Office of the Secretary
Service Date
December 29, 2023

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** **ORDER NO. 36048**

On May 1, 2023, Idaho Power Company ("Company"), filed an application ("Application") with the Idaho Public Utilities Commission ("Commission") proposing changes to the Company's on-site and self-generation tariffs.

On May 23, 2023, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 35790. The Commission granted intervention to: Idaho Irrigation Pumpers Association, Inc. ("IIPA"); Idaho Conservation League ("ICL"); Idaho Hydroelectric Power Producers Trust, d/b/a IdaHydro ("IdaHydro"); Clean Energy Opportunities for Idaho ("CEO"); Micron Technology, Inc. ("Micron"); the city of Boise City ("Boise City"); and Vote Solar. Order Nos. 35781; 35803; 35824. On June 27, 2023, the Commission issued a Notice of Parties.

On August 10, 2023, the Commission issued a Notice of Modified Procedure and Notice of Virtual Public Workshops. Order No. 35881. On October 10, 2023, the Commission issued a Notice of Customer Hearings and Notice of Public Comment Deadline. Order No. 35955. On October 24, 2023, the Commission held a customer hearing in Boise, and on November 8, 2023, the Commission held a customer hearing in Twin Falls, Idaho.

THE APPLICATION

The Company requested that the Commission authorize: (1) real-time net billing with an avoided cost-based financial credit rate for exported energy; (2) a methodology for determining annual updates to the Export Credit Rate ("ECR"); (3) a modified project eligibility cap for commercial, industrial, and irrigation ("CI&I") customers; (4) related changes to the accounting for and transferability of excess net energy financial credits, and (5) updated tariff schedules necessary to administer the modified on-site generation offering. The Company requested a January 1, 2024, effective date.

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

The Company represented that the proposed changes to the on-site generation service offerings would only apply to non-legacy[1] customers taking service under Schedules 6, 8, and 84. Customers with legacy systems would continue to take service under the rules of monthly net energy metering ("NEM") until legacy status terminates. *Id.* at 16.

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

The Company proposed a seasonal and time variant ECR to compensate for energy and other elements associated with avoided capacity, line losses, and integration costs. *Id.* at 19-20.

The Company also sought a change in how the project eligibility cap was defined for Schedule 84 customers. The Company proposed that the Schedule 84 project eligibility cap be set at the greater of 100 kilowatts ("kW") or 100% of demand at the service point for CI&I customers. *Id.* at 20-21.

The Company represented that for the purpose of administering the cap, the Company proposed using the maximum billing demand from the last twelve (12) months, measured when the customer generation application was submitted. *Id.* at 22. The Company stated that for irrigation customers without a full in-season billing history, a conversion factor related to the

[1] "Legacy" systems for Schedules 6 and 8 are systems that were installed or purchased by December 20, 2019, and that meet other eligibility requirements. Order Nos. 34509 and 34546. "Legacy" systems for Schedule 84 are systems that were installed or purchased by December 1, 2020, and that meet other eligibility requirements. Order Nos. 34854 and 34892.

horsepower of the customers' pump(s) at the service point would determine the maximum demand. *Id.*

The Company represented that for customers with non-legacy systems, the Company would treat ECR expenditures as a net power supply expense ("NPSE") subject to 100% recovery through the Company's Power Cost Adjustment ("PCA"). *Id.* at 23-24. The Company proposed that financial credits may offset all billing components of the bill, not just the energy-related portion of a customer bill. *Id.* at 24.

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

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

PUBLIC COMMENTS

A. Comments

As of December 13, 2023, eight hundred and forty-six (846) public comments have been filed in this case. Of those comments, there were one hundred and twenty-seven (127) customers who signed a single petition asking the Commission to support solar power; keep the program as it currently exists, and to grant current customer-generators grandfathering. This petition was recorded as a single customer comment and is not reflected in the breakdown of customer comments below.

Aside from that petition, there have been seven hundred and nineteen (719) customer comments representing individuals and interested parties in Idaho and out of state, including customers of the Company, other utilities, non-profit organizations, and businesses within the solar power industry. Of the seven hundred and nineteen (719) individual comments, one hundred and eighty-three (183) customers (25%) identified themselves as non-legacy customers, while only forty-nine (49) customers (7%) clearly identified themselves as legacy customers. Another one hundred and fifty-five (155) customers (22%) indicated they have a net-generation system but did not identify their status as legacy or non-legacy.

1. Issues

i. Previous Orders

Customers expressed concerns regarding grandfathering with two hundred and sixty-seven (267) customers (37%) stating that all current net generation customers should be granted legacy status. Another seventy-four (74) customers (10%) claimed they were not aware of possible changes to the program at the time they had their systems installed. Most of these customers stated they would not have gone forward had they known the rates would change.

There were ninety-eight (98) customers (14%) who disagreed with the outcome of IPC-E-22-22, including fifty-two (52) customers (7%) who challenged the objectivity of the Company's Value of Distributed Energy Resources study, and forty-one (41) customers (6%) who suggested that the Commission failed to consider third-party studies and the concerns of interested parties. There were one hundred and fifty-three (153) customers (21%) who urged further consideration of environmental benefits.

ii. Structure and Compensation

Regarding any change to compensation, three hundred and fifty-three (353) customers (49%) wanted no change to the structure of the program, and three hundred and twenty-nine (329) customers (46%) wanted to keep monthly net metering versus real time metering.

Regarding the accrued kWh credits accumulated by both legacy and non-legacy customers, forty-nine (49) customers (6%) expressed concern about the future value and traceability of accumulated credits and advocated for customer options for the applicability of those credits. Regarding financial credits under the proposed changes, forty-one (41) customers (6%) worried about the accountability of those financial credits and the value of those credits.

Thirty-one (31) customers (4%) offered comments on the ECR, with seventeen (17) customers (2%) wanting the ECR tied to retail rates, and fourteen (14) customers (2%) expressing a desire for an unbiased annual review of ECR rates. One hundred and four (104) customers (14%) offered comments regarding compensation for peak versus non-peak hours, time-of-day versus peak and non-peak hours, seasonal demand versus customer peak hours, and use of a single rate versus peak and non-peak hours. Customers expressed that compensation for peak hours extends into the evening even as generation declines and suggested that compensation for peak hours should start earlier in the day.

iii. Incentives

One hundred and four (104) customers (14%) said the Company needs to provide more incentives to customers to encourage net generation.

PARTY COMMENTS

On October 12, 2023, Staff, CEO, Boise City, ICL, IIPA, and Vote Solar all filed initial comments on the Application. IdaHydro and Micron did not submit any comments. On November 2, 2023, Staff, CEO, Boise City, ICL, and Vote Solar all filed all-party reply comments. IdaHydro and Micron did not submit any reply comments. On November 16, 2023, the Company filed final comments.

INTERVENOR FUNDING

On November 30, 2023, Vote Solar filed a Petition for Intervenor Funding. Vote Solar requested that the Commission grant Intervenor Funding in the amount of $8,880.00 for attorney fees for the work of A. Germaine.

COMMISSION FINDINGS AND DECISION

The Commission has jurisdiction over the Company's Application and the issues in this case under Title 61 of the Idaho Code including *Idaho Code* §§ 61-301 through 303. The Commission is empowered to investigate rates, charges, rules, regulations, practices, and contracts of all public utilities and to determine whether they are just, reasonable, preferential, discriminatory, or in violation of any provisions of law, and to fix the same by order. *Idaho Code* §§ 61-501 through 503.

The Commission now considers the Company's request to modify the compensation structure for on-site generators under Schedules 6, 8, and 84. The Commission has reviewed the long history of cases dealing with on-site generators, and the Commission recognizes the growing availability and impact that solar self-generation has on electric customers in Idaho.

In making its decisions in this case, the Commission maintains that the fundamental purpose of on-site generation is to offset a customer's own usage; that on-site generation should not create cost shifting between generators and non-generators, and that on-site generators should be given a fair value for their exported energy.

The parties have presented differing sets of proposals related to the Company's Application, including among other things proposals for the measurement interval applied for measuring energy, the valuation of the ECR, and various administrative items related to the implementation of an avoided cost-based ECR. In this Order, the Commission has striven to accurately assign the appropriate share of fixed costs and unquantified benefits of on-site customer generation, and to provide a reasonable balance between the interests of customers with on-site generation, and customers without. The Commission does not make these decisions lightly, and the Commission recognizes that this Order does not put to rest the issues of on-site generation in Idaho.

A. Summary of Decisions

The Commission approves the Company's Application to implement a real-time net billing ECR in accordance with the Application as modified by the Company's revised proposal and the provisions of this Order. The ECR shall be seasonal and time variant with avoided cost-based value considerations. The ECR summer season shall be June 1 through September 30 and align with the summer season in the Company's general rate case ("GRC") Case No. IPC-E-23-11. The ECR summer On-Peak hours shall be 3 p.m. to 11 p.m., Monday through Saturday, excluding holidays, during the summer season. Any future updates to the summer season or the hours of highest risk shall be considered in a separate docket or in a GRC filing as appropriate.

The avoided energy value of the ECR shall be determined using twelve (12) months of Energy Imbalance Market ("EIM") Load Aggregation Point ("ELAP") market prices ending December 31, weighted for historical customer-generator exports, and the avoided energy value shall be distributed in alignment with the summer and non-summer seasons.

For avoided generation capacity, the ECR shall use a 5-year rolling average of the Effective Load Carrying Capability ("ELCC") to determine the avoided capacity value, and the most current levelized capacity cost for the least-cost dispatchable resource from the 2023 IRP. The ECR shall include customer-generator exports for all hours in the calendar year in the calculation of the rolling average ELCC and shall account for line losses for capacity by applying the line loss gross up after the ELCC and avoided capacity values are determined.

With respect to avoided transmission and distribution capacity, the Commission approves the proposed project deferral analysis with a 20-year project specific review. With respect to avoided line losses, the ECR calculation shall apply the annual energy line losses to the energy value, 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. At this time the ECR shall not include any adjustments for environmental costs or fuel cost risk.

The Company is authorized to use the integration rates from the 2020 Variable Energy Resource ("VER") study as proposed and shall file an update to Schedule 87 rates and integration costs from the 2020 VER study for Commission approval. The Company is directed to complete an updated integration study as soon as possible, and to file the updated study for Commission approval and inclusion for future ECR updates.

At this time the eligibility caps for Schedule 6 and Schedule 8 shall remain unchanged. The eligibility cap for Schedule 84 customers shall be the greater of 100 kW or 100% of demand. The Company is directed to include additional proposed interconnection requirements in Schedule 68 concurrent with the effective date of real-time net billing. The Company shall exclude energy storage and only include the nameplate capacity of generation for purposes of the eligibility cap, and the Company shall meet with Staff and interested parties on the feasibility of implementing a surcharge to recover ongoing costs of system upgrades. The Company shall submit its findings to the Commission within ninety (90) days of this Order.

The Company shall update all proposed components of the ECR except the season and hours of highest risk in an annual filing beginning April 1, 2025. ECR expenditures shall be recovered as a NPSE subject to 100% recovery through the PCA.

With respect to the use and transferability of accumulated financial credits, non-legacy customers shall be allowed to transfer financial credits to other accounts held in their name for their own usage, and financial credits may be applied to all billing components. Accumulated financial credits may be transferred when a customer relocates within the Company's service area. At this time no time limit will be set for such a transfer. If a customer completely discontinues service with the Company, any accumulated unused financial credits shall be paid out to the customer. On December 31, 2024, all accumulated kilowatt-hour credits for non-legacy systems shall be converted to financial credits using a blended average retail energy rate.

The Company shall submit a compliance filing with Schedules 6, 8, 68, and 84 conforming with this Order.

B. Measurement Interval

The Company recommended that the Commission implement a real-time measurement interval. Company Comments at 12. Boise City noted that an hourly measurement interval should be considered for consistency with Clean Energy Your Way ("CEYW")-Construction. Boise City Comments at 6-7. Staff considered both a real-time, and hourly, netting interval, and based on its analysis, Staff believed that a real-time measurement interval was more accurate, more understandable, and more malleable than a net hourly interval. Staff Comments at 12.

After considering the options presented, the Commission believes that a real-time netting interval provides the most accurate value for the ECR calculation. While some raised concerns about how understandable real-time calculation may be for customers, the accuracy provided by a real-time measurement interval using the Company's Automated Metering Infrastructure is reasonable. In addition, the Commission believes that customer-generators will have access through their My Account information on the Company's website to data accounting for their imports and exports for their meter.

C. ECR Rate Design

Staff recommended that the Company align the summer seasons of the ECR to match the summer season of June l to September 30 presented in the concurrent GRC. Staff Comments at 16. Staff believed that a misalignment of the summer season for all Schedules in the GRC and the ECR summer season would cause customer confusion. *Id.* The Company agreed with Staff's proposed modifications to the ECR rate design and updated the seasons in the Company's revised proposal. Company Comments at 16.

As part of its comments, IIPA suggested that irrigation and non-irrigation net export energy have substantially different annual shapes and warrant separately calculated export credits. IIPA Comments at 2. Staff disagreed with the IIPA's proposal to adopt different ECRs based on export shape, and Staff noted that the logic of a separate ECR for each unique export shape would lead to multiple ECRs for each rate class and for each exporting technology type; would reduce transparency; would increase confusion; and could lead to dissatisfaction among customers. Staff Reply Comments at 3-4. The Company also disagreed with IIPA's suggestions reasoning that 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. Company Comments at 17.

After considering the options presented, the Commission finds that aligning the summer season for purpose of the ECR with the summer season presented in the GRC is the most reasonable option to provide consistency and understandability to customers. With respect to IIPA's suggestion, the issue of separately calculated export credits by different usage shapes and classes is not the issue before the Commission in this case, and the record in front of the Commission does not support any determination on that issue.

D. Avoided Energy

Staff agreed with the Company's proposed method for valuing avoided energy based on the EIM ELAP pricing. Staff Comments at 17. The value of avoided energy would be determined by the hourly prices from the EIM using ELAP pricing. *Id.* The Company would use the twelve (12) months of market data ending December 31 of each year, and the avoided energy component of the ECR would be calculated by multiplying the ELAP hourly price of energy by the total MWhs exported by customer-generators each hour. *Id.* However, Staff disagreed with the Company's proposed method to distribute the value of avoided energy, and Staff recommended that the value of avoided energy be allocated between the Summer and Non-Summer seasons and the definition of Summer and Non-Summer for the ECR be aligned with the Summer and Non-Summer seasons for the corresponding consumptive tariffs proposed in the Company's GRC. *Id.* at 18.

IIPA recommended that the Company 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. IIPA Comments at 10. Further, IIPA noted that the Company expects market prices to decline over time during solar production hours, which means that the export credit will also decline over time. *Id.* at 2. IIPA recommended that the Company provide notice of this by including tariff language that informs customers of the expected decreases in the net export credit over time. *Id.*

ICL strongly opposed IIPA's request for tariff language relying on market predictions because tariffs should present only verifiable, objective information on service offerings. ICL Reply Comments at 7.

The Company was not opposed to IIPA's proposal to create a balancing account to track the differences in historical and average market prices; however, the Company believed that such a mechanism would create an additional layer of complexity that the Commission might not wish to adopt. Company Comments at 22.

After considering the options presented, the Commission finds that the Company's proposed method for valuing avoided energy under the revised proposal is reasonable. Currently, the Commission does not believe that a balancing account is necessary as the trailing twelve (12) month market data provides self-correction, albeit with some lag. With respect to tariff language, the Commission does not believe it is warranted to require language regarding potential effects of future market prices.

E. Avoided Generation Capacity

Staff believed that the Company's proposed method for valuing avoided generation capacity of exports was reasonable. Staff Comments at 19. However, to increase the stability, accuracy, and transparency of the proposals, Staff recommended that the Company: (1) use a 5-year rolling window instead of a 3-year rolling window to estimate ELCC values; (2) modify the method used to incorporate line losses in calculating capacity value by applying the line loss gross up after the ELCC and avoided capacity values are determined; and (3) use all exports from customer-generators in its calculation of the ELCC. *Id.* at 19-21. Staff also believed the Company's proposal to distribute all the generation capacity value to the On-Peak hours was reasonable. *Id.* at 21.

CEO believed that if the Commission were to accept a suggestion to reduce the generation capacity valuation on the assumption that EIM market prices reflect capacity value, then the "nonfirm" adjustment should be removed. CEO Comments at 4.

ICL recommended that the Commission: (1) adjust the Company's ECR methodology to include marginal line loss calculations and avoided cost figures based on battery storage as the alternative dispatchable resource. ICL Comments at 2.

Vote Solar recommended that the Company's methodology for calculating avoided generation capacity costs be changed to: (1) update the value for avoided generation capacity costs to more accurately reflect the cost of resources the Company plans to build; (2) use the capacity factor method for calculating capacity value; and (3) include a line loss gross up. Vote Solar Comments at 19. Vote Solar noted that the Company's proposed generation capacity cost was based on the capital cost of a simple cycle combustion turbine ("SCCT") from the Company's 2021 Integrated Resource Plan; however, Vote Solar reasoned that the Company's 2021 Preferred Portfolio does not include the addition of new gas resources, and Vote Solar believed it was more appropriate to base avoided generation capacity costs on the capital costs of battery storage. *Id.* at 20.

Staff did not agree with the recommendations to change the generation capacity calculation based on battery storage. Staff Reply Comments at 5. Staff believed there were two factors to consider when choosing a surrogate dispatchable resource to establish a purely avoided cost of capacity: (1) the resource should have the lowest levelized fixed cost including capital cost and fixed operation and maintenance cost; and (2) the resource should be reliably dispatchable regardless of the time or duration needed. *Id.*

The Company generally aligned with Staff's proposed avoided generation capacity value modifications to: (1) update the dispatchable resource cost to $145.94 per kW-year as defined in the 2023 IRP; (2) use a 5-year rolling average to calculate the ELCC value; and (3) exports for all hours in a calendar year in its rolling average ELCC calculation. Company Comments at 28-29. The Company indicated that if the Commission directed, the Company would 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. *Id.*

The Company disagreed with Vote Solar's recommendation to use the capacity factor method over the ELCC method as the Company reasoned that the capacity factor method is a less accurate measurement, particularly considering recent widespread adoption of the ELCC as the preferred method for measuring the resource adequacy contribution of intermittent and energy-limited resources. *Id.* at 30-31. Further, the Company did not agree with the recommendation to utilize battery storage as the alternative dispatchable resource as the Company believed it most appropriate to utilize the lowest levelized cost of capacity resource, which was identified as an SCCT in the 2023 IRP, for avoided capacity cost calculations. *Id.* at 33.

After considering the options presented, the Commission finds that using a trailing 5-year average ELCC as proposed in the Company's revised proposal is reasonable. However, the Company is directed to account for line losses for capacity by applying the line loss gross up after the ELCC and avoided capacity values are determined.

With respect to changing the Company's methodology for calculating the ECR avoided generation capacity costs to reflect the cost of battery storage resources the Company plans to build; the Commission does not believe that is warranted at this time. The Commission has expressed "the importance of an avoided generation capacity value that accurately considers capacity costs actually avoided." Order No. 35631 at 29. However, there are multiple factors taken into consideration when the Company selects its IRP Preferred Portfolio, not simply avoided generation capacity costs, and based on the record before it, the Commission cannot find that a value based on the avoided capacity costs of battery storage provides the most accurate or reasonable valuation.

F. Avoided Transmission and Distribution ("T&D") Capacity

Staff believed the Company's proposed method of project-by-project deferral assessments was reasonable and Staff agreed that assessing every T&D capacity project over a 20-year time span was sufficiently comprehensive. Staff Comments at 22. Staff believed the Company's proposal to distribute all the T&D deferred capacity value to the On-Peak hours was also reasonable. *Id.*

CEO requested that because new transmission lines like B2H, SWIP-north, and Gateway West sections 8 & 9 will be used to access remote generation sources, in future ECR updates 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. CEO Comments at 4.

Vote Solar recommended an avoided transmission cost value that is based on the current FERC-approved transmission rate for the Company. Vote Solar Comments at 24-25. Boise City also recommended an avoided transmission cost value that is based on the current FERC-approved transmission rate. Boise City Comments at 3.

Staff did not agree with the recommendation to include a higher transmission and distribution value because on-site generation export specific data and assumptions used to value the ECR transmission and distribution deferral would result in a more accurate transmission and distribution value specific to customer-generators. Staff Reply Comments at 5.

The Company recommended that the Commission approve its proposed project deferral analysis for valuing the T&D capacity deferral component of the ECR and reasoned that the proposal to use the FERC transmission rate or other marginal cost rate did not represent capacity costs actually avoided, or deferred, as directed by the Commission. Company Comments at 38.

After considering the options presented, the Commission finds that the Company's proposal to use a project-by-project deferral assessment and that assessing every T&D capacity project over a 20-year time span is reasonable.

G. Avoided Line Losses

Staff reviewed the Company's data and report with the underlying calculations for overall losses compared to the nationwide average. Staff Comments at 23. Staff believed that the Company's analysis was reasonably accurate but disagreed with the Company's proposed coefficients. *Id.* Staff recommended that the ECR utilize the industry-typical loss calculations, not the Company's unique extrapolation of those losses, as Staff believed it more accurately aligns the loss measurements with each of the avoided values and streamlines any future studies by only using the industry-typical calculations. *Id.*

Vote Solar represented that line losses increase exponentially as system load increases, so the line losses associated with marginal additions of load are substantially higher than the average line losses used in the Company's calculations. Vote Solar Comments at 16.

CEO requested that the value of the line loss coefficient be no lower than the 5.8% value proposed by the Company in IPC-E-22-22, and that the Company be directed to hold a technical workshop to review its methodology for line loss calculations prior to filing its next ECR update recommendation. CEO Reply Comments at 2.

The Company recommended the Commission approve Staff's proposal of applying the annual energy loss coefficient to the avoided energy value. Company Comments at 42. The Company also recommended the Commission approve the Company'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. *Id.*

The Company represented that Vote Solar's claim of the proposed ECR including average line losses was incorrect, as the Company calculated separate peak and average line losses in its line loss study, and that 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. *Id.* The Company also stated that CEO's proposal 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. *Id.* at 43.

After considering the options presented, the Commission finds it reasonable to apply the annual energy line losses to the energy value, 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.

H. Avoided Environmental Costs

Staff considered a national carbon tax, an Idaho Renewable Portfolio Standard ("RPS") policy, social health, and Renewable Energy Credits ("RECs") as options that could be used to provide a value of an environmental benefit. Staff Comments at 24. Staff explained that there was no mandated Carbon Tax, Idaho RPS policy, or other environmental costs to the Company on a state or federal level. *Id.* Staff believed that outside of a mandate there was no other identified environmental benefit that has a direct and quantifiable impact on the Company's rates. *Id.* Regarding RECs, Staff reasoned that ownership remains with the owner of the on-site generation system absent an RPS or other legislation, and until a state or federal legislation mandates a quantifiable environmental cost or adder to the Company's rates, Staff did not believe it was appropriate to include any associated environmental benefits in the ECR. *Id.*

CEO recommended that Schedule 6 be modified such that customers transfer ownership of the renewable energy attributes of their exports to the Company. CEO Comments at 6. CEO would support that Schedule 6 allow customers to opt-out of this transfer if the interest in an opt-out outweighs administrative matters associated with offering it. *Id.* CEO requested that as part of the annual ECR update the Company report on opportunities to monetize the value of renewable energy attributes of exports as well as opportunities for aggregation and/or certification of customer-owned generation. *Id.* at 7. CEO asked that a placeholder be defined to ensure ongoing evaluation of opportunities to monetize the value of renewable energy attributes of customer-owned resources, and that the ECR methodology should retain an annual calculation of environmental benefits. *Id.*

Boise City recommended that the Commission direct the Company to work with interested stakeholders to evaluate the feasibility of implementing a method to compensate customers for renewable energy attributes of exported energy. Boise City Comments at 9.

Vote Solar represented that although the Company does not have a requirement to comply with a Renewable Portfolio Standard, the Company does have a goal to provide 100% clean power to its customers by 2045, and without the clean power provided by on-site generation customers, the Company would have to build or purchase an equivalent amount of clean power or purchase an equivalent amount of RECs to meet its goal. Vote Solar Comments at 29. Vote Solar reasoned that larger customers with on-site generation may be willing to transfer RECs to the Company given sufficient financial motivation, and in fact some customers already transact in RECs with the Company through the Green Power Prudency Program. *Id.* at 29-30. Vote Solar concluded that the value of RECs purchased to meet customer needs through this program was $7.10 per MWh in 2022, or 0.07 cents per kilowatt-hour. *Id.* at 30.

ICL also believed that the parties fully demonstrated that the environmental benefits of non-carbon emitting resources are non-zero, and if the Commission was not satisfied with the analytic methods promoted by parties, ICL recommended any adopted ECR include a placeholder value to be addressed in future proceedings. ICL Reply Comments at 8-9.

The Company maintained its recommendation that until state or federal legislation mandates a quantifiable environmental cost or adder to the Company's rates, it was not appropriate to include any associated environmental benefits in the ECR. Company Comments at 45.

After considering the options presented, the Commission finds it reasonable not to include any avoided environmental costs in the ECR calculation at this time. It is undisputed that there are no state or federal legislative mandates that provide a quantifiable environmental cost or adder to the Company's rates, and the Commission is not persuaded by the arguments that groundwork needs to be set to provide a future system for self-generators to monetize RECs. The Commission maintains that the purpose of self-generation is to offset a generator's own usage.

I. Fuel Cost Risk

CEO recommended that the ECR be updated to reflect a fuel price hedge value that was not zero, and that ECR rates reflect a price risk benefit equal to 5% of avoided energy value consistent with the E3 recommendation to PacifiCorp. CEO Comments at 3. CEO asked that at minimum the energy value of customer exports be increased by 3.9% to reflect a fuel price hedge value consistent with the analysis completed by Rocky Mountain Power for its Idaho on-site generation customers. *Id.* at 3-4.

Boise City believed that the Commission should incorporate a value for avoided fuel price risk and an increased transmission and distribution deferral value if an ECR is approved. Boise City Comments at 8.

Vote Solar recommended the Commission acknowledge that on-site generation does provide a hedge benefit and approve an avoided fuel cost risk value of 0.462 cents per kWh during on-peak periods, 0.268 cents per kWh during off-peak periods, and 0.281 cents per kWh averaged annually. Vote Solar Comments at 26-27.

ICL supported Vote Solar, Boise City, and CEO's positions of a non-zero fuel hedge and environmental value ECR components. ICL Reply Comments at 8-9. ICL reasoned that an adopted ECR must fully and comprehensively compensate customers, and in lieu of an exact fuel hedge value, a value equal to 5% of avoided energy costs was both reasonable and consistent with values assigned in other jurisdictions. *Id.*

The Company recommended the Commission not include a value for fuel cost risk in the ECR as the ELAP price is directly impacted by natural gas market prices and to add a 5% premium would result in double counting and over-inflate the value paid to customer-generators and collected from all other customers. Company Comments at 48.

After considering the options presented, the Commission finds it reasonable not to include any value for fuel cost risk based on the application of the ELAP price in valuing the ECR.

J. Integration Costs

Staff agreed with the Company's 2020 VER basis for and inclusion of the $0.00293/kWh integration cost in the ECR; however, Staff recommended that the Commission: (1) authorize the integration rates for purposes of the ECR rates in this filing; (2) direct the Company to file the 2020 VER study for Commission authorization to update Schedule 87 and to be used in future ratemaking that requires it, including future updates to CEYW and ECR-related rates; and (3) direct the Company to file all future VER studies and integration costs for Commission authorization, if integration cost have materially changed from those authorized. Staff Comments at 25. Staff also recommended the Company conduct a new integration study as soon as possible, file the study for Commission approval, and incorporate the results of the new integration study into the next possible ECR adjustment filing. Staff Reply Comments at 6.

Both CEO and Vote Solar requested that the proposed ECR be updated to reflect the integration costs of $.64/MWh associated with Case 9 in the 2020 VER Integration Study rather than the $2.93/MWh the Company proposed. CEO Comments at 2; Vote Solar Comments at 18.

The Company maintained that Case 1 was the appropriate integration cost scenario because it was most reflective of integration costs from distributed energy resource exports on the Company's system. Company Comments at 53. However, the Company was 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 updates. *Id.*

After considering the options presented, the Commission finds it reasonable to authorize the Company to use the integration rates from the 2020 VER study as proposed; however, the Company shall file an update to Schedule 87 rates and integration costs from the 2020 VER study for Commission approval and the Company is directed to complete an updated integration study as soon as possible, and to file the updated study for Commission approval and inclusion for future ECR updates.

K. Transition/Gradualism Considerations

Boise City recommended that the Commission ensure compensation changes were gradual, easily understandable to all customers, promoted rate stability, and sent appropriate price signals in this dynamic energy landscape. Boise City Comments at 6. Boise City believed that an ECR should not be implemented for five months and then updated again on June 1, 2024, and that the Commission should consider changes to the measurement interval and an ECR separately. *Id.* Boise City also believed that the Commission should consider a transition period similar to what was discussed in the Settlement Agreement in IPC-E-18-15. *Id.* at 7.

CEO believed that gradualism was a merited concern for Residential and Small General Service Customers. CEO Comments at 2. CEO suggested that the Commission set the effective date for the ECR of January 1, 2024, but set the next update of the ECR to occur in June 2025 rather than June 2024; however, if the Commission considered delaying implementation of the ECR, CEO requested that non-ECR related changes to Schedule 84 be effective January 1, 2024, in order not to impede the design, evaluation, application process, and installation of projects for the irrigation season. *Id.*

Vote Solar represented that should the Commission implement the Company's proposed ECR, some non-legacy customers would be substantially worse off, especially when accounting for changes to rates that have been proposed in the Company's GRC. Vote Solar Comments at 45. Vote Solar reasoned that the total impact of granting those customers legacy status was immaterial, and given the substantial hardship experienced by nonlegacy customers if they were immediately transitioned to an ECR, Vote Solar recommended that customers who had already applied to interconnect solar or made a financial commitment to install solar before the date of the Commission's final order in this docket should be permitted to remain on the legacy rate for twenty (20) years. *Id.*

Further, Vote Solar recommended that the Commission implement a measured transition, or glide path, to the lower export rate by setting the initial export rate equal to the value of the average volumetric retail rate for each customer class, to mitigate negative impacts on the market for rooftop solar and provide a measure of parity for prospective solar customers. *Id.* at 48. Vote Solar also recommended the rate decline by a maximum amount as the total capacity of on-site generation installed in the Company's service territory reached defined thresholds. *Id.*

Staff did not recommend any transition period. Staff Comments at 40. Staff believed that allowing current non-legacy customers to use accumulated kWh credits over the 2024 calendar year would provide enough transition and opportunity for current NEM customers to learn the new program. *Id.* However, Staff proposed that the first update to the ECR begin in 2025 rather than 2024. *Id.* Staff believed an acclimation period was necessary for customers to adjust to the ECR billing structure without having the ECR billing rate change in the first six months of a new program. *Id.* With respect to Grandfathering, Staff noted that the Commission has been clear through Order Nos. 34509, 34546, and 34854, that established legacy status for Schedule 6, 8, and 84 customers would not be expanded. Staff Reply Comments at 7. Staff did not recommend expanding grandfathering, or legacy status, and Staff believed that Commission Orders regarding grandfathering were clear on that matter. *Id.*

The Company was not opposed to Staff's recommendation to delay the first annual update to be filed April 1, 2025, with an effective date of June 1, 2025; however, the Company opposed all other recommended changes or proposed transition periods. Company Comments at 60-61.

After considering the options presented, the Commission does not believe that a transition period is necessary; however, after the initial implementation of new ECR schedules consistent with this Order on January 1, 2024, the Commission does find that a delay of the first annual update to April 1, 2025, with an effective date of June 1, 2025, is reasonable. On the issue of grandfathering, the Commission's stance has clearly been stated in its prior orders.

L. Financial Credit Expiration

Staff disagreed with the Company's proposal regarding the expiration of financial credits, and Staff recommended that the Commission order the Company to transfer financial credits to a customer's new meter when a customer relocates within the Company's system and refund the amount of accumulated financial credits to the customer in the event the customer relocated outside the Company's system. Staff Comments at 39.

The Company recommended that the Commission reject the proposal to provide a financial payment to a customer in any event. Company Comments at 69. The Company was not opposed to Staff's 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; however, the Company requested that the Commission limit the time period the Company must track the financial credit and find that the transfer of financial credits must occur within six months of the account being closed or be forfeited if not transferred. *Id.* at 70.

After considering the options presented, the Commission finds it reasonable that accumulated financial credits be transferrable when a customer relocates within the Company's service area. At this time no time limit will be set for such a transfer. Additionally, if a customer completely discontinues service with the Company, any accumulated unused financial credits shall be paid out to the customer. The Commission is cognizant of the potential behavior impacts inherent in a system that pays out financial credits; however, the Commission believes that the limited conditions under which a customer may receive a payout mitigates those impacts.

M. Intervenor Funding

Intervenor funding is available pursuant to *Idaho Code* § 61-617A and the Idaho Public Utilities Commission Rules of Procedure 161-165. *Idaho Code* § 61-617A(1) provides that it is the "policy of this state to encourage participation at all stages of all proceedings before the commission so that all affected customers receive full and fair representation in those proceedings." The Commission may award a cumulative amount of intervenor funding not to exceed $40,000 for all intervening parties in a single case. *Idaho Code* § 61-617A(2).

Commission Rule 162 provides the form and content of petitions for intervenor funding. Each petition must contain: (1) an itemized list of expenses broken down into categories; (2) a statement of the intervenor's proposed findings or recommendation; (3) a statement showing that the costs the intervenor wishes to recover are reasonable; (4) a statement explaining why the costs constitute a significant financial hardship for the intervenor; (5) a statement showing how the intervenor's proposed recommendations differed materially from the testimony and exhibits of the Staff; (6) a statement showing how the intervenor's recommendation or position addressed issues of concern to the general body of the utility users or consumers; and (7) a statement showing the class of customer on whose behalf the intervenor appeared. IDAPA 31.01.01.162.

Vote Solar is a nonprofit organization. Based upon the Commission's review of Vote Solar's petition, the Commission finds that the funding request complies with the procedural and substantive requirements of the statute and the rules. The Commission finds that Vote Solar has materially contributed to the Commission's decision-making; Vote Solar's participation added a unique and well-informed perspective to the record; and it is fair, just, and reasonable to award intervenor funding. The Commission finds it appropriate to award Vote Solar intervenor funding in the amount of $8,880.00. The award shall be chargeable to residential and small commercial customer classes. *Idaho Code* § 61-617A(3).

ORDER

IT IS HEREBY ORDERED that the Company's Application as modified by the Company's revised proposal and the provisions of this Order is approved.

IT IS FURTHER ORDERED that the Company shall submit a compliance filing with Schedules 6, 8, 68, and 84 conforming with this Order.

IT IS FURTHER ORDERED that Vote Solar's petition for intervenor funding is granted in the amount of $8,880.00.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date upon this Order regarding any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *Idaho Code* §§ 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 29th day of December 2023.

ERIC ANDERSON, PRESIDENT

JOHN R. HAMMOND JR., COMMISSIONER

EDWARD LODGE, COMMISSIONER

ATTEST:

Monica Barrios-Sanchez
Interim Commission Secretary

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