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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO IMPLEMENT CHANGES TO THE COMPENSATION STRUCTURE APPLICABLE TO CUSTOMER ON-SITE GENERATION UNDER SCHEDULES 6, 8, AND 84 AND TO ESTABLISH AN EXPORT CREDIT RATE	**Case No. IPC-E-23-14** **Clean Energy Opportunities for Idaho** **Reply Comments**

Clean Energy Opportunities for Idaho (CEO) appreciates the thoughtful proposals and well-structured comments submitted by Commission Staff. Immediately below is a summary of CEO's specific comments and requests, followed by further explanation and specific replies, and lastly our closing remarks.

I. Summary of Requests

1. **Time Period Rate-Differentiation based on System Reliability Risk:**
   1.1. CEO supports Staff's proposal to define the Summer season as June 1 – September 30 and agrees with Staff's support for the Company's proposed Summer On-Peak window of 3pm -11pm.
   1.2. CEO requests that the Company provide an updated analysis of highest risk hours reflecting the Battery Energy Storage Systems installed on the Company's system as soon as feasible in order to inform a) ECR avoided generation capacity value, b) ECR updates with regard to highest risk hours, and c) workshops agreed to by the parties in IPC-E-23-11.

2. **Avoided Energy:**
   2.1. CEO supports the Company's proposed method for valuing avoided energy based on ELAP hourly pricing from the prior year weighted by hourly exports in that year because the method provides an appropriate balance of accuracy, stability, and transparency.
   2.2. CEO supports Staff's proposal (at 18) to assign the energy value in accordance with energy-defined Seasons, and to implement three ECR values: Non-Summer, Summer Off-Peak, and Summer On-Peak.

3. **Fuel price hedge benefit:** CEO asserts that an accurate fuel price hedge value is not zero and requests that the ECR reflect a price hedge benefit equal to either 5% of the avoided energy value (consistent with the E3 recommendation to PacifiCorp[1]), or, at a minimum, 3.9% of the avoided energy value (consistent with Rocky Mountain Power study of on-site generation for Idaho.[2])

[1] Jan 22, 2019 ORDER NO. 19-021 at 20, UM_1910_Order.pdf&il=true (state.or.us)
[2] PAC-E-23-17, Rocky Mountain Power On-Site Generation Study, at 23.

4. **Avoided Generation Capacity.**
    4.1. CEO supports Staff's request to use a 5-year rolling average of the ELCC percentage to determine load carrying capacity contribution of solar customer-owned solar generation rather than the 3-year rolling average proposed by the Company.
    4.2. As stated above in 1.2, CEO requests that the Company provide an updated analysis of highest risk hours reflecting Battery Energy Storage Systems installed on the Company's system as soon as feasible in order to inform a) ECR avoided generation capacity value, b) ECR updates with regard to highest risk hours, and c) workshops agreed to by the parties in IPC-E-23-11.

5. **Avoided T&D:** CEO requests that, in future ECR updates, because new transmission lines like B2H, SWIP-North, and Gateway West sections 8 & 9 are to be used to link remote generation sources to load centers, 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.

6. **Avoided Line Losses:** CEO requests that the value of the line loss coefficient implemented in any 2024 ECR should 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, which update will presumably occur in April of 2025.

7. **Integration Costs.** CEO requests that the proposed ECR be updated to reflect the integration costs value of $.00064/kWh associated with Case 9 (Case 9 assumed 200MWs of storage on the Company's system) in the 2020 VER integration study. Case 9 more accurately reflects the on-line and in construction additions of approximately 180MWs of Company controlled battery storage capacity, rather than the $0.00293/kWh associated with Case 1 in that study (Case 1 assumed zero storage on the Company's system).

8. **Environmental Attributes:** CEO reiterates our general request that resolution of the ECR include a mechanism for monetizing renewable energy attributes of exports from self-generating customers covering: a) transferal of ownership of those attributes, b) a process for ongoing evaluation of opportunities to monetize renewable energy attributes, and c) at least a placeholder in this ECR for adding the value of such attributes in the future ECR updates. Specifically -
    8.1. Schedule 6 should be modified such that a) customers would, by default, transfer ownership of the renewable energy attributes of their exports to the Company, b) customers may opt out of this transfer, and c) the effective date for such transfer will begin with exports occurring on or after the effective date of the 2025 ECR update.
    Given that transfer of ownership is an important step toward monetizing renewable energy attributes, CEO requests that if the Company does not support this specific proposal, the Company then propose for the Commission's consideration an alternative means to establish a path such that customers will have the option to transfer ownership of renewable energy attributes to the Company.
    8.2. The Company should be directed to evaluate opportunities for customer-owned generation to provide a resource for avoiding the costs the Company would otherwise incur to serve potential Clean Energy Your Way (CEYW) Flexible customer needs.
    8.3. As part of the annual ECR update, the Company should report on opportunities to monetize the value of renewable energy attributes of exports (including opportunities where the renewable attributes are not formally certified as RECs) as well as opportunities for aggregation and/or certification of customer-owned generation.

9. **Initial ECR Effective Date and First Update:** For Schedule 84, CEO strongly supports Staff's proposal to implement changes January 1, 2024 and for the first update to be filed in April 2025. Past dockets have built a substantial record of requests from agribusinesses for timely visibility to changes affecting the design and compensation for on-site generation.

10. **Project Eligibility Cap:** CEO supports the IPC-E-23-14 proposed changes to the Schedule 84 project eligibility cap.

II. Supporting Comments and Specific Replies

1. Time Period Rate Differentiation based on System Reliability Risks.

CEO supports Staff's proposal to align the ECR definition of the Summer season (June 1 through September 30) with the definition of the Summer season proposed in the Company's general rate case, IPC-E-23-11.

Similarly, CEO supports the Company's proposal and Staff's support for defining Summer On-Peak as 3pm to 11pm because it moves closer to a uniform definition of the System-level summer on-peak period being used for both supply and demand side rate designs.

CEO shares Staff's concern that the Company's model for analyzing highest risk hours excluded the impacts of the Battery Energy Storage Systems ("BESS") installed on its system. CEO requests that the Company provide an updated hourly LOLP analysis which includes the use of BESS resource additions the Company has made in 2023 as soon as such an analysis can be performed. The parties to IPC-E-23-11 agreed[3] to a series of workshops which include review of cost of service methodologies and Time of Use rates. The hours of highest reliability risk are a key component to those matters, thus a more accurate analysis of highest risk hours is needed both in this matter as well as to inform those workshops.

2. Avoided Energy.

2.1 CEO agrees with Staff and the Company regarding the proposed method for valuing avoided energy based on ELAP hourly pricing from the prior completed year weighted by hourly exports in that year. Rate-making often calls for a balance between perfect accuracy and the need for stability, understandability, and transparency, all of which are criteria that were established in IPC-E-22-22.

Some commenters argue that this proposal for valuing avoided energy is too complex or is unstable, one commenter argues that use of historical pricing is imperfect in accuracy and proposes additional complexity and instability. CEO supports Staff's assessment that the Company-proposed method achieves a fair balance between accuracy and the need for stability and transparency, and that it is "important to provide customers a fixed set of published energy values for a year."[4]

CEO understood that the intent of using EIM sourced ELAP pricing as a component of ECR valuation was to reflect the local energy value in each hour. This understanding conflicts with one party's assertion that the ELAP prices presented in this docket are inappropriately overstated by including a California Greenhouse Gas component associated with EIM sales made into the CAISO market[5]. CEO requests that the Company clarify (in their final reply comments) whether a Greenhouse Gas adder is, or is not, included in the ELAP prices.

In general, a market price reflects a balance of supply and demand, regardless of whether every buyer in the market values the same attributes of the commodity. The Company does not have the opportunity to purchase energy from the Energy Imbalance Market at lower than market price, thus the actual EIM market price accurately represents avoidable energy costs.

2.2 CEO supports Staff's proposal (at 18) to assign the energy value in accordance with energy-defined

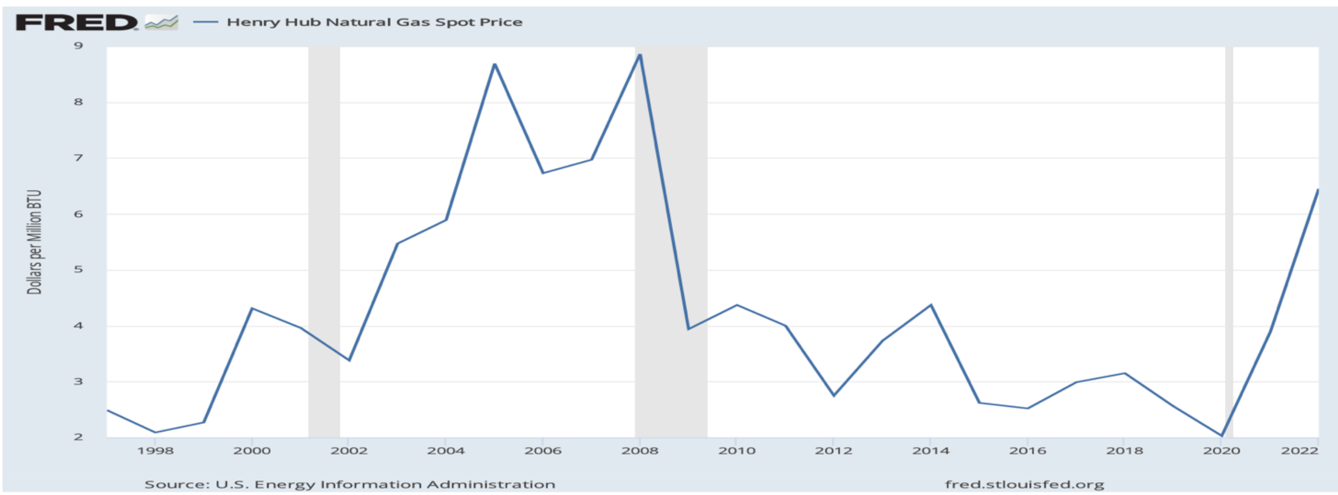
[3] IPC-E-23-11, Motion for Approval of Stipulation and Settlement at 11-12.
[4] IPC-E-23-14 Staff Comments at 17: "Staff believes it is more important to provide customers a fixed set of published energy values for a year, than to assign an unknown and highly variable real time price to each unit of exported energy."
[5] See IIPA comments, item #3, page 2

Seasons, and to implement three ECR values: Non-Summer, Summer Off-Peak, and Summer On-Peak.

3. Fuel Price Hedge.

The Commission ordered in IPC-E-21-21 that the VODER should evaluate a fuel price hedge value. The VODER presented the Company's position, not an evaluation. The value of a fuel price hedge is not zero as noted in evidence presented on best practices[6], by parties to this docket (CEO, Vote Solar, City of Boise), by the PUC of Oregon[7], and by Rocky Mountain Power's June 2023 On-Site Generation study for Idaho.[8]

Natural gas prices have a history of volatility (see image below)[9]. Plans to shift Company generation resources at Valmy and Jim Bridger from coal to gas fired serve to only increase customer exposure to annual rate variations via the larger PCA adjustments that such year-to-year fuel price changes produce.



Customer load reduction at any hour reduces the aggregate fuel the Company would either buy directly or implicitly through market purchases. Protecting customers from a portion of that volatility has a value and the ECR should be updated to include a fuel price hedge value that is not zero. For that reason, CEO reiterates its requests –

► That ECR rates reflect a price risk benefit equal to 5% of avoided energy value consist with the E3 recommendation to PacifiCorp[10]. In the event the Commission does not accept this request, CEO asks at

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[6] *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation*, p36, Interstate Renewable Energy Council: "A fuel price hedge value should be included." Referenced by CEO in IPC-E-21-21 & IPC-E-22-22.

[7] Oregon PUC, ORDER NO. 19-021 regarding Hedge Value:

> "For this element, we adopted the E3 suggestion for a 5 percent hedge value of avoided energy. E3 's recommendation is derived from a peer-reviewed paper entitled How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest. We noted that "[w]e decline the suggestion for a zero value, because similar to Market Price Response, we are persuaded that there is value to this element." [Order No. 17-357]

[8] PAC-E-23-17, Rocky Mountain Power On-Site Generation Study, at 23. "PacifiCorp's calculation of the energy value and cost-effectiveness of energy efficiency measures used these stochastic results to identify the incremental value associated with these risks, and PacifiCorp has calculated the avoided risk associated with customer exports using the same risk values applied to energy efficiency. Over the 2021 IRP horizon, this increases the energy value of customer exports by 3.9 percent, or $1.24/MWh as shown on summary tab of CONF Appendix 4.2: ID EE Cost-Effectiveness."

[9] Annual average Henry Hub spot gas price. Source: US Energy Information Administration

[10] Jan 22, 2019 ORDER NO. 19-021 at 20, UM 1910 Order.pdf&il=true (state.or.us)

minimum that the energy value 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. [11]

4. Avoided Generation Capacity.

4.1 CEO supports Staff's request to use a five-year rolling average of the ELCC percentage to determine the load carrying capacity contribution of solar customer-owned solar generation rather than the 3-year rolling average proposed by the Company.

4.2 As stated above in 1.2, CEO requests that the Company provide an updated analysis of highest risk hours reflecting Battery Energy Storage Systems installed on the Company's system as soon as feasible in order to inform a) ECR avoided generation capacity value, b) ECR updates with regard to highest risk hours, and c) workshops agreed to by the parties in IPC-E-23-11.

IIPA asserts that "market prices during hours where the market is capacity constrained have both a capacity and energy component."[12] CEO contests the accuracy of this assertion. The Energy Imbalance Market (EIM) is just that: an energy market. Participants in the market must be fully reserved against their forecast load before being able to participate in EIM transactions. The EIM transaction values reflect the marginal cost for energy (with location based adjustments for losses and congestion) in any period. High marginal energy prices occurring during periods of high WECC load reflect the higher operating costs for generation resources higher in the dispatch stack. CEO maintains that short-term EIM prices do not reflect a capacity value as that term is used in this case.

Perhaps in 2027, if the Company is then participating in the WRAP (Western Resource Adequacy Program), a broader WECC-wide view of capacity may be warranted. But today, capacity value, as it is considered in this case, is determined at the Idaho Power system level. Customer exports to the monopsony purchaser (IPC) should be valued based on the benefit they provide in allowing IPC to avoid the cost of adding an incremental resource to maintain an acceptable level of reliability within the Company's system. EIM prices should be considered as an appropriate measure of marginal energy value but not as including any capacity value.

► CEO opposes IIPA's requests to re-price the on-peak energy credit to equal the off-peak energy credit given that customer exports to the monopsony purchaser (IPC) during certain hours with a high loss of load risk, reflect the avoided cost for IPC to maintain reliability levels within IPC's system. If such a request were granted, CEO would request that the non-firm adjustment be removed so as not to double-discount the value of exports.

5. Avoided T&D Capacity -Future treatment of marginal transmission

CEO requests that, in future ECR updates, because new transmission lines like B2H, SWIP-north, and Gateway West sections 8 & 9 are 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.

IIPA suggests that customers who reduce their bill via on-site generation "will receive double compensation for reduced distribution costs" when they decrease their bill for consumption if energy charges include some portion of distribution demand costs[13]. The Commission thoroughly reviewed this matter in IPC-E-17-13 and found that matters of fixed cost recovery behind them meter are separate from matters of valuing net excess

[11] PAC-E-23-17, Rocky Mountain Power On-Site Generation Study, at 23.

[12] IPC-E-23-14 IIPA Initial Comments at 7.

[13] IPC-E-23-14 IIPA Initial Comments at 3.

energy, which is the focus of this docket. Per Order No. 34147 at 16, "It is reasonable and fair to distinguish a customer's freedom to offset usage behind the meter from a customer's choice to export energy to the grid."

6. Avoided Line Losses

CEO appreciates the thoughtful improvement to line loss calculations proposed by Staff. Nevertheless, CEO refers to our initial comments recounting concerns with process. E.g., the VODER the Company filed in June 2022 did not study and compare *marginal* line losses as ordered in IPC-E-21-21[14], the further discussion among the parties encouraged by the Commission in IPC-E-22-22[15] did not occur, and the Company instead is proposing in this docket to reduce the line loss coefficient from the 5.8% it presented in IPC-E-22-22. CEO requests –

- ► That the line loss coefficient implemented in 2024 should be no lower than the 5.8% proposed by the Company in IPC-E-22-22.
- ► That the Company be directed to hold a technical workshop to review its methodologies for line loss calculations prior to filing its next ECR update recommendation presumably in April of 2025.

7. Integration Costs

As noted by Staff, the Company proposes to use its 2020 VER integration study to provide an integration cost of $0.00293/kWh to be accounted as a reduction to the proposed ECR. The Company presumes that Case 1 of that 2020 study (which assumes zero storage on the Company's system) is still most fitting. Staff's comments did not address which Case scenario evaluated in the 2020 VER integration study was most accurate. The Company now has 120MW of storage online and another 60MW under development.[16]

As noted in CEO's initial comments as well as Vote Solar's initial comments, **Case 9, which assumes 200MW of storage and implies an integration cost of $.00064/kWh, is now a more accurate representation of the Company's system than Case 1 which assumed zero storage.**

- ► CEO requests that the proposed ECR be updated to reflect the integration costs of $.00064/kWh associated with Case 9 rather than the $0.00293/kWh the Company proposed.

8. Environmental Attributes

CEO acknowledges that avoided costs for environmental benefits may be currently assigned to zero in an ECR effective January 1, 2024 yet reiterates our request that this docket provide a placeholder, process, and platform to value the potential for the Company to avoid costs or increase revenues by utilizing the renewable energy attributes associated with customer on-site generation.

Staff's comments regarding avoided environmental costs assumed that customers retain ownership of REC's.[17] IIPA makes similar comments related to customers retaining ownership of the renewable attribute of their exports.[18] CEO maintains that the ownership of renewable attributes is transferrable.[19] There is the potential for

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[14] IPC-E-21-21, Order 35284 at 20, the Commission found: "It is also reasonable to study the difference between using static or marginal losses and the magnitude of each as part of the valuation to be included in the ECR."

[15] ORDER NO. 35631, p 29: "We believe that additional discussion between Staff, Intervenors, and the Company on the topic of avoided line losses, during the implementation case, may be fruitful and potentially resolve any remaining issues or confusion surrounding the Company's calculation of avoided line losses."

[16] IDACORP Q2 2023 Earnings Conference Call, August 3, 2023.

[17] IPC-E-23-14, Initial Comments by IPUC Staff at 24, **"**Regarding Renewable Energy Credits ("RECs"), ownership remains with the owner of the on-site generation system absent an RPS or other legislation."

[18] IPC-E-23-14 IIPA comments page 2 "net metering participants retain RECs and all renewable attributes of their net production, thus these customers should not be compensated as if these attributes are being provided to IPC"

the Company to avoid costs it would otherwise incur to purchase REC's (a quantifiable avoided cost) by substituting the renewable attributes of the exports it purchases from self-generating customers. This potential needs to be reviewed.

For the year 2022, the Company purchased 37,519 MWh renewable energy certificates at an expense of $266,379.34 to fulfill the needs of the Green Power Program.[20] Further, as described in CEO's initial comments, some portion of the customers who are willing to pay a 1¢ premium for renewable energy may value the option to purchase renewable attributes of exports from self-generators in their community even if those exports were not formally certified by Green-e or other entity.

Given informal discussion among stakeholders in response to initial comments, 8.1. reflects a modification to CEO's specific proposal in initial comments, while 8.2 and 8.3 reiterate our requests from initial comments:

8.1 Schedule 6 should be modified such that a) customers would, by default, transfer ownership of the renewable energy attributes of their exports to the Company, b) customers may opt out of this transfer, and c) the effective date for such transfer will begin with exports occurring on or after the effective date of the 2025 ECR update.
Given that transfer of ownership is an important step toward monetizing renewable energy attributes, CEO requests that if the Company does not support this specific proposal, the Company then propose for the Commission's consideration an alternative means to establish a path such that customers will have the option to transfer ownership of renewable energy attributes to the Company.

8.2 CEO requests that the Company be directed to evaluate opportunities for customer-owned generation to provide a resource for avoiding the costs the Company would otherwise incur to serve potential Clean Energy Your Way (CEYW) Flexible customer needs.

8.3 CEO requests that, as part of the annual ECR update, the Company should report on opportunities to monetize the value of renewable energy attributes of exports (including opportunities where the renewable attributes are not formally certified as RECs) as well as opportunities for aggregation and/or certification of customer-owned generation. More generally, <u>CEO is asking that a placeholder in the ECR value stack be defined to ensure ongoing evaluation of opportunities to monetize the value of renewable energy attributes of customer-owned resources</u>, and that ECR methodology should retain an annual calculation of environmental benefits.

9. Effective Date, Gradualism, & Timing of ECR Update

CEO remains empathetic for the Residents and Small General Service customers who have sought to manage their rising energy costs via on-site generation and assumed that the regulatory process applies principles of gradualism across all customer classes, including Schedules 6 & 8. While Staff notes that the regulatory process has provided notice of the potential for changes to rates affecting on-site generation, CEO reiterates that *notice* does not substitute for *gradualism* in the regulation of rates.

CEO maintains that customer classes are impacted differently, and that changes to Schedule 84 should be implemented January 1, 2024. Past dockets have built a substantial record of agribusinesses requesting visibility as soon as possible to Schedule 84 changes affecting the design and compensation structure for on-site generation. A few representative examples include –

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[19] Rocky Mountain Power Service Schedule NO. 107, https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/rates/107_Solar_Incentive_Program.pdf

[20] Idaho Power Response to CEO Production Request No. 2.

- In IPC-E-20-26, agribusinesses asked that the Commission do "everything it can to enable farmers to make informed decisions on solar generation during 2021."[21]
- In IPC-E-21-21, the Idaho Farm Bureau asked that the study be conducted in an "efficient, thorough, fair, and expedited manner" and reiterated a request "that this entire process be done in a timely manner for Idahoans to take advantage of funding opportunities that exist to aid those that may choose to pursue on-site generation."[22]
- In IPC-E-22-12, the Idaho Grain Producers Association commented, "Improving the predictability and stability of export compensation rates is critical for farmers."[23]

In reply to one party's proposal to delay implementation of the ECR until June of 2024: for Schedule 84, CEO strongly favors Staff's proposal to implement the proposed changes January 1, 2024 and that the first update occur in 2025 given the need for stability and the harm of further delay. A farmer commenting in IPC-E-22-12 summarized the matter: "As many farmers testified to the PUC in 2020, we are harmed by the delay in addressing the 100kW cap and a lack of predictability or stability of the future export credit rate."[24]

For residents and small general service customers, if the Commission does not support proposals by other commenters concerned with gradualism, CEO supports Staff's request for a January 1, 2024 effective date and for the first update to be filed in April 2025, which aligns with CEO's request in initial comments.

10. Project Eligibility Cap for Schedule 84.

CEO supports the IPC-E-23-14 proposed changes to the Schedule 84 project eligibility cap.

11. IIPA proposal to include market predictions in tariffs

IIPA asserts that, given market prices may decline over time, that the ECR will decline, and therefore "IPC should provide notice of this by including tariff language that informs customers of the expected decreases in the net export credit over time." CEO opposes this proposal for many reasons, two of which include: 1) A tariff is not the place to make predictions regarding future market prices, 2) the Commission does not have evidence supporting a declaration of future market prices. Market prices have gone both up and down since the VODER study was ordered. Natural disasters, a potential carbon adder, and other unforeseen events could impact the value of the ECR as well as rates for consumption over the coming decade.

If the Commission believes that visibility to future ECR is merited, a more appropriate approach would be a mechanism for publishing an indicator of the next year's ECR based on the trailing twelve months of available data. CEO offers this suggestion not as a request, only as a more appropriate alternative than ordering that a presumption of future market prices should be incorporated into tariffs.

III. Closing Remarks

While there are vastly different views regarding the regulation of on-site generation in Idaho, we can all agree on two things – that an order in this docket will reflect a significant milestone, and that the journey will continue. The energy world keeps changing, which challenges us all to maintain an open, curious, and adaptive mindset. As Idaho grows, technologies evolve, and the Company invests $3 billion of capital expenditures over the next five years, maintaining the affordability of electricity in Idaho requires an ongoing and collective effort to better understand the drivers of costs and benefits. That endeavor will serve Idaho well by informing rates

[21] IPC-E-20-26 public comment, Michael N. Kochert, Roseberry Farms, Gooding, Idaho, 12/28/2020
[22] IPCE-21-21 public comment, Idaho Farm Bureau, 11/30/21.
https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2121/PublicComments/20211130Comments(38)_38.pdf
[23] IPC-E-22-12 Public Comment, Idaho Grain Producers Association, 12/19/2022.
https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2212/PublicComments/20220720Comments(2)_2.pdf
[24] IPC-E-22-12 Public Comment, Russell Schiermeier, 12/19/2022.

which allow customers the freedom to control their own energy costs and the opportunity to mitigate future costs for all.

Dated this 2nd day of November, 2023.

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Courtney White

Managing Director

Clean Energy Opportunities for Idaho

CERTIFICATE OF SERVICE

I hereby certify that on this 2nd day of November, 2023. I delivered true and correct copies of the foregoing COMMENTS to the following persons via the method of service noted:

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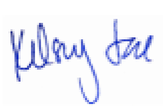

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