 34854, Case No. IPC-E-20-26, the Commission ordered new Schedule 84 customer-generators to have a single meter but allowed existing customers to maintain a two-meter system. With a single meter, the Company will be able to easily determine if a customer-generator is exporting and/or consuming instantaneously. Due to timing, however, there were no Schedule 84 single-meter systems with twelve months of data in 2021. *See* Response to Production Request No. 1a and 1b.

Thus, the Company was unable to perform a real-time and hourly net billing analysis for Schedule 84 customers due to the meters measuring all generation and consumption separately. Once the Company has more data available for single meter customer systems under Schedule 84, Staff expects to review it.

Export Credit Rate

Staff's analysis of the avoided cost components that can potentially be included in the ECR focused on two questions:

1. Did the Company's Study comply with Commission orders; and

[2] Grandfathering, or legacy status, is granted if an installed solar system is an existing system under Schedule 6, 8, or 84 or the customer made a financial commitment as of 12/20/2019 and interconnect their system within one year, from 12/20/2020 for Schedule 6 and 8, or one year from 12/1/2020 for Schedule 84. *See* Order Nos. 34509, 34546, and 34854.

2. What are the important considerations in evaluating the options for determining the value of the different components.

Avoided Energy Cost

Compliance with Commission Orders

Staff believes that the Study complied with Order No. 35284 for determining the avoided cost of energy component in the ECR. However, Staff recommends that the Company include an amendment to the Study that provides additional explanation and data that supports: (1) the firm to non-firm energy adjustment; and (2) the proposed "On Peak" high-value time window.

The Company provided several methods for determining the avoided cost of energy for exported energy on a dollar per kilowatt-hour ("$/kWh") basis, ranging from a single flat rate to a seasonal time-variant rate. The Company included a reasonable adjustment to the value based on the non-firm nature of customer exports. The Company utilized multiple methods for determining the avoided energy value including forecasted prices from the latest Integrated Resource Plan ("IRP") and market indices. This section of the Study also evaluated fuel price risk as required by the Order, reasoning that the market energy prices inherently incorporate fuel price risk.

Evaluation of Options

There are two main considerations in the valuation of avoided energy cost: (1) whether to use actual market pricing or a weighted-average of established energy prices; and (2) the source of pricing information.

The Study proposed three sources of pricing information: (1) the IRP pricing forecast, (2) the Intercontinental Exchange Mid-Columbia ("ICE Mid-C") day-ahead market, and (3) the Energy Imbalance Market ("EIM") Load Aggregation Point ("ELAP") – real time market.

Staff believes actual market pricing would be the most accurate means of assigning value, but it is the least stable and predictable option for the customer. Conversely, a weighted average of established energy prices would be stable and predictable, but less accurate. However, the Study only mentions actual market pricing as a possibility and does not explore its feasibility or its advantages and disadvantages.

The Study identified three considerations if using weighted-average energy pricing data: (1) the source of the data; (2) the number of years of pricing data to incorporate; and (3) whether to use a weighted average method that focuses value into critical hours (Seasonal Time Variant rate) or spreads it evenly throughout the year (Flat Annual rate).

Regarding the source of pricing data, IRP pricing is likely the least accurate because it is a forecast, especially over time. The two market indices would be more accurate, but the accuracy would be delayed since current market fluctuations would not be reflected in the ECR until the ensuing year. All three pricing sources would be equally stable and predictable since they are predetermined values.

Regarding the number of years of pricing data to incorporate, more years would enhance price stability but would reduce accuracy in the short term. Over time, the value accuracy should even out.

Regarding the weighted averaging method, the seasonal time variant method is a more accurate assignment of the time-value of exports because the higher value of energy during the critical hours would be assigned only to those hours, instead of being evenly spread across the whole year. The seasonal time variant method would provide price signals to incentivize customer behavior to enhance grid reliability. Some customer-generators would presumably try to maximize exports during the critical hours, including by use of stored energy. This arrangement would favor customers with battery storage if many of the critical hours are after the sun goes down.

If a seasonal time variant option is chosen, the time windows used to differentiate the value of energy need additional consideration in the Study. The Company has proposed "On-Peak" and "Off-Peak" time windows that are aligned with its critical capacity needs but are not necessarily aligned with time windows for valuing energy. Critical capacity needs are based on the capacity needs of the Company's system. However, avoided energy cost is valued based on a comparison of market prices to the cost of energy from resources dispatched at the top of its resource stack. Staff does not believe the Study provides information and justification as to why On and Off-peak time-differentiation windows used for valuing capacity is appropriate for valuing energy. Staff recommends the Company provide, as an amendment to the Study, a comparison for the amount of cost paid for avoiding the cost of energy using two sets of time windows: (1) windows with enough resolution to differentiate the avoided cost of energy; and (2) the proposed "On-Peak" and "Off-Peak" time windows.

<u>Avoided Capacity Value</u>

Compliance with Commission Orders

Staff believes that the Study complied with Order No. 35284 for determining the avoided cost of capacity component in the ECR with two exceptions. First, the Company did not account for the impact to the avoided cost of capacity as the first deficit year changes. Second, Staff does not believe that the Company's method used to calculate the avoided capacity cost for the seasonal time variant scenario is correct.

The Study did not explicitly address the first deficit year as required by Order No. 35284 at 18. However, because the Study assigned value for avoided capacity cost, it implies that the first deficit year is in effect, which the Company confirmed. *See* Response to Production Request No. 30. The Company should amend the Study to explicitly address how this component's value may be affected with respect to the first deficit year.

The Company utilized the same compensation formula in its flat annual rate scenario as it did for its seasonal time-variant scenario. Staff believes that these two rate structures are fundamentally different, and the calculations need to align to the underlying structure. The contribution of capacity in the time-variant scenario is embedded in the energy actually delivered and does not require a separate capacity contribution estimate as required in the flat annual rate scenario. Staff recommends that the Commission order the Company meet with Parties and amend the Study, if necessary.

Evaluation of Options

The main consideration in determining avoided capacity value is whether to use a flat annual rate structure or a seasonal time variant rate structure.

The true value of avoided capacity is derived only when energy is exported during the On-Peak period. The seasonal time-variant approach keeps the value assigned only to the On-Peak exports. This approach more accurately assigns value to individual exporters, and also provides price signals to incentivize customer behavior to enhance grid reliability.[3] The flat rate would accurately assign value to the class, but not to individual exporters. Both structures would provide stable pricing since they would be derived from historical data.

Within the flat annual rate structure is an additional option regarding the calculation method for capacity contribution. Capacity contribution can be estimated using the Effective Load Carrying Capacity ("ELCC") algorithm, or the National Renewable Energy Laboratory ("NREL") 8760 algorithm. The Company has used both methods in the past, using the NREL 8760 in the 2019 IRP, and the ELCC in the 2021 IRP.

The ELCC is increasingly used by the power industry because it is considered a more accurate representation of the capacity contribution for each specific utility system, which has been implemented in the Company's 2021 IRP. Its downside is that it is a complex calculation made by the Company using Aurora software and is therefore not transparent to the customer.

Conversely, the NREL 8760 method is less accurate than the ELCC because it is a method for providing a rough estimate across a broad range of utility systems but is more transparent since it can be calculated with a spreadsheet and a simple algorithm.

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

Compliance with Commission Orders

Staff believes that the Study complied with Order No. 35284 for the evaluation of avoided T&D capacity costs. The Study provided a credible method to assess exports that contribute to avoiding capacity limits on each segment of the T&D systems, and it provided detailed information to support its analyses in Appendix 4.13.

Evaluation of Options

The main consideration in determining Avoided T&D Capacity Costs is whether to use a flat annual rate structure or a seasonal time-variant rate structure.

Like the avoided generation capacity cost in the preceding section, the true value of avoided T&D capacity is derived when energy is exported during the On-Peak period. The seasonal time-variant approach keeps the value assigned only to the On-Peak exports. This

[3] Behaviors include shifting consumption patterns or investing in energy storage to allow higher levels of exports to the grid during On-Peak periods.

approach more accurately assigns value to individual exporters, but because the value of this component is small, the impact on customer-generator behavior should be negligible. The flat rate would accurately assign value to the class, but not to individual exporters. Both structures would provide stable pricing since they would be derived from historical data.

Avoided Line Loss

Compliance with Commission Orders

Staff believes that the Study complied with Order No. 35284 for the evaluation of avoided line loss with three exceptions. First, the Company derived the value for line loss from a 2012 study but proposed ignoring transformer losses. Staff is not convinced that transformer losses should be ignored, nor can Staff reconcile the proposed reduction with data in the 2012 study. Second, the VODER Study was ambiguous about whether line loss applied to energy or capacity or both. The Company clarified that line loss is attributable to both, but the Study only calculated the energy line loss adjustment in the avoided line loss component. Third, according to the Company, the line loss adjustment for capacity was incorporated into the avoided generation capacity cost component. If Staff's method for calculating the capacity contribution for the seasonal time-variant rate is appropriate, the line loss adjustment factor would need to be explicitly applied. Staff recommends the Commission order the Company meet with Parties on these three issues and provide an amendment to the Study.

Evaluation of Options

This component does not have any options to consider. The line loss adjustment factor should be applied consistently to the avoided energy cost regardless of its rate structure.

Avoided Environmental Costs

Compliance with Commission Orders

The Commission stated that the Study should include "an evaluation of all benefits and costs that are quantifiable, measurable, and avoided costs that affect rates." Order No. 35284 at 27. The Study identified three potential costs that could be avoided under the Order: Renewable Energy Credits ("REC"), carbon taxes, and fulfillment of Renewable Portfolio Standard ("RPS"). Staff believes that the Company complied with the Commission's Orders with one minor exception and recommends that the Company amend the Study to further justify its conclusions related to RECs.

The Study analyzed the administrative and legal barriers to monetize RECs with individual customer-generators and concluded that the administrative burden on both the Company and each customer would be high in comparison to the value that could be included in the ECR. Because of this, the Company did not propose a value to be included. Staff asked the Company to provide information to explain the requirements to obtain and track RECs for customer-generators. *See* Response to Production Request No. 46. To comply with the Commission directive, the Study "must use the most current data possible and must be readily available to the public." Order No. 34509 at 9. Staff recommends that the information from the Response to Production Request No. 46 be included in an amendment to the Study to provide transparency to the public. The explanation should provide the public with information related to the intricacies and requirements to obtain and track RECs.

Evaluation of Options

The environmental avoided cost component does not have any options to consider, since there are currently no environmental costs that the Company could feasibly avoid. However, this component should be revisited should legislative requirements change imposing a cost that would be included in the Company's rates.

<u>Integration Costs</u>

Compliance with Commission Orders

The Study complied in its evaluation of Integration Cost, including evaluation at different levels of variable energy resource ("VER") penetration. It utilized integration cost information from a 2020 Variable Energy Resource Integration Study performed by an independent contractor. The results of that study are adequate for the VODER Study analysis because the baseline scenario was targeted to 2023 and it reasonably approximates the existing resource portfolio. The Company plans to perform a new integration study after the 2023 or 2025 IRP.

Evaluation of Options

This component does not have any options to consider. The integration cost factor should be applied to the ECR, regardless of the rate structure (single annual flat rate, or seasonal time variant rate structure) to develop an accurate avoided cost. Integration rates should not adversely affect the stability of the ECR when updated, since the Company only recalculates them every two to four years.

Frequency of ECR Updates

The Commission ordered "the study needs to consider the impact of timing of updates and identify potential processes, cases, or mechanisms for identifying updates to the export credit rate." *See* Order No. 35284. Staff believes that the Company complied with Order No. 35284 and feels that the updates to the ECR should be transparent, understandable, and provide the impacts when each ECR component is updated.

The Company looked at the impact of updating each component of the ECR. During the implementation process, Parties' recommendations should include a schedule that outlines when ECR component updates may occur. Customer-generators' need for stability and accurate rates should be balanced with the need for regular updates to accurately track avoided costs in the ECR.

Compensation Structure

The Company included additional information regarding compensation structures that was not outlined in prior Commission orders. Staff is confident the material presented is transparent, understandable, and provides impacts to current non-legacy customer-generators. During the implementation process, Staff recommends that the compensation structure be expanded to show impacts of various ECRs for all non-legacy customer-generators. The VODER Study outlines what the compensation structure could be when applying one specific ECR using the measurement intervals. The VODER Study evaluated NEM, used as a base, to net billing hourly and to net billing real-time. The measurement intervals, which were discussed above, refers to the measurement for both energy consumption and energy generation. Under the scenarios presented in the Compensation Structure section of the Study, moving from current NEM to a net billing scenario, customer-generators will see lower generator export bill credits and will see higher electric bills under the hypothetical ECR proposed by the Company.

Class Cost-of-Service

Staff evaluated the CCOS presented in the VODER Study and believes it complied with Order No. 35284. The Company provided information that is accurate, transparent, understandable, and showed results that the Company has not recovered its authorized revenue requirement from customer-generators. The Company provided a comparison of two CCOS methodologies. The results showed that the Company is not collecting its full share of revenue requirement from Schedule 6 and 8 customer-generators. Rate design must be addressed in a general rate case to align Schedules 6, 8, and 84 customers to cost of service.

Recovering ECR Expenditures

In Order No. 35284, the Commission stated that the Study must include the annual costs for different ECR values and include how these costs would be recovered by rate class. *Id* at 11-12. The VODER Study complied with these requirements, identifying a range of annual costs from $309,933 to $590,947. Study at 94. The Study also included a proposal that the value of the credits would be recorded in FERC Account 555 – Purchased Power and included in the PCA without any sharing band, similar to QF expenses. The Study proposes that the program administration costs be recovered through base rates. Study at 93-95.

Project Eligibility Cap

Staff believes that the Project Eligibility Cap section in the Study has met the Commission's expectations in Order Nos. 34046, 34509, and 35284. However, Staff has identified additional factors to be considered in setting the cap. Staff also recommends that the Study be supplemented with information on the Project Eligibility Cap received through discovery, as discussed below.

<u>Compliance with Commission Orders</u>

Staff believes that the Study addressed Commission orders by providing a thorough evaluation of existing eligibility caps and by identifying factors that need to be considered for modifying existing caps. Specifically, the Study includes an analysis of average system sizes of each exporting customer class compared to the respective existing caps and has examined demand-based caps in terms of interconnection requirements, distribution system operations, and implementation considerations. Staff believes the study has met the Commission's expectations in Order Nos. 34046, 34509, and 35284.

Customer Interest in Setting Eligibility Cap

The Study included an analysis of active and pending exporting system counts, total capacity, and average system sizes for Schedule 6, 8, and 84 customers. The results showed that the average system sizes as percentages of existing caps for Schedule 6, Schedule 8, and Commercial and Industrial customer within Schedule 84 customers are 30%, 31%, and 33%, respectively. However, for irrigation customers in Schedule 84, the average system size is 91% of their cap. Study at 98. These results and the comments, particularly from irrigation customers, indicate that irrigation customers under Schedule 84 are more interested in raising their existing 100 kW project eligibility cap.

Safety and Reliability Factors

According to the Company, regardless of the size of the project, every project interconnection point needs to be evaluated for its safety and reliability impact to the system. As long as each project's interconnection point is evaluated and the proper investments and upgrades to harden the system are implemented based on these evaluations, the size of the eligibility cap from a safety and reliability perspective is not an issue. *See* Responses to Staff Production Request Nos. 4, 7, 10, and 11. These incremental costs to harden the system are already addressed in Schedule 68[4], and should be recovered from each customer causing the additional cost. To ensure transparency, the information should be readily available to the public to show compliance with Commission Order No. 34509. Staff recommends that the VODER Study be amended to include the information from the aforementioned production requests.

Policy Factors

Eligibility Cap Used to Limit Cost Shifts

The Study included considerations for setting the cap based on current subsidies that exist under the current net-metering framework where credits are rewarded on a one-for-one kWh

[4] Schedule 68 (Interconnections to Customer Distributed Energy Resources) is the Company's service schedule which provides for interconnection to customer generation.

basis. Study at 97. This is an important consideration if credits are awarded on a dollar per kWh basis through an ECR that is set higher than the Company's avoided cost. The size of the cost shift to non-generating customers will depend on (1) how much higher the ECR is above the avoided cost, and (2) the amount of customer exports allowed in the system. It is important to properly set the ECR so potential cost shifts are limited. If the ECR rate is higher than the avoided cost of the Company's system, one way to minimize the amount of the cost shift is to limit the size of the eligibility cap to hold down the total amount of customer exports into the Company's system.

Overlap of PURPA and Customer-Generation

Staff also identified PURPA as a consideration in setting the eligibility cap. Because customer-generation projects could be implemented as PURPA qualifying facilities and vice versa, gaming could occur, especially if PURPA rates, terms, and requirements are different than those for customer-generators, thus providing an incentive for customer-generators or PURPA projects to manipulate the rules to achieve more favorable rates and terms.

For example, this type of gaming historically occurred when large PURPA solar and wind projects that should have qualified as IRP-based projects disaggregated into smaller published rate projects in order to receive higher rates. This was resolved by lowering the published rate eligibility cap from ten average-megawatt to 100 kW. Order No. 32697 at 13-14. Staff recommends that an evaluation of potential gaming between PURPA and customer-generation be conducted during the next phase of the case to prevent unfavorable manipulation of requirements and rules.

Demand-Based Eligibility Cap

The Study briefly explored four areas associated with the implementation of demand-based caps by posing the following questions:

a. Should a demand-based system size cap apply to all customer-generators or only commercial, industrial, and irrigation customers?
b. What is the definition of a customer's demand for purposes of a system size cap?
c. How will a demand-based system cap be defined for a customer without historical usage data? (Response to Production Request No. 11 states "[a] customer's

demand, irrespective of the definition or criteria used, is not a technical factor that will define a project eligibility cap to ensure that the Company's system remains safe and reliable.")

d. How do changes in system ownership that result in considerable changes in customer demand impact a customer-specific and demand-related cap?

Staff believes these questions are important to consider if a demand-based eligibility cap is implemented.

Implementation Timing

The implementation timing for changing the eligibility cap is a consideration to protect non-generating customers from cost shifts. As discussed above, subsidies exist under the current NEM framework where credits are rewarded on a one-for-one per kWh basis. If the eligibility cap is increased prior to an avoided-cost-based ECR being implemented, it would result in more customer generation capacity being added with additional cost shifts to non-generating customers.

Other Areas of Study

In Order No. 35284, the Commission stated that the Study must: (1) quantify the magnitude, duration, and value of accumulated credits; (2) show how the Company does or does not benefit from expiration of credits; and (3) show how non-customer-generators are harmed or benefited from expiration of customer export credits. *Id* at 28.

In the VODER Study, the Company states as of December 31, 2021, it had 17.1 million kWh credits owed to customer-generators. The credit balance owed has grown at an annual rate of approximately 66% since 2014 when the Company had 0.5 million kWh owed to customer-generators. Study at 104. To monetize the credits, the Company assumed 7.5 million kWh would be used by the customer-generators and removed that amount from the calculation. To calculate the monetary value of the remaining credits, the Study uses the average energy rate of each class adjusted for the effects of the Fixed Cost Adjustment ("FCA") and the Sales Based Adjustment ("SBA"). These credits are now used to reduce overall consumption which affects both the FCA and SBA. The value of the credits would be $290,116. Study at 104.

Of the 17.1 million kWh accumulated, 2.1 million kWh were generated from non-legacy systems. The Company proposes that these credits would convert to a financial credit when the customer is moved to a financial compensation structure. Study at 105. These credits would be exchanged at a flat ECR because the Company does not have the records identifying when each kWh was generated, and therefore could not apply a variable ECR. Using the ECR from Section 6 of .03781 per kWh, the results would be a value of $77,823. The Company also included the value of these credits on differing ECRs in Appendix 10.1. Due to the FCA and SBA, this expiration and change to financial credits would benefit other customers by $76,759. The Company would also receive a $45,433 financial benefit from the conversion of kWh credits to financial credits. Study at 105-106 and Appendix 10.1.

Staff believes there may be some scenarios for pricing that are feasible but not included in the Study. These include allowing non-legacy systems to keep the kWh credits instead of exchanging them for financial credits and allowing legacy systems to exchange the kWh credits for financial credits.

The Company included additional items in Section 10.2 of the VODER Study that were included but not required to be studied in Order No. 35284. This section details resources available to the public on the Company's website to assist in making informed decision about the economics of on-site generation, including customer usage, rates, solar energy information, hourly energy production, sample payback, and interconnection requirement.

Implementation Considerations

Staff evaluated implementation considerations in Section 11 of the VODER Study. The Company provided information that is transparent, understandable, and showed that the Company is awaiting final input from all Parties and the public to make implementation process recommendations. Although, the Company did not offer any transition guidelines, the Company anticipates filing such recommendations in the next phase.

The Company outlined additional implementation considerations in Section 11, such as billing system updates, tariff language, and communication materials for both installers and customers. The Company states it will need additional time, following a Final Order in this case, to finalize the full implementation of a new net billing program.

PUBLIC INPUT

Public Workshops

Idaho Power held a virtual public workshop on August 31, 2022, and Staff held two virtual public workshops. The first Staff workshop was held the evening of September 6, 2022, and the second was held on the afternoon of September 7, 2022. Among the topics discussed at the workshop were the VODER Study, history of the case, and grandfathering. Where appropriate, Staff addressed customers' comments and concerns in these areas.

Customer Comments

In Case No. IPC-E-18-15, the Commission weighed the importance of public input. In fact, public comments weighed heavily "against the Settlement Agreement, the parties' comments in support of the Settlement Agreement, and the parties' briefs regarding treatment of existing customers." Order No. 34509 at 4.

Knowing the weight of the public's concern, Staff encourages the Company to present additional review of the public's comments and outline the important topics that may or may not be included in their reply comments. As of September 7, 2022, 559 public comments have been filed in this case. Of these comments, 170 (30% of total) were received from customers who acknowledged owning a solar system and enrolled in NEM.

Staff will continue to review public comments and looks forward to hearing further feedback from the public about the VODER Study. Customer comments offered included thoughts and opinions, while not offering separate findings they wanted introduced for consideration.

Of the total (559) customer comments received to date, the following were the five main views expressed by customers:

<u>Public Hearings</u>

Three hundred eighty-eight customer comments (69% of total) requested opportunities to attend a public hearing throughout the state to be conducted at various times to allow maximum public participation.

Grandfathering

Even though previous cases and Commission Orders have clearly addressed grandfathering, customers continue to express concerns and the need for additional grandfathering, which can affect compensation for customers who have recently installed systems or are considering the payback period of a future installation. One hundred nineteen customer comments (21% of total) mentioned the date of grandfathering as an issue which was addressed in Order Nos. 34509, 34546 and 34854. *See* footnote 2 to these Comments.

Compensation and Structure

The issue of compensation and structure was raised in 331 customer comments (59% of total). Compensation affects the payback period for all customers who have not been grandfathered. Systems have an anticipated thirty-year life and a lower compensation level that requires the customer or potential customer to reevaluate the financial burdens and weigh the financial and the environmental and societal benefits against the cost. Should a customer sell the property before a loan has been paid, the remaining debt decreases the value of the sale.

Environmental and Societal Costs or Benefits

The VODER Study does not identify specific environmental costs or benefits. Two-hundred forty-nine customer comments (44% of total) expressed their concern that a lack of environmental benefits included for compensation of the ECR discourages investment in solar power. Customers suggest that the environmental and societal benefits of solar will benefit their extended families and society as a whole and should be included for compensation in the ECR.

Reject the Company's VODER Study and Have a Third-Party Independent Study Completed

Eighty-eight customer comments (15% of total) asked that the Commission reject the VODER Study, with several of them asking for a third-party to conduct an independent study.

STAFF RECOMMENDATIONS

Staff recommends approval of the Study, as it complies with Order Nos. 34046, 34509, and 35284, contingent on the following modifications if approved by the Commission as outlined below:

1. ECR.
    a. Avoided Energy Value – submit an amendment to the Study that provides additional explanation and data for: (1) the firm to non-firm energy adjustment; and (2) comparison for the amount of cost paid for avoiding the cost of energy using two sets of time windows with enough resolution to differentiate between the proposed "On Peak" high-value and "Off-Peak" value.
    b. Avoided Capacity Value – two exceptions that should be addressed by an amendment to the Study: (1) how the Company accounts for the impact to the avoided cost of capacity as the first deficit year changes; and (2) update the Company's method used to calculate the avoided capacity cost for the seasonal time-variant scenario.
    c. Avoided Line Losses – Submit amendments to the Study after meeting with Parties regarding (1) appropriate application of transformer line losses, (2) inclusion of line losses in the avoided cost of capacity; and (3) applying the line loss adjustment using Staff's capacity contribution for the seasonal time-variant rate.
    d. Environmental and Other Benefits – submit an amendment to the Study that provides additional explanation of RECs provided in Company's Response to Staff's Production Request No. 46.
2. Class Cost of Service ("CCOS") and Rate Design – future studies of CCOS and rate design must be evaluated and implemented in the Company's next general rate case.
3. Project Eligibility Cap – submit an amendment to the Study that provides the following: (1) the Study be supplemented with information received through discovery; (2) the policy factors identified be considered in setting the cap and include an evaluation of potential gaming and manipulation between PURPA and customer-generation be conducted.
4. Implementation Considerations – transition guidelines be submitted during an implementation process.

Respectfully submitted this 21st day of September 2022.

Riley Newton
Deputy Attorney General

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Chris Hecht
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i:umisc/comments/ipce22.22rntncchjbmsyyjt comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 21st DAY OF SEPTEMBER 2022, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-22-22, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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