BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation Into Interconnection Process and Policies.	UM 2111

COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL ON THE STAFF PROPOSAL FOR REVISIONS TO THE SMALL GENERATOR INTERCONNECTION AND NET METERING RULES

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I. Introduction

A. Background

The Interstate Renewable Energy Council, Inc. (IREC) is a 501(c)(3) non-partisan, non-profit organization working nationally to build the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy, and our planet. In service of our mission, IREC advances scalable solutions to integrate distributed energy resources (DERs), e.g., renewable energy, energy storage, electric vehicles, and smart inverters, onto the grid safely, reliably, and affordably. IREC supports the creation of robust, competitive clean energy markets, though IREC does not have a financial stake in those markets. IREC works across numerous diverse states to improve the rules, regulatory policies and technical standards that enable the streamlined, efficient and cost-effective interconnection of DERs.

Order No. 20-211 opened Docket No. UM 2111 to "consider the broad range of interconnection issues in a manner that is inclusive of all generator types."[1] On March 30, 2022, IREC placed the *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-*

[1] Order No. 20-211, Appendix A, at 5 (July 6, 2020).

Plus-Storage) (BATRIES Toolkit) into the record in this proceeding[2] and requested that the UM 2111 work group consider BATRIES Toolkit's recommendations and associated model language when developing revisions to Oregon's interconnection procedures. On April 22, 2022, the Commission issued Order No. 22-126 establishing a work group process to address the following issues:

- Modernizing the screening and interconnection study practices;
- Incorporating advanced inverters, storage, islanding, and other modern configurations; and
- Incorporating IEEE 1547-2018 standards.[3]

Over the course of the past year, Staff hosted 16 workshops.[4] At the workshops, IREC presented a matrix with a framework for decision-making to implement the IEEE 1547-2018 standard,[5] analyses comparing Oregon's interconnection and net metering rules to national models,[6] and discussion drafts of redlines to Oregon's interconnection and net metering rules.[7] IREC was a key member of the work group, participating in each workshop and leading the discussion at many. Participants included the utilities, the Energy Trust of Oregon (ETO), the

[2] Interstate Renewable Energy Council, et. al, Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage (March 2022), downloadable at https://energystorageinterconnection.org/.

[3] Order No. 20-126, Appendix A, at 12 (April 22, 2022). The order also contemplated a stakeholder-led working group to address "access to transparent data about utility standards, costs, and study assumptions," however a stakeholder-led working group never convened, and these issues were not addressed.

[4] Workshops occurred on March 9, 2022, March 28, July 15, Aug. 9, Aug. 31, Sept. 14, Sept. 28, Oct. 6, Oct. 25, Nov. 17, Dec. 7, Dec. 20, Jan. 17, 2023, Feb. 15, March 15, and March 28.

[5] See *e.g.,* Staff's Presentation for the Workshop on August 31, 2022 (IREC presentation of Decision Adoption Matrix).

[6] See *e.g.,* Staff's Presentation for the Workshop on September 14, 2022 (IREC presentation of Screen Comparison Tables for Level 1 and Level 2).

[7] See *e.g.,* Staff's Presentation for the Workshop on August 9, 2022 (IREC presentation of draft rule sections Supplemental Review and Export Controls).

Interconnection Trade Associations, and others. Based on the discussions in the workshops and comments provided to the work group, in March 2023 Staff issued a proposal for revisions to Oregon Administrative Rules Divisions 860-082 and 860-039 (Staff Proposal),[8] and requested written comments on its proposal. In response to this request, IREC respectfully submits the following comments.

The UM 2111 work group worked diligently over the past year to develop changes to Oregon's rules that will modernize and streamline the interconnection evaluation process, explicitly authorize the use of energy storage and other modern configurations that use export controls, and authorize the use of advanced inverters that comply with the IEEE 1547-2018 standard. IREC presented proposals to modernize Oregon's interconnection procedures in line with national models and recently developed best practices. The work group reached consensus to support most of IREC's proposed changes. IREC thanks the participants—particularly Staff, the utilities, and ETO—for bringing an open mind and a constructive attitude to the work group's discussions. IREC generally supports the Staff Proposal with select revisions identified herein.

The work group reached consensus to revise Oregon's interconnection rules to explicitly authorize the use of energy storage and other modern configurations that limit the export of DERs to the grid. The work group adopted the approach described in the Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) Toolkit. The BATRIES initiative is a collaboration between IREC, the Electric Power Research Institute, Shute Mihaly and Weinberger, LLP, Solar Energy Industries Association, New Hampshire Electric Co-operative,

[8] Staff Proposal Oregon Small Generator Interconnection Rules (March 31, 2023) (Originally filed on March 8, 2023, and updated version was e-mailed to the UM 2111 service list on March 31, 2023); Staff Proposal Net Metering Rules (March 27, 2023) (Attached to Staff's Presentation for the Workshop on March 28, 2023).

California Solar and Storage Association, and PacifiCorp. The BATRIES Toolkit includes model interconnection rule language that identifies methods that DERs can use to control their export.

B. IREC recommends certain changes to the Staff Proposal that ensure utilities appropriately evaluate the impact of DERs.

One principle of interconnection evaluations is to examine the DER's impact on the distribution system. Accordingly, the work group agreed that when a DER controls its export using certain defined methods, utilities' interconnection evaluation will consider as an impact to the distribution system only exported power. Further, the work group agreed that interconnection evaluations should not use direct current (DC) nameplate ratings, and instead should use alternating current (AC) nameplate ratings, because impacts to the distribution system are measured in AC.[9] However, during the workshops the utilities explained that their DER databases do not include the AC nameplate rating for many older projects, and argued that inputting this data for older DER could be administratively burdensome. As explained below, IREC is concerned that continuing to use the DC nameplate rating for older DER will overstate their impact in interconnection evaluations. Thus, the Commission should set a date certain by which utilities must include in their DER databases the AC nameplate rating of all existing DERs.

Oregon's current interconnection rules evaluate whether a project is effectively grounded using something commonly known as the line configuration screen.[10] The utilities and IREC agreed to modernize this screen, but the work group ran out of time before finalizing a new screen. Below, IREC recommends that the Commission adopt a revised line configuration screen

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[9] *See* Staff Proposal OAR 860-082-0015(28), defining nameplate rating "in Alternating Current (AC)."

[10] OAR 860-082-0050(2)(f).

that differentiates between rotating and inverter-based DER and explicitly identifies three configurations that inverter-based DER can use.

The Staff Proposal differs from the BATRIES Toolkit's model language for export controls in two ways that are inappropriate. First, the Staff Proposal allows utilities to require high-speed reclosing.[11] As explained below, IREC objects to this addition because the concern it addresses is based on a misinterpretation of how non-exporting relays operate. Second, the Staff Proposal allows utilities to unilaterally reject the use of Relative DER Ratings.[12] Allowing utilities to unilaterally reject the use of Relative DER Ratings undermines the purpose of including the new export controls section: providing customers sufficient regulatory certainty to design a DER with knowledge that the controls are acceptable under the interconnection rules and the DER will not need to be redesigned after utility review.

II. To avoid overestimating the impact of DERs on the distribution system, the Commission should order utilities to update their DER databases to include nameplate ratings in alternating current.

The Commission should set a date certain by which utilities must include in their DER databases the nameplate rating in AC for all existing DERs. The utilities agreed to this for newer DERs, but argued that it would be administratively burdensome to find and use the AC nameplate rating for older DERs. The Commission should require the utilities to complete this task by a date certain because the nameplate ratings in their existing databases overstate the impact of DERs on the distribution system.

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[11] Staff Proposal OAR 860-082-003X(3)(a)(A)-(B) ("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.").

[12] Staff Proposal OAR 860-082-003X(3)(a)(C) ("Upon utility agreement, ...").

The distribution system operates in AC, while most DERs produce power from solar panels in direct current (DC). DERs use inverters to convert the DC power produced by a solar panel to AC power that can be exported to the distribution system. Utility databases can record the nameplate rating of solar panels in DC, and the nameplate rating of the inverter in AC.

During the UM 2111 workshops, ETO explained that it is common for the DC nameplate rating of solar panels in Oregon to be 35 percent larger than the AC nameplate rating of the inverter. Put another way, DER developers often undersize a project's inverter relative to the nameplate rating of the solar panels.

The goal of interconnection evaluations, *i.e.*, limited generation feeders, screens, and studies, is to evaluate impacts on the distribution system. Because the distribution system operates in AC, the nameplate rating most relevant to interconnection evaluations is in AC. For most DERs, this is the AC nameplate rating of the inverter, not the DC nameplate rating of the solar panels.

A. Utilities' DER databases do not include the AC nameplate rating for many older projects.

Historically, Oregon utilities only included a DER's DC nameplate rating in their databases. IREC understands that Oregon utilities began recording inverter information, which can include the AC nameplate rating, when they switched to a modern DER database software called Power Clerk. Based on the work group's deliberations, IREC understands that Portland General Electric (PGE) began using Power Clerk in 2020, and PacifiCorp began using Power Clerk in 2019. ETO's Power Clerk database dates to 2003 and includes many of these older projects for which the utilities' databases lack sufficient inverter data.[13]

[13] Staff Summary of January 17 Workshop, at 2 (Jan. 17, 2023).

In the work group, utilities agreed to use AC nameplate rating in interconnection evaluations when the utility's DER database includes a project's inverter data.[14] However, for older projects, the utilities argued that it would be administratively burdensome to find and use the AC Nameplate Rating, as this would require either searching utilities' records for the DER's original application, or signing a reciprocal data sharing agreement to get the information in database format from ETO.[15]

B. Using the DC nameplate rating instead of the AC nameplate rating overstates the impact of DERs on the distribution system.

Without updating their DER databases to include the AC nameplate rating of each DER, the utilities cannot practically use this data in decision-making or planning processes. There are numerous distribution system operations, distribution system planning, and interconnection evaluation processes that use the AC nameplate rating of DERs. These include, among others: the interconnection screening process, the interconnection study process, distribution system operations, distribution system modeling, distribution system planning, and hosting capacity analyses.

There are many ways that failing to update existing DERs' nameplate ratings will overstate impacts on the distribution system. First, using the DC nameplate rating instead of the AC nameplate rating for existing DERs likely causes the utilities to prematurely designate a feeder as a "limited generation," which prevents additional DER from interconnecting without an expensive and time-consuming study process.

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[14] See Staff Proposal OAR 860-082-0015(28), defining nameplate rating "in Alternating Current (AC)." Utilities are already collecting AC nameplate ratings for all new projects.

[15] A reciprocal data sharing agreement would require the utilities to provide ETO certain data about DERs, and the ETO to provide utilities certain data. Such a reciprocal agreement would benefit the public service mission of ETO, and all Oregonians. Staff Summary of January 17 Workshop, at 2 (Jan. 17, 2023).

Second, using the DC nameplate rating instead of the AC nameplate rating for existing DERs means that utilities are likely requiring upgrades that are not necessary. Or if the upgrades would have eventually been required by a later queued DER anyway, utilities may wrongly assign the cost of the upgrade to an earlier-queued DER.

Third, having databases that accurately show the size of existing DERs is a key input to a hosting capacity analyses. IREC strongly opposes utilities spending any time or resources to perform a hosting capacity analyses unless the Commission and stakeholders have confirmed that appropriate data, including AC nameplate ratings and measured load data, is input into the model.

These are just three examples of why it is important for utility databases to include appropriate data, and there are surely many others. Therefore, it is unreasonable to allow utilities to use inappropriate data in distribution system operations, distribution system planning, and the interconnection evaluation process in perpetuity.

C. The Commission should set a date certain by which utilities must include in their DER databases the AC nameplate rating and export capacity of all existing DERs.

Performing this task for circuits and transformers that have higher DER penetrations is more urgent, as the major factor in sending projects to the time-consuming and expensive interconnection study process—and potentially requiring upgrades—is the circuit or transformer's DER penetration.

The work group reached consensus that the new rules should include a 90% of minimum load threshold for aggregate export capacity (for older projects, export capacity is the same as nameplate rating[16]) on circuits,[17] and an 80% of minimum load threshold on substation transformers.[18]

Therefore, IREC proposes that the Commission order the utilities to first update their databases to include AC nameplate ratings on any circuit or transformer with an aggregated export capacity of more than 70% of minimum load. This allows utilities to prioritize higher penetration circuits and transformers, where the change will likely have the most impact. IREC selected 70% because it is below, but close to, the 90% and 80% thresholds used in the Staff Proposal. Utilities should complete this task no later than six months after the Commission's order on this topic. This should be an ongoing requirement, such that if any new interconnections cause a circuit or transformer's aggregated export capacity to exceed 70% of minimum load, utilities must immediately update their DER database for existing DERs on those circuits. This approach would strike a balance between addressing the urgent need for utilities to update their databases, and limiting administrative burden.

Then, the Commission should set a long-term deadline for the utilities to have accurate and complete AC nameplate rating data for the entire distribution system. IREC suggests requiring the utilities to complete this 12 months following the Commission's adoption of revised interconnection rules, which will likely provide utilities well over 12 months from signing the data sharing agreement to complete the task.

To accomplish this, IREC recommends the Commission issue an order in this proceeding, docket UM 2111, that includes the following language:

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[16] Staff Proposal OAR 860-082-0015(11) (export capacity equals nameplate rating where no export controls are used).

[17] Staff Proposal OAR 860-082-0045(2)(c), 0050(2)(b)(B).

[18] Staff Proposal OAR 800-082-0045(2)(b), 0050(2)(a), 006X(2)(b)(D).

- Within three months of the issuance of this order, Portland General Electric and PacifiCorp shall enter into reciprocal data sharing agreements with the Energy Trust of Oregon concerning the attributes of distributed energy resources.
- Within six months of the issuance of this order, Portland General Electric, PacifiCorp, and Idaho Power shall update their distributed energy resources databases to include nameplate rating values in alternating current for every distributed energy resource connected to a circuit or transformer where the aggregated export capacity exceeds 70% of minimum load. If new interconnection applications cause a circuit or transformer's aggregated export capacity to exceed 70% of minimum load, utilities will immediately update their DER database to use AC nameplate ratings for existing DERs on that circuit or transformer.
- Within twelve months of the issuance of an order revising OAR 860-082 to use nameplate rating in alternating current, Portland General Electric, PacifiCorp, and Idaho Power shall update their DER databases to include nameplate rating values in alternating current for every distributed energy resource.

III. The Commission should modernize the line configuration screen to allow inverter-based DER to pass if connected to one of three listed transformer configurations.

Oregon's current interconnection rules evaluates whether a project is effectively grounded using something commonly known as the line configuration screen.[19] The utilities and IREC agreed to modernize this screen. Despite productive conversations and significant progress, the work group ran out of time before agreeing on a new screen. The utilities appear to agree with IREC that the screen should differentiate between inverter-based and rotating DERs. IREC recommends that the Commission adopt a line configuration screen that not only differentiates between rotating and inverter-based DER, but also explicitly identifies three connection transformer configurations that inverter-based DER can use.

The work group explored ways to modernize the line configuration screen. On March 23, 2023, Staff facilitated a meeting on this topic with interested stakeholders, including the Joint Utilities, IREC, Electric Power Research Institute, and other industry experts. Discussions provided participants a better understanding of IEEE Standard C62.92.6, which includes

[19] OAR 860-082-0050(2)(f).

guidance on grounding for inverter-based systems,[20] and how the existing line configuration screen unfairly subjects inverter-based DERs to screening criteria designed for rotating machines.[21] At the end of the meeting, IREC left with an understanding that the Joint Utilities provisionally supported:

- Retaining existing requirements for rotating generation.
- For inverter-based generation, allowing DER to pass the screen if:
    - o the interface connection transformer is Yg-yg, or
    - o the DER uses medium voltage sensing for voltage protection.

Following the meeting, IREC and the utilities traded drafts of the revised screen. In advance of filing these comments, IREC reached out to the utilities to ask for a meeting to reach consensus on new screen language. On April 28, 2023 the Joint Utilities shared with IREC a revised screen proposal, but noted that due to ongoing internal deliberations the Joint Utilities reserved the right to propose a different screen in comments.

A. The Commission should adopt a line configuration screen that lists three transformer configurations that pass the screen and allows other transformer types to pass the screen if effectively grounded.

In the Staff Proposal OAR 860-082-0050(2)(g), a table identifies the types of interconnections that pass the line configuration screen. The Staff Proposal includes two types of transformer configurations that allow inverter-based DER to pass the screen.

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[20] IEEE C62.92.6, Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI - Systems Supplied by Current-Regulated Sources (2018).

[21] The current version of this screen was designed to evaluate how rotating machines operate and fails to account for a modern understanding of how inverters respond to ground faults. These outdated assumptions result in unnecessary supplemental grounding requirements for inverter-based systems. Requiring supplemental grounding for inverter-based systems both raises the cost of DERs and may also negatively impact distribution system protection.

While the meeting discussed the entire line configuration screen, participants focused their attention on proposed edits for inverter-based DERs that connect to a primary distribution line that is three-phase, four wire (or mixed three wire and four wire).

There are six notable interface connections transformer configurations available: Yg-yg, Yg-delta, Yg-y, Delta-delta, Delta-y, and Delta-yg. IREC recommends that inverter-based DER can use any of the first three configurations, *i.e.*, those that include a Yg on the utility side, because the grounded source provides the ability to measure on any individual phase. This is a reasonable utility practice. PacifiCorp's Interconnection Requirements Handbook, section 3.2.1 includes the same approach proposed by IREC in this rule, labeling the first three transformer configurations as "acceptable."[22] To provide customers and utilities clarity and certainty, Oregon's interconnection rules should specifically identify that, for inverter-based DER, these three configurations pass the screen.

First, Yg-yg is suited for grounded secondary (inverter) side applications, while Yg-delta is used for ungrounded inverter side applications. Both Yg-yg and Yg-delta act as a grounding source that feeds into the utility (or primary) system. IREC understands that Yg-yg and Yg-delta configurations are most commonly used by DERs. Therefore, specifically listing the Yg-yg configuration, as the Staff Proposal does, will provide clarity and certainty for utilities and customers evaluating interconnections using this common configuration.

Second, for the same reason the screen should explicitly list the Yg-delta configuration. IREC understands the Staff Proposal's allowance for DERs with "medium voltage sensing for voltage protection with preferred default settings found in the interconnection requirement

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[22] PacifiCorp, Distributed Energy Resource (DER) Interconnection Policy, Facility Connection (Interconnection) Requirements for Distribution Systems 34.5 kV and Below, Engineering Services & Asset Management Policy 138, at 12 (Dec. 28, 2020) (Section 3.2.1 listing "acceptable" interconnection transformer winding configurations as "Grounded Wye / Grounded Wye," "Grounded Wye / Wye," and "Grounded Wye / Delta," and conditionally acceptable configurations as "Delta / Delta," "Delta / Wye," and "Delta / Grounded Wye."), https://www.pacificpower.net/content/dam/pcorp/documents/en/pp-rmp/customer-generation/Facility_Interconnection_Requirements_for_Distribution.pdf.

handbook" applies only to Yg-delta configurations. Therefore, IREC proposes specifically listing Yg-delta in that provision,[23] as follows:

- Yg-delta with the small generator facility ~~is on a mixed three-wire/four-wire line and uses~~ using medium voltage sensing for voltage protection with preferred default settings found in the interconnection requirements handbook.

Third, different from Yg-yg, Yg-y includes an ungrounded source that feeds into the primary system. Because the inverter grounding for the Yg-y configuration does not affect the utility's primary system, the Yg-y configuration should also pass the screen. IREC's proposed line configuration screen includes Yg-y alongside Yg-yg because both configurations establish a grounded primary side while still allowing voltage sensing on the secondary side.

Fourth, IREC does not propose listing Delta-delta, Delta-y, and Delta-yg as configurations that independently passes the screen. Such configurations may still be acceptable by meeting the "effectively grounded" requirement (previously intended only for rotating machines).

B. IREC's Line Configuration Screen

The April 28, 2023 Joint Utilities' proposal clarifies that certain listed configurations are applicable to the transformer's high side connection. Clarifying the side of the transformer connection eliminates ambiguity, which makes the screen more transparent and its application more predictable, so IREC incorporates this change in our proposal below. IREC recommends the Commission adopt the following line configuration screen, which as noted above, is the same as the requirement in PacifiCorp's interconnection requirement handbook:

> (g) Line Configuration Screen. Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of

[23] In addition, there is no need to list "mixed three-wire/four-wire line" in the lower right cell of the table, as that primary distribution line type is identified in the lower left cell of the table.

the type of electrical service provided to the project, including line configuration and the transformer connection to limit the potential for creating over-voltages on the interconnecting public utility's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line Required to Pass Screen**
Three-phase, three-wire	~~Ungrounded on primary or any type on secondary~~ Interface connection transformer high side is phase-to-phase
Three-phase, four-wire	Interface connection transformer high side is single-phase, line-to-neutral
Three-phase, four-wire or mixed three-wire and four-wire	Interface connection transformer high side is three-phase, line-to-neutral and effectively grounded, or For inverter-based generation,~~:~~ interface connection transformer is: • Yg-yg or Yg-y, or • Yg-delta with the small generator facility~~ is on a mixed three-wire/four-wire line and uses~~ using medium voltage sensing for voltage protection with preferred default settings found in the interconnection requirements handbook. ~~For rotating generation: connected line-to-neutral and effectively grounded.~~

IV. IREC supports the Staff Proposal's export control section with two revisions.

The work group reached consensus to revise Oregon's interconnection rules to explicitly authorize the use of energy storage and other modern configurations that limit the export of DERs. One of the primary benefits of identifying appropriate means of export control in the interconnection rules is that it minimizes the amount of back and forth between the customer and utility, and it provides customers with the information they need to design projects appropriately from the start.[24]

[24] BATRIES Toolkit at 45 ("Clear identification of standardized methods of controlling export in interconnection rules also provides interconnection customers the information they need to properly design ESS projects prior to submitting interconnection applications. This regulatory certainty reduces the time and costs associated with ESS interconnection by minimizing the amount of customized review needed and by empowering customers to design projects that avoid the need for distribution upgrades.").

The work group started by reviewing the model rule language for export controls found in the BATRIES Toolkit. The Staff Proposal adopts the BATRIES Toolkit's model rule language for export controls, with two additions that undermine the goal of allowing customers to design projects appropriately from the start.[25] The Commission should reject these two modifications; the model rule language was thoroughly vetted during the development of the BATRIES Toolkit and at no point did any of the participating utilities or research engineers identify a need for these changes.

A. The export control section should not allow utilities to require high-speed reclosing because such protection concerns are appropriately addressed through other protection devices or settings.

The first inappropriate departure from the model rule language concerns the use of two different export control settings for traditional utility-grade relays, Device 32R and 32F.[26] In both cases, the time limit for non-export is typically set at 2.0 seconds, and if export occurs for more than 2 seconds the relay trips a circuit beaker and the DER is disconnected from the grid. In comments, the utilities objected to using a 2 second time delay on circuits using high-speed reclosing due to concerns about creating an island, and asked that the export controls section allow a shorter time delay for these circuits.[27]

IREC agrees that a DER located on a circuit using high speed reclosing may need protection equipment that responds to adverse distribution system conditions in under 2 seconds, but modifying the export controls section is unnecessary to accomplish this. DERs use either a certified inverter or a multi-function relay to protect from adverse distribution system conditions.

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[25] Staff Proposal OAR 860-082-003X (Export Controls).

[26] Staff Proposal OAR 860-082-003X(3)(a)(A)-(B).

[27] See Joint Utilities' Initial Comments Regarding Export Control and Supplemental Review Issues, at 5-6 (Oct. 25, 2022) (Joint Utilities Oct. Comments).

In either case, adverse system conditions would cause the DER to trip offline within the appropriate time.

First, the presence of an inverter with UL 1741 certification ensures protection against adverse distribution system conditions according to industry standards.[28] For example, any certified inverter is equipped with appropriate anti-islanding and voltage protection. Adding an export-limiting relay does not remove or disengage the inverter's anti-islanding or voltage protection functionality. The required voltage protection will cause the inverter to trip within 0.16 seconds of detecting adverse system conditions.[29] In the vast majority of DERs, IREC expects a certified inverter to serve as the protection against adverse system conditions, so the relay would only serve to prevent export and not provide other protection functions.

Second, a multi-function relay has different settings for each function it serves. A multi-function relay's *protection time delay setting* for responding to adverse conditions on the external grid is separate and distinct from the *non-export time delay settings* for responding to internal changes in the DER's output and power flow. Staff Proposal OAR 860-082-003X(3)(a)(A)-(B)'s 2 second time delay setting only applies to the relay's non-export function. The utilities appear to misinterpret this section of rule as specifying the relay's protection time delay settling for other trip functions. It does not. For example, a multi-function relay with a non-export time delay setting of 2 seconds would also include a voltage protection with a setting that

[28] *See* IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, IEEE 1547-2018, subclause 8.1 (discussing islanding). Inverters certified to IEEE 1547-2003 are also equipped with anti-islanding functionality.

[29] IEEE 1547-2018 subclause 6.4.1 specifies mandatory voltage tripping requirements for DER. The clearing time for any DER is 0.16 seconds when voltage is greater than 120% for any of the abnormal performance categories (categories I, II or III). Any DER must meet IEEE 1547 requirements, and inverters do so through UL 1741 certification.

causes the relay to trip within 0.16 seconds of detecting adverse conditions on the external grid.[30] Thus, it is unnecessary to adjust a relay's non-export settings to respond to adverse conditions on the external grid.

IREC understands that some relay' non-export function can be set with a delay of less than 2 seconds. However, there appears to be no safety or reliability-related need to do so, and the 2 second delay has been used effectively elsewhere in the country.

States with numerous DERs, like California and Hawaii, have for many years allowed relays with a non-export time delay of 2.0 seconds; Illinois and New Mexico also use this time delay.[31]

Requiring a shorter non-export time delay for only some circuits may require a redesign of the DER's control system to avoid nuisance tripping. As noted above, the Commission should avoid adopting rules that could make such redesigns—which increase the cost of DERs—more likely unless there is a clear and relevant distribution system concern.

IREC respectfully requests that the Commission adopt the model rule language for non-export relays found in the BATRIES Toolkit, and delete the following sentence from Staff Proposal OAR 860-082-003X(3)(a)(A) and 003X(3)(a)(B):

> ~~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.~~

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[30] *Id*. IEEE 1547-2018 subclause 6.4.1 also applies to DERs using relays as their voltage protection equipment because IEEE 1547-2018 is a technology neutral standard. IEEE 1547-2018 notes "the DER includes any equipment required to meet the interconnection performance and interoperability requirements of the standard, *including protective relays* and measurement transducers" (emphasis added).

[31] CA, Pacific Gas & Electric Co., Rule 21, Sheets 145-146, https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_21.pdf; HI Electric Co., Rule 14, at Sheet 34B-17; 83 IL Admin. Code § 466.75; NM Admin. Code R. § 17.9.568.12.

B. The export control section should clearly identify the technical requirements for using Relative DER Ratings.

IREC does not support allowing the use of the Relative DER Rating option only upon utility approval.[32] Allowing a utility to unilaterally reject the use of the Relative DER Rating even if it meets a clearly defined standard undermines the customer's ability to design a project in advance prior to applying. Most importantly, the use of a conservative threshold of 50% of the customer's verifiable load is well established and has been non-controversial for over twenty years.

The use of a Relative DER Rating using a 50% threshold has been in place in California's Rule 21 since at least 2000, and IREC is unaware of any issues with its implementation in California in all this time.[33] Since that time it has also been adopted by PacifiCorp's sister utility NV Energy and multiple other states;[34] again, IREC is unaware of any other objections being raised to its use. The Relative DER Rating was also vetted during the development of the BATRIES Toolkit and at no point did any of the participating utilities or research engineers identify concerns with this approach.

The Staff Proposal denies the customer the opportunity to clearly understand what the technical basis would be for re-evaluating the threshold and the utilities have not provided adequate evidence to demonstrate that additional discretion is warranted. For the reasons described above, IREC respectfully requests that the Commission follow the established

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[32] Staff Proposal OAR 860-082-003X(3)(a)(C).

[33] Pacific Gas & Electric Co., Rule 21, at Sheet 147.

[34] States that have designated a relative DER rating using a 50% of minimum verifiable load threshold, without additional utility approval necessary, include: California, Hawaii, Illinois, Nevada, and New Mexico. See, *e.g.*, *id.*; HI Electric Co., Rule 14, at Sheet 34B-17 to Sheet 34B-18; 83 IL Admin. Code § 466.75(c)(3); NV Pub. Util. Comm., Dkt. 17-06014, NV Power Co. Rule 15, at Sheet 93AD (April 11, 2018); NM Code R. § 17.9.568.12(C)(1)(c).

practices and research, and authorize the use of the Relative DER Rating without the need for additional utility approval by deleting the first clause from Staff Proposal OAR 860-082-003X(3)(a)(C):

> **Relative Distributed Energy Resource Rating**: ~~Upon utility agreement, t~~This option requires the Small generator facility's Nameplate Rating to be so small . . .

V. When adopting the revised rules, the Commission should end the limited generation feeder exception to OAR 860-082 and OAR 860-039.

The work group agreed to replace the Commission's interconnection rule exception that allows utilities to designate limited generation feeders with the Substation Transformer Backfeed Screen.[35] When adopting these rules, the Commission should also explicitly rescind the ill-defined limited generation feeder process.

VI. OAR 860-082 and OAR 860-039 should use the same eligibility threshold for Tier 1 projects.

The work group agreed that inverter-based DER with an export capacity up to 25 kW and nameplate rating up to 50 kW may use the simplified and expedited screening process for small DERs, called Tier 1 in Staff Proposal OAR 800-082-0045.[36] The Commission's net metering rules also include a simplified and expedited screening process for small DERs,[37] however the Staff Proposal OAR 860-039-0030(1)(b) only allow DER with "a capacity of 25 kW or less" to use NEM Tier 1. Under the staff proposal, the NEM Tier 1 projects will be evaluated using the screens found in Staff Proposal OAR 800-082-0045.[38] There is no technical reason to treat NEM projects differently from other DERs, particularly when the evaluation will use the

[35] Staff Proposal OAR 800-082-0045(2)(b), 0050(2)(a), 006X(2)(b)(D).

[36] Staff Proposal OAR 800-082-0045(1)(a).

[37] Staff Proposal OAR 800-039-0030.

[38] Staff Proposal OAR 800-039-0030(2).

same screens. IREC recommends allowing NEM projects with an export capacity up to 25 kW and nameplate rating up to 50 kW to use Tier 1 by modifying OAR 860-039-0030(1)(b) to read:

> The facility has an export capacity of 25 kilowatts or less and a nameplate rating of 50 kilowatts or less.

VII. The Commission should adopt the Staff Proposal's recommendations concerning supplemental review, the feasibility study, and IEEE 1547-2018.

In this section, IREC addresses the utilities' concerns about the supplemental review penetration screen and making the feasibility study optional, and supports the Staff Proposal's IEEE 1547-2018 implementation process.

A. Utilization of a 100% of minimum load screen is well-established and has a long track record of adequately protecting safety and reliability when applied in conjunction with the other supplemental review screens.

The Staff Proposal includes a supplemental review process with three screens that are designed to be applied together to determine whether a project requires further study after failing one or more of the Tier 1 or 2 screens. The first screen, known as the penetration screen, evaluates whether the additional export capacity from the project will exceed 100% of the minimum load on the feeder or line section. In the Joint Utilities' October 23, 2022 comments, they oppose the utilization of 100% of minimum load, instead preferring to use 90% of minimum load. The Commission should adopt the Staff Proposal and reject the Joint Utility's proposal as unnecessary to protect system safety and reliability.

The Staff's Proposal is based upon a now very well established framework that has been adopted by the Federal Energy Regulatory Commission (FERC)[39] and over ten states, including most of the high penetration DER states in the country such as California, New York,

[39] Federal Energy Regulatory Commission, Small Generator Interconnection Procedures § 2.4, https://ferc.gov/sites/default/files/2020-04/sm-gen-procedures.pdf.

Massachusetts, and Colorado.[40] California first adopted use of a supplemental review process with the 100% of minimum load screen over a decade ago and innumerable solar projects have since been safely interconnected using this screen across the country without any record of safety or reliability issues as a result.

The Joint Utilities primary argument against the use of the 100% of minimum load threshold relies on a mischaracterization of how supplemental review is intended to function and the protections already built into that process. The penetration screen is only the first screen in the supplemental review process, projects that pass that screen are then subject to both the voltage and power quality screen *and* the safety and reliability screen. Before a project can be interconnected without going to the full study process, *it has to pass all three screens*.[41] Nonetheless, the Joint Utilities state that if an applicant passes the penetration screen "the utility is required to automatically approve the interconnection without any additional study."[42] Oddly, they bury in a footnote the fact that the project actually has to pass ALL the screens, and despite

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[40] To IREC's knowledge, at least the following jurisdictions have adopted a supplemental review process using a 100% of minimum load screen: Arizona, California, Colorado, Illinois, Iowa, Minnesota, Michigan, New Mexico, New York, Ohio, and Washington, DC. AZ Admin. Code § R14-2-2620(E)(1)(a); Pacific Gas & Electric Co., Rule 21, Sheets 152-155; 4 CO Code Regs. § 723-3855(d); 83 IL Admin. Code § 466.100(f)(4)(A), IA Admin Code § 199-45.9(6); MN Pub. Util. Comm., Dkt. E-999/CI-16-521, Order Approving Tariffs with Modifications and Compliance Filings, Distributed Energy Resources Interconnection Process (MN DIP) § 3.4.4.1; MI Admin. Code R460.901a, Rule 50(6)(a); NM Code R. § 17.9.568.16; NY Pub. Service Comm., Standardized Interconnection Requirements and Application Process for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems, Appendix G, at 3 (May 1, 2022) (NY SIR); OH Admin Code § 49-1:1-22-07(c); DC Mun. Regs. tit 15 § 4011(a).

[41] *See* FERC Order 792 at 82-85 (Repeatedly emphasizing the relationship between the three screens and the ability of the other two screens to address concerns associated with using a 100% of minimum load threshold.).

[42] Joint Utilities Oct. Comments at 9-10.

clearly having this awareness, they go on to repeat their mischaracterization multiple times.[43] The fact that the project has to go through the other screens is not a minor point, the other two screens are designed expressly to address the concerns the utilities are raising, and are a crucial reason why it would be inappropriate to lower the threshold for the penetration screen.

The two additional supplemental review screens are designed to provide the utilities with the exact opportunity they seek: to ensure that there is adequate evaluation of whether allowing a project to interconnect up to that threshold might trigger any specific voltage, power quality, safety, or reliability issues.[44] The other screens merely obligate the utility to identify the specific technical concern they have about a project; this is a reasonable expectation and a well-founded compromise now utilized widely across the United States.

It is also important to recognize that the 100% of minimum load threshold is not nearly as risk-laden as the utilities' characterization. First, it is not necessarily the case that generation exceeding load will cause any system safety or reliability issues. It can be safe and even desirable to allow backfeed on radial distribution circuits if this means power can serve other

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[43] *Id.* at footnote 8 ("The applicant would also need to pass the other Supplemental Review screens before the application would be approved."); *id.* at 10 (repeatedly using the term "automatic approval" and characterizing the screen as having no buffer despite the existence of the other two screens).

[44] FERC Order 792 at 81-82 ("We appreciate the concerns of Transmission Providers with regard to the Minimum Load Screen, but believe that the Minimum Load Screen is sufficiently conservative, *particularly when viewed together with the other two supplemental review screens*. Taken as a whole, the supplemental review screens provide the flexibility to identify circumstances when additional studies may be required while avoiding an unjust and unreasonable increase in expense and delay in interconnection. That is, *the three screens in the supplemental review are designed to strike a balance* between handling the increased volume of interconnection requests and penetrations of small generators and maintaining the safety and reliability of the electric systems.") (emphasis added).

nearby customers. This is regularly done across the country.[45] Rather than 100% of minimum load being "the limit" after which safety issues will necessarily occur, it should be seen as an appropriate threshold only after which study should be required.

It is true that subsequent changes in load could cause the amount of generation on a feeder to exceed the load at some point in the future. This would be true at 90%, 80% or even a lower threshold. The additional supplemental review screens are designed to allow the utilities to identify if there is a particularly high risk of load changes.[46] There is also some natural "buffer" built into the screen as it is unlikely that all the interconnected generators will be operating at the absolute maximum of their proposed output simultaneously, particularly where some of the systems installed on a feeder are behind-the-meter and may be serving a portion of onsite load at any point.

The Joint Utilities raise other more specific technical concerns associated with PGE's use of high-speed reclosing and the interaction with inverter response time when detecting the presence of the formation of an unintentional island.[47] While IREC is not persuaded that the Joint Utilities have properly characterized the risks associated with the speed of island detection, again, the proper approach is to rely on the application of the two other supplemental review

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[45] For example, for many years now Hawaii has increased its threshold for transient overvoltage from 120% to 250% of minimum load, relying on the capabilities of advanced inverters to detect and manage overvoltage concerns from loss of load. *See* HI Pub. Util. Comm., Dkt. 2014-0192, Hawaiian Electric Companies' Motion for Approval of NEM Program Modification and Establishment of Transitional Distributed Generation Program Tariff, at 16-20 (Jan. 20, 2015), https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15A20B13419D27829.

[46] For example, one of the elements the utility can consider in applying the Safety and Reliability Screen is: "Whether the Line Section has significant minimum loading levels dominated by a small number of customers (i.e., several large commercial customers)." Staff Proposal OAR 860-082-006X(2)(C)(A).

[47] Joint Utilities Oct. Comments at 11.

screens to address this concern.[48] Since fast reclosing is not utilized on all circuits in Oregon, it is not necessary to build in protections for this scenario for all projects by lowering the penetration screen threshold. Rather, where this scenario is of concern, the utilities can flag the issue and propose a solution during the application of the voltage and power quality or safety and reliability screens.

The Commission can be assured that adoption of a 100% of minimum load threshold is safe and reasonable. The balance of the supplemental review screens provides ample opportunity for additional evaluation and enables the utilities to send a project on for further study if they identify a specific concern using those screens. It is also reasonable for the Commission to rely on the ample record of this screen's use in many states. Indeed, in some states, a 100% of minimum load screen is now used directly in the equivalent Tier 1 and Tier 2 screens,[49] where a project can proceed to an interconnection agreement even without application of the additional supplemental review screens. The Staff's Proposal is well supported and should be adopted.

[48] The Joint Utilities cite a Sandia National Lab paper for the assertion that "island detection can significantly slow down due to the interaction of the island detection from various inverters." Joint Utilities Oct. Comments at 11. However, they provide no page citation and IREC does not agree that this is a relevant conclusion to draw from the Sandia paper. While IEEE 1547 allows un-intentional island run-on times to be up to 2 seconds, anti-islanding functions can act faster, and the paper noted scenarios of when the functions did so. The minimum run-on time noted in the paper was 0.26 seconds, which is longer than the reclose time noted by the utilities. *Id*. ("In other words, when a fault occurs, the recloser will open and then close within approximately 0.2 seconds"). Therefore, it is not relevant that run-on times increase further due to the interactions of various inverters. In any scenario, PGE would need to ensure coordination between high-speed reclosing at 0.2 seconds and inverter tripping.

[49] Admin. R. MT 35.8.8410(2)(a); MN DIP § 3.2.1.2; 83 IL Admin. Code § 466.100(a)(1); NM Admin. Code § 17.9.568.16(B)(2).

B. Feasibility studies are not necessary for all projects and it is appropriate to allow the customer to determine if it will benefit from the study in light of the additional time and cost.

A feasibility study is the first in a series of three studies that the current interconnection rules use to assess project impacts. While feasibility studies were originally included in the FERC's Small Generator Interconnection Procedures, and a number of states incorporated them into their state rules, many states never included the option for this third study,[50] and states with that option have begun to eliminate the study[51] or make it optional only by customer agreement.[52] The Staff Proposal includes making the feasibility study optional at the customer's request and IREC supports this proposal: customers should be able to determine whether they will benefit from a feasibility study. IREC would also support elimination of the feasibility study altogether, as recommended by the National Renewable Energy Laboratory as an effective method of streamlining the study process.[53]

The additional time and costs associated with a feasibility study could be considerable and it is reasonable for a customer to be able to determine if they would prefer to proceed directly to the more costly system impact study. The customer options meeting provides the opportunity for the customer to discuss these options with the utility, and for the customer to

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[50] For example, California, Massachusetts, Minnesota and New York have never had a feasibility study in their rules. See *e.g.*, Pacific Gas & Electric Co., Rule 21, Sheets 75-135; National Grid US, Standards for Interconnection of Distributed Generation, Sheets 13-30, https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/mdpu_1468_dg_interconnection_tariff_.pdf; NY SIR.

[51] North Carolina and South Carolina have eliminated the feasibility study. See *e.g.*, NC Util. Comm., Dkt. E-100 Sub 101, Interconnection Procedures, Forms, and Agreements, at 32-48 (October 11, 2021); Duke Energy Progress, LLC, South Carolina Generator Interconnection Procedures, Forms, and Agreements, at 17-19 (April 26, 2016).

[52] See, *e.g.*, 83 IL Admin. Code § 466.120; NM Code R. § 17.9.568.18(B)(2).

[53] Kevin Fox et al., *Updating Small Generator Interconnection Procedures for New Market Conditions*, at 31-37, (Dec. 2012) http://www.nrel.gov/docs/fy13osti/56790.pdf.

make an informed choice about whether they would benefit from understanding the overall feasibility of a project before proceeding to the more in-depth system impact study. Customers also have considerably more information available to them to help evaluate project feasibility thanks to the creation of pre-application reports, the publication of distribution system data on OASIS, and hopefully, eventually, hosting capacity analyses.

IREC proposed making the feasibility study optional in redlines distributed to the service list on November 23, 2022.[54] In the five months since then, the utilities have had ample time to consider this approach, discuss their concerns in workshops, and make arguments in written comments. Therefore, there is no benefit for the Commission in delaying this conversation to a later date. The Commission should enable customers to determine whether the feasibility study will benefit their project considering the complexity of the interconnection and the anticipated time and costs associated with the study. There are no safety or reliability impacts associated with waiving the feasibility study as the system impact study (which is not waivable at the customer's sole discretion) will thoroughly analyze the project impacts.

C. The Staff Proposal's process to implement IEEE 1547-2018 and interconnection requirements handbooks is reasonable.

IREC supports the IEEE 1547-2018 implementation process found in the Staff Proposal OAR 860-082-0030(1). When considering how to implement technical standards such as IEEE 1547-2018, the Commission must consider the balance between establishing uniform statewide technical standards in the rule and allowing utilities to set different technical requirements for how DERs operate. The Staff Proposal strikes an appropriate balance by specifying important technical requirements, including for abnormal performance and normal performance, in rule,[55]

[54] IREC Discussion Draft Redline to OAR 860-082 (Nov. 23, 2022).

[55] Staff Proposal OAR 860-082-0030(1)(a).

while requiring utilities to specifically define other preferred default settings in published interconnection requirements handbooks.[56]

IREC supports the interconnection requirements handbooks proposal because stakeholders are provided the opportunity to review, provide feedback on, and raise to the Commission objections on the contents of interconnection requirements handbooks before the handbooks go into effect.[57] While IREC is not concerned about the name given to such a document, with the implementation of IEEE 1547-2018 it is important for each utility to publicly post specific preferred default settings for DERs. This provides customers certainty that they will not need to redesign their DER using different settings after submitting an interconnection application.

While IREC supports the Staff Proposal, IREC would also support the more informal approach for interconnection handbook review proposed by the Interconnection Trade Associations to the service list on February 14, 2023 and at the subsequent workshop.[58] Specifically, IREC can support any process where interested persons can review handbook

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[56] Staff Proposal OAR 860-082-0030(1)(c)(A)-(E).

[57] Staff Proposal OAR 860-082-0030(1)(b).

[58] Recommendation of the Interconnection Trade Associations in UM 2111 (Feb. 14, 2023) ("The utilities would conduct a notice and comment process with their updated interconnection handbooks. The utilities would be required to file the updated interconnection handbook with the [Commission], publicly post the proposed changes and the date for submission of comments, and provide actual notice to all interconnection customers or applicants. The Interconnection Trade Associations recommend 60 days. After the 60 days, if no interested party has challenged the updated interconnection handbook, then the utility would be allowed to make the changes to its handbook without a determination on the legality or reasonableness of the requirements. If an interested party did challenge the updated interconnection handbook, then it would go to the Commission for a formal determination on the objections before the utility was allowed to make changes to its interconnection handbook.").

revisions and raise objections to the Commission, then if objections are lodged than the Commission must make a formal determination before the revised handbook becomes effective.

In addition, IREC strongly supports the Interconnection Trade Associations' proposal limiting upgrades to those that bring the distribution system to a normal performance standard found in an interconnection handbook. To accomplish this, IREC suggests adding the following sentence to the end of Staff Proposal OAR 860-082-0030(1)(b):

> Public Utilities may only require interconnection upgrades that bring the distribution system to a normal performance standard standard listed in their interconnection handbook, unless the upgrade relates to safety, reliability, or an adverse system impact.

IREC also supports the Interconnection Trade Associations' suggestion for a process for interested persons to suggest updates to handbooks that reflect new technical methods or approaches to interconnection design.

Finally, to ensure the rule is internally consistent, IREC suggests updating all dates originally listed as July 1, 2023 to January 1, 2024, matching the work group's most recent decision for the implementation date.

VIII. Conclusion

IREC thanks the Commission for the opportunity to provide these comments and strongly supports adopting the Staff Proposal with the revisions described herein.

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