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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

CEO acknowledges Idaho Power Company's extensive effort in preparing the VODER analysis. CEO also recognizes and appreciates the open and constructive communication the Company, PUC Staff and other parties engaged in on September 12th discussing technical issues related to eligibility caps for customer self-generation.

We appreciate this opportunity to address specific aspects of the VODER study where CEO believes additional perspective is merited.

Chapter 4 – Export Credit Rate

Section 4.1 Avoided Energy Costs – Within the VODER study three possible data sources are suggested for measuring the value of avoided energy – IRP, ICE Mid-C and ELAP. While the IRP does provide a multitude of data streams that are useful in many regulatory situations, CEO believes that for multiple reasons the IRP forecasts are inferior to the two market price alternatives.

Within the IRP, future estimates of hourly prices are largely influenced by the natural gas price forecasts that were fed into the Aurora model. In the middle of the last decade natural gas prices dropped dramatically as a result of the use of hydraulic fracturing. At that time concern arose about PURPA contracts containing prices which were dramatically higher than spot electricity prices. That condition arose because prices in the PRUPA contracts had been produced using the natural gas price assumptions in early decade IRPs.

Today the situation is reversed – high current natural gas prices make IRP hourly forecasted prices much lower than market. The Company reflects this by their own actions. When requesting its current year power cost adjustment, the Company used forward month price estimates rather than the forecast in its most recent IRP. Apparently, the Company did not view its IRP forecast prices as adequately representative of actual 2022 power costs.

For long-term resource planning purposes, variations in year-to-year natural gas prices balance out. The Company also has the opportunity to revisit IRP assumptions at the time of critical decision points. But for the public to perceive that the prices paid for energy from self-generators' exports are fair, using an indicator of actual market prices would be superior to the often quickly outdated IRP forecast values.

The Company implicitly acknowledges the natural linkage between export values and market prices, noting in a VODER section 8.2 discussion related to its recovery of export credit expenditures that:

> *"Excess energy purchased from onsite generation customers benefits the entire system, not unlike energy purchased on the market"*

In sum, the Company does not always use forecasted energy prices from the IRP when proposing changes for consumption rates, such as in a PCA application. Neither should the ECR use IRP forecasts. Within the two market price alternatives, CEO notes that CAISO EIM prices are available to all to see via the internet. ICE prices may in some cases be confidential. The VODER study should include explanations of these fairness and transparency issues.

Section 4.1.2 – Weighted average energy price methods. CEO sees two opportunities for additional clarity to be provided in this section of the VODER study.

First – Rather than a weighted average, avoided energy could be credited with real-time prices. If either of the net billing proposals (hourly or real time) were implemented, exports could be credited with an avoided energy value that reflects the actual market prices (either ICE or ELAP could work) at the time the export occurs. The VODER study should note that, especially if the transparent ELAP market price were utilized, customers could monitor prices on the CAISO website and possibly modify their consumption plans to increase exports when they are most valuable on the grid.

Secondly – If real-time market prices are not used for valuing exports, the method should use recent market prices rather than three years of historical market prices. The avoided energy component of the ECR could reflect an annually updated weighted average of prior year hourly exports and market prices.

As the Company notes, the prices used in calculating energy value in an export credit should logically align with the time that such exports occur:

> *"For example, energy prices during the night, when most customer-generators are not exporting should not carry the same weight as hours when most customer-generators have energy exported to the grid."*

Using actual prior year experience to calculate the current year avoided energy component in an ECR is also attractive in its transparency and ease of understanding. Self-generating customers would know what price they were to receive for all exports they provided during the year.

Section 4.1.2.2 Energy: Seasonal Time Variant Export Credit Value - The seasonal "time-variant" rate the Company proposed sends price signals to customers related to the time-value of exports. TOU rates for consumption also signal the time-value of a kWh consumed. Until customers have access to a similar "symmetrical" time-of-use pricing on the consumption side CEO sees the use of this "time-variant" price for exports only as problematic in a couple of respects.

Rates for consumption don't currently allow self-generators to benefit from reducing their load during On-Peak hours. The VODER study finds that 92% or 97% of exports occur during the time-variant Off-Peak period (assuming ELCC methodology). Given that the overwhelming majority of exports occur during the

Off-Peak period, it is unclear whether the large difference in price the Company suggested would create the economic incentive for self-generators to export rather than consume their generation during peak.

Secondly, the asymmetry is unfair to multiple parties. A customer using on-site generation to reduce their load during peak would benefit at a fraction of the rate applied to a customer using on-site generation to export during peak. The VODER study should point out these problems with asymmetrically imposing on-peak/off-peak rates for exports while customers have no access to on-peak/off-peak rates for consumption.

4.1.3 Evaluation of Firmness of Export Energy - In October 2018, the Company initiated IPC-E-18-15: The Study of Costs, Benefits, and Compensation of Net Excess Energy Supplied by Customer On-Site Generation. A Settlement Agreement reflecting significant investment of time and resources by the Company, PUC staff and intervening parties was filed a year later in October 2019. When the Commission chose not to accept the Settlement Agreement and re-ordered the study, the Commission stated, **"The work done in this docket can and should be built upon in the next docket."** (Order No 34509 at 7 and reiterated in Order No. 34892 at 9).

In addition to the 82.4% value, the VODER Evaluation of Firmness of Export Energy should acknowledge the firmness value that the Company, PUC Staff, and signatory parties found in the prior study (IPC-E-18-15 Settlement Agreement at 3):

> "The energy value will be decreased by 10% to reflect the non-firm nature of the energy provided by on-site generators."

4.3 Avoided Transmission and Distribution Costs. The lumpy nature of T&D projects presents challenges in how to value avoided costs and there are multiple methodologies for doing so. Some methodologies are "lumpy", some use statistical analysis to smooth the long-term relationship between exports and T&D costs. If a project-specific, all-or-nothing method is used, it can result in near zero values (as is the case with Idaho Power's approach at this time) or could result in extremely high values (envision the straw that broke the camel's back by requiring an expensive upgrade, and the cost assignable to that straw).

The determination of the ECR should be informed by the range of potential values resulting from different methodologies. Consideration is merited of alternative methods which take a smoother, more probabilistic approach to valuing avoidable T&D costs over time. The VODER study should reflect those alternative methodologies.

Section 4.5 Avoided Environmental Costs - The Commission directed that the VODER Study reflect a value of exports based only on measurable costs and benefits that effect rates. In the VODER study and again in a May 6 workshop regarding a study of distributed energy resources, the Company indicated that they perceive the environmental values of self-generating customers to be limited to reductions the Company would otherwise pay for emissions pollution. Consequently, the VODER study presents the value of measurable environmental costs and benefits impacting ratepayers as $0.

CEO believes that looking only at emission pollution costs is an unnecessarily narrow perspective. As a consequence, by inadequately reviewing the value of environmental attributes of exports the VODER study is deficient in valuing "all benefits & costs that are quantifiable, measurable, and avoided costs that affect rates" (Order 35284, p27).

Within the Company's customers there are individuals and entities willing to pay a premium for renewable energy. This creates a market value for the "environmental attributes" of renewable generation. Idaho Power currently purchases REC's (certified renewable energy credits) and resells them to customers willing to pay a premium for renewable energy.

The Company suggests that the environmental characteristics of the Green Power it sells to some of its customers need to be formally registered as RECs. CEO agrees that some large customers may require certification ("RECS"). But assuming that everyone willing to pay a premium for renewable energy would require that the electricity undergo the costly and administratively challenging process to be certified by an agency as renewable is untested and may not be accurate.

CEO believes that not all customers who are willing to pay extra for the environmental attributes of renewable energy would require REC certification to meet their needs. There are numerous examples of commenters who value clean energy noting the merits of locally produced energy. Avoiding the need for REC certification allows for a value to be placed on the environmental attributes of customer exports. Certainly, the Company's billing system (which would be the source of information that an export by a self-generator had occurred) is sufficiently robust to ensure that Green Power customers are in fact receiving the environmental characteristics of a renewably generated kWh.

Customers with self-generation who export to the Company should have the option to sell to the utility the environmental attributes of their exports. The VODER study should reflect an alternative where customer generators have an option to sell to the utility the environmental attributes of their exports and a receive value for this sale.

The VODER study suggests that one step required in order for customers to be compensated for the environmental attributes of their renewable energy is "that the customer legally transfer the environmental attributes of the on-site generation" (VODER, p62). CEO requests that, at the time net metering tariffs are revised, such revisions should provide customers the option when registering an on-site generation system to transfer to the Company the environmental attributes of their future exports. While the study is currently deficient in presenting instruments for valuing those environmental attributes, there is no need to delay putting in place the mechanism necessary to allow the option of transferring them. Should self-generating customers with exports choose to retain the environmental characteristics of all their generation they should have the option of doing so but would as a result receive a lower price for their exported power (a price which did not include the benefit the Company would receive from the environmental characteristics of those exports).

Exports by customers with renewable self-generation could be valued by the revenue they provided the Company - the $.01/kWh charged to those purchasing clean energy under the Green Power, (eventually the CEYW "Flexible") program offering. Alternatively, because the Company purchases some RECs to supply to customers, the value of avoiding some of those purchases (by using instead the environmental

characteristics of the solar energy customers with self-generation export) could be considered an avoided environmental cost.

In either case the environmental attributes of self-generator exports do tie to a measurable and avoidable cost impacting rates. The VODER study needs to accurately reflect those avoided cost (or increased revenue) impacts.

Chapter 5 – Frequency of ECR Updates

The value of Avoided Energy is a significant portion of the ECR and, as such, merits a more frequent update than other components in order to maintain a fair ECR value.

5.1 Energy Price Inputs. As noted earlier:

- Market prices much more accurately reflect the time value of exports than IRP values, which are highly sensitive to excursions from forecast natural gas pricing and can become quickly outdated.
- Using the actual market price at the time of the export occurs would be perceived as most accurate and thus fair.
- The VODER should note that avoided energy component of the ECR could reflect an annually updated weighted average of prior year hourly exports and market prices – providing an attractive balance of fairness, transparency, and ease of understanding. Self-generating customers would know what ECR to expect during the year, and an annual update based on prior year actual market prices would provide a more accurate and thereby more fair value than IRP estimates.

Chapter 7 – Class cost-of-service

Section 7.2 CCOS results - CEO acknowledges that an up-to-date class cost-of-service analysis is a valuable tool for analyzing pricing structure. But fair allocation of largely sunk costs is not the only relevant factor to consider when establishing a price structure.

Directing the Company to produce the VODER study had obvious advantages, especially due to the Company's expertise and access to relevant data. But having a party with a natural interest in the outcome of any review of self-generation produce the study does present opportunities for issues to be analyzed through a one-way lens. Cost analysis is one such example.

On page 86 the study notes:

> *"opportunity exists to better align the pricing structure with the underlying cost structure"*

Adequate revenue recovery to cover fixed cost expenses is an obvious constraint on any pricing structures. But CEO disagrees with Company's implied position that the goal of rate design is to align with the Company's cost structure.

The VODER study does not make reference to the large amounts of new solar generation the Company projects as needed in the preferred portfolio of its latest IRP. In addition to being fair and reasonable, prices should also encourage optimal future behavior. To the extent that customers choose to make investments in solar self-generators, some of the Company's future expenditures for solar generation could be offset. Also, while large concentrated utility scale has cost advantages it is less resilient to a single line or transformer failure or cloud coming over - the geographic diversity of customer installed solar provides a resiliency benefit.

While the timing and extent of those capital expenditure offsets and resiliency benefits may be difficult to quantify, the VODER study should note such values as relevant in any future pricing structures.

Chapter 9 – Project Eligibility Cap

CEO comments regarding the content of Chapter 9 are organized as follows: (1) Study deficiencies, (2) Highlights of findings to date, and (3) Add potential alternatives.

1) Study deficiencies.

The VODER study was deficient in its evaluation of the Project Eligibility Cap. The study was directed to "Analyze the pros and cons of setting a customer's project eligibility cap according to a customer's demand as opposed to predetermined caps of 25 kilo-watt ("kW") and 100 kW" (Order 35284 @25). After the VODER study was released, CEO received inquiries asking where to find this analysis within the Study – those readers assumed that there must be more to the eligibility cap review than Chapter 9.

Similarly, in its first Production Request, PUC Staff asked -

> "Please identify where the pros and cons of setting a cap according to a customer's 100% and 125% demand as opposed to predetermined caps of 25 kW and 100 kW are located in the VODER study. If this was not provided in the VODER study, please provide them."

The Company responded:

> "Section 9.1 of the VODER Study evaluates the existing project eligibility cap, and Section 9.2 considers a modified project eligibility cap set relative to a customer's demand. Both sections describe the considerations evaluated. From the Company's perspective, assessing the interconnection requirements and distribution system operational impacts is of primary importance."

But even with the expressed concern regarding interconnection matter, the VODER Study evaluation of interconnection requirements was incomplete. The Study notes in section 9.2.2 Modified Cap Impact:

> "Modifications to the project eligibility cap would require an evaluation of the interconnection requirements".

As described more fully below, via Production Requests and a meeting of the parties 9/12/2022 to discuss technical aspects of the project eligibility cap, progress in addressing this deficiency has been made.

2) Highlights of findings to date

To supplement gaps in the VODER study, CEO presents below highlights from the study, comments Production Requests and other sources:

VODER study highlights:

- "[R]etaining the 25-kW cap for residential and small general customers could be reasonable." (VODER p101)
- About 85% of solar irrigation systems bump up against the 100kW cap.
- IEEE 1547 compliance has reduced safety, service quality, and reliability risks.
- Setting a cap to customer demand is more challenging for customers/service points with lower demand, presents issues when there's a change in ownership, and may not align with the changing needs of customers.
- The Company proposed that in 2023 it would "likely endeavor to hold technical workshops with Commission Staff, installers, and other interested stakeholders to discuss proposed interconnection requirements". (VODER Study, page 112)

Public record highlights (from public comments, IPC-E-20-26 and/or IPC-E-22-12):

- Idaho Grain Producers Association explained in IPC-E-22-12 comments:

  > "The current 100kW cap on irrigator projects imposes unnecessary costs on farmers who want to invest in solar. Rather than being able to design, build, and connect a single site to match their consumption, farmers are instead required to build multiple, smaller sites in multiple locations – which is more expensive and less efficient for all parties involved."

- Multiple agribusiness interests have noted the urgency in revising the 100kW in 2022 given agribusiness vulnerability to energy costs, rising electricity costs, and time-sensitive access to federal funds.
- Commenters to IPC-E-22-12 noted that if the CEO petition were not limited to the cap alternative ordered in IPC-E-21-21, that an absolute level of 2000kW or a table of eligibility levels with protocols for each level should be considered.

Highlights from Company Responses to Production Requests and All-Party meeting 9/12:

- **It is the review process, not the cap, that protects the grid**. Concerns related to safety, service quality and grid reliability issues can be and are adequately addressed through the generator interconnection process. Changes to tariffs necessary to implement a modified cap are minimal.
- A 5 MW project might easily connect to a distribution feeder, while a 100-kW project located many miles from the substation and at the end of smaller conductor might present issues or require system upgrades. These issues are identified and addressed in the existing interconnection review process.

- Currently, prior to interconnection, all on-site generation projects undergo a Feasibility Review, and some projects may require a Feasibility Study. Per response from the Company:[1]

  > The Company envisions the first step in reviewing larger projects would be to use the current internal screen for each project. The current internal screen evaluates the project size relative to the individual service transformer size and the distribution feeder hosting capacity – in Schedule 68, this is referred to as the Feasibility Review. If the project passed the initial screen, then the project would be approved. However, if the project fails, the Company would require a more detailed study to look at potential operational, safety, or power quality issues caused by the project. These studies could follow the process for PURPA projects, with an initial feasibility study being completed within 30 days and, if necessary, a system impact study that would take an additional 30 days. Each study would require funding from the customer to cover the cost of the study.

- Schedule 68 currently addresses interconnection criteria for on-site generation systems up to 3 MVA (the equivalent of 3000 kW) and additional criteria for systems over 3 MVA.
- "[T]he interconnection considerations related to a generator will be evaluated independently from a customer's demand."[2] Setting a cap according to demand is unrelated to interconnection matters and does not affect safety, service quality, and reliability risks as those matters are addressed in the interconnection review process.
- While a 25kW cap addresses the vast majority of R&SGS, there are customers with higher electricity requirements who would value a path to apply for larger systems.

Additional observations:

- There are implicit limitations to system size irrespective of customer demand:
  - **No benefit to over-sizing**: An ECR credit redeemable only against energy expenditures provides no economic benefit to customers for building over-sized systems.
  - **Upgrade costs:** Potential costs for required distribution system upgrades often limits economic installation size to existing transformer/line capacity.
  - **Space limitations:** Rooftops, acreage, etc.

[1] Idaho Power Response to the First Production Request of PUC Staff, No. 9, c.
[2] Idaho Power Response to the First Production Request of PUC Staff, No. 4, b.

3) Additional cap alternatives need consideration

A consideration behind setting the cap according to demand was summarized by the phrase "if it can make, it can take it." That is, if the grid can safely deliver a customer's peak demand, the grid has the capacity to receive a similar amount of customer-generated exports. Findings now indicate that a cap based on technical criteria (such as absolute size) merits consideration as an alternative to setting the cap according to demand. Such a technical cap should be considered under the VODER study.

For example -

- Rocky Mountain Power was ordered in 2020 to study setting the project eligibility cap according to demand. RMP implemented a non-residential cap of 2000kW in Utah.

- Idaho Power proposed to study setting the cap according to demand in IPC-E-21-21. The VODER study raised administrative complexities with setting the cap to demand.

- Idaho Power clarified in the course of Production Requests that customer demand is not a factor in evaluating the interconnection requirements required to ensure safety, service quality, and reliability.

In sum, there exists sufficient evidence that setting the cap according to demand should not be the only alternative considered for modifying the cap.

In Exhibit 1 below, CEO presents four cap design alternatives and suggests, based on findings to date, a possible scoring theme for how well each alternative address three criteria: grid safety, fairness and administration.

Clean Energy Opportunities for Idaho

Exhibit 1: Alternatives for Modifying Project Eligibility Caps

In considering a modified cap, the Commission may be concerned with the following three factors:

1) Grid impacts (a primary focus): Can safety, service quality, and grid reliability be ensured under the modified cap?
2) Fair & Equitable: Is the modified cap fair and equitable across customers and classes?
3) Administrative: Is modified cap administratively straightforward and efficient to maintain?

Alternatives for Modifying the Cap:	**Grid*** Safety, service quality, & reliability	**Fair & Equitable**	**Administrative efficiency**	**Related Findings**
A) Maintain current 25kW & 100kW caps		**Harms CI&I, particularly Irrigators**		Public record demonstrates: • 100kW cap harms CI&I customers VODER demonstrates: • Inequitable cap effects on different customer classes. • The 100kW cap is unnecessary
B) Set cap according to demand for all customers		**Disfavors customers w/ growing needs, or those with continuous loads**	**Problematic for small systems; changes in needs/ ownership raises issues**	VODER presents cons of setting cap set to demand: • Challenging for smaller systems • Changes in ownership raises issues • Customers have changing needs
C) Set cap to be the greater of 25kW or a percentage of customer demand for all customer classes		**Disfavors large customers w/ growing needs or continuous loads**	**Changes in needs or ownership raises issues**	• • Efficient and fair for R&SGS • Far superior to current 100kW cap Incurs the cons of setting the cap according to demand without clear benefits
D) Set an absolute cap level of 2MW for all customer classes				• Easiest to understand and administer. • ECR compensation policy allows customers no benefit for over-sizing systems. • Interconnection criteria & requirements serve to further govern system sizes

* **GRID** – The review procedures required for interconnection identify and address any issues with safety, service quality, and grid reliability.

Chapter 11 – Implementation considerations

11.1 Transitional Rates

The VODER study invited input regarding a reasonable transition time period or impact on customers for implementation of new net metering terms. Some commenters have also raised the issue of providing legacy treatment to existing non-legacy customers. In IPC-E-18-15, the parties agreed to an 8-year glide path which was projected to average an 8% decline per year relative in the export credit rate. This had the advantage of not only preventing rate shock but also offering a transition period for customers and the industry to build the skills, tools, and experience base needed to evaluate the economics of on-site generation systems.

Informed by what was agreed to as reasonable in IPC-E-18-15, CEO would suggest that the VODER study should include an option for implementation that would set a limit that the Export Credit Rate would not decline more than 8% per year relative to the average retail rate until such time that it reaches the then-current ECR.

11.2.2 Tariff Changes

The Company notes that "modifications to the project eligibility cap would require changes to Schedule 68, which may include expanded interconnection requirements." (VODER, p112) CEO is under the perception that such changes are minimal given responses to Production Requests and a meeting of the parties September 12, 2022.

CEO requests that the impact on CI&I customers who are impeded by the 100kW cap should be among the VODER considerations. Such considerations include –

The harm to customers of delaying the implementation of a modification to the 100kW cap.

- Time-sensitive access to federal funds.
- The challenge of supply chain issues, which create delays from the time an application is approved to the time equipment is procured, installed, and operational.

CERTIFICATE OF SERVICE

I hereby certify that on this 21st of September, I delivered true and correct copies of the foregoing INITIAL COMMENTS to the following persons via the method of service noted:

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