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VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Commission Staff
Attn: Curtis Dloughy
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97301

RE: ADV 1600 – Idaho Power Advice No. 24-01 – Schedule 84 Net Metering Follow-up to Questions Asked at the April 4, 2024, Workshop

Attention Commission Staff:

Attached please find the responses of Idaho Power Company ("Idaho Power" or "Company") to the seven (7) Informal Data Requests sent to Idaho Power by Staff on April 5 and 16, 2024, as a follow-up from the April 4, 2024, workshop hosted by Staff. Additionally, the Company provides the following general information for additional context pertaining to Staff's questions and the Company's responses.

Until recently, Idaho Power has offered net metering services consistently between its Oregon and Idaho jurisdictions pursuant to its Idaho tariffs, schedules, and regulations as contemplated by ORS 757.300(9). This not only included the Company's service schedule for on-site generation customers (previously Idaho Schedule 84) but also its interconnection rules and requirements set forth in Idaho Schedule 68. Subsection (9) of Oregon's net metering law reflects the Oregon Legislature's acknowledgement that, in certain contexts, Idaho Power should be afforded special regulatory treatment to account for the Company's unique circumstances in Oregon. Specifically with respect to Oregon's net metering law, subsection (9) served to eliminate the confusion, disparate impact, inefficiencies, and unnecessary burdens and costs that would result if the Company was required to have two sets of rules for net metering by allowing the Company to offer a single service offering, with a single set of interconnection rules and procedures to all of its customers.

The Company has requested that it be authorized to continue to offer net metering services in Oregon consistent with its Idaho offering as contemplated by subsection (9), which deems a qualifying utility compliant with Oregon's net metering rules if it offers services to its customers in Oregon in accordance with tariffs, schedules and other regulations promulgated by the appropriate authority in the state where the electric utility's headquarters are located. In other words, pursuant to the updated program recently implemented in Idaho under a legacy framework specific to Idaho Power's Oregon service area in accordance with the current versions of Idaho Schedules 6 (residential), 8 (small general service), or 84 (commercial, industrial, and irrigation), depending on customer class, and Schedule 68 (interconnection). All three of the Company's net metering service schedules contain rules for both legacy and non-legacy systems.

The discussion and questions posed in this docket have implied that there may be a hybrid option pursuant to which the Company could maintain the legacy Idaho program in Oregon based on the Commission's ability to limit new customer generators to balance the interests of retail customers under ORS 757.300(6), which they believe would not be as onerous as implementing a true third program, Oregon net energy metering ("NEM"). In the event, however, that the Company is directed to implement a program in Oregon that is differently structured from what it offers in Idaho, the Company believes it would legally be required to comply with Oregon's net metering rules including the requirements governing net metering interconnections. Addressing the scope and applicability of net metering facility rules, OAR 860-039-0005(1) provides:

> OAR 860-039-0010 through 860-039-0080 (the "net metering rules") establish rules governing net metering facilities interconnecting to a public utility as required under ORS 757.300. Net metering is available to a customer-generator only as provided in these rules. These rules do not apply to a public utility that meets the requirements of ORS 757.300(9).

Similarly, subsection (9) exempts the Company from the requirements of 757.300(2)–(8), and OAR 860-039-0010 through 860-039-0080 by extension, enabling the Company to offer a single, non-conforming program across jurisdictions. However, as the Company understands it, subsection (6) does not excuse the Company from the legal requirements contained in OAR 860-039-0010 through 860-039-0080. While that provision does provide a certain amount of discretion to the Oregon Commission, it is not clear whether that would encompass relieving the Company from other statutory requirements.[1]

As a reminder, effective January 1, 2024, Oregon Schedule 84 was revised as an interim schedule based on the Commission's desire for the Company to maintain the status quo pending further consideration by the Commission. However, because Oregon Schedule 84 referred to Idaho Schedule 84, in order for the Company to continue offering net metering service to Oregon customers pursuant to the version of Oregon Schedule 84 that was in effective as of December 18, 2023, it needed to memorialize the version of Idaho Schedule 84 that was in effect on that date, which is no longer operative in Idaho having been modified effective January 1, 2024, in Idaho Case No. IPC-E-23-14.[2] This was applied as a stopgap measure on an interim basis, and to the extent that Staff or stakeholders suggest Idaho's old offering could be permanently implemented in Oregon, it is the Company's belief that anything different than what is currently in place in Idaho would constitute an Oregon-specific offering that would need to comply with the requirements of Oregon Administrative Rules, Chapter 860, Division 39, Net Metering Rules, which include, but are not necessarily limited to, Oregon specific interconnection review procedures; application forms, processing procedures, and timelines; interconnection fees and costs; billing specifications; and mapping, records and reporting requirements, all of which vary

[1] But see OAR 860-039-0075, which refers to the Commission's authority under ORS 757.300(6) as the ability to limit the cumulative generating capacity of net metering systems.

[2] As a reminder, the Company's net metering service offering is now split between three schedules: Schedules 6 (residential), 8 (small general service), and 84 (commercial, industrial, and irrigation)), each of which contains rules for both legacy and non-legacy systems.

significantly from the Company's current practices. Ensuring compliance with applicable Oregon rules would in itself be a significant task.

The suggestion that the administrative burden would be minimized by offering all Oregon on-site generation customers (past, present, and future) service in accordance with the rules applicable to legacy systems is flawed. The legacy concept is based in investment-backed decisions and the reasonable expectations of the customer-generator when they established service; it is the system that has been designed and installed to meet the current rules that qualifies for legacy treatment. While the Company agreed with Staff that different cut-off dates for Oregon Legacy treatment were appropriate based on the reasonable expectations of its Oregon customers when they established net metering services, by nature legacy treatment has a cutoff and is not envisioned to be offered in perpetuity. Removing the distinction between existing and new systems for Oregon customers simply becomes a new Oregon-specific service offering.

Ultimately, the Company believes there are two options, either (1) the Company has a single program offered across jurisdictions pursuant to the current versions of Idaho Schedules 6 (residential), 8 (small general service), or 84 (commercial, industrial, and irrigation), depending on customer class, and Schedule 68 (interconnection); or (2) the Company implements a separate offering for Oregon in compliance with Oregon law; practically speaking, the Company does not see that there is a middle ground approach alternative to implementing a "true third NEM program just for Oregon." As more fully described in its attached responses to Staff's informal data requests, if it is not authorized to proceed pursuant to 757.300(9), it is the Company's understanding it will be subject to the full range of Oregon's net metering requirements and anticipates it will be required to incur what could be significant costs to implement separate interconnection rules, personnel, systems, and processes for an Oregon specific net metering offering, which the Company would expect would be entirely assigned to its Oregon jurisdiction given it would be driving the need. Considering the small number of Oregon customers, such increased costs would be particularly impactful.

The Company looks forward to providing additional comments on May 6th as provided for in the schedule. In the meantime, if you have any questions regarding these responses, please do not hesitate to contact me.

Very truly yours,

Connie Aschenbrenner

Connie Aschenbrenner

CA:sg
Attachments

STAFF INFORMAL DATA REQUEST NO. 1:

Can you provide a narrative description of what the administrative costs and burden would be of having a separate NEM program for Idaho and Oregon including those associated with having a true third NEM program just for Oregon as well as what it would be if IPC just kept the legacy TOU program in place in perpetuity in Oregon?

REPONSE TO STAFF'S INFORMAL DATA REQUEST NO. 1:

As highlighted in the accompanying cover letter, if the Company is not permitted to offer its Idaho offering in its entirety, the Company will be subject to Oregon-specific net metering rules. Compliance with those rules will result in increased costs associated with creation of new processes, additional employee training, development of two sets of customer self-service tools and materials, separate customer communications, and so forth as more fully set forth below. The Company believes it is important for the Commission, Staff, and other stakeholders to understand the costs of which will be entirely assigned to its Oregon jurisdiction, given it would be driving the need. Considering the small number of Oregon customers, the Company anticipates incurring such costs would be particularly impactful.

While the Company has not completed an exhaustive analysis to identify all aspects of increased costs associated with managing a separate net metering program, in order to comply with OAR 860-039-0010 through OAR 860-039-0080, there would be both **upfront costs to reconfigure existing systems to manage new processes**, as well as **on-going costs to administer two distinctly different offerings**. Examples of these new requirements from Oregon Administrative Rule Chapter 860, Division 039:

- 860-039-0030 through 860-039-0040: There are three different tiers (1, 2, and 3) of Net Metering that all have different and more complex application processes than Idaho Power currently administers under Idaho Schedule 68. New applications, form agreements, and internal procedures would need to be created to comply with determining these levels and providing the required interconnection review process for each level.
- 860-039-0045: Idaho Power currently has different interconnection fees than what is allowed in this section. The fees allowed in this section are lower than what the Company currently charges, which will reduce how much of the program is funded by participating customers and will result in increased costs to non-participants.
- 860-039-0055 & 860-039-0060: Requires an "annual billing cycle" whereby unused kWh credits are valued at an avoided cost and transferred to customers who are participating in the utility's low-income assistance programs. Idaho Power's on-site generation offering provides for the credits to remain with the customer's active service agreement. This change would require configuration changes to Idaho Power's billing system, which results in an upfront cost and ongoing administration. Additionally, these sections would impose new reporting requirements on the Company.
- 860-039-0065: The aggregation rules laid out in this section differ from what is currently in place for the Company's on-site generation offering. This would again create two separate systems across the Company's service area.
- 860-039-0070: Each public utility must maintain current maps and records of customer-generator net metering facilities showing size, location, generator type, and date of installation, and file an annual report with the Commission with information on the number and generation capacity of NEM facilities and, upon request file maps, records, and reports to identify, locate and summarize net metering facilities in a form satisfactory to the Commission. There would be upfront

costs associated with configuring the Company's systems to comply with these requirements in addition to ongoing costs associated with the reporting and recordkeeping requirements.

Based on the questions received through the process, the Company has estimated the costs associated with two possible scenarios: (1) continuation of retail rate net metering, and (2) a new "unknown" compensation structure. As noted above, the continuation of retail rate net metering isn't without incremental costs, as new systems would need to be established and/or modified to adhere to the Oregon net metering rules.

While not exhaustive, the Company has provided the following estimates based on its experience.

Costs	NEM Continuation	New (TBD) Billing Structure
Upfront/Set Up Costs		
Interconnection Database Reconfiguration	$23,000	$23,000
Billing System Reconfiguration	$8,700 minimum	$995,955
Upfront Admin Costs	$16,600	$16,600
Customer Solar Calculator	N/A	$20,000
Ongoing/Annual Administrative Costs		
Ongoing Administrative Expenses	$231,750	$231,750
Interconnection Database Maintenance (Programmer Costs)	$21,000	$21,000
Customer Solar Calculator Subscription	Unknown	$80,935

Upfront Cost/Set Up Costs:

Key expenses in implementing a different system in Idaho and Oregon include:

Interconnection Database Reconfiguration: This encompasses costs for a programmer to reconfigure its system for a separate Oregon offering utilizing the company's Customer Generation (CG) database. This system is used to process interconnection applications, run automated engineering review screening, send automated customer emails, manage workflows, documents, and track on-going compliance with the tariffs or rules.

Billing System Reconfiguration: A new billing structure would necessitate building new functionality in the Company's customer information system specific to the Oregon offering. This entails modifying the customer bill configuration and integrating new data services. These changes are critical for maintaining the functionality of 'My Account' across various software applications. Additionally, the reconfiguration will extend to updates on the web and app interfaces that customers interact with, ensuring they receive accurate and up-to-date information regarding their new billing structure. Collectively, these updates will require significant investment, both in terms of financial resources and labor, to execute effectively.

Upfront Admin Costs: The administration of a separate billing structure for Oregon necessitates an additional increase of one-time labor costs. This estimate encompasses various functions, not all of which are captured in this document. Some key components identified are:

- **Process Development/Integration:** including labor expenses for IPC staff to develop new processes, as well as contract management, interconnection database contractor management and testing. Also includes work to develop customer communications.
- **Training**: Involves education and outreach with customers, training of internal Energy Advisors and Customer Solutions Advisors who work directly with our customers. Development of training curriculum and updating of internal training documents and guides.
- **New Interconnection Forms:** The development of new forms and programming on-line webform applications requires careful consideration of technical, legal, and regulatory requirements. These forms are vital for customers to connect an on-site generation system to the grid safely and effectively.

Customer Solar Calculator- Idaho Power offers a web-based calculator to help new customers evaluate if solar is right for them. The current calculator has functionality for rate changes under the existing structure and the existing license can also present net energy metering. However, if Oregon implements something different, there will be an additional set-up cost depending on new rules or structure.

Ongoing/Annual Administrative Costs:

Ongoing Administrative Expenses: These costs are largely expected to be associated with labor incurred to manage a separate Oregon program, which includes interconnection application reviews/processing, coordination and development of customer communications via multiple channels (i.e., webpage updates/maintenance), database quality assurance/testing, installer trainings, managing installer lists, inverter lists, customer meetings, additional annual reporting requirements, ongoing training and curriculum development for customer facing staff.

It is also important to note, given the complexity of the Oregon rules governing interconnection requirements and/or required processes, there is also uncertainty regarding the ability for the Company to automate its processes to the same level that exists under compliance with Idaho Schedule 68. Manual processes will increase costs in this category.

Interconnection Database Maintenance (Programmer Costs): The upkeep and programming of a new Interconnection Database for Oregon customers would have an annual maintenance expense.

Customer Solar Calculator Subscription- The current calculator has functionality for rate changes under the existing structure and the existing license can also present net energy metering, however if a different structure is created and cannot be configured under the current format, then an additional annual subscription charge would apply. It is unknown as to whether the current licensing arrangement (that allows for presentment of net energy metering) will continue to be available.

The outlined estimated costs reflect the additional financial commitment required to initiate and sustain a separate customer generation offering in Oregon, which increases the complexity of daily operations. It is important to note that these figures are only estimates and would vary based on actual program implementation and operational experience.

STAFF INFORMAL DATA REQUEST NO. 2:

What is the total NEM capacity in MW for Oregon and for the full IPC system?

RESPONSE TO STAFF'S INFORMAL DATA REQUEST NO. 2:

Total NEM capacity for Oregon is 3.48 MW this includes both active and pending systems. The total NEM capacity for the full IPC system is 175.56 MW, including both active and pending systems.

STAFF INFORMAL DATA REQUEST NO. 3:

What is the historic peak load both for Oregon and the full IPC system?

RESPONSE TO STAFF'S INFORMAL DATA REQUEST NO. 3:

Year	Oregon System Coincident Demand	System Peak
2019	115	3,242
2020	112	3,392
2021	145	3,751
2022	132	3,568
2023	127	3,615

**Note: As Oregon demand is not demand response adjusted, the analogous non demand response adjusted peak is used for system.*

STAFF INFORMAL DATA REQUEST NO. 4:

What considerations went into determining that the 6-month offline period should be the cutoff to make a legacy customer non-legacy?

RESPONSE TO STAFF'S INFORMAL DATA REQUEST NO. 4:

In accordance with the criteria established by the Idaho Public Utilities Commission for maintaining legacy status, Idaho's on-site generation schedules provide that grandfathered status of a system is forfeited if the system is offline for more than six months.[1] This timeframe derives from Idaho Power's interconnection requires for distributed energy resources (DER) set forth in Schedule 68, which provides:

> The Customer shall notify the Company immediately if a DER is permanently removed or disabled. Permanent removal or disablement for the purposes of this Schedule is any removal or disablement of a DER lasting longer than six (6) months. If the Customer wishes to interconnect the DER after six (6) months, the Customer Generator must reapply and meet the interconnection requirements in place at the time of application.[2]

Consistent with this framework, Idaho's on-site generation schedules address the impact of "permanent removal or disablement" of an on-site generation system: "Permanent removal or disablement for the purposes of this schedule is any removal or disablement of an Exporting System lasting longer than six (6) months. Customers with permanently removed systems will be removed from service under this schedule and placed on the appropriate standard service schedule."[3]

In the building industry, imposing temporal limits to ensure work is timely completed is standard practice. See, for example, 2018 International Building Code, 105.5 Expiration (stating that permits become invalid if work under the permit is not commenced within 180 day of its issuance or if the work is suspended or abandoned for a period of 180 days after the work is commenced). Similar to building codes and regulations, Idaho Power's interconnection requirements help ensure safety and quality. The reasons for the six-month timeframe by which an on-site generation system is deemed to be permanently removed, for legacy status or otherwise, are severalfold. As an initial matter, electrical codes and regulations and interconnection standards are not static; they evolve to incorporate the latest safety standards and practices, and placing a time limit helps the Company ensure that on-site generation systems adhere to the most up-to-date safety requirements. This mechanism also holds customers accountable for making sure their system does not linger offline indefinitely and is back on-line within a reasonable timeframe and helps to ensure that customers are taking service under the appropriate rate schedule.

An on-site generation system that is offline longer than 6 months may fall into disrepair and/or become outdated, which could lead to potential issues or code violations. Requiring review and reevaluation of a system that has been offline for an extended period of time is important to verify that the system is in good working order and in compliance with applicable rules and regulations.

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[1] See *In the Matter of the Petition of Idaho Power Company to Study the Costs, Benefits, and Compensation of Net Excess Energy Supplied by Customer On-Site Generation*, Case No. IPC-E-18-15, Order No. 34509 at 14-15 (Dec. 20, 2019) and Order No. 34546 at 8-11 (Feb. 5, 2020); IPUC No. 30,Tariff No. 101, Schedules 6, 8, and 84.
[2] *See* Schedule 68, First Revised Sheet No. 68-10.
[3] *See* Schedule 6, Original Sheet No. 6-7; Schedule 8, Original Sheet No. 8-7; Schedule 84, Original Sheet No. 84-8.

As described above, the six-month offline time period is not limited to legacy status requirements but part of a larger framework; it sets the parameters for classifying when a system is deemed to be "permanently removed" for purposes of interconnection and service schedules,[4] and so is, by extension, also the timeframe used for determining if a legacy system has been permanently removed.

If the event the Company becomes aware that a customer's on-site generation systems is offline, it notifies the customer in writing, typically via email, citing the deadline for the system to get back online. If the customer is not responsive, the Company will reach out to the customer again via direct mail, phone call, and/or another email. If the system remains offline, the Company will continue to check in with the customer throughout the six months, providing reminders of deadlines and any relevant information it may possess to help the customer remedy the situation. This is true regardless of whether the system is legacy or non-legacy.

It should be noted that an on-site generation system remaining offline for more than six months is not a frequent occurrence. For example, in 2023, the Company did not identify any Oregon systems that were offline for more than six months. More broadly, in those instances where Idaho Power has become aware that a system is offline, most customers address the situation and return to operation within six months, though there is a small number of customers that choose not get their system back online.

[4] *See* Schedule 6, Original Sheet No. 6-7; Schedule 8, Original Sheet No. 8-7; Schedule 68, First Revised Sheet No. 68-10; Schedule 84, Original Sheet No. 84-8.

STAFF INFORMAL DATA REQUEST NO. 5:

Can you explain the 2-meter to 1-meter conversion issue addressed in the final condition of the legacy conditions in Schedule 84? It sounds like it's a rare edge case, but we'd like to have it explained in writing if possible.

RESPONSE TO STAFF'S INFORMAL DATA REQUEST NO. 5:

In the Company's experience, a customer has not sought to convert from a two-meter configuration to a single-meter configuration.

By way of background, Idaho Schedule 84 is the tariff schedule for the Company's commercial, industrial, and irrigation ("CI&I") customers to take net metering service. Prior to 2020, CI&I net metering customers were required to install a second meter to measure the energy provided by the customer's generating facility. This metering configuration allowed CI&I customers to offset any energy charges with the production from their on-site generation system and enabled collection of demand and basic load capacity charges based on the customer's gross demand, measured independent of the on-site generation.

In 2020, Idaho Power proposed to modify the metering requirement under Schedule 84 from a two-meter to a single-meter requirement for all new Schedule 84 customers.[5] The Company initiated the change in response to feedback received from customers, installers and stakeholders, in order to remove potential barriers to participation and reduce incremental costs and complexities resulting from the existing two-meter requirement.

Accordingly, the Company requested to modify Schedule 84's metering requirement in order to improve the customer generation service offering to ease impacts on customers. Recognizing the advantages of removing the then-existing two-meter requirement the Idaho Commission noted:

> A single-meter system reduces customer costs, streamlines administration, and can perform the requisite functions. We cannot ascertain from the record why a new customer would choose a dual-meter system going forward . . . For administrative efficiency and the reasons previously stated, all new customer-generators taking service after the service date of this Order must install a single-meter system.[6]

As part of the Company's request to remove the two-meter requirement for new Schedule 84 new customer generators, the Company also requested the Idaho Public Utilities Commission to establish grandfathering criteria for existing Schedule 84 customer-generators similar to what was done for other classes of on-site generators. Ultimately, the Idaho Commission established criteria for defining legacy treatment for existing Schedule 84 systems similar to that for residential and small general service customers, pursuant to which existing Schedule 84 customers could retain their two-meter systems.[7] In Oregon, there are currently 19 CI&I customer generators with two-meter systems. The Idaho Commission reiterated that the concept of "grandfathering" was based in investment-backed decisions and the reasonable expectations of the customer-generator when they established service:

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[5] *In the Matter of Idaho Power Company's Application for Authority to Modify Schedule 84's Metering Requirement and to Grandfather Existing Customers with Two Meters,* Case No. IPC-E-20-26.
[6] *Id*. at 12.
[7] *Id.*, Order No. 34854 at 12-13 and Order No. 34892 at 9 (Jan. 14, 2021).

> Therefore, it is the system that has been designed and installed to meet the current rules that qualifies for legacy treatment. If a customer wants to switch to a single-meter system, they can do so but they would forfeit the system's grandfathered status. Similarly, if the customer wants to expand their system beyond the limits previously stated, the new portion of their system would not qualify for legacy treatment.[8]

The provision contained in draft Oregon Schedule 84 sought to align the legacy criteria for Oregon CI&I customers with those of Idaho CI&I customers. Given, under the Company's proposed Oregon legacy framework, there will be single-meter setups for legacy customers, the Company believes it could be reasonable to exclude this draft provision from the proposed tariff.

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[8] *Id*. at 11.

STAFF INFORMAL DATA REQUEST NO. 6:

How would a customer be billed as a legacy NEM customer that is also part of the TOU program, and is this any different than a non-legacy customer? Here, we're interested in whether there are some billing problems that might arise from having a full retail rate credit under NEM or the new ECR combined with a time-varying retail rates under TOU.

RESPONSE TO STAFF'S INFORMAL DATA REQUEST NO. 6:

If the Company is authorized by the Commission to offer net billing services to its non-legacy Oregon customers in accordance with its recently modified on-site generation tariff schedules in effect in Idaho, under a legacy framework specific to Idaho Power's Oregon service territory, Oregon Legacy customers would be billed pursuant to the Net Energy Metering conditions set forth in Idaho Schedule 6, 8, and 84, as applicable and non-legacy systems, customers would be billed pursuant to the Net Billing conditions set forth in those schedules as applicable.[9] Under Idaho Schedule 6, Oregon residential on-site generators will have the option to elect time-of-use ("TOU") rates as defined in Oregon Schedule 5, Residential Service Time-of-Day Pilot Plan.

For Oregon Legacy customers that elect TOU, if electricity supplied by the Company during the billing period exceeds electricity generated by the customer and exported to the grid, the customer will be billed for the net electricity supplied by the Company at the applicable TOU rate. If the energy generated by the customer and delivered to the Company exceeds the electricity supplied by the Company, the difference is carried forward as a kilowatt hour ("kWh") credit to offset future energy use.

For non-legacy customers requesting to participate in optional time-of-use service under Idaho Schedule 6, the customer first consumes their generation on-site, which reduces the amount of energy they consume from the grid, and any excess generation is exported to the grid. All kWh consumed from the grid is measured and valued at the TOU rate and all energy exported to the grid is measured and valued based on the time-differentiated Export Credit Rate ("ECR"). The customer will generate a financial credit for excess generation, based on the product of measured exported energy and the ECR, that can be monetized to offset current or future charges associated with utility-provided service. The financial credit is added as a line item at the end of the bill and the amount is subtracted from the customer's total bill. Any remaining financial credit will be carried forward.

[9] Note, however, that Monthly Charges in Idaho Schedules 6 and 8 do not apply; all Monthly Charges and provisions for service related to Idaho Power supplied energy are defined in the Company's applicable Oregon tariff schedules.

STAFF INFORMAL DATA REQUEST NO. 7:

Does the Company have any plans in the near or long term to make storage accessible to Oregon or Idaho customers (i.e. Company incentives, federal grants, other funding sources, etc.)? We expect OSSIA to write on this in their comments, and we as Staff see value to both the Company and customers if on-site generation customers are able to respond to price signals.

RESPONSE TO STAFF'S INFORMAL DATA REQUEST NO. 7:

Pursuant to Idaho's interconnection tariff applicable to on-site generation systems, customers can choose to pair energy storage with an on-site generation system (typically solar) and, taking service under Idaho Schedules 6, 8 or 84, may export to the grid. As part of the Company's modified on-site generation program recently implemented in Idaho, the Idaho Commission approved the Company's request to exclude energy storage and only include the nameplate capacity of generation to enforce the eligibility caps for Schedules 6, 8, and 84.[10] Stated differently, for systems with energy storage devices, only the amount of generation nameplate capacity is used to determine whether the applicable cap is exceeded, which removes a potential barrier for customers that desire to incorporate energy storage in their on-site generation system.[11] In addition to modifying administration of how energy storage devices are applied to the project eligibility cap, the Company proposed, and the Idaho Commission approved, an ECR rate design in recognition of the value provided by energy storage. The seasonal time-variant ECR rate structure implemented by the Company provides a mechanism by which on-site generators who invest in storage can realize the value of their investment when they export stored energy. By aligning the rate design for the ECR with the hours of highest risk, it sends a price signal to customers with energy storage when dispatching their batteries to the grid is valued and needed most. The Company also offers a number of energy-saving programs and resources to customers and shares information with customers about state and federal incentives or grant programs as appropriate. While it does not currently have an energy storage incentive program, it continues to evaluate new customer programs for cost effectiveness and would bring viable programs to the Commission for consideration. In addition, customer-generators may be able to take advantage of federal policies intended to encourage homeowners to install energy storage such as federal tax credits available under the Inflation Reduction Act including the Residential Clean Energy Credit.

[10] The eligibility caps for Schedules 6 and 8 are 25 kW and 100 kW or 100% of demand for Schedule 84.
[11] The sum of both generation capacity and storage capacity continues to be considered in the feasibility review process. In the event the Company's review of the combined system indicates a system upgrade is necessary, the customer would be required to pay the upfront costs.