BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. AR 659

In the Matter of Rulemaking to Update Division 82 Small Generator Interconnection Rules, and Division 39 Net Metering Rules.	Staff Opening Comments

Contents

Staff of the Oregon Public Utility Commission (OPUC or Commission) appreciates the collaborative process that led to the development of draft rules for the formal phase of this rulemaking and offer the following comments to aid the Commission in making their final determination on a handful of outstanding technical and policy issues.

Section 1: Technical Issues

Section 1.1 – Advanced Inverter Equipment Requirement Date

Staff's draft proposal includes a placeholder date to begin requiring advanced inverter equipment that is compliant with Institute of Electrical and Electronics Engineers (IEEE) 1547 standards. At the October 17 Special Public Meeting the Interstate Renewable Energy Council (IREC) indicated that there should be sufficient equipment available to make January 1, 2024, an acceptable date for requiring IEEE 1547-2018 compliant equipment of all new applicants. Given the time to finalize and publish these rules, as well as interconnection requirements in handbooks, Staff recommends using February 1, 2024, as the date to require new applicants to use IEEE 1547-2018 certified equipment. OAR 860-082-0030(1) would read:

> (1) IEEE 1547. An interconnection customer or applicant must construct, operate, and maintain a small generator facility and its associated interconnection equipment in compliance with IEEE 1547 and 1547.1. New interconnection applicants will be required to use IEEE 1547-2018 compliant equipment ~~by no earlier than January~~ starting February 1, 2024. For purposes of OAR 860-082-0030, capitalized terms not otherwise defined in Division 082 have the meaning set forth in IEEE 1547.

Section 1.2 – High-Speed Reclosing Equipment Requirements

Parties did not reach alignment on the potential for utilities to require additional equipment beyond advanced inverters to facilitate reclosing on circuits using high-speed reclosing. IREC does not support the requirement of additional protective relays to limit inadvertent export on circuits using high-speed reclosing, while the Joint Utilities (JU) argue that the ability to require such equipment is necessary because of a lack of confidence in advanced inverters to perform as expected. The requirement is included in three places in OAR 860-082-0033, subsection (3)(a)(A), (3)(a)(B) and (3)(b)(A). The sentence at issue is:

> When a project is located on a circuit using high-speed reclosing the utility may require a maximum delay of less than 2.0 seconds to safely facilitate the reclosing.

Comments filed October 26, 2023, by Adam Morse, VP Engineering of ProtoGen Inc. also raise concerns with the JU position. Mr. Morse believes the JU's concerns are not substantiated in actual operations, stating, "someone can create a theoretical possibility for an event to be

protected against, but the probabilities defy the human imagination.[1]" Further, Mr. Morse claims that the case studies of inverter malfunctions cited in defense of the requirement are not relevant to this high-speed reclosing requirement.

At the October 17 special public meeting, the Commission questioned the longevity of a policy based on a fear that the advanced inverters will malfunction. JU noted that the use of 'may' allows long-term flexibility for the utility in requiring additional equipment. Staff appreciates that there is flexibility to "futureproof" this requirement as utilities gain confidence in advanced inverter performance but is concerned about the lack of clarity about when or how the utility will apply this requirement. Staff believes that more specificity will help provide certainty to the market and ensure that the utilities are not making DER development unnecessarily expensive.

If the utilities are not able to provide more specificity in this rulemaking proceeding, Staff provides two suggestions. First, Staff believes that the Commission should direct the utilities to specify the circumstances under which the utility will require additional protective equipment on circuits with high-speed reclosing within their interconnection handbooks. Also, if there is a list of manufacturers, or specific inverter functionality that would alleviate the necessity for addition equipment the utility needs to provide such listings in their handbooks.

Second, Staff suggests adding an additional condition where the utility would be required to provide the interconnection customer the underlying reasoning of any additional requirements, including an explanation why the customer's proposed configuration is insufficient. The following would replace the current sentence:

> When a project is located on a circuit using high-speed reclosing the utility may require a maximum delay of less than 2.0 seconds to safely facilitate the reclosing if the utility provides the rationale for the requirement as well as any other equipment modifications that would alleviate the need for additional equipment.

This approach puts the onus on the utility to be judicious in the identification of additional equipment requirements for each applicant. It could be possible that an alternative inverter would suffice for the utility and avoid the need for additional equipment; Staff would expect the utility to inform applicants of this fact.

Staff believes the requirements for additional information from the utilities on a case-by-case basis will improve the transparency of the process while respecting the safety issues raised by the JU.

Section 1.3 – Size Threshold for Net Metering Tier 1 Screen

Staff's proposal standardizes the Tier 1 screening criteria across residential net metering, non-residential net metering, and Qualifying Facilities. As incorporated in 860-039-0030(1)(b)

[1] Page 1 of ProtoGen Comments https://edocs.puc.state.or.us/efdocs/HAC/ar659hac141321.pdf

and 860-082-0045(1)(a) the eligibility for Tier 1 interconnection review was updated from a maximum capacity of 25 kW in the currently rules to a maximum export capacity of 25 kW with a maximum of 50 kW of nameplate capacity in the proposal. This is intended to take advantage of modern technologies that allow DERs to provide more value to the system throughout the day without putting more than 25 kW onto the system at a given time. Should the Commission decide to change the overall cap on residential net metering systems at 25 kW under OAR 860-039-0010 the proposed draft rules will not require further changes to the Tier 1 screening requirements. Staff is unaware of any opposition to this approach but seeks to ensure that there is clear understanding of this across participants in the rulemaking.

Section 2: Process Items

Section 2.1 – Utility Interconnection Handbook Review Process

Participants in the informal rulemaking discussed the value of articulating a process for the utilities to share changes to their detailed interconnection requirements (referred to collectively as Handbooks) and bring disputed issues to the Commission. Staff's proposal as presented in the public meeting memo dated August 15, 2023, envisioned a two-part process for updating the utility handbooks. The first part would focus on notification of the change and an opportunity to informally resolve concerns. If a concern is not resolved informally, a party can bring it to the Commission for review.

ITA proposes a slightly different approach that appears to be overly cumbersome and could result in more disputes than resolution. First, it requires the utilities send "notice to interconnection customers with an interconnection agreement or active interconnection request."[2] Staff is concerned that the ITA language that covers "developers with operating projects and projects in development"[3] may require the utility to notify thousands of residential net-metering customers of Handbook changes.

In addition, the ITA proposal requires the utility file the updated handbook for Commission review and approval, "if a person challenges the revisions…"[4] Staff understands that the utilities may have more resources to initiate a Commission review than a developer or solar installer and may be more likely to find informal solutions if the onus is on the utility to bring the issue forward. However, Staff is concerned that the requirement for a utility to describe another party's concern will create more disputes and complexity. Staff is also concerned that this approach will encourage parties to limit participation in the informal process to force a Commission review of the handbook updates.

Staff also seeks to clarify that notifying interconnection customers in this context means notifying the solar installers that are responsible for interfacing with the utility on behalf of their clients, and not directly contacting retail customers that have net metering systems. Staff also believes that the utilities can consult with Energy Trust of Oregon and Oregon Solar and Storage Industry Association for further support informing the net metering installer community of Handbook changes.

Staff suggests time requirements for comments and replies to address deficiencies in our initial proposal, as well as eliminate any confusion. Finally, Staff proposes to clarify that parties could request Commission intervention if necessary to resolve issues, this requirement will be on the participants, not the utility.

> 860-082-0030 (1)(b)Interconnection requirements handbook. Each public utility must post an interconnection requirements handbook on its public website.

[2] Comments of the Community Renewable Energy Association, Renewable Energy Coalition, and the Oregon Solar + Storage Industries Association, page 2 of 26.
[3] Ibid at page 3.
[4] Ibid at page 2.

> Prior to revising its interconnection requirements handbook, a public utility must provide public notice on its website and to interconnection customers. The utility must provide ~~and an opportunity~~ a minimum of 30 days for ~~to~~ stakeholders to comment and the public utility must provide public responses within 30 days ~~respond~~ to any comments received. Parties may request Commission intervention if concerns raised are not fully addressed by the utility.

The ITA proposal also includes requirements for an initial compliance filing by the utilities to review and ensure the updates incorporate the preferred default settings. Staff believes such a requirement is best addressed by a Commission order, and not incorporated in the OARs; Staff included a detailed proposal in its Public Meeting memo dated August 15 addressing this issue.[5]

Section 2.2 – Timeline for Updating Legacy Utility Data

While working through export controls and screening improvements, it became clear that the utilities have not collected net metering and small generator project data in a manner that allows interconnection analysis to reflect the transition to export capacity. This will require an effort to update data on existing projects and change the data collection approach for new projects moving forward.

Given the new technologies, and the new metrics for measuring the impact of small generators new data will be collected, and old data needs to be updated to reflect the current understanding of what is on the grid. Both the JU and the Energy Trust have been involved in preliminary analysis of updating the current data. The Energy Trust has a vast database of installations prior to the 2021 timeframe. It appears the utilities could make use of this data in updating the historic data sets.

Other parties to the docket, including IREC, ITA, and OSSIA have filed comments asking for the data to be updated by a date certain.

The JU initially opposed a requirement that they update all legacy interconnections as there will be a significant effort to do so, requiring time and expense. They also believe the conversion will not have a material impact on the interconnection capacity on any given circuit. The JU offered a compromise proposal in the informal staged, and further updated their proposal in comments filed October 13. The latest JU proposal would allow full data conversion withing 12 months for PGE and Idaho Power, with PacifiCorp requiring 18 months.

Staff believes the JU proposal is a reasonable approach and supports it with some minor additions. First, the utilities should be encouraged to focus as much as practicable on the most congested feeders initially in updating data. Staff assumes this prioritization approach could be done in a manner that would not slow the update process. The utilities should incorporate the updates on a regular basis, relying on the updated information in any interconnection review process. A situation where 12 to 18 months pass before utilities rely on updated information would be sub-optimal. Staff also believes the utilities should provide regular updates on their progress at six-month intervals.

[5] See page 11

Finally, Staff continues to support consideration for legacy projects that are challenging to update, although Staff is hopeful the majority of the legacy data could be updated through utilities working with the Energy Trust data.

Section 2.3 – Minor Equipment Modification

In Staff's proposal there is an opportunity for projects in the interconnection queue to adjust their nameplate by up to ten percent if this does not impact lower queued projects.[6] The ITA suggested that consideration for impacts on lower queued projects should not be included in the rules. Additionally, ITA advocates for larger changes to be made through the evaluation process, including a 60 percent reduction in nameplate capacity prior to execution of a system impact study, and an additional 15 percent reduction prior to execution of a facilities study. Staff believes that, with clear rules about how much a higher queued project can change, projects entering the queue should be able to plan for potential changes in higher queued projects and make decisions accordingly. Therefore, Staff supports providing some flexibility to adjust project size during the interconnection process to help facilitate DER development. However, a 60 percent reduction does not seem to qualify as a "minor equipment modification" that Staff can support.

Staff recommends that the Commission remove consideration for lower queued projects while keeping the minor modification cap at a 10 percent reduction.

> OAR 860-082-0015(27)(c) Includes a reduction in the nameplate rating and/or export capacity of the small generator facility of 10 percent or less ~~provided that a change made to a small generator facility with a pending completed application must not adversely impact lower queued projects~~.

It should be noted that OAR 860-082-0075(5), which allows changes in existing facilities for existing customers also relies on the definition of "minor equipment modifications." OAR 860-082-0075(5) currently states:

> A public utility may temporarily disconnect a small generator facility if an interconnection customer makes any change to the facility, other than a *minor equipment modification*, without the public utility's prior written authorization. The public utility may disconnect the small generator facility for the time necessary for the public utility to evaluate the effect of the change to the small generator facility on the public utility's transmission or distribution system. (emphasis added)

If the Commission determines changes to the definition of minor equipment modifications greater than 10 percent are appropriate, there will likely need to be changes to OAR 860-082-0075(5) as well. Staff would not want larger equipment modifications for existing systems to be allowed at larger sizes without informing the interconnecting utility, as is now allowed. The revised section could be written as:

[6] Minor equipment modification is also used in rule OAR 860-082-0025(1)(b) in reference to changes to existing systems.

> A public utility may temporarily disconnect a small generator facility if an interconnection customer makes any change to the facility, other than a maximum 10 percent reduction in export capacity ~~minor equipment modification~~, without the public utility's prior written authorization. The public utility may disconnect the small generator facility for the time necessary for the public utility to evaluate the effect of the change to the small generator facility on the public utility's transmission or distribution system.

This would continue to allow what are currently called minor equipment modifications for existing customers.

Section 2.4 – Timelines for Execution of Interconnection Agreement

In Staff's proposal, utilities will provide an executed interconnection agreement to applicants upon notice that the applicant passed the screening process. This eliminates a current step in the process where utilities would provide an unexecuted agreement and was designed to streamline the process. As part of a compromise the JU agreed to provide the executed agreement, as long as the deposit was collected with the counter-signed agreement.

The ITA would like to change the process for returning the counter-signed agreement to 30 days.[7] Staff understands that interconnection customers need time to arrange financing at this stage, but it is unclear whether 30 days will actually result in more successful interconnections or simply increase delays in the interconnection queue. Further, Staff is hesitant to alter the compromises offered by the JU in the informal process.

[7] See page 2 of Comments of the Community Renewable Energy Association, Renewable Energy Coalition, and the Oregon Solar + Storage Industry Association.

Section 3: Issues to be Considered for Inclusion in the Formal Rulemaking Scope

Section 3.1 – Interconnection Agreement Length

The ITA raised the issue of mismatch with the length of a generator interconnection agreement (GIA) and a power purchase agreement (PPA).[8] In response to the ITA concerns Staff reached out to the JU to see if there were ways to address the ITA's stated concerns on securing financing. According to the ITA, if the GIA ends before the PPA financing could be problematic. In response, the JU proposed language to address the issue, allowing GIA terms to match PPAs that are for a specific period of time, the underlined language below is the revised proposal. At the October SPM the ITA indicated the language would address their concerns. Staff believes this issue has been resolved within the proposed rules.

> (3) Before beginning operation of a small generator facility, an interconnection customer or applicant must receive approval of the facility under the small generator interconnection rules and must execute an interconnection agreement with the interconnecting public utility. Applicants or interconnection customers are entitled to a 20-year term for an interconnection agreement, or, if the interconnection customer and the utility have entered a separate Power Purchase Agreement for a specified period of time, to a term that coincides with the length of such Power Purchase Agreement.

Section 3.2 – Deposit Amounts and Timing

While deposit requirements were not originally at issue in this rulemaking, ITA proposes two changes to the Commission's current deposit requirements for small generators. First, the ITA believes that the deposit should not be due at the time the interconnection agreement is executed but that utilities, "should require the deposit furnished a reasonable time (e.g., 20 days) before commencement of those activities."[9] The activities referenced would support procurement and construction of the interconnection facilities.

As discussed above, while the utilities would prefer to initially send an unsigned agreement to the applicant, they agreed to IREC's proposal to send an executed agreement with the condition that rules require the interconnection customer to provide the deposit with the counter-signed agreement. The JU argue that not allowing collection of the deposit at that time could lead to an applicant being in breach of the contract.[10]

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[8] See page 15 of Supplemental Joint Comments on behalf of the Community Renewable Energy Association, Renewable Energy Coalition, and the Oregon Solar + Storage Industry Association.

[9] See page 17 of Comments of the Community Renewable Energy Association, Renewable Energy Coalition, and the Oregon Solar + Storage Industry Association.

[10] See Joint Utilities' Comments Regarding Staff's Initial Redlines, page 5, lines 17-19: Requiring that the deposit be provided at the same time as the counter signed agreement avoids the situation where a customer signs an

Staff does not support the ITA proposed change in process. The position put forth in Staff's proposal was a compromise position reached through discussions within the informal process. The utility is making a commitment to interconnect an SGIP facility via the signed agreement, a deposit from the applicant with the counter-signed agreement is entirely reasonable.

ITA's second raised issue states deposits can be significant, "several hundred thousand or even millions of dollars in some cases."[11] It was Staff's intention to impose a limit on the amount of any deposit that would be due like the limitation on deposits due when an interconnection applicant agrees to make progress payments under OAR 860-082-0035(5). Accordingly, Staff supports clarifying the language of the proposed rules.

To clarify the deposit limit, Staff proposes modifying OAR 860-082-0025(7)(f) to clarify that the deposit will be identified consistent with the guidance in OAR 860-082-0035(5)(a). This would ensure that deposits will be limited as required elsewhere in the Division 82 rules. The proposed rule would read as follows, with the added phrase underlined:

> (f) Interconnection Agreement. If the proposed interconnection is approved and requires no construction of facilities by the public utility, the public utility must provide the applicant an executed interconnection agreement no later than five business days after approving the interconnection. If the proposed interconnection is approved and requires construction of facilities, the public utility must provide the applicant an executed interconnection agreement, along with a non-binding good faith cost estimate and construction schedule for any required upgrades, no later than 15 business days after approving the interconnection. If the applicant does not return a countersigned interconnection agreement and any required deposit, to the public utility, or request negotiation of a non-standard interconnection agreement, within 15 business days of receipt of an executed interconnection agreement, the application is deemed withdrawn. A utility may not require a deposit under this section that exceeds 25 percent of the estimated costs identified in the Interconnection Agreement or $10,000, whichever is less.

agreement and is immediately in breach because they have not provided the deposit required under the agreement.

[11] Ibid.

Section 4: Additional Proposed Rule Edits

Section 4.1 – Joint Utility Edits

The JU filed comments dated October 13, 2023, which requested "two substantive revisions to the Division 39 rules.[12]" The two issues raised include 1) Delete OAR 860-039-0030(11) and 2) add language around approval despite screen failure for Division 39, Tier 2 rule.

For the first suggested edit, Staff agree with the JU, OAR 860-039-0030(11) was not intended to be in Staff's proposal. The inclusion of this was an oversight; Staff agrees it should not be part of the formal rules.

The second revision proposed by the JU will allow the utility to approve Tier 2 net metering interconnections with only minor modifications, as is allowed for Tier 1 installations. Staff believes this is an appropriate modification to the rules as it will, in principle, allow additional interconnections without additional process. Staff suggests adding the following section to OAR 860-039-0035:

> (5) Approval despite screen failure.
>
> (a) Despite the failure of one or more screening criteria, the public utility, at its sole option, may approve the interconnection provided such approval is consistent with safety and reliability.
>
> (b) If the public utility determines that the customer-generator can be interconnected safely if minor modifications to the transmission or distribution system were made (for example, changing meters, fuses, or relay settings), then the public utility must offer the applicant a good-faith, non-binding estimate of the costs of such proposed minor modifications. Modifications are not considered minor under this subsection if the total cost of the modifications exceeds $10,000. If the applicant authorizes the public utility to proceed with the minor modifications and agrees to pay the entire cost of the modifications, then the public utility must approve the application.

The other subsections in OAR 860-039-0035 will be renumbered as well for completeness.

The JU also raised a number of "Minor Corrections and Revisions for Clarity."[13] Staff has reviewed the suggested edits and concurs with the JU that the edits are appropriate.

Section 4.2 – Additional Edits

In comments filed October 12 the ITA/ITG raised additional definitional issues, specifically calling for eligibility for small generators to be based on the export capacity of the facility. At

[12] Joint Utilities' opening comments regarding proposed Division 39 and Division 82 rules, page 1.
[13] Ibid at page 3.

the Special Public Meeting parties were not in consensus on this particular change, arguing it had not been discussed in the workshops.

Staff is concerned that basing eligibility to use the SGIP rules on export capacity could have unintended consequences. It seems that a customer could cite a 100 MW generator behind the meter with controls limiting the export capacity to 10 MW. It is not clear that a generator this size should be eligible for the SGIP process.

Staff agrees with the ITA/ITG comments that an "8 MW AC solar array to include a 3 MW battery,"[14] should be eligible for the SGIP rules, assuming the capacity of the DC inverter is no more than 10 MW. However, instead of using 'Export Capacity' in the eligibility, Staff would suggest focusing on the underlying generation capacity. To solve the issue, Staff recommends two changes to address the concerns raised by ITA. First, a new term would be added under the definitions, "Generator Nameplate Capacity." This would focus on the size of the stand-alone generator, excluding any co-located storage. The definition incorporated would mirror the definition currently approved for SGIP eligibility. This definition would be added to OAR 860-082-0015:

> "Generator Nameplate Capacity" means the full-load electrical quantities assigned by a facility's designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, as expressed in amperes, kilovoltamperes, kilowatts, volts, megawatts, or other appropriate units. Nameplate capacity is usually indicated on a nameplate attached to the individual device.

To incorporate the use of this definition OAR 860-082-0005(1) would be edited to include "Generator" as follows:

> (1) OAR 860-082-0005 through 860-082-0085 (the "small generator interconnection rules") govern the interconnection of a small generator facility with a generator nameplate capacity of 10 megawatts or less to a public utility's transmission or distribution system. These rules do not apply if the interconnection between the small generator facility and the public utility is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

The combination of these two changes would ensure an "8 MW AC solar array to include a 3 MW battery," would be eligible for the SGIP process.

/s/ Ted Drennan

[14] Page 6 of ITA/ITG comments