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IDAHO PUBLIC
UTILITIES COMMISSION

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November 16, 2023

Jan Noriyuki, Secretary
Idaho Public Utilities Commission
11331 W. Chinden Boulevard
Building 8, Suite 201-A
Boise, Idaho 83714

Re: Case No. IPC-E-23-14
Application for Authority to Implement Changes to the Compensation Structure Applicable to Customer On-Site Generation Under Schedules 6, 8, and 84 and to Establish an Export Credit Rate Methodology

Dear Ms. Noriyuki:

Attached for electronic filing is Idaho Power Company's Final Comments in the above-entitled matter.

If you have any questions about the attached documents, please do not hesitate to contact me.

Sincerely,

Megan Goicoechea Allen

Megan Goicoechea Allen

MGA:sg
Enclosures

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Attorneys for Idaho Power Company

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 IDAHO POWER COMPANY'S FINAL COMMENTS

COMES NOW, Idaho Power Company ("Idaho Power" or "Company"), in accordance with Rule 203 of the Rules of Procedure of the Idaho Public Utilities Commission ("Commission") and the Notice of Modified Procedure, Order No. 35881, issued August 10, 2023, respectfully submits its Final Comments[1] in the above-referenced case as follows.

[1] Idaho Power indicated in its Notice filed November 2, 2023, that it would utilize these Final Comments to respond to all comments submitted to date.

I. INTRODUCTION

The situation and issues confronting the Commission in this docket are not dissimilar to those that have, are, or will be faced by numerous state regulatory commissions nationwide. Throughout the country, regulators have been compelled in recent years to revisit and reform existing net energy metering ("NEM") rules and regulations that were established decades ago under vastly different circumstances. Like Idaho, most states historically employed a relatively straightforward and administratively simple approach at "netting" and valuing NEM on-site generation and consumption and were able to overlook program design inefficiencies and resulting implications for other customers when behind-the-meter systems were few in number. And similar to what has occurred in Idaho, rapid growth of on-site generation systems and a changing energy landscape has exacerbated the regulatory and policy concerns prompting many regulators to reevaluate net energy metering policies to better align with sound regulatory principles. Though each jurisdiction is unique with its own set of stakeholders, cost studies, rate designs, average retail rates, and approaches to successor net metering service offerings, net metering policy generally is in a period of transition across the nation.[2]

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[2] According to the NC Clean Energy Technology Center's ("NCCETC") annual review and Q4 2022 update report, nearly every state in the country took some type of distributed solar policy action during 2022," a trend which has continued over the past several years and is likely to continue through 2023 and beyond." The top solar distributed policy trends of 2022 identified in the report include states moving away from traditional net metering; net billing becoming the dominant successor tariff structure; growing use of time-varying compensation rates for distributed generation; and distributed generation programs increasing in complexity, with more granular credit rate structures and intricate program designs being adopted. Apadula, E., et al. *The 50 States of Solar: Q4 2022 & Annual Review Executive Summary* at 9-10, NC Clean Energy Technology Center, Jan. 2023.

Available at: https://nccleantech.ncsu.edu/wp-content/uploads/2023/01/Q4-22-Solar-Exec-Summary-Final.pdf.

In Idaho at least, this transition was inevitable; in considering the practice of retail rate net metering over twenty years ago, Commission Staff cautioned:

> For the Commission to accept a net metering tariff where customer generation is credited at full retail rates, it must be willing to accept the fact that Idaho Power may not recover its full costs of providing service from net metering customers.[3]

For its part, the Commission was amenable to this valuation approach in 2001 despite concerns that some of the costs of serving net metering customers would likely be subsidized by other customers given the limits on participation and its mandate for future monitoring and assessment of the new service offering.[4] The Company's net metering service fulfilled the Commission's desire to implement a service offering, subject to modification as experience was gained, and helped support the continuing development of renewable energy resources and advances in energy generation technology.

Since the 1983 inception[5] of Idaho Power's retail net metering offering, the Company has been taking incremental steps as it gained experience to lay the foundation and prepare for updating its on-site generation offering to ensure equity among all customers moving forward. In the interim, the solar industry in Idaho was able to gain its footing and is thriving.[6] Against the backdrop of these dynamic circumstances, the need for transparency became paramount, even prompting the involvement of the Idaho

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[3] *In the Matter of the Application of Idaho Power Company for Approval of a New Schedule 84—Net Metering Tariff*, Case No. IPC-E-01-39, Comments of the Commission Staff at 3 (Dec. 21, 2001).

[4] *Id*., Order No. 28951 at 11-12 (Feb. 13, 2002); *In the Matter of the Application of Idaho Power Company for Amendments to Schedule 84—Net Metering*, Case No. IPC-E-02-04, Order No. 29094 at 7 (Aug. 21, 2002).

[5] Case No. U-1006-200, Order No. 18358 (Oct. 20, 1983).

[6] In the last ten years the number of solar installers in Idaho Power's service territory has increased from 19 known installers to over 65.

Legislature, which added a new chapter to Idaho Code in 2019 requiring certain solar contract disclosures in order to facilitate customers' access to key information and guard against misleading or inaccurate sales representations.[7] Similarly, Idaho Power has endeavored to ensure customers were and are fully apprised of the potential changes, undertaking extensive efforts – including numerous direct mailings – over the years to communicate with both customer-generators and non-participating customers regarding the NEM service offering and regulatory proceedings related to potential changes.

Over the last several decades, the Company gained the requisite experience and laid the foundation necessary for updating its on-site generation offering as proposed in this case, which would, in conjunction with the changes to be implemented in the Company's current general rate case,[8] result in offerings that are better aligned with current circumstances, economically supportable, and fair to all customers.

II. COMPANY REVISED PROPOSAL

Based on the input received by Staff and other Parties[9] and the analysis presented in the following sections of its Final Comments, the Company recommends that the Commission issue an order to:

[7] To date, state-level mandatory solar contract disclosure policies have been adopted in many states including Arizona, California, Florida, Hawaii, Idaho, Illinois, Maryland, Massachusetts, Minnesota, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Oregon, South Carolina, Texas, Utah, and Washington.

[8] *In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service in the State of Idaho and for Associated Regulatory Account Treatment*, Case No. IPC-E-23-11 (filed June 1, 2023).

[9] As referenced throughout Parties collectively refer to intervenors in this docket.

(1) Implement real-time net billing with an avoided cost-based, seasonal, time-variant Export Credit Rate ("ECR"), with the following modifications or clarifications:

(a) Align the ECR Summer *season* with the base rate summer season of June 1 through September 30 as proposed in the Company's general rate case in Case No. IPC-E-23-11. Direct the Company to review and update the *season* in a general rate case filing as appropriate;

(b) Define the ECR Summer On-Peak *hours* as 3 p.m. to 11 p.m., Monday through Saturday, excluding holidays, during the summer season, and if future Integrated Resource Plan ("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;

(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 Effective Load Carrying Capability ("ELCC") to determine the avoided capacity value;

(f) Calculate the rolling average ELCC with the inclusion of line losses applied to the hourly customer-generator exports to calculate the avoided capacity value;

(g) Include customer-generator exports for *all* hours in the calendar year in the calculation of the rolling average ELCC;

(h) Apply the annual energy line losses to the energy value;

(i) Apply the peak hour line losses to the On-Peak hours and apply the annual energy line losses to all other hours of the capacity value;

(2) Direct the Company to update all proposed components of the ECR except the season and hours of highest risk in an annual filing beginning April 1, 2025.

(3) Maintain the current Schedule 6 and Schedule 8 eligibility caps.

(4) Modify the eligibility cap for Schedule 84 customers to the greater of 100 kilowatts ("kW") and 100 percent of demand and direct the Company to include additional proposed interconnection requirements in Schedule 68 concurrent with the effective date of real-time net billing.

(5) 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 direct the Company to meet with Staff and submit its findings to the Commission within 90 days of an order on the feasibility of implementing a surcharge to recover ongoing costs of system upgrades.

(6) Approve the Company's request to recover ECR expenditures as a net power supply expense subject to 100 percent recovery through the Power Cost Adjustment ("PCA").

(7) Approve the Company's proposals on the use and transferability of financial credits.

(8) Approve the Company's proposal to convert accumulated kilowatt-hour ("kWh") credits to financial credits using a blended average retail energy rate on December 31, 2024, for non-legacy systems.

(9) Direct the Company to transfer any accumulated financial credits when a customer relocates within the Company's service area within six months.

(10) 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 to 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.

  (b) Direct the Company to file all future VER studies and integration costs for Commission authorization if integration costs have materially changed from those authorized.

(11) Direct the Company to adjust the language of Schedules 6, 8, 68, and 84, according to all recommendations presented above in a compliance filing.

III. EXPORT CREDIT RATE

The Company appreciates the comprehensive review and comments from the public and Parties in this matter. The Company has evaluated the Parties' comments while considering the primary objectives laid out in its Application:

(1) Develop a compensation structure that will accurately measure a customer-generator's use of the system for recording exported and consumed energy.

(2) Apply methods to ensure a fair and accurate valuation of customer exports.

(3) Implement a repeatable method for updating the ECR to ensure timely recognition of changing conditions on Idaho Power's system and the broader power markets that may warrant changes to the ECR.

(4) Balance accuracy with customer understandability.

After careful evaluation of each Party position, the Company has considered the merits of modifications to its proposed ECR that would enhance understandability and transparency, while ensuring progress towards modernizing the customer on-site generation offering. A summary of the Company's revised ECR is included in the below table compared to its initially filed ECR and Attachment No. 1 is the revised workpaper.

Table 1
Company Filed and Revised ECR

	Season/Time	Filed	Revised
Export Profile			
Volume (kWh per kW)	Annual	1,465	1,465
Capacity Contribution (%)	Annual	8.76%	10.12%
Export Credit Rate by Component (cents/kWh)			
Energy	Summer On-Peak	8.59 ¢	5.65 ¢
Including integration and losses	Summer Off-Peak	4.91 ¢	5.65 ¢
	Non-Summer	4.91 ¢	4.84 ¢
	*Annual**	*5.16 ¢*	*5.16 ¢*
Generation Capacity	Summer On-Peak	11.59 ¢	10.61 ¢
	Summer Off-Peak	0.00 ¢	0.00 ¢
	*Annual**	*0.79 ¢*	*1.01 ¢*
Transmission & Distribution Capacity	Summer On-Peak	0.25 ¢	0.18 ¢
	Summer Off-Peak	0.00 ¢	0.00 ¢
	*Annual**	*$ 0.02*	*0.02 ¢*
Total	**Summer On-Peak**	**20.42 ¢**	**16.43 ¢**
	Summer Off-Peak	**4.91 ¢**	**5.65 ¢**
	Non-Summer	**4.91 ¢**	**4.84 ¢**
	*Annual**	*5.96 ¢*	*6.18 ¢*

**Annual values provided for informational purposes only and reflect seasonal weighting for 12 months ending December 2022.*

Note: The revised Summer season is defined as June 1 - September 30; the filed Summer season was defined as June 15 - September 15. Revised and filed Summer On-Peak hours defined as 3pm - 11pm, Monday - Saturday, excluding holidays, and all other hours defined as Off-Peak.

The Company's Final Comments summarize the Parties' positions for each element of the Company's proposal and Idaho Power's filed and revised position to reflect where it has modified its proposal. Staff and Vote Solar's comments included substantive positions on the various elements of the Company's filed proposal and, therefore, have been addressed explicitly in the summary table. Clean Energy Opportunities for Idaho

("CEO"), City of Boise, Idaho Conservation League ("ICL"), and Irrigation Pumpers Association, Inc.'s ("IIPA") comments included positions on select elements of the Company's proposal and, therefore, have been consolidated under "Other Party Positions" within the structure of the Company's Final Comments.

A. Measurement Interval

Summary of Measurement Interval Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	Real-Time	Real-Time	Not Specified	City of Boise - Hourly	Real-Time

The current NEM structure uses a monthly netting interval which allows the exporting customer to "bank" credits from exports, in the form of a kWh credit, for use during hours when the customer uses more energy than they generate. This allows a customer to use any excess kWh credit from exports to offset their monthly billing consumption when they are not exporting. The Company evaluated a real-time and hourly measurement interval for net billing and proposed to implement a real-time measurement where the meter will record real-time net grid electricity consumption and exports independently and the customer would continue to "bank" credits from exports, in the form of a financial credit.[10]

[10] Aschenbrenner DI at 26.

Staff Position

Staff considered both a real-time and hourly netting interval consistent with Order No. 35631 and did not consider any interval larger than hourly, citing the lack of accuracy the measurement provides. Staff noted "that a real-time interval presents many advantages in terms of accuracy, understandability, and malleability of the ECR."[11] Additionally, by using a real-time measurement interval, exports would be tracked in a manner consistent with imported power. Staff believes that having consistency between exports and billing will increase customer understandability and transparency.[12] Staff also recognized that implementing a real-time measurement interval would likely increase bills for on-site generation customers; however, the impact would be strictly from increasing the accuracy of measuring exports and would reduce cost-shifting to non-customer generators. Last, Staff notes that the Company would incur additional costs to implement an hourly measurement with no additional benefit over implementing a real-time measurement.[13]

Vote Solar Position

Vote Solar did not specifically address the measurement interval if the Commission elects to approve an ECR. However, the avoided energy value calculated in Vote Solar's workpaper is weighted relative to the real-time exports in each hour.[14] Therefore, it appears that Vote Solar does not dispute the use of a real-time measurement.

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[11] Staff Comments at 10 (Oct. 12, 2023).

[12] *Id*. at 11.

[13] *Id*. at 12.

[14] Vote Solar Workpapers A 10.12.23 (included as attachment to Vole Solar Comments).

Other Party Positions

The City of Boise stated that the Commission should consider consistency in the measurement interval with the Clean Energy Your Way – Construction service offering ("CEYW-Construction"), and, therefore, consider implementing an hourly netting period.[15]

CEO, ICL, and IIPA did not specify a recommendation for the measurement interval.

Idaho Power Position

The Company recommends that the Commission implement a real-time measurement interval. The analysis provided in Staff's comments comprehensively captures the trade-offs between a real-time and hourly measurement interval.

The City of Boise suggests an hourly measurement interval should be considered for consistency with CEYW-Construction. While the City of Boise acknowledges that the program constraints differ, it fails to mention critical differences between that service offering and on-site customer generation. Most notably, CEYW-Construction customers continue to pay the fixed cost component of the retail energy rate for all energy offset by the renewable energy facility. Said differently, a customer participating in CEYW-Construction can only offset the cost of *energy* embedded in their volumetric rate, an amount of around 3 cents per kWh. This same fixed-cost recovery does not occur for customer on-site generation because customers taking service under Schedules 6, 8, and 84 are permitted to offset *all* costs included in the volumetric rate. Depending on the customer class, this bypass results in an under-recovery of between 5 and 12 cents per

[15] City of Boise Comments at 6-7 (Oct. 12, 2023).

kWh consumed on-site. A difference in measurement interval is warranted to increase the accuracy and reduce cost-shifting to non-customer generators.

B. ECR Rate Design

Summary of ECR Rate Design Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	Seasonal/Time-Variant Rate *Jun 15 - Sep 15 3-11pm*	Seasonal/Time-Variant Rate *Jun 1 to Sep 30 3-11pm*	Flat & Optional Seasonal/Time Variant	IIPA – Separate ECR by Class CEO – Agreed with Staff	Seasonal/Time-Variant Rate *Jun 1 - Sep 30 3-11pm*

The Company's proposal for the ECR in its Application included a seasonal time-variant rate structure.[16] The specific rate structure results in a higher ECR in the summer on-peak hours and a lower ECR in all other hours. In its Application, the Company proposed defining the summer season as June 15 to September 15 and the on-peak hours as 3 p.m. to 11 p.m., Monday through Saturday.[17] The Company determined the season and hours based on the Loss of Load Expectation ("LOLE") analysis which identifies the timing of highest risk.

Staff Position

Staff recommends that the Company align the summer season of the ECR to match the summer season of June 1 to September 30 presented in the concurrent general rate case.[18] Staff also recommends updating the seasons as part of future general rate case filings as informed by the most recently filed IRP. As a result, Staff is comfortable with the Company's proposed on-peak ECR hours of 3 p.m. to 11 p.m. for the summer

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[16] Application at 19.

[17] *Id*. at 20.

[18] Staff Comments at 16 (Oct. 12, 2023).

season of June 1 to September 30; however, it notes that there should be 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 hours for both the ECR and Time of Use ("TOU") rates.[19]

In response to IIPA's proposal to calculate an ECR by customer class, Staff recommends the Commission not adopt IIPA's request.[20] Staff believes that multiple ECR's would reduce transparency, increase confusion, and could lead to a dissatisfaction among customers. Additionally, its notes that the intent of Schedules 6, 8, and 84 is to provide customers the opportunity to offset their energy usage. Staff's position is that if irrigation customers want to receive compensation based on their export shape, they can apply as a Qualifying Facility.[21]

Vote Solar Position

Vote Solar recommends that the Commission approve a flat annual average ECR as the default offering and that an optional time-differentiated ECR be available to customers with on-site generation at their discretion.[22] Vote Solar suggests that a flat annual average ECR as the default offering will allow customers with on-site generation to adjust to the new construct of an export rate. Vote Solar does not agree with distributing avoided energy value in alignment with summer and non-summer seasons as proposed

[19] Staff Comments at 16 (Oct. 12, 2023).

[20] Staff Reply Comments at 4 (Nov. 2, 2023).

[21] *Id.*

[22] Vote Solar Comments at 34-36 (Oct. 12, 2023).

by Staff. Vote Solar's rationale cites that the proposed method will not substantially improve the economics of exporting power during the period.[23]

In response to IIPA's recommendation to calculate an ECR by customer class, Vote Solar does not agree with this approach and recommends the ECR should not vary based on the customer that exports energy.[24] Vote Solar states that the value of exported energy does not vary based on the type of customer who generated the power and points out that load profiles vary even among customers within a class.

Other Party Positions

IIPA recommends that irrigation and non-irrigation should have separately calculated export credit rates. IIPA notes that a disproportionately large share of irrigation net energy export occurs in winter and shoulder months, thus suggesting this warrants a differently calculated export credit rate. [25]

CEO supports Staff's proposal to align the ECR summer season with the proposed summer season in the Company's general rate case definition of June 1 to September 30.[26] Similarly, CEO supports the Company's proposal and Staff's support for defining Summer on-peak as 3 p.m. to 11 p.m. CEO also supports Staff's proposal to assign the energy value by season, and to implement three ECR values: Non-Summer, Summer Off-Peak, and Summer On-Peak.[27]

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[23] Vote Solar Reply Comments at 7 (Nov. 2, 2023).

[24] *Id*. at 6.

[25] IIPA Comments at 2 (Oct. 12, 2023).

[26] CEO Reply Comments at 3 (Nov. 2, 2023).

[27] *Id*. at 4.

ICL and City of Boise did not specify a recommended rate design for the ECR. However, ICL does recommend rejecting IIPA's request for a separate ECR for Schedule 6, 8, and 84. ICL states that any energy exported to the grid at a given time should be equal regardless of the source of the exported energy. [28]

Idaho Power Position

The Company recommends the Commission approve Staff's proposed modifications to the ECR rate design. It is appropriate to generally align the season and the hours for the ECR and TOU in place for consumption. Therefore, the Company recommends that the Commission approve a June 1 to September 30 summer season for the ECR. The Company maintains that the on-peak ECR hours should be 3 p.m. to 11 p.m., which generally aligns with its proposed mid- and on- peak hours for its TOU offerings for residential, commercial, and industrial customers as proposed in the Settlement Stipulation in Case No. IPC-E-23-11. This is aligned with recommendations from Staff and CEO. The Company is also supportive of Staff's recommendation to file a separate docket to update the highest risk hours for both ECR and consumption rates as indicated by future IRP analysis.

The Company appreciates Vote Solar's concern for customer understandability, which led to its recommendation for a flat annual ECR. However, the Company believes that a seasonal time-variant structure is most accurate and appropriate, and this level of complexity is not uncommon for the Company's optional service offerings. The Commission also recognized the value from "peak hour pricing or another variable pricing mechanism so on-site generators who invest in storage can realize the value of their

[28] ICL Reply Comments at 7-8 (Nov. 2, 2023).

investment when they export stored energy."[29] Therefore, the Company recommends the Commission decline Vote Solar's recommendation to have a default flat annual ECR and an optional seasonal, time-variant ECR. However, if the Commission elects to approve a flat annual ECR, the Company requests to have a singular rate design option for the ECR for all net billing customer-generators as optionality could lead to an overly complex and less accurate annual update process, as well as potential gaming from customers switching between offerings.

The Company is in agreement with other intervenors' recommending that IIPA's proposal to have a separate ECR by customer class be rejected by the Commission. The intent of an ECR representative of avoided costs should be applicable to exported energy from customer-generators irrespective of customer class or generation source. The Company evaluated the feasibility of implementing class-specific ECRs in advance of its filing, as more fully explained on page 10 of Mr. Ellsworth's pre-filed testimony, and the Company ultimately determined a class-specific ECR would not be advisable, for many of the reasons listed by Staff.

By aligning the rate design for the ECR with the hours of highest risk, it also sends a price signal to customers with energy storage when dispatching their batteries to the grid is valued and needed most. At the Customer Hearing on October 24, 2023, several participants stated that there are barriers preventing them from dispatching battery storage to the grid. However, such barriers don't presently exist for customers that have

[29] *In the Matter of Idaho Power Company's Application to Initiate a Multi-Phase Collaborative Process for the Study of Costs, Benefits, and Compensation of Net Excess Energy Associated with Customer On-Site Generation*, Case No. IPC-E-21-21, Order No. 35284 at 16 (Dec. 30, 2021).

batteries paired with their generation as an Exporting System; pursuant to Schedule 68, the Exporting System incorporates both the generation and storage.

C. Avoided Energy

Summary of Avoided Energy Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	EIM/ELAP *Trailing 12 Months, Weighted On/Off-Peak*	EIM/ELAP *Trailing 12 Months, Weighted by Season*	EIM/ELAP *Trailing 36 Months, Weighted On/Off Peak*	IIPA – Adjusted EIM/ELAP CEO – Agreed with Staff	EIM/ELAP *Trailing 12 Months, Weighted by Season*

The Company proposed that the value of avoided energy be determined by the hourly prices from the Energy Imbalance Market ("EIM"), which is the western region's real-time energy market. EIM prices vary by location, so the Company proposed to use the EIM Load Aggregation Point ("ELAP") prices independently determined on an hourly basis by the California Independent System Operator ("CAISO"). The Company proposed to use the 12 months of market data ending December 31 each year to calculate an average price weighted for customer-generator exports for on-peak and off-peak avoided energy values.[30]

Staff Position

Staff agrees with the Company's proposed method for valuing avoided energy based on historical weighted ELAP pricing. Staff believes hourly ELAP prices are reasonable because they reflect the actual energy market value in the Company's service area. While historic pricing is less accurate than real-time pricing, Staff notes that a benefit is rate stability and transparency for customers. Staff agrees with the Company's proposal

[30] Ellsworth DI at 10, 13.

to use the most recent year's pricing data and not to incorporate multiple years of pricing data via some type of rolling average.[31]

However, Staff disagrees with the Company's method of distributing the value of avoided energy and recommends that the value of avoided energy be allocated between the summer and non-summer seasons. Staff believes that the on-peak time window is determined primarily by capacity considerations – not energy considerations. Staff's proposal would produce three ECR values: Non-Summer, Summer Off-Peak, and Summer On-Peak.[32]

Staff disagrees with IIPA's assertion that EIM pricing contains a component of capacity-related value.[33]

Vote Solar Position

Vote Solar did not oppose the Company's proposal to use ELAP prices to value the avoided energy component of the ECR. However, Vote Solar proposed using a three-year historical rolling average of market prices to mitigate severe price swings in the avoided energy value from year to year and improve customer predictability and stability.[34] Vote Solar opposes IIPA's proposals for a balancing account to track the difference between the energy paid to customers and the value received and that ELAP

[31] Staff Comments at 17 (Oct. 12, 2023).

[32] *Id.* at 18.

[33] Staff Reply Comments at 4 (Nov. 2, 2023).

[34] Vote Solar Comments at 16 (Oct. 12, 2023).

prices include a capacity component and maintains that they are a reasonable proxy for the avoided energy costs that result from exports.[35]

Other Party Positions

IIPA suggests that the on-peak energy credit equal the off-peak energy credit to avoid double counting capacity value.[36] IIPA asserts that the "EIM prices used to calculate the on-peak energy value are, on average, hours where scarcity pricing results in market prices compensating for capacity as well as energy."[37] IIPA also suggests excluding the Greenhouse Gas component of the ELAP prices.[38] Additionally, IIPA recommends that Idaho Power should develop a balancing account to track the difference between the energy value paid to customers and the value received from customers and amortize the balance in each ECR update.[39]

CEO agrees with Staff and the Company regarding the proposed method for valuing avoided energy based on ELAP hourly pricing from the prior year weighted for hourly exports in that year.[40] However, CEO requests that the Company provide an updated hourly Loss of Load Probability ("LOLP") analysis which includes the use of battery storage resource additions.[41] CEO's understanding of the intent of using ELAP pricing was to reflect the local energy value in each hour – which conflicts with the position

[35] Vote Solar Reply Comments at 8 and 12 (Nov. 2, 2023).

[36] IIPA Comments at 8 (Oct. 12, 2023).

[37] *Id*. at 7.

[38] IIPA Comments at 8 (Oct. 12, 2023).

[39] *Id*. at 10.

[40] CEO Reply Comments at 3 (Nov. 2, 2023).

[41] *Id*.

from IIPA that suggests the ELAP prices are overstated by a Greenhouse Gas component. CEO requests that the Company clarify whether a Greenhouse Gas adder is, or is not, included in the ELAP price.

ICL and City of Boise did not provide specific recommendations for the avoided energy value.

Idaho Power Position

The Company recommends the Commission approve the Company's filed request for the avoided energy component of the ECR to use 12 months of ELAP market prices ending December 31 weighted for historical customer-generator exports to determine the avoided energy value of the ECR. To keep the value of energy as accurate as possible, the Company maintains its proposal to use the most recent year's pricing data rather than incorporating multiple years of pricing data as proposed by Vote Solar.

The Company is aligned with Staff's proposal to allocate the value of avoided energy between the summer and non-summer season rather than the on-peak and off-peak hours as proposed in the Company's initial filing. Vote Solar's rationale for opposing this approach is that it "will not substantially improve the economics of exporting power."[42] However, the Commission has been clear in previous orders that the purpose is to ensure that customers are paid fair, just, and reasonable rates for their exports and non-self-generating customers are not subsidizing the rates for self-generating customers – *not* to ensure that customers who have installed self-generation facilities are able to recoup their

[42] Vote Solar Reply Comments at 7 (Nov. 2, 2023).

investment or earn a return on investment.[43] Therefore, Vote Solar's opposition to this approach shouldn't impact the decision for how to most appropriately calculate the avoided energy value for the ECR.

As a matter of clarification, the Company believes IIPA misunderstood the Greenhouse Gas component in the ELAP price. The Greenhouse Gas component reflects a carbon compliance cost and is therefore a negative value. Therefore, the Company disagrees with the proposal from IIPA to remove the value of the Greenhouse Gas Component, as the ELAP price is representative of the avoided cost of energy provided from customer-generators. The ELAP price reflects the balance of supply and demand, and the Company does not have the opportunity to purchase energy from the EIM at lower than market price, thus the ELAP price reflects the marginal cost for energy with location-based adjustments for losses, congestion, and carbon compliance costs in any period.

The Company is not opposed to the proposal by IIPA to create a balancing account to track the differences in historical and average market prices; however, it also acknowledges that such a mechanism does create an additional layer of complexity that the Commission may not wish to adopt at this time. If the Commission determines there is merit to IIPA's concern related to the timing differences, it could direct the Company to track and report on the impact over a certain number of years.

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[43] *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, Order No. 35631 at 28 (Dec. 19, 2022).

The Company recommends the Commission approve the filed highest-risk hours of 3 p.m. to 11 p.m. in the summer season and that any changes should be evaluated within the context of the Company's planning process. The Company agrees with Staff's recommendation that future changes to the hours should align between the ECR and TOU rates for retail energy consumption.

The below table compares the avoided energy value between the Company's filed and revised proposal.

Table 2
Avoided Energy Value Comparison (cents per kWh)

Idaho Power – Filed		**Idaho Power - Revised**	
On-Peak *Jun. 15-Sep. 15, 3pm-11pm, excluding Sundays & Holidays*	8.59 ¢	**Summer** *Jun. 1 – Sep. 30, all hours*	5.65 ¢
Off-Peak *All other days and hours*	4.91 ¢	**Non-Summer** *Oct. – May 31, all hours*	4.84 ¢
Annual Weighted Average	***5.16 ¢***	***Annual Weighted Average***	***5.16 ¢***

Note: Revised values include the Company's proposal for integration costs and line losses.

D. Avoided Generation Capacity

Summary of Avoided Generation Capacity Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	ELCC *Trailing 3-Year Average ELCC and Least-Cost Dispatchable Proxy Resource*	ELCC *Trailing 5-Year Average ELCC and Least-Cost Dispatchable Proxy Resource*	Capacity Factor *Battery Storage as Proxy Resource*	CEO – Agreed with Staff *City of Boise & ICL - Battery Storage as Proxy Resource*	ELCC *Trailing 5-Year Average ELCC and Least-Cost Dispatchable Proxy Resource*

To determine the capacity contribution of customer-generators, the Company's proposed avoided generation calculations use a 3-year average of the ELCC, multiplied by the maximum hourly exports (of the latest year's data) and valuing it at the levelized capacity cost of the least-cost dispatchable resource in its most recently filed IRP.[44] The ELCC method measures a resource's contribution during the hours of highest risk – as more renewable generation is introduced to the grid, the hours of highest system load and the hours of highest risk generally do not align. The true value of avoided capacity occurs during the hours of highest risk, so the ELCC is a more accurate means of assigning value than other methods such as the National Renewable Energy Laboratory ("NREL") 8,760-hour method, or the Peak Capacity Allocation Factor ("PCAF") method. These alternative methods 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 approaches to assigning an avoided generation capacity value.[45]

Staff Position

Staff believes that the Company's proposed method for valuing the avoided generation capacity of exports is reasonable.[46] However, Staff recommends that the Company implement the following:

(1) Use a *5-year* instead of a 3-year rolling average to estimate the ELCC;

(2) Modify the method to incorporate line losses in calculating capacity value;

(3) Use all exports from customer generators in its calculation of the ELCC.

Staff agrees with the Company's proposal to use the levelized capacity cost of the least-cost dispatchable resource as identified in the most recently filed IRP. On September 30, 2023, the Company filed the 2023 IRP in Case No. IPC-E-23-23, which

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[44] Ellsworth DI at 16.

[45] Ellsworth DI at 15.

[46] Staff Comments at 19 (Oct. 12, 2023).

identified the least-cost dispatchable resource as a single-cycle combustion turbine ("SCCT"), with a levelized cost of $145.94 per kW-year.[47] Staff recommends that this updated value be used to determine the avoided capacity value because it is more current and therefore more accurate.[48] Staff believes a surrogate dispatchable resource to establish a purely avoided cost of capacity should meet the following criteria:

(1) Have the lowest levelized fixed cost including capital cost and fixed operation and maintenance cost;

(2) Be reliably dispatchable regardless of the time or duration need.

Staff does not believe that proposals by Vote Solar and City of Boise to use battery storage as the proxy for avoided cost of capacity fits either of these two criteria. Therefore, Staff suggests that using battery storage as a surrogate capacity resource does not provide an ideal fit.[49]

The recommendation to increase the ELCC to a 5-year rolling average addresses Staff's concern that the ELCC could trend down as solar penetration increases. Staff notes that utility-scale solar generators can lock in the ELCC through a contract with the Company, but notes doing so is not practical for a class of customers with participants who enter and exit the class continuously. 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 an extended period. Staff also notes that 2020 was the first year ELCCs could be accurately determined for customer-generator

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[47] 2023 Integrated Resource Plan Appendix C: Technical Report at 18.

[48] Staff Comments at 20 (Oct. 12, 2023).

[49] Staff Reply Comments at 5 (Nov. 2, 2023).

exports on Idaho Power's system, 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 results as it became available through 2024.[50]

Staff acknowledged that the Company's filed proposal grosses up the hourly customer-generator exports by the corresponding line loss factor when importing the data into its Reliability and Capacity Assessment Tool ("RCAT"), which is then utilized to perform the ELCC calculations. Staff believes that the ELCC algorithms do not have the resolution to account for the small line loss increases, thus nullifying line losses.[51] Therefore, Staff recommends the Company account for line losses for capacity by applying the line loss gross up *after* the ELCC and avoided capacity values are determined. Staff also believes the Company's proposal to distribute all generation capacity value to the On-Peak hours is reasonable.[52]

Vote Solar Position

Vote Solar suggests it is "more appropriate to base avoided generation capacity costs on the capital costs of battery storage, which results in a generation capacity cost of $192 per kW-year."[53] Vote Solar believes that the "ELCC is computationally intensive because doing so requires a substantial amount of data," making "ELCC calculations less transparent because the assumptions and calculations are challenging for stakeholders

[50] Staff Comments at 19-21 (Oct. 12, 2023).

[51] Staff Comments at 21 (Oct. 12, 2023).

[52] *Id.*

[53] Vote Solar Comments at 20 (Oct. 12, 2023).

to review."[54] Vote Solar recommends the capacity factor method as a simplified alternative to the ELCC and states that it is still "sufficiently accurate."[55]

Vote Solar claims that it is the only intervenor that proposed a generation capacity value that represents capacity costs actually avoided because it uses the levelized cost of battery storage as the surrogate resource.[56] Vote Solar states that its calculation accounts for avoided line losses and Idaho Power's planning reserve margin – suggesting that when load is reduced by a kilowatt, the amount of generation the utility must procure is reduced by a kilowatt plus its planning reserve margin.[57] Vote Solar suggests that Idaho Power's capacity value calculations lack accuracy and transparency – pointing to Idaho Power's 2023 IRP ELCC values for existing and future resources.[58] Vote Solar also compared the Company's analysis for the highest-risk hours with its proposed approach of using the top ten percent of load hours and found that 99 percent of the high load hours occurred in the On-Peak period (as identified by the Company's highest-risk hours).[59]

Other Party Positions

CEO supports Staff's request to use a five-year rolling average of the ELCC instead of a three-year rolling average.[60] CEO maintains that EIM prices do not reflect a

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[54] *Id.*

[55] *Id*. at 21.

[56] Vote Solar Reply Comments at 10-11 (Nov. 2, 2023).

[57] *Id.* at 10.

[58] Vote Solar Reply Comments at 14-15 (Nov. 2, 2023).

[59] *Id.* at 16.

[60] CEO Reply Comments at 5 (Nov. 2, 2023).

capacity value and that the EIM transaction values reflect the marginal cost for energy, with location-based adjustments for losses and congestion, as suggested by IIPA.[61]

City of Boise and ICL recommend the avoided generation capacity valuation use battery storage as the alternative dispatchable resource.[62]

IIPA did not make specific recommendations for the avoided generation capacity value. However, IIPA did suggest concerns with potential double counting between the avoided energy value and capacity value as mentioned in the Avoided Energy section of these comments.

Idaho Power Position

The Company is generally aligned with Staff's proposed modifications to the avoided generation capacity value:

(1) The Company agrees with Staff's proposal to update the dispatchable resource cost to $145.94 per kW-year as defined in the 2023 IRP.

(2) The Company agrees with Staff's proposal to use a five-year rolling average to calculate the ELCC value.

(3) The Company agrees with Staff's proposal to include exports for all hours in a calendar year in its rolling average ELCC calculation.

(4) If directed, the Company can adopt Staff's recommendation to apply the line losses after the ELCC calculation by instead modifying the avoided generation capacity value equation to include the peak line loss factor,

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61 *Id.*

62 ICL Comments at 2 (Oct. 12, 2023) and City of Boise Reply Comments at 6 (Nov. 2, 2023).

however, the Company describes its revised proposal for the Commission's consideration in the comments that follow.

The table below compares the avoided generation capacity value components between the Company's filed and revised proposal, which accepts proposed changes by Staff except for the application of line losses *after* the ELCC calculation.

Table 3
Avoided Generation Capacity Value Components Comparison

Idaho Power – Filed		**Idaho Power – Revised**	
ELCC *Jun. 15 - Sep. 15, 3:00 pm - 11:00 pm, Excludes Sundays and Holidays*	8.76%	**ELCC** *Jan. 1 - Dec. 31, All Hours*	10.12%
Max Output *Based on 2022 Data*	62.86 MW	**Max Output** *Based on 2022 Data*	62.86 MW
Avoided Cost *LCOC of SCCT From 2021 IRP*	$131.6/kW-year	**Avoided Cost** *LCOC of SCCT From 2023 IRP*	$145.94/kW-year
Energy Risk Hours *Jun. 15 - Sep. 15, 3:00 pm - 11:00 pm, Exclude Sundays and Holidays*	6,255.03 MWh	**Energy Risk Hours** *Jun. 1 - Sep. 30, 3:00 pm - 11:00 pm, Exclude Sundays and Holidays*	8,752.71 MWh
Loss Coefficient *On-Peak Credited Hours Input to ELCC Calculation*	1.050	**Loss Coefficient** *System Peak Applied as an Input*	1.053 (On-Peak Hours) 1.044 (All Other Hours)

The Company generally accepts Staff's proposal for calculating the avoided generation value; however, to maintain a clear record, it would like to address the following for the Commission's consideration regarding Staff's proposed method of applying line losses directly to the avoided generation capacity value instead of applying to the exports as an input into the calculation. While Staff suggests that the ELCC algorithms do not have the resolution to account for the small line loss escalations, the resolution is a function of all resource nameplates included in the RCAT which makes it a discrete (not continuous) value. As customer-generator penetration increases the impact will be accurately captured in the ELCC calculation under the Company's proposal. In illustration of this point, the Company modeled customer-generator exports assuming an increased level of penetration on its system and calculated the ELCC with and without losses applied, as seen in the table below.

Table 4
Line Loss Application Illustration – *For a Single Test Year with Export Data Increased by a Factor of 2x*

ELCC of Actual Export Data		ELCC of Increased Export Data (2x)	
No Losses Applied	**Losses Applied**	**No Losses Applied**	**Losses Applied**
2 MW	2 MW	5 MW	6 MW

The illustrative ELCC results show that as customer generation penetration increases, the Company's filed method to apply line losses *within* the ELCC calculation would increase the capacity contribution result. Staff's proposed method of applying the line loss coefficient *after* the ELCC calculation may provide better transparency/simplicity in the calculation of line losses to the avoided generation capacity value but would result in the utilization of a less accurate methodology, which as shown in the above table, could understate the value in the future. The table illustratively shows how the ELCC is impacted by hourly line loss application when the 2022 exports are doubled - 2023 maximum exports measured as much as 1.77x levels in 2022. Therefore, the issue Staff intends to address is already not an issue at the current level of on-site generation penetration. Accordingly, the Company contends its proposed method is most accurate, however, if the Commission adopts Staff's proposal, it will update the ECR as directed.

While Vote Solar recommends the capacity factor method as a simplified alternative to the ELCC method, the Company disagrees that implementing a less accurate measurement is appropriate, particularly in light of recent widespread adoption of the ELCC as the preferred method for measuring the resource adequacy contribution of intermittent and energy-limited resources.[63,64] Vote Solar's comparison of the capacity factor method as a reasonable approximate to the ELCC method is based on a report written in 1997. This is irrelevant considering the significant changes undergone by the electric system in the past 25 years. The Company last utilized a variant of the capacity factor method in the 2017 IRP, where the capacity contribution of solar was calculated for the top 150 load hours and resulted in a value of 28.4 percent for a fixed-tilt system oriented due south.[65] Recognizing that the basis of the capacity factor method was limited and did not capture the impact of high solar penetration, the Company transitioned to the 8,760 hour-based method developed by the National Renewable Energy Laboratory ("NREL") in the 2019 IRP.[66] To further capture the impact of higher variable and energy-limited resource penetration levels, the Company, with the support of its Integrated Resource Plan Advisory Council ("IRPAC"), adopted the preferred industry method,

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[63] ELCC has quickly gained traction among ISOs and utilities. *See* Olson, A., Ming, Z., and Carron, B. *ELCC Concepts and Considerations for Implementation* at slide 12, Presentation for NYISO Installed Capacity Working Group, Aug. 30, 2021.

Available at:
https://www.nyiso.com/documents/20142/24172725/NYISO%20ELCC_210820_August%2030%20Presentation.pdf

[64] N. Schlag, Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, and H. Jiang. Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy at 3, Energy and Environmental Economics, Inc., Aug. 2020.

Available at: https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

[65] *In the Matter of Idaho Power Company's 2017 Integrated Resource Plan*, Case No. IPC-E-17-11, 2017 IRP at 37 and 130.

[66] *In the Matter of Idaho Power Company's 2019 Integrated Resource Plan*, Case No. IPC-E-19-19, 2019 IRP at 37.

ELCC, for the 2021 IRP.[67] The Company also rejects Vote Solar's attempt to suggest that its method is not transparent and easily reviewable by stakeholders. The RCAT is simply a code implementation/interface of a system reliability textbook methodology.[68]

The capacity factor method only utilizes the system load as a weighting factor for evaluating capacity contribution and does not capture the shift in timing of the system's high-risk hours. In result, the capacity factor method determines capacity contribution independent of renewable penetration which means it is incapable of adequately accounting for changes in intermittent and energy-limited resource penetration on the system. Vote Solar found that over 99 percent of high load hours occur in the months the Company defines as the hours of highest risk;[69] the observation is irrelevant as it does not consider the timing of those hours nor does it consider if the highest risk hour occurs when customer-generator exports occur.

Vote Solar states that it does not agree with Staff's claim that the true value of avoided capacity occurs during the hours of highest risk.[70] Vote Solar incorrectly suggests that if system peak load increases, then Idaho Power must construct or procure new capacity resources to reliably serve customers.[71] Vote Solar's comments are ill-informed and inaccurate – the highest-risk hours are the only time when capacity is avoided. Idaho

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[67] *In the Matter of Idaho Power Company's 2021 Integrated Resource Plan*, Case No. IPC-E-21-43, 2021 IRP at 51.

[68] Reliability Evaluation of Power Systems (Billinton, R. and Allan, R.N. (1996) Reliability Evaluation of Power Systems. 2nd Edition, Plenum Press, New York).

[69] Vote Solar Reply Comments at 16 (Nov. 2, 2023).

[70] *Id*. at 17.

[71] *Id.*

Power will only procure new capacity resources if it is in a period of capacity shortfall as measured by the reliability threshold. If system peak increases but the reliability, as measured by the LOLE, does not change, Idaho Power will not procure more resources.

Additionally, Vote Solar's avoided generation capacity value analysis includes a cost increase by an amount equal to the Company's 2021 IRP Planning Reserve Margin ("PRM").[72] The PRM has no relation to the avoided capacity of a single resource. The claim that the avoided generation should be increased by the PRM is flawed. Load is not being *reduced* due to the presence of exports but rather load is being *served* by the presence of exports. When exports do not appear or go away suddenly (e.g., due to weather patterns or time of day) the load remains, and Idaho Power is still required to serve it. As such, the valuation of avoided generation capacity should not include the PRM in the calculations for the cost of avoided generation capacity.

Finally, the Company does not agree with the recommendation to utilize battery storage as the alternative dispatchable resource. For avoided capacity cost calculations, the Company finds it most appropriate to utilize the lowest levelized cost of capacity resource which was identified as an SCCT in the 2023 IRP.[73] The Company agrees with Staff's position that a surrogate dispatchable resource should have the lowest levelized fixed cost and be reliably dispatched. Additionally, an August 2022 Commission order upheld this approach as reasonable, where the Commission stated:

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[72] Vote Solar Reply Comments at 10 (Nov. 2, 2023).

[73] 2023 Integrated Resource Plan Appendix C: Technical Report at 18.

> We find it fair, just, and reasonable that the resource(s) used as a surrogate to determine avoided capacity cost be identified using the lowest-cost selectable resource from the most recently acknowledged IRP…[74]

In response to the recommendation from CEO to remove the non-firm adjustment,[75] the Company wishes to clarify that there is not a non-firm adjustment included in the Company's filed proposal and therefore there is no adjustment to remove as suggested by CEO.

For the reasons stated herein, the Company recommends the Commission approve the Company's revised proposal for determining the avoided generation capacity value of customer generator exports. The table below compares the avoided generation capacity value between the Company's filed and revised proposal which incorporates the majority of Staff's proposed modifications.

Table 5
Avoided Generation Capacity Value Comparison (cents per kWh)

Idaho Power – Filed		**Idaho Power – Revised**	
On-Peak *Jun. 15 - Sep. 15,* *3:00 pm - 11:00 pm,* *Exclude Sundays* *Exclude Holidays*	11.59 ¢	**On-Peak** *Jun. 1 - Sep. 30,* *3:00 pm - 11:00 pm,* *Exclude Sundays* *Exclude Holidays*	10.61 ¢
Off-Peak *All Other Days & Hours*	0.00 ¢	**Off-Peak** *All Other Days & Hours*	0.00 ¢
Annual Weighted Average	***0.79 ¢***	***Annual Weighted Average***	***1.01 ¢***

Note: Revised values reflect Idaho Power's proposal for valuation of line loss coefficients in the ELCC.

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

[75] CEO Reply Comments at 5 (Nov. 2, 2023).

E. Avoided Transmission and Distribution Capacity

Summary of Avoided Transmission and Distribution Capacity Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	Project Deferral Analysis *20-year project specific review*	Project Deferral Analysis *20-year project specific review*	FERC Transmission Rate	CEO – Marginal Transmission Line Cost *City of Boise – FERC Transmission Rate* *IIPCA – Rate Design Considerations*	Project Deferral Analysis *20-year project specific review*

The Company compares transmission and distribution ("T&D") capacity shortfalls throughout its system and overlays customer exports to determine how long it can delay projects that increase transmission and distribution capacity. The value is determined based on the cost of capital of the project investment and length of time a project can be delayed. The distribution of value for avoided T&D capacity follows similar rationale as the allocation of value for avoided generation capacity. Therefore, the Company proposed that the capacity value should be distributed to exports during the on-peak hours of highest risk.

Staff Position

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.[76] Staff believes the Company's proposal to distribute all T&D deferred capacity value to the on-peak hours is reasonable.[77]

[76] Staff Comments at 22 (Oct. 12, 2023).

[77] *Id*. at 23.

Staff does not agree with IIPA's assertion that the Company's proposed method assumes that 100 percent of the customer's generation is exported.[78] Additionally, Staff does not agree with IIPA's claim that there is double counting between the avoided distribution value in the ECR and avoidance of energy charges for customer classes with distribution-related costs embedded in their retail energy rates.[79]

Staff believes that City of Boise's recommendation to use energy efficiency ("EE") T&D deferral value is inappropriate. Staff notes that while the input data is the same, the 2023 IRP describes that the EE avoided T&D costs are calculated using EE specific assumptions and reduction amounts. Meanwhile, the proposed ECR uses export data and assumptions specific to on-site generation customers to calculate the T&D deferral value. Staff recommends that on-site generation export specific data and assumptions are used to value ECR T&D deferral and believes it will result in a more accurate T&D value specific to customer-generators.[80]

Vote Solar Position

Vote Solar recommends an avoided transmission cost value that is based on the current Federal Energy Regulatory Commission ("FERC")-approved transmission rate for Idaho Power of $31.42/kW-year.[81] Vote Solar's proposed calculation results in a value of 7.39 cents per kWh during the on-peak period or 0.50 cents per kWh annually. Vote Solar's comments did not describe a proposed method for the avoided distribution

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[78] Staff Reply Comments at 4 (Nov. 2, 2023).

[79] *Id.* at 5.

[80] *Id*. at 5-6.

[81] Vote Solar Comments at 24-25 (Oct. 12, 2023).

capacity component, but in its ECR summary it includes a value of 0.254 cents per kWh during the on-peak period or 0.017 cents per kWh annually.[82] Vote Solar disagrees with IIPA's position and maintains that the value of avoided distribution capacity should be included in the ECR and apply to all customers, regardless of their rate schedule.[83]

Other Party Positions

CEO requests that in *future* ECR updates, because new transmission lines are anticipated to be used to access remote generation sources, the costs for those marginal transmission lines should be treated in the same fashion as other marginal generation resources when quantifying the T&D capacity contribution of self-generation.[84] CEO also disagrees with IIPA's position and cites previous Commission findings that matters of fixed cost recovery behind the meter are separate from matters of valuing excess energy.[85]

City of Boise suggests that a "reasonable transmission & distribution deferral value" should be included in the ECR. Specifically, City of Boise recommends a higher value for avoided transmission costs be assigned by reflecting the Company's FERC transmission rate.[86]

[82] Vote Solar Comments at 33 (Oct. 12, 2023).

[83] Vote Solar Reply Comments at 18 (Nov. 2, 2023).

[84] CEO Comments at 4 (Oct. 12, 2023).

[85] CEO Reply Comments at 5 (Nov. 2, 2023).

[86] City of Boise Comments at 3 (Oct. 12, 2023).

IIPA recommends that the T&D capacity credit should only apply to schedules with no transmission or distribution revenue requirement included in the energy charge.[87] IIPA is concerned that if the energy component of the customer's bill includes distribution costs, the customer will receive double compensation for reduced distribution costs, once directly through the capacity component of the ECR and again through avoiding energy charges with self-consumed energy.

ICL does not specify a recommendation related to deferred T&D capacity value for the ECR.

Idaho Power Position

The Company recommends the Commission approve its proposed project deferral analysis for valuing the T&D capacity deferral component of the ECR. The alternative recommendations presented by Vote Solar, CEO, and City of Boise do not accurately value the T&D cost deferred by customer-generator exports.

Vote Solar and City of Boise have not attempted to evaluate whether the results of Idaho Power's project deferral analysis were reasonable. Instead, both suggest a different method should be used because the Company's proposed method does not yield a high enough value with no support for why the value is understated or the underlying methodology is flawed. CEO also recommends including a marginal cost analysis for transmission projects. The proposal to use the FERC transmission rate or other marginal cost rate does not represent capacity costs actually avoided, or deferred, as directed by the Commission.[88]

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[87] IIPA Comments at 11 (Oct. 12, 2023).

[88] Case No. IPC-E-22-22, Order No. 35631 at 29.

The Company agrees with Staff's analysis that IIPA has incorrectly characterized the T&D deferral approach, which uses the exports from customer-generators – not 100 percent of the generation. The Company also does not agree with IIPA that the proposed T&D deferral value is double counting with the customer-generators ability to reduce energy charges and its considerations for transmission and distribution-related costs embedded in the energy charge for certain customer classes should instead be addressed through rate design through a general rate case or separate proceeding.

The below table compares the Company's filed T&D value, updated for the revised summer and non-summer seasons as proposed by Staff.

Table 6
Avoided Transmission & Distribution Capacity Value Comparison (cents per kWh)

Idaho Power – Filed		**Idaho Power – Revised**	
On-Peak *Jun. 15-Sep. 15, 3pm-11pm, excluding Sundays & Holidays*	0.25 ¢	**On-Peak** *Jun. 1 – Sep. 30, 3pm-11pm, excluding Sundays & Holidays*	0.18 ¢
Off-Peak *All other days and hours*	0.00 ¢	**Off-Peak** *All other days and hours*	0.00 ¢
Annual Weighted Average	***0.02 ¢***	***Annual Weighted Average***	***0.02 ¢***

F. Avoided Line Losses

Summary of Avoided Line Loss Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	On-Peak and Off-Peak Line Loss Coefficients	Average Energy Losses and Peak Capacity Losses	Marginal Line Losses	CEO & ICL – Marginal Line Losses	Average Energy Losses and Peak Capacity Losses

Idaho Power completed its most recent system loss study in March 2023.[89] The electric utility industry typically calculates lines losses by evaluating the total system losses over the entire year and during the peak hour of the year, which the Company completed in the March 2023 line loss study. The originally filed On-Peak line loss coefficient (1.050) was a modification of the calculated peak hour coefficient (1.053), which accounted for all the hours within the previously identified On-Peak period. In the March 2023 line loss study, the peak hour coefficient was adjusted using hourly data from the 138-kV system to calculate the On-Peak line loss coefficient. The 138-kV system was used as a proxy given the high-resolution data available and being an adequate representation of the native load in the Company's system as most of the wheeling across Idaho Power's transmission system occurs at higher voltage. The resulting on- and off-peak loss coefficients in the Company's filed proposal were applied to on- and off-peak hours respectively.

Staff Position

Staff reviewed the Company's line loss study completed in March 2023 and concluded that the analysis was reasonably accurate but disagreed with the proposed

[89] Ellsworth DI, Exh.4.

coefficients.[90] Staff believes the Company's approach "embeds too many assumptions, obfuscates the calculations, and jeopardizes the accuracy."[91] Staff also states that it is inappropriate to apply a capacity-based loss rate to the ECR energy value. Staff recommends that the ECR utilize "industry-typical loss calculations." As a result, Staff concludes that the avoided energy value should be grossed up by the annual energy loss coefficient and the avoided capacity value should be grossed up by the standard peak hour loss coefficient.

Vote Solar Position

Vote Solar claims that the Company's suggested ECR includes average line losses, and it recommends that marginal line losses should be used as they are "typically at least twice as high as average system losses."[92] Vote Solar proposes doubling the proposed line loss coefficients proposed by Idaho Power.

Other Party Positions

CEO requests that the Company's proposal to decrease line loss assumptions, relative to the line losses used in the October 2022 VODER Study, be denied, and that the line loss should not be less than 5.8 percent – referring to the line loss value used in Case No. IPC-E-22-22.[93] ICL recommends the use of marginal line loss calculations.[94]

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[90] Staff Comments at 23 (Oct. 12, 2023).

[91] *Id*.

[92] Vote Solar Comments at 17 (Oct. 12, 2023).

[93] CEO Comments at 5 (Oct. 12, 2023).

[94] ICL Comments at 2 (Oct. 12, 2023).

City of Boise and IIPA did not specify a proposed method for determining line losses in their comments.

<u>Idaho Power Position</u>

The Company recommends the Commission approve Staff's proposal of applying the annual energy loss coefficient to the avoided energy value. The Company also recommends the Commission approve Idaho Power's revised proposal of applying the standard peak hour loss coefficient to the On-Peak hours and the annual energy loss coefficient to all other hours for customer-generator exports in the ELCC calculation which is utilized to inform the avoided capacity value. The Company believes its proposal is an accurate calculation and most representative of the distribution system for all on-peak hours, on average. However, it is not opposed to Staff's proposal if the Commission believes the tradeoff between accuracy and understandability is warranted.

The Company would like to clarify that Vote Solar's claim of the proposed ECR including average line losses is incorrect, as the Company calculated separate peak and average line losses in its line loss study. Peak losses were applied to the annual capacity value and average line losses were applied to the annual energy value.

The Company experiences reverse power flow from the distribution system to the transmission system in several substations due to generation on the distribution system, which increases the line losses. Therefore, if the Commission were to approve the use of marginal losses in the ECR calculation, it would result in additional costs to account for the increase in line losses. Additionally, Vote Solar states that marginal losses are twice as high as average system losses; this assumption is based on a 2011 study that analyzed a hypothetical utility and assumed annual resistive losses.[95] The Company's 2023 line loss study utilized hourly historical data to calculate the peak and average losses, which provided the ability to calculate components such as the annual resistive losses instead of relying on general assumptions. Therefore, the Company suggests that the Commission reject Vote Solar's proposed marginal line loss calculation.

The proposal by CEO to utilize line loss coefficients from the Company's 2012 line loss study does not rely on using the most recent data available to derive an accurate ECR value. Therefore, the Company recommends the Commission reject the proposal by CEO to maintain a line loss value of 5.8 percent or higher when more recent and reflective data is available. The table below compares the Company's filed and revised proposal for line loss coefficients to account for line losses in the ECR.

Table 7
Line Losses Coefficient Comparison

Idaho Power – Filed		**Idaho Power – Revised**	
Credited Hours On-Peak *Jun. 15 - Sep. 15,* *3:00 pm - 11:00 pm,* *Excluding Sundays & Holidays* *For Avoided Energy & Capacity*	1.050	**Capacity** *Jun. 1 - Sep. 30,* *3:00 pm - 11:00 pm,* *Excluding Sundays & Holidays* *For Avoided Capacity Only*	1.053 (On-Peak) 1.044 (All Other Hours)
Off-Peak *Jan. 1 - Jun. 14 & Sep. 16 - Dec. 31,* *All Days & All Hours* *For Avoided Energy & Capacity*	1.044	**Energy** *All Days & All Hours* *For Avoided Energy Only*	1.044

95 Vote Solar Comments at 17 (Oct. 12, 2023).

G. Avoided Environmental Costs

Summary of Avoided Environmental Cost Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	Not included	Not included	Reduced carbon emissions	CEO & City of Boise - Monetize renewable attributes	Not included

The Company has not proposed to include any avoided environmental benefits in the ECR. Idaho Power is not subject to a carbon tax or a Renewable Portfolio Standard ("RPS"). Idaho Power does not have a mandatory requirement to produce a set amount of renewable energy and, therefore, has no need to purchase Renewable Energy Certificates ("RECs"). Although customer generation from renewable resources may avoid some fossil fuel generation, thereby reducing carbon emissions, Idaho Power is not subject to a carbon tax and cannot monetize those emission reductions as a credit in customer rates.

Staff Position

Staff considered the appropriateness of relying on a national carbon tax, an Idaho RPS, social health, and RECs as options that could be used to provide a value of an environmental benefit. Staff concluded that until 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.[96]

[96] Staff Comments at 24 (Oct. 12, 2023).

Vote Solar Position

Vote Solar mentions several topics regarding environmental and social costs and benefits but does not make a specific recommendation for the Commission to consider.[97] Vote Solar quantifies "additional benefits" that result in an additional value of approximately 2.1 cents per kWh but doesn't specifically suggest using this value in the total ECR value.[98]

Other Party Positions

CEO and City of Boise recommend that the Company work with interested stakeholders to evaluate further opportunities to monetize the renewable energy attributes associated with exported energy.[99] CEO specifically suggests residential customer-generators opt out of the transfer of renewable attributes to the Company. CEO also requests that the Company be directed to report on opportunities to monetize the value of renewable energy attributes.

ICL and IIPA did not specify a recommendation related to quantifying a value for environmental benefits for the ECR.

Idaho Power Position

The Company maintains its recommendation that until 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. The Company has concerns with CEO and the City of Boise's proposal to attempt to monetize the

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[97] Vote Solar Comments at 27-32 (Oct. 12, 2023).

[98] *Id*. at 33.

[99] CEO Comments at 5-7 (Oct. 12, 2023) and City of Boise Comments at 3 (Oct. 12, 2023).

renewable attributes of customer generation on the customer's behalf. While CEO suggests these are "solvable" issues, Idaho Power maintains that these are not representative of a cost avoided in customer rates.

In most states, including Idaho, the environmental attributes of on-site generation remain with the owner. For Idaho Power to retain and retire (or sell) RECs on an on-site generation customer's behalf, the current registration process would require the customer to legally transfer the environmental attributes of the on-site generation, and the customer would no longer be able to claim the clean nature of the energy used to power their home or business to prevent double counting of those attributes. Idaho Power does not believe this is viable as customers typically install on-site generation, in part, for such claims of clean energy as demonstrated in the public comments and testimony in this docket. Further, Idaho Power does not have any mechanism that allows for the exchange of on-site generation RECs – Idaho does not have a RPS with a distributed generation carve-out, a Solar Renewable Energy Certificate market, or any legislation that establishes specific treatment of on-site generation RECs. For these reasons, the Company recommends that the Commission not direct further investigation as proposed by CEO and City of Boise.

H. Fuel Cost Risk

Summary of Fuel Cost Risk Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	N/A	N/A	Valued at 5% of Avoid Energy Cost	Valued at 5% of Avoid Energy Cost	N/A

In response to feedback from stakeholders in Case No. IPC-E-22-22, the Company evaluated the potential for a fuel-cost risk benefit for customer-generator exports. In the October 2022 VODER Study, the Company found that exports from customer-generators do not provide a fuel-cost hedge benefit. Customer-generator exports on Idaho Power's system occur intermittently in the midday hours when it is generally less valuable, rather than on a firm basis in the highest net-peak hours, when it would be most needed – resulting in no reduction in pricing risk during the net-peak load.[100]

Staff Position

Staff did not specifically address a fuel cost risk benefit in its comments regarding the Company's proposal.

Vote Solar Position

Vote Solar notes that gas prices are volatile and highly variable throughout the year, concluding that when energy exported from on-site solar displaces a marginal gas-fired power plant, customers benefit from reduced dependence on gas prices and lower exposure to gas volatility.[101] Vote Solar recommends the Commission acknowledge that on-site generation does provide a hedge benefit and approve an avoided fuel cost risk

[100] October 2022 VODER Study at 55.

[101] Vote Solar Comments at 25-26 (Oct. 12, 2023).

value equal to five percent of avoided energy costs – citing a methodology adopted by the Public Utility Commission of Oregon.[102]

Other Party Positions

CEO cites the same method as Vote Solar which assigns a value of five percent of the avoided energy component of the ECR as the fuel cost risk benefit. As an alternative, CEO suggests the value should at least be set at 3.9 percent as suggested in a study specific to Rocky Mountain Power ("RMP").[103] City of Boise and ICL also recommend the Commission incorporate a non-zero fuel hedge value in similar support to Vote Solar and CEO.[104]

IIPA did not specify or mention a value related to fuel cost risk.

Idaho Power Position

The Company recommends the Commission not include a value for fuel cost risk in the ECR. Vote Solar, CEO, City of Boise, and ICL do not specifically address the issues and concerns with the proposed reduction in fuel cost risk as evaluated in the October 2022 VODER Study. Instead, these stakeholders reference methods adopted in *other jurisdictions*, which ignores the details specific to this proposal. In particular, the ELAP price is directly impacted by natural gas market prices. To add a five percent premium would result in double counting and over-inflate the value paid to customer-generators and collected from all other customers. CEO posits that the Company's response and rationale is "inadequate" with no further support for its position. The Company does not

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[102] Vote Solar Comments at 26 (Oct. 12, 2023).

[103] CEO Comments at 3-4 (Oct. 12, 2023).

[104] City of Boise Comments at 8 (Oct. 12, 2023), City of Boise Reply Comments at 6 (Nov. 2, 2023), and ICL Reply Comments at 8 (Nov. 2, 2023).

believe that what other jurisdictions adopt is indicative of what should occur in Idaho without consideration to the specific considerations in this docket. Other states have elected to assign a value while acknowledging it is challenging to quantify a fuel risk benefit. The Company believes it would be imprudent to follow similar logic as proposed. In Case No. IPC-E-22-22, Crossborder Energy, which had support from CEO, ICL and other intervenors for its review of the Company' s study in that docket, stated the following regarding the use of the ELAP market price and a corresponding fuel hedge value for exported energy:

> . . . there is little or no fuel hedge value. Electricity market prices are directly impacted by natural gas market prices. Rather, it is the behind the meter solar generation serving the customer's load that provides a hedge against the gas-cost sensitive utility supply costs that otherwise would have to be incurred by [Idaho Power].[105]

Vote Solar references an article titled "How Big is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest" to support its proposed five percent adder for a fuel cost risk value. The article concludes that "there is a risk premium of about 5 percent <u>in the forward price</u> for delivery at the Mid-Columbia hub for the Pacific Northwest."[106] Applying this five percent premium to the ECR when not using a forward price from the Mid-Columbia hub would be an inappropriate use of the proposed method. The ECR as proposed uses <u>actual</u> prices which already reflects the market-based

[105] Case No. IPC-E-22-22, ICL's Response to Request No. 22 of Idaho Power Company's Second Production Request to ICL.

[106] DeBenedictis A., Miller, D., et al, "How Big is the Risk premium in an Electricity Forward Price? Evidence from the Pacific Northwest," The Electricity Journal Volume 24, Issue 3 April 2011, pages 72 – 76, *available at* https://www.sciencedirect.com/science/article/abs/pii/S1040619011000601 *(emphasis added).*

variability risk premium cited in the article.[107] CEO's suggestion that as an alternative to the five percent, the Commission adopt a 3.9 percent adder (cited from RMP's study) is equally flawed, as RMP's study envisioned the adder when the avoided energy component was based on an energy price forecast, not actual prices.

In the Oregon docket referenced by Vote Solar, the OPUC-retained evaluator, E3, rejected the idea that the avoided hedge value should be included in the calculation for the value for solar because this hedge value does not accrue to all customers, but to the owner of the solar generation:

> [T]o the extent that a utility acquires a solar resource as part of its generation portfolio, that resource allows the utility to avoid market purchases of electricity and/or natural gas and any associated hedging costs.
>
> However, for behind-the-meter generation, this value accrues to the owner of the solar installation, not to non-participating utility ratepayers. Solar owners acquire the resource for the purpose of offsetting all or a portion of their onsite consumption, thereby replacing their potentially variable electricity bill with a more stable cost stream based on the cost of solar ownership. The solar installation thereby provides a hedge value for the solar owner.
>
> The remaining load does not experience a reduction in volatility as a result of the solar installation. Behind-the-meter solar does not become part of the utility's resource portfolio. Rather, behind-the-meter solar functions like direct access, in which the load is separated from the remaining bundled customers and served with a third-party resource, i.e., a resource that is outside the utility's portfolio. Since the utility does not own or contract directly with the solar PV resource, the utility therefore will need to continue to hedge any market transactions for the remaining load in the same proportion as if the solar installation had not occurred. As a result, the hedge value accrues to the system owner, and the remaining utility ratepayers do not experience a reduction in bill volatility.[108]

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[107] *See* Idaho Power Company's Response to Request No. 43 of the Fifth Production Request of Commission Staff.

[108] *Investigation to Determine the Resource Value of Solar,* OPUC Docket No. UM 1716, Staff Exhibit 401 of Exhibits in Support of Cross Responsive Testimony (Jul. 21, 2016), at Olson 23-24 (Staff Response to TASC Data Request 20).

The Commission has clearly stated in previous orders that generic conclusions and benefits or costs that cannot be quantified or shown to affect customers' rates should not be considered in valuing an ECR.[109] Therefore, the proposal to include a fuel cost risk or hedging value related to reduced price volatility should be rejected.

I. Integration Costs

Summary of Integration Cost Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	VER Study Case 1	VER Study Case 1	VER Study Case 9	CEO - VER Study Case 9	VER Study Case 1

The Company proposes to use its 2020 Variable Energy Resources ("VER") Integration Study to determine the integration cost component of the ECR. Integration studies are periodically conducted by the Company to quantify the cost of regulating variable, non-firm energy sources into the Company's system such as exports from customer-generators. The Company proposes to use its VER Study Case 1 with an integration cost of $0.00293/kWh in the ECR.

Staff Position

Staff agreed with the Company's basis for and inclusion of the $0.00293/kWh integration cost in the ECR.[110] Staff recommends the Commission authorize the integration rates for purpose of the ECR in this filing, direct the Company to file the 2020 VER study for Commission authorization to update Schedule 87, and direct the Company to file all future VER studies and integration costs for Commission authorization.[111]

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[109] Case No. IPC-E-22-22, Order No. 35631 at 29.

[110] Staff Comments at 25 (Oct. 12, 2023).

[111] *Id.*

Staff believes that the presence of battery storage in the Company's system can influence integration costs. Because the Company will have installed approximately 120 megawatts ("MW") of battery storage by the end of the year, Staff recommends the Company conduct a new integration study as soon as possible. Staff also recommends that the Company file the study for Commission approval and incorporate the results into the next possible ECR adjustment filing.[112]

Vote Solar Position

Vote Solar claims that Idaho Power's actual resource portfolio is better reflected by Case 9 in the VER integration study, reflecting an integration cost of $0.64 per megawatt-hour ("MWh"). Vote Solar states that Case 9 assumes the addition of 251 MW of solar and 200 MW of storage and that battery storage helps to smooth the variability of output from resources like solar, reducing integration costs.[113]

Other Parties Position

CEO makes a similar argument to Vote Solar and suggests that the proposed ECR should reflect the integration costs of $0.64 per MWh from Case 9.[114]

ICL, City of Boise, and IIPA did not comment on integration costs.

[112] Staff Reply Comments at 6 (Nov. 2, 2023).

[113] Vote Solar Comments at 18 (Oct. 12, 2023).

[114] CEO Comments at 7-8 (Oct. 12, 2023).

Idaho Power Position

The Company maintains that Case 1 continues to be the appropriate integration cost scenario because it is most reflective of integration costs from distributed energy resource exports on the Company's system. Additionally, the Company is not opposed to Staff's proposal for the Commission to direct the Company to complete an updated integration study as soon as possible and file for Commission approval and inclusion for future ECR update.

Vote Solar and CEO's proposal incorrectly applies the integration costs from the 2020 VER Integration Study. Case 1 includes the addition of 251 MW of solar above the 2020 level of utility-scale solar on the Idaho Power system. In comparison, Case 9 was a sensitivity case to determine the incremental integration cost for adding 794 MW of solar coupled with 200 MW of battery energy storage above the 251 MW of solar added in Case 1.

The integration costs for Case 1 and Case 9 from the 2020 VER Integration Study cannot be directly compared. The $2.93 per MWh integration cost from Case 1 is the calculated cost for adding 251 MW of utility-scale solar. The integration cost of $0.64 per MWh from Case 9 is the calculated incremental integration cost to integrate 794/200 MW of coupled solar/battery beyond the 251 MW of utility-scale solar from Case 1 – this is not representative of the cost to integrate customer-generator exports.

IV. UPDATES TO ECR

Summary of ECR Update Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	Annual ECR Update for all Net Billing customers *All components updated*	Annual ECR Update for all Net Billing customers *All components except season and hours*	Vintage ECR by interconnection year and "lock in" for at least 10 years	ICL – Update every two years like IRP	Annual ECR Update for all Net Billing customers *All components except season and hours*

The Company proposed to update the inputs that inform the ECR annually on April 1, to be effective June 1. This timeline is consistent with the Company's other annual spring update filings. Under the Company's filed proposal, the real-time exports, ELAP hourly market prices, contribution capacity, and peak annual exports would be updated annually based on historical export and market data. Additionally, the Company proposed to update the levelized cost of an avoided resource, hours of capacity need, T&D deferral, line losses, and integration costs on a routine basis.[115] These inputs are based on other Company filings that are completed on a consistent cycle.

Staff Position

Staff believes updating the real-time exports, ELAP hourly market prices, contribution capacity, and peak annual exports on an annual basis is a reasonable amount of time between updates to help ensure rates closely resemble market conditions while balancing the need for rate stability for customer generators.[116] Staff agrees with the Company's proposal to file updates on April 1. Staff notes that if the Company were

[115] Anderson DI at 29-33.

[116] Staff Comments at 30 (Oct. 12, 2023).

to update the hours of capacity need 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, T&D deferral, line loss and integration costs on a routine basis specific to each input as proposed in the Company's filing.[117]

However, Staff disagrees with the Company's proposal to update the hours of capacity need for on-peak hours in the proposed annual filing. Staff recommends that the Commission order the Company to update the *hours* of capacity need in a separate filing. Staff suggests that 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.[118]

Vote Solar Position

Vote Solar recommends that the ECR should be locked-in for individual customers with on-site generation at the rate effective at the time of the customer's application to interconnect their system for a period of at least 10 years.[119] Vote Solar believes that it "is impossible for a prospective solar customer to predict their long-term savings from installing solar when they are subject to an export rate that changes every year."[120] Vote Solar cites similar vintaging treatment that occurs in Nevada and Arizona. Vote Solar supports Staff and CEO's recommendation that if an ECR is implemented, the first annual

[117] Staff Comments at 31 (Oct. 12, 2023).

[118] *Id.*

[119] Vote Solar Comments at 36 (Oct. 12, 2023).

[120] *Id*.

update should be effective June 1, 2025, and supports an ECR update period longer than one year.[121]

Other Party Positions

ICL recommends the Commission approve an update period every two years to follow Idaho Power's IRP cycle.[122] City of Boise recommends that any changes "be phased in over a reasonable implementation period" but does not specify a specific recommendation for timing.[123] However, City of Boise also suggests that "the Company's proposed methodology for determining annual updates to the ECR could be reasonable."[124]

CEO and IIPA do not specify a recommendation for updates to the ECR.

Idaho Power Position

The Company recommends the Commission approve its revised proposal to update the components of the ECR annually in a filing on April 1, with an effective date of June 1, and to have any changes to the season and hours of highest risk be updated as part of a separate filing.

The Company does not support Vote Solar's recommendation to vintage customers by year and lock-in the ECR at the time the customer interconnects. In its justification, Vote Solar highlights similar vintaging of customer's credits for exports in other jurisdictions as a reason for why this Commission should follow suit; however it is

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[121] Vote Solar Reply Comments at 19 (Nov. 2, 2023).

[122] ICL Reply Comments at 5 (Nov. 2, 2023).

[123] City of Boise Comments at 3 (Oct. 12, 2023).

[124] *Id*. at 6.

important to note, at least one of the jurisdictions referenced – Arizona – is currently considering a change to its 10-year export rate effective period and grandfathering policy for net metering customers.[125] Additionally, Vote Solar's primary rationale for this proposal is to provide certainty to customers regarding their ability to pay off their investment. The Company believes this rationale ignores previous Commission orders:

> [W]e want to reiterate here that the purpose of establishing a NEM rate is *not* to ensure that customers who have installed self-generation facilities are able to recoup their investment or earn a return on investment, it is to ensure that customers are paid fair, just, and reasonable rates for their exports and non-self-generating customers are not subsidizing the rates for self-generating customers.
>
> . . .
>
> As we cautioned many times before, tariffs are not contracts and are subject to change. Order No. 35284 at 10. It should come as no surprise to anyone who invested in an on-site generation solar system after December 20, 2019, that the Company may be authorized by the Commission to change fundamental aspects of its NEM program—including the imposition of an ECR—which can affect the payback period for customers. Idaho Code § 48-1805 states that every solar installer must provide notice to a potential customer, in capital letters, "with substantially the following form and content: 'LEGISLATIVE OR REGULATORY ACTION MAY AFFECT OR ELIMINATE YOUR ABILITY TO SELL OR GET CREDIT FOR ANY EXCESS POWER GENERATED BY THE SYSTEM AND MAY AFFECT THE PRICE OR VALUE OF THAT POWER.'" We reiterate that a 'reputable seller of onsite generation systems would not and will not represent that the program will never change.' Order No. 34892.[126]

The Company will further address the recommendations by Parties to delay the first annual update effective date to June 1, 2025, in its comments below regarding transition/gradualism considerations.

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[125] In the Matter of the Application of the Arizona Corporation Commission's Exploration of Changes to the Up to 10 % Annual Reduction in the Export Credit Rate and the 10-Year Export Rate Effective Period Under the Resource Comparison Proxy Methodology Approved in the Value and Cost of Distributed Generation Docket (E-00000J-14-0023), Docket No. AHD-00000J-23-0273, Hearing Division Memorandum (Oct. 16, 2023).

[126] Case No. IPC-E-22-22, Order No. 35631 at 28, 30 (emphasis in original).

V. TRANSITION/GRADUALISM CONSIDERATIONS

Summary of Transition/Gradualism Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	None	First Annual Update June 1, 2025	Multi-Year Glide Path from Retail Rate to ECR	CEO - First Annual Update June 1, 2025 City of Boise – Delay until June 1, 2024	First Annual Update June 1, 2025

After reviewing the relevant Commission orders and considering the extensive communication by the Company and Commission to notify customers of the potential for change, the Company did not include a proposal for transition and proposed that the successor service offering should be applicable to all customers that the Commission defines as not being grandfathered into the existing monthly NEM one-for-one kWh compensation structure.

Staff Position

Staff does not recommend any transition period.[127] Staff notes that the Company, the Commission, and several intervening parties have been involved in changing the NEM service offering since 2017 through a multitude of dockets. 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. Staff does not recommend expanding grandfathering, or legacy status, and believes that the Commission has been clear through Order Nos. 34509, 34546, and 34854, that legacy status will not be expanded.[128]

However, Staff believes that under the Company's proposal, customers will not have had sufficient time to adjust to the new rate before the first proposed update to the

[127] Staff Comments at 40 (Oct. 12, 2023).

[128] Staff Reply Comments at 7 (Nov. 2, 2023).

ECR. 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 therefore recommends that the Company delay the first effective update to the ECR until June 1, 2025.[129]

Vote Solar Position

Vote Solar recommends the Commission implement a transition, if the ECR is lower than the retail rate, by setting the initial ECR equal to the value of the average volumetric retail rate for each customer class.[130] Vote Solar recommends the rate decline by a maximum amount, for example five percent, as the total capacity of on-site generation installed in Idaho Power's service area reaches defined thresholds. Additionally, Vote Solar recommends customers remain on the rate current at the time they apply for 10 years.

Other Party Positions

CEO supports Staff's proposal to set the effective date for Schedule 84 as January 1, 2024, and the first update to occur June 1, 2025.[131] ICL recommends the Commission provide one year transitional period for Schedule 6 and 8 but no transition period for Schedule 84.[132] City of Boise recommends the Commission delay implementation of any

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[129] Staff Comments at 31 (Oct. 12, 2023).

[130] Vote Solar Comments at 48 (Oct. 12, 2023).

[131] CEO Reply Comments at 2 (Nov. 2, 2023).

[132] ICL Comments at 2 (Oct. 12, 2023) and ICL Reply Comments at 5 (Nov. 2, 2023).

changes in this docket until June 1, 2024, delay the first update until June 1, 2025, and implement a transition period to phase in the ECR by 25 percent every two years.[133]

IIPA does not address transition/gradualism considerations.

Idaho Power Position

The Company is not opposed to the recommendation by Staff to delay the first annual update to be filed April 1, 2025, with an effective date of June 1, 2025. The Company agrees with Staff that it can use this "acclimation period" to provide educational materials and for customers to adjust to the real-time net billing structure.[134]

The Company opposes all components of Vote Solar's proposed transition. As explained in its discussion of updates to the ECR, the Company believes locking in rates for customers is inconsistent with previous Commission orders cautioning that tariffs are not contracts and are subject to change.[135] Additionally, the proposed transition would result in a continuation of the cost shift from customer-generators to customers without on-site generation. Vote Solar's proposed transition would also impact other considerations in the Company's proposal. For example, modifications to the project eligibility cap while customers continue to be overcompensated for their on-site generation would exacerbate the problem that the existing cap was intended to address. The application and transferability of financial credits also would need to be reconsidered under any transition that results in an ECR which is higher than the avoided cost during the transition period. If the Commission finds that an accurately valued ECR is aligned

[133] City of Boise Comments at 6 (Oct. 12, 2023) and City of Boise Reply Comments at 5-6 (Nov. 2, 2023).

[134] Staff Comments at 31-32 (Oct. 12, 2023).

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

with the Company's proposal, it should be implemented for all customers the Commission defines as not being grandfathered to mitigate – not intensify – the existing cost shift to non-participants. However, in the event the Commission believes a transition period is appropriate, the Company recommends it also considers delaying any modification to the Schedule 84 project eligibility cap and reevaluate the proposed transfer criteria for excess credits for the reasons discussed herein and in the Company's Application.

VI. OTHER CONSIDERATIONS

A. Modifications to Project Eligibility Cap

Summary of Project Eligibility Cap Positions					
Party	**Idaho Power (Filed)**	**Staff**	**Vote Solar**	**Other**	**Idaho Power (Revised)**
Position	Modify Schedule 84 Cap to 100% of demand or 100 kW	Modify Schedule 84 Cap to 100% of demand or 100 kW	Modify Schedule 84 Cap to 100% of demand or 100 kW	Modify Schedule 84 Cap to 100% of demand or 100 kW	Modify Schedule 84 Cap to 100% of demand or 100 kW

The Company did not propose changes to the eligibility cap for Schedule 6 and Schedule 8 customers because it believes the current cap of 25 kW is not limiting for these customers. Coincident with the implementation of the proposed ECR, the Company proposed modifying the Schedule 84 eligibility cap to 100 kW or 100 percent of demand concurrent with a change to real-time net billing with a cost-based ECR.[136] The Company's rationale for a demand-based cap for Schedule 84 cited concerns regarding the ongoing cost associated with upgrades, that it does not routinely install facilities larger than customer demand in other situations, and alignment with the intent of net metering to offset energy usage behind the meter.[137]

[136] Application at 3.

[137] Ellsworth DI at 28, ll. 4-15.

Additionally, the Company proposed that for systems with energy storage devices, only the amount of generation nameplate capacity be used to determine whether the cap is exceeded for Schedules 6, 8, and 84. If the aggregate capacity of generation and storage triggers the need for upgrades to the system, the customer would be required to pay the upfront cost.

Staff Position

Staff agrees with the Company's proposal to maintain the project eligibility cap for Schedule 6 and Schedule 8 but recommends the Company monitor when the cap becomes limiting and consider changes to the cap if warranted.[138] Additionally, Staff recommends approval of the Company's proposed eligibility cap for Schedule 84 customers to be the greater of 100 kW or 100 percent of demand.[139]

Staff also addresses several items regarding administration of a demand-based project eligibility cap for Schedule 84: (1) how demand is determined, (2) demand changes after installation, (3) additional interconnection requirements, and (4) additional costs for system upgrades triggered by the addition of energy storage.[140]

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[138] Staff Comments at 33 (Oct. 12, 2023).

[139] *Id.*

[140] *Id.* at 33-38.

Other Party Positions

Vote Solar, CEO, ICL, and City of Boise are generally supportive of the Company's proposal to modify the project eligibility cap for Schedule 84 and did not oppose the recommendation to modify the application of the project eligibility cap to energy storage not counting towards the defined capacity limits.[141]

IIPA did not comment on the proposed modification to the project eligibility cap for Schedule 84.

Idaho Power Position

The Company continues to recommend the Commission maintain the project eligibility cap for Schedule 6 and Schedule 8, and to modify the cap for Schedule 84 to the greater of 100 kW and 100 percent of a customer's demand. However, as mentioned in its discussion of transition/gradualism, the Company has concerns with modification to the cap if a transition period, such as Vote Solar suggests, were to be implemented. The resulting transition, and therefore the corresponding delay in mitigating cost-shift, wouldn't match the timing for modification of the existing cap.

(1) How Demand is Determined for Schedule 84 Customers

Staff describes its concerns with the Company's proposal for how to determine the cap for customers without 12 months of billing data (i.e., Scenario B and C in Staff's Comments).[142] To clarify, the Company did not propose to simply rely on a customer's beliefs as Staff interpreted its proposal. However, the Company's revised proposal to address Staff's concern is that any customer without full 12 months of billing data could

[141] Vote Solar Comments at 48-49 (Oct. 12, 2023) and CEO Comments at 8 (Oct. 12, 2023).

[142] Staff Comments at 34 (Oct. 12, 2023).

install up to their registered demand in the available billing months. In any case that a Schedule 84 customer has a projected load ramp that exceeds actual billing demand data, the Company proposes requiring the customer to provide an analysis of the facility's power needs performed by a third-party professional engineer and paid for by the customer. An analysis by a professional engineer must include a detailed load analysis based on the equipment that will be used at the service point. If the customer has a similar business/service point (e.g., chain store) within Idaho Power's service area, the customer could use this as a proxy to reference that premise's demand for Idaho Power to determine whether the analysis by a professional engineer could be waived. The Company believes it would be prudent to include additional language as part of Schedule 84 to clarify how determination of the project cap will be administered. If the Commission approves the Company's revised proposal, the Company will incorporate the necessary conditions into Schedule 84 as part of its compliance filing for Staff and Commission review.

(2) Demand Changes After Installation for Schedule 84 Customers

The Company proposed in its filing 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.[143] Staff agrees with the Company's proposal but recommends that the description of the treatment be incorporated in Schedule 84 language. The Company believes it would be prudent to include additional language as part of Schedule 84 to

[143] Application at 22-23 and Anderson DI at 9-10.

clarify how a system expansion would be handled. If the Commission approves the Company's proposal, the Company will incorporate the necessary language into Schedule 84 as part of its compliance filing for Staff and Commission review.

(3) Additional Interconnection Requirements for Schedule 84

The Company proposed 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 exporting systems 3 MW and greater.

Staff recommends approval of these changes in Schedule 68 as necessary to interconnect exporting systems larger than 100 kW safely and reliably due to the increase of the project eligibility cap for Schedule 84. Additionally, through responding to discovery, the Company identified an additional modification to Schedule 68 is necessary to ensure a prospective customer pays all costs incurred as part of the interconnection process. As further explained in the Supplemental Response to the Ninth Production Request of the Commission Staff in Response No. 55, included as Attachment No. 2, the Company believes it is necessary to require projects greater than 100 kW to require a $1,000 deposit for any project where the Feasibility Review determines that a Feasibility Study is required. This provision will ensure the Company is made whole for all costs incurred to evaluate the interconnection requirements for a prospective on-site generation customer and that those costs are not borne by other customers. The Company believes it would be prudent to include additional language as part of Schedule 84 to clarify the deposit requirement for any project that requires a Feasibility Study be conducted. If the Commission approves the Company's request to increase the project eligibility cap for Schedule 84 customers, the Company will incorporate this provision into Schedule 68 as part of its compliance filing for Staff and Commission review.

(4) Upgrade Costs for Systems with Battery Storage

While, as a matter of principle, the Company is not opposed to Staff's recommendation for customers to fund ongoing operations and maintenance cost associated with required system upgrades, the administration of such a charge is potentially complex and burdensome. Accordingly, the Company respectfully requests the Commission to direct Idaho Power and Staff to meet to discuss the feasibility of implementing and administering a potential surcharge for the ongoing operations and maintenance expense associated with system upgrades. Additionally, the Company respectfully requests the Commission direct it to submit its findings and recommendation in this docket for Commission consideration within 90 days of the Commission's final order.

B. Recovery of ECR Expenditures

The Company recommends recovery of ECR expenditures as a net power supply expense subject to 100 percent recovery through the PCA. Staff agrees with the Company that the energy purchased from self-generators is a must-take resource and should be recovered through the PCA.[144]

Vote Solar, CEO, ICL, City of Boise, and IIPA did not comment on the Company's proposal regarding recovery of ECR expenditures.

C. Financial Credit Use and Transferability

The Company proposed two recommendations for future use and transferability of accumulated financial credits: (1) non-legacy customers be allowed to transfer financial credits to other accounts held in their name for their own usage and (2) financial credits apply to all billing components, including customer service charge, energy charges, riders, and other billing components.

Staff and Vote Solar support the Company's recommendation for the ECR financial credits to offset all billing components and that customers be permitted to transfer financial credits to other accounts in their name.[145] Additionally, Vote Solar suggests that customers should receive a *payment* for the value of any unused financial credits remaining at the conclusion of their annual billing cycle. In contrast, ICL suggests the financial value of unused financial credits should *roll over* into the next annual billing period.[146]

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[144] Staff Comments at 39 (Oct. 12, 2023).

[145] Staff Comments at 38 (Oct. 12, 2023) and Vote Solar Comments at 38 (Oct. 12, 2023).

[146] ICL Comments at 2 (Oct. 12, 2023).

The Company recommends the Commission reject Vote Solar's proposal to provide a financial *payment* to customers. Rejecting this proposal is consistent with the Commission's prior decisions:

> [T]he primary thrust of net metering is to provide customers the opportunity *to offset their own load and energy requirements*. *See* Order No. 28951 at 11 (Case No. IPC-E-01-39). We find that allowing a [bankable credit] furthers the intent of net metering by encouraging potential net metering customers to install only the distributed generation that they need to offset their load. Conversely, we find that allowing a financial payment for excess net energy would encourage customers to install more distributed generation than they need so they can sell excess power at wholesale to the Company without entering into a power purchase contract under Schedule 86. . . Again, the purpose of net metering is to allow a customer to *offset usage*, not to sell power to the Company. If a customer wishes to become a power seller, then the customer must proceed with a contract under Schedule 86.[147]

The Company also notes that under the Company's filed proposal customer-generator's unused financial credits would roll over into the next annual billing period as requested by ICL. In fact, under the Company's filed proposal the customer-generator's unused financial credits would be retained indefinitely so long as the customer continues taking service at the Point of Delivery associated with the Exporting System.

[147] *In the Matter of Idaho Power Company's Application for Authority to Modify its Net Metering Service and to Increase the Generation Capacity Limit*, Case No. IPC-E-12-27, Order No. 32880 at 3 (Aug. 14, 2013) (emphasis in original).

D. Financial Credit Expiration

The Company's proposed tariff language for Schedules 6, 8, and 84 includes a provision in the "Conditions of Purchase and Sale" that states:

> 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.

The language is consistent with the provision for net energy metering as approved by the Commission in Order No. 32846.[148] However, 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.[149]

For the reasons discussed in the previous section regarding the transferability of financial credits and the primary thrust of net metering, the Company recommends the Commission reject the proposal to provide a financial payment to a customer in any event. The Commission previously evaluated the merits of providing a financial credit, stating that a financial payment

> . . . may incent potential net metering customers to overbuild their systems. The net metering tariff is for those who wish to offset a portion of their load. Those wishing to be wholesale power providers should look to Schedule 86 as the vehicle for that type of transaction. We believe that removing the cash payment takes away this gaming opportunity and encourages customers to right-size their systems.[150]

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[148] Case No. IPC-E-12-27, Order No. 32846 at 15, 19 (Jul. 3, 2013).

[149] Staff Comments at 39 (Oct. 12, 2023).

[150] Case No. IPC-E-12-27, Order No. 32846 at 15.

The Company is not, however, opposed to Staff's second recommendation to transfer a financial credit to other service points or meters on the customer's account when they relocate within the Company's service area. Because the proposed transfer when a customer relocates would require a manual process, if the Commission ultimately adopts Staff's recommendation, the Company requests the Commission limit the time period under which it must track the financial credit. Accordingly, the Company requests the Commission find that the transfer of financial credits must occur within six months of the account being closed or be forfeited if not transferred. This provision is important because the Company's system is not able to hold a financial credit on a closed account indefinitely. It should be noted that in the event a financial credit on a closed account is forfeited, the Company will record the entire amount as a credit to the PCA, which is a benefit to all customers with no shareholder benefit.

E. Accumulated kWh Conversion Rate and Timeframe

The Company has proposed that any accumulated kWh credits be converted to a financial credit for customers with non-legacy systems as of December 31, 2024, using a blended average retail energy rate to value any excess kWh credits. The calculation of the blended average retail energy rate for each non-legacy customer class is the sum of charges for energy, Fixed Cost Adjustment ("FCA"), and PCA, divided by the total kWh consumed.

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 also notes that the Company should notify each non-legacy customer with 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. Staff also 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, Irrigation, and Industrial customers.[151]

Vote Solar, CEO, ICL, City of Boise, and IIPA did not comment on the treatment of accumulated kWh credits and the conversion to a financial credit.

VII. CONCLUSION

The instant case is reflective of the larger national debate surrounding NEM, which unfortunately often finds stakeholders at cross-purposes, with utility efforts to modify NEM rules or rate design met with stiff resistance from solar contractors and customers and others that desire to maintain the status quo. Like in prior dockets, the members of the public that have chosen to participate in this case generally disfavor changes to Idaho Power's net metering practice, with common concerns being the high cost they paid for their solar generation system, the impact that the proposed changes would have on the payback period for customers (potentially making them unwilling or unable to pay for an expensive solar system), and unawareness that fundamental aspects of NEM could change.

Though Idaho Power is not privy to the details of the bilateral transactions between sellers or installers of on-site generation systems and their customers, a number of stakeholders appear to put the onus on the utility for ensuring the transaction is equitable and economically supportable. This, however, is not within Idaho Power's purview. As a publicly regulated utility, Idaho Power is differently situated than a private seller or

[151] Staff Comments at 40 (Oct. 12, 2023).

installer; it is accountable to the Commission and legally obligated to consider the collective interests of all its customers and to recommend rates that are just, reasonable, and non-preferential.

Idaho Power understands and appreciates that some customers desire to offset their energy bills through on-site self-generation and help reduce demand on the Company's system; goals that are consistent with the underlying intent of the Company's on-site generation offerings: to provide customers the opportunity to serve some of their load through their own generation. These objectives, however, cannot be achieved with a blind eye to the cost and effects on non-participants nor can the business or personal interests of solar contractors and customers be pursued at the expense of non-participating customers. The Company has a responsibility to approach this issue with a focus on establishing mechanisms and rates that lead to safe, reliable, and affordable energy for customers, rather than as a means to achieve particular policy goals. The proposal presented in this docket, as summarized on pages 4 – 7 of these comments, was developed by the Company pursuant to these fundamental principles and, consistent with the study approved in Case No. IPC-E-22-22, will help ensure that on-site generation continues to play an important role in the Company's energy portfolio well into the future.

DATED at Boise, Idaho, this 16th day of November 2023.

Megan Goicoechea Allen

MEGAN GOICOECHEA ALLEN
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 16th day of November 2023, I served a true and correct copy of Idaho Power Company's Final Comments upon the following named parties by the method indicated below, and addressed to the following:

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Stacy Gust

Stacy Gust, Regulatory Administrative Assistant

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-14

IDAHO POWER COMPANY

ATTACHMENT NO. 1
Revised Workpaper

SEE ATTACHED SPREADSHEET

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-14

IDAHO POWER COMPANY

ATTACHMENT NO. 2
Supplemental Response to the Ninth Production Request of the Commission Staff

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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 METHODOLOGY	CASE NO. IPC-E-23-14 IDAHO POWER COMPANY'S SUPPLEMENTAL RESPONSE TO THE NINTH PRODUCTION REQUEST OF THE COMMISSION STAFF TO IDAHO POWER COMPANY

COMES NOW, Idaho Power Company ("Idaho Power" or "Company"), and in response to the Ninth Production Request of the Commission Staff ("Commission" or "Staff") dated September 13, 2023, herewith submits the following supplemental information:

<u>STAFF REQUEST FOR PRODUCTION NO. 55</u>: Please explain whether the Company plans to charge customer generators for the cost of a power needs analysis, if needed, for the following cases:

a. To ensure they do not go over the eligibility cap if a customer is new, doesn't have historical billing data available, or they are a new customer with demand that exceeds prior customer needs; and

b. To determine if the sum of the customer' s generation nameplate capacity plus the capacity of a battery exceeds the eligibility cap or requires an upgrade.

<u>SUPPLEMENTAL RESPONSE TO STAFF'S REQUEST FOR PRODUCTION NO. 55</u>: After filing its initial response, Staff requested additional information regarding any study or review required for a customer-generator. Idaho Power provides this supplemental response to address potential study costs or system review costs and how those would be funded by the customer/applicant.

Pursuant to Schedule 68, an initial Feasibility Review occurs for all customer-generator applications, after which, as discussed in Response to Staff's Request for Production No. 46, there are up to three interconnection studies that may be required as part of the interconnection process consisting of (1) Feasibility Study, (2) System Impact Study, and (3) Facility Study. These steps and associated costs are described in more detail as follows:

(1) <u>Feasibility Review</u>: Standard engineering review of a proposed customer-generator system intended to ensure the Company's system is equipped to incorporate the proposed facilities. The Feasibility Review may determine that upgrades are necessary. Funding, construction, installation, and maintenance of required upgrades will be subject to the Company's standard Rule H regarding New Service Attachments and Distribution Line Installations or Alterations. The cost of the Feasibility Review is covered by the cost of the $100 application fee.

(2) Feasibility Study: More detailed engineering assessment for Distributed Energy Resources ("DERs") as determined by the Feasibility Review. This study includes protection coordination and system voltage management requirements necessary for the project. For projects under 3 MVA, Schedule 68 does not require a deposit, but the $100 application fee does not cover the cost of the study. For projects 3 MVA or greater, the $1,000 application fee is applied against costs the Company incurs to perform the Feasibility Study. The Company believes it would be appropriate, and consistent with larger projects, to require a $1,000 deposit for any project where the Feasibility Review determines that a Feasibility Study is required. Please see the file labeled "Attachment – Supplemental Response to Staff Request No. 55" for the Company's proposed revision to Schedule 68.

(3) System Impact Study (only applicable for projects 3 MVA or greater): The System Impact Study provides a detailed assessment of the distribution and/or transmission system adequacy to accommodate the DER by evaluating equipment capabilities and electrical performance requirements. This step may not be necessary for some projects, depending on the size and location of the project. The System Impact Study Agreement includes a deposit of $2,000 for a distribution system impact study or a $10,000 deposit for a transmission system impact study.

(4) Facility Study (only applicable for projects 3 MVA or greater): The Facility Study includes the engineering to determine the project's design specifications. The Facility Study Agreement includes a deposit of 5% of the total project costs specified in the System Impact Study Report ("SISR") or the Feasibility Study Report if a SISR is not required, capped at $30,000.

The response to this Request is sponsored by Jared L. Ellsworth, Transmission, Distribution & Resource Planning Director, Idaho Power Company.