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PACIFIC POWER
A DIVISION OF PACIFICORP

March 30, 2025

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: UM 2111/AR 659—PacifiCorp's Oregon Distribution Interconnection Handbook Update

In accordance with Order No. 24-068, PacifiCorp d/b/a Pacific Power hereby submits for filing the attached Update to the Oregon DER Interconnection Handbook and share draft amendments. Below are the following proposed changes as listed in the Update:

Section 1.2 Disconnect Switch

- Added language about what PP will require for solar + battery or battery only projects
  - Applies to net metering customers only
- Added Appendix B – Net Metering Solar and ESS Disconnect Requirements
  - Added figures B1 & B2 showing what is required

Section 4.1.1 UL 1741 SB Certified Inverter Systems

- New section in handbook
  - Aligned with Policy 138
    - Any three phase DER 500 kW or greater will require a utility grade relay
    - IBR greater than 2500 kW will require three phase interrupting device such as a recloser
    - Three phase DER located within a wildfire risk zone will require a relay
    - Inverters do not require separate synchronizing equipment

Section 4.1.2 Synchronous Generators, Induction Generators and Non-UL1741/UL 1741 SB Certified Inverter Systems

- New section in handbook
  - Aligned with Policy 138
    - Any generation will require a relay and interrupting device
    - Effective grounding is required when aggregate generation exceeds 10% of the area EPS
    - Automatic synchronizing is required
    - Must meet applicable ANSI and IEEE standards
    - Must operate within the full range of voltage and frequency excursions on the PAC system
    - Must operate within frequency ranges shown in Table 7

Section 4.2.1 Winding Configuration

- Replaced existing table with updated table from Policy 138

Section 4.2.2 Grounding Transformer

- Replaced "Grounding Transformer" with "Effective Grounding"
    - This aligns with Policy 138
- Added "All conditionally acceptable transformer winding configurations shall require the installation of a grounding bank."

Section 4.4.1 Dead Line Check

- Replaced "dead line check" with "hot line block"
    - They both mean the same thing and this aligns the handbook with Policy 138

Section 4.4.2 Direct Transfer Trip

- Updated IBR requirements that came from Policy 138
    - Changed the 90% of circuit minimum load to 80% of substation transformer minimum load
    - Added language that says that only IBR greater than 500 kW can be required to have DTT
    - Non-IBR can have DTT no matter the size if it exceeds 80% of the substation minimum load

Section 5.6.1 Voltage Trip Settings and Ride-through

- Updated Table 6 to align with Policy 138

Section 5.6.2 Frequency Trip Settings and Ride-through

- Updated Table 7 to align with Policy 138

Enclosed with this filing is the Interconnection Handbook 2026 Update in its entirety. PacifiCorp respectfully requests the Commission approve its proposed revisions. If you have any questions about this filing, please contact Amira Thompson, State Regulatory Affairs Manager, at (503) 260-4420.

Sincerely,

Robert Meredith
Director, Regulation

Enclosures

PACIFIC POWER®
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Pacific Power
Oregon
Distribution Interconnection Handbook

March 2026

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Introduction

This Oregon Distribution Interconnection Handbook (Handbook) is a resource for Oregon customers of PacifiCorp, dba Pacific Power, (PacifiCorp or Pacific Power) proposing to interconnect net metering facilities or Oregon- jurisdictional generators under the Public Utility Commission of Oregon's (Commission) Division 39 net metering rules and Division 82 interconnection rules.

If Pacific Power prospectively proposes revisions to this Handbook, Pacific Power will provide: (1) public notice on its website, including the Open Access Same-Time Information System (OASIS) website, and (2) email notice to the parties listed on the "notification list" listed in this Handbook. Pacific Power will provide a minimum of 30 days for interested persons to comment on any proposed revisions. Pacific Power will then respond within 30 days to any comments received and make its responses public.

Additional resources are available on Pacific Power's website that provides more in-depth and technical information to allow for interconnection. Policy 138 is PacifiCorp's Distributed Energy Resource (DER) Interconnection Policy that provides the technical interconnection requirements for distribution level customers served by Pacific Power and Rocky Mountain Power in California, Idaho, Oregon, Utah, Washington, and Wyoming.[1]

Facilities that are not covered in this document are those:

1. Interconnecting to Pacific Power's high-voltage transmission system and under the jurisdiction and requirements of the Federal Energy Regulatory Commission (FERC).

2. Interconnecting to the Pacific Power system but under the jurisdiction and requirements of FERC due to their wholesale market sales of electricity.

3. Interconnecting to the Pacific Power system for DERs larger than 20 megawatts (MW) in nameplate capacity and not selling electricity on a wholesale basis. Such DERs follow Oregon Standard Interconnection Procedures and Agreements Adopted for Large Qualifying Facilities (QFs) in Commission Order Nos. 20-268 and 24-036.

1 Net Metering Requirements Summary

Oregon Administrative Rules (OAR) 860-039-0010 through 860-039-0080 establish rules governing net metering facilities interconnecting to a public utility as required under Oregon Revised Statutes (ORS) 757.300. The information provided in this section of the Handbook is intended to be used during the application and review process, as well as to provide a summary of requirements.

1.1 *Definitions*

A complete set of definitions can be found in OAR 860-039-0010.

1.2 *Disconnect Switch*

For customer services of 600 volts or less, a disconnect switch is required for a net metering facility that is inverter-based with a maximum rating as shown in the table below.

[1] PacifiCorp serves customers in California, Oregon, and Washington as Pacific Power and in Idaho, Utah, and Wyoming as Rocky Mountain Power.

Service Type	Maximum Size (AC)
240 V, single phase, 3 wire	7.2 kW
120/208 V, three phase, 4 wire	10.5 kW
277/480 V, three phase 4 wire	25.0 kW

Table 1: AC disconnect switch requirements.

For other service types, the net metering facility must not impact the customer-generator's service conductors by more than 30 amps.

The disconnect switch shall be within 10 feet of the utility meter, however, may be more than 10 feet from the public utility meter if permanent instructions are posted indicating the disconnect switch's precise location. The public utility must approve the disconnect switch location prior to the net metering facility installation.

The customer-generator's electric service may be disconnected by the public utility entirely if the net metering facility must be physically disconnected for any reason.

For net metering customers that have solar generation paired with an energy storage system (ESS) the disconnect switch(es) must isolate the generation from the customer's load and service from the utility. The Customer's load must remain energized by the Utility at all times. This also applies to net metering customers with standalone energy storage systems. Figure B1 shows PacifiCorp's preferred disconnect design that allows a rapid shutdown device (RSD) or emergency power off (EPO) switch to isolate the generation from the Customer's load and Utility service. If the Customer's equipment does not allow for the preferred design, Figure B2 shows an alternative design that has a typical AC knife-blade type switch for the solar and/or the ESS. Any disconnect exception request made by the Customer must be approved by PacifiCorp personnel.

1.3 *Net Metering Interconnection Review Tiers*

Net metering interconnection review tiers help tailor polices for different system sizes to encourage interconnection adoption and maintain grid stability. Each tier has differing screens and requirements for interconnection approval.

1.3.1 Tier 1

Tier 1 is the most common interconnection review for residential and small commercial interconnections. To be eligible for a Tier 1 interconnection review, the facility must be inverter-based and have a generation capacity of 50 kilowatts or less and an export capacity of 25 kilowatts or less. It must also pass a number of screens. If any of the screens fail, the interconnection will then pass to the Tier 2 review.

A complete text of the rule can be found at OAR 860-039-0030.

1.3.2 Tier 2

To meet the Tier 2 interconnection review requirements, a net metering facility must have a capacity of two (2) MWs or less and does not qualify for Tier 1 interconnection review procedures. A complete text of the rule can be found at OAR 860-039-0035.

1.3.3 Tier 3

There is no Tier 3 interconnection review for net metering customers.

1.3.4 Tier 4

To meet the Tier 4 interconnection review requirements, a net metering facility must have a capacity of two (2) MWs or less and does not qualify for or failed to receive approval in Tier 1 or Tier 2 interconnection review procedures. A complete text of the rule can be found at OAR 860-039-0040.

2 Small Generator Interconnection

OAR 860-082-0005 through 860-082-0085 establish rules governing small generation facilities 10 MW or less interconnecting 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 FERC.

2.1 *Definitions*

A complete set of definitions can be found in OAR 860-082-0015.

2.2 *Pre-Application Process*

A complete text of the rule can be found at OAR 860-082-0020.

Pacific Power will designate an employee or office from which relevant information about the small generator interconnection process, Pacific Power's transmission or distribution system, and affected systems may be obtained through informal requests for a potential applicant proposing a small generator facility at a specific site. Pacific Power will post contact information for the employee or office on Pacific Power's website. The information provided by Pacific Power in response to a potential applicant's request will, as applicable, include relevant existing studies and other materials that may be used to understand the feasibility of interconnecting a small generator facility at a particular point on the Pacific Power's transmission or distribution system. Pacific Power will comply with reasonable requests for access to or copies of such information, except to the extent that providing such materials would violate security requirements, confidentiality obligations to third parties, or be contrary to federal or state regulations. Pacific Power may require a person to sign a confidentiality agreement if required to protect confidential or proprietary information. For a potential small generator facility requiring Tier 4 review, and at the potential applicant's request, Pacific Power will meet with the potential applicant to exchange information. A Pacific Power employee with relevant technical expertise will attend any such meeting.

A person requesting information as part of the pre-application process must reimburse Pacific Power for the reasonable costs of gathering and copying the requested information.

2.3 *Small Generator Interconnection Review Tiers*

Small generator interconnection review tiers help tailor policies for different system sizes to encourage interconnection adoption and maintain grid stability. Each tier has differing screens and requirements for interconnection approval.

2.3.1 Tier 1

To be eligible for a Tier 1 interconnection review, a small generator facility must be inverter-based and have a generation capacity of 50 kilowatts or less and an export capacity of 25 kilowatts or less. The facility must not be interconnected to a transmission line or area network. A complete text of the rule can be found in OAR 860-082-0045.

2.3.2 Tier 2

To meet the Tier 2 interconnection review requirement, a small generator facility must be inverter-based that does not meet the Tier 1 screening requirement or if the generation export capacity doesn't exceed the limits in OAR 860-082-0050(1) Table 1. A complete text of the rule can be found in OAR 860-082-0050.

2.3.3 Tier 3

To meet the Tier 3 interconnection review requirement, a small generator facility must have a nameplate capacity of two (2) MW or less and must not be interconnected to a transmission line. Also, the facility must not export power beyond the point of interconnection and must use low forward power relays or other protection functions that prevent the flow of power beyond the point of interconnection. A complete text of the rule can be found in OAR 860-082-0055.

2.3.4 Tier 4

To meet the Tier 4 interconnection review requirement, the small generator facility must have a capacity of 10 MW or less and does not qualify or failed a Tier 1, Tier 2, or Tier 3 interconnection review. A complete text of the rule can be found in OAR 860-082-0060.

2.4 *Supplemental Review*

OAR 860-082-0063 adds an option for the supplemental review and provides the process to follow for interconnection application review.

The Supplemental Review refers to an additional evaluation process related to interconnection applications that offers more detailed and concise screens. To begin the supplemental review process, the applicant must submit a signed copy of the Supplemental Review Agreement and pay a supplemental review fee of $1,000, both within 10 business days of the offer. If the written agreement and fee have not been received within that timeframe, the Application will be deemed withdrawn unless the applicant has notified Pacific Power that they wish to continue being evaluated under the Tier 4 review procedures.

Within 20 business days of an applicant's election to undergo supplemental review, Pacific Power will perform supplemental review using the screens set forth in OAR 860-082-0063(2)(a)-(c),

notify the applicant of the results, and include with the notification a written report of the analysis and data underlying Pacific Power's determinations under the screens.

If the proposed interconnection passes the supplemental screens, Pacific Power will approve the application, and the Applicant will receive an executed Interconnection Agreement pursuant to the procedure set forth in OAR 860-082-0025(7)(e).

After receiving an Interconnection Agreement executed by Pacific Power, the Applicant must proceed under the terms of the applicable level of review under which the application was initially studied.

Applicants undergoing Supplemental Review will be able to access, review, and verify minimum load calculations except in cases where the minimum load data contain identifiable individual customer data.

2.5 *Export Controls*

OAR 860-082-0033 establishes requirements for use of export controls for small generator facilities.

2.5.1 Non-exporting small generator facility

Acceptable control methods for a non-exporting facility must include one of the following: reverse power protection (device 32R), minimum power protection (device 32F), or use a relative DER rating which requires the facility's nameplate rating to be so small in comparison to the facility's minimum load that the use of additional protective functions is not required to ensure that power will not be exported to the electric distribution system. Other options include the use of a certified power control system, or by an agreed upon means between the Applicant and Pacific Power. Please refer to OAR 860-082-0033(3)(a)-(c) for a complete text of the rule.

2.5.2 Limited export small generator facility

Acceptable control methods for a limited export facility must include one of the following: directional power protection (device 32), a configured power rating utilizing the power configuration setting to ensure the facility does not generate power beyond a certain value lower than the nameplate rating, use of a certified power control system, or by an agreed upon means between the Applicant and Pacific Power. Please refer to OAR 860-082-0033(3)(b) and (c) for a complete text of the rule.

2.6 *Export Controls and High-Speed Reclosing*

When a project is located on a circuit using high-speed reclosing, the project must be capable of taking the generation offline within 0.1 seconds to coordinate reclosing timing with the tripping speed of affected DER in an effort to avoid equipment damage and prevent unacceptable stresses or disturbances on the system. At the time of this handbook publication, there are no commercially available inverters that are UL certified to take the generation offline within 0.1 seconds and able to detect fault conditions on the high side of the step-up transformer, and therefore no inverter specifications or options will satisfy the requirement without the need for

additional equipment. As inverter technologies advance and as Pacific Power periodically reviews and updates this handbook, Pacific Power will assess whether inverter specifications have advanced to the point where an inverter setting or option may satisfy the requirement to take the generation offline within 0.1 seconds. Until that time, projects seeking to interconnect to a circuit using high-speed reclosing will be required to install protective equipment. The specific equipment that will be required must be assessed on a case-by-case basis, but can include protective relays, reclosers, and/or direct transfer trip.

To ensure there is no inadvertent export before the interrupting device closes back in, Pacific Power will allow the following options:

2.6.1 Primary Metered DER

For primary metered DER projects, Pacific Power requires the installation of a breaker or recloser with protective relays on the customer side of the interconnection. An example of this is shown in Policy 138, Figure C1 of Appendix C.

2.6.2 Non-Primary Metered DER

For non-primary metered inverter based DER projects, Pacific Power requires a UL certified power control system (PCS) that meets Pacific Power requirements. If not available, a reverse power relay (860-082-0033(3)(a)(A)) or an agreed upon means between the applicant and Pacific Power shall be required.

3 Oregon Community Solar Program

The Oregon Community Solar program gives customers an option to receive utility bill credits in exchange for buying or leasing part of a community solar project. Community solar projects are large solar systems and can be located on buildings – like businesses, government buildings, schools or churches – or they can be free-standing solar arrays in an undeveloped area.

Project managers develop and build community solar projects, and customers can subscribe to part of a project to receive credits on your electric bills.

For more information, please visit oregoncsp.org.

4 Equipment Requirements

Pacific Power's Policy 138 is the distribution DER interconnection document that encompasses all of PacifiCorp's customers in six states that include California, Idaho, Oregon, Utah, Washington, and Wyoming. The following section of this Handbook is intended to reference sections of Policy 138 that pertain to Oregon customers. Please visit Pacific Power's website to view Policy 138.

4.1 *Facility Protective Equipment*

The Interconnection Customer is solely responsible for the protection of Interconnection Customer-owned DER and interconnection equipment.

The DER facility shall be designed and operated in such a manner that there are no noticeable adverse impacts to system voltage, frequency, harmonics, etc.

If adverse issues are identified, the DER facility must take corrective action at its own expense. If the DER facility does not take corrective action or continues to operate the equipment causing interference without restriction or limit, Pacific Power may, without liability, disconnect the DER facility equipment from Pacific Power's distribution system in accordance with an executed agreement.

Additional requirements for all generators, inverter-based DER, synchronous generators and induction generation can be found in Policy 138 Section 3.1.

4.1.1 UL 1741 SB Certified Inverter Systems

IBR interconnections with aggregate inverter nameplate capacity of 500 kW or greater shall install a utility grade microprocessor based multifunction protective relay and circuit breaker capable of interrupting the available fault current. If the step up transformer is configured in a Grounded Wye-Delta arrangement then a three phase interrupting device and utility grade protective relay will be required on the high side of the step up transformer.

Individual IBR with aggregate inverter nameplate capacity of 2500 kW or greater will require the installation of a three phase interrupting device and utility grade protective relay on the high side of the step up transformer. This interrupting device, typically a recloser will be owned, operated and maintained by the Utility at the Customer's expense.

All three-phase IBR regardless of size shall at a minimum require the installation of a low side circuit breaker and utility grade relay when installed within an identified wildfire risk area.

Utility-interactive inverters do not require separate synchronizing equipment. Inverters shall be UL 1741 SB certified for interconnection to the utility grid.

4.1.2 Synchronous Generators, Induction Generators and Non-UL1741/UL1741 SB Certified Inverter Systems

Synchronous Generators, Induction Generators and Non-UL 1741/ UL 1741 SB Certified Inverter Systems shall install a utility grade microprocessor based multifunction protective relay to accomplish required protective functions and a circuit breaker capable of interrupting the available fault current. If the step up transformer is configured in a Grounded Wye-Delta arrangement then a three phase interrupting device and utility grade protective relay will be required on the high side of the step up transformer.

When aggregated generation resources on the area EPS downstream of the nearest interrupting device exceeds 10% of the circuit segment minimum loading effective grounding is required.

Automatic synchronizing is required for all synchronous generating units.

Generating units must meet all applicable ANSI and IEEE standards.

The prime mover and the generator shall be able to operate within the full range of voltage and frequency excursions that may exist on the PacifiCorp system without damage to the equipment.

The generating unit must be able to operate through the specified frequency ranges for the time durations listed in Table 7, to enhance system stability during a system disturbance.

4.2 *Interconnection Transformer*

4.2.1 Winding Configurations

The following winding configuration requirements shall apply where a DER interconnection application requires a transformer replacement or an additional transformer.

Acceptable	Grounded Wye / Grounded Wye < 2500 kW
	Grounded Wye / Delta
Conditionally Acceptable	Delta / Delta
	Delta / Wye
	Delta / Grounded Wye
	Grounded Wye / Grounded Wye >= 2500 kW

Table 2: Transformer Winding Configurations

For non-primary metered Pacific Power customers,, single phase DER must be connected line to neutral and three phase DER must be connected grounded wye/grounded wye, or grounded wye/delta.

4.2.2 Effective Grounding

There are generally two options available to ensure DER facilities do not contribute to transient overvoltage conditions. The first option is to utilize inverters that

comply with the transient overvoltage limits specified in the latest revision of IEEE 1547, Section 7.4.2, figure 3. The second option is to utilize a grounding transformer with an associated relay control system.
All conditionally acceptable transformer winding configurations shall require the installation of a grounding bank. The grounding transformer can be a wye–delta or a zig–zag transformer. In either case, the connection of the grounding transformer must be configured to ensure the grounding transformer is in service when the DER facility is connected to Pacific Power's system and is disconnected when the main DER transformer is disconnected.

Single-phase DER interconnection facilities are to be connected phase-to-neutral on Pacific Power's distribution system.

DER facilities connecting to Pacific Power's primary distribution system can utilize an IEEE 1547-2018 inverter without the need for a grounding bank if each of the following conditions are met:

- The customer owned transformer is connected grounded wye/grounded wye.
- The inverter(s) are UL1741 SB certified.
- The customer will install a low side circuit breaker and relay with appropriate voltage and current sensing to trip all three phases for adverse system conditions. The breaker will need to have stored energy in order to operate in the absence of service voltage.
- A one-line diagram of the interconnection shall be provided to Pacific Power to review that these conditions have been met.

4.3 *Metering*

The general requirements for metering a DER facility are like that of metering electrical retail service from PacifiCorp. The metering requirements are available in Pacific Power's Electric Service Requirements (ESR), chapter 9. Additional information on metering can be found in Policy 138 Section 3.4.

4.3.1 Basic Meter Programs

The standard Pacific Power meter program will include:

- Bi-directional active (MWh) and reactive energy (MVArh)
- Sliding, peak demand (MW) quantities
- Interval MW, MVAr, volt, and amp data

4.3.2 Multiple Generators

When multiple generators are connected at a single Pacific Power Point of Delivery that is aggregated at a nameplate rating of 3 MW and above, additional real-time telemetry metering is required at the Point of Delivery to the Pacific Power system. The DER facility shall have each DER unit metered, and in addition the Point of Delivery will also be metered. See Policy 138 Section 3.6 for details on what data is to be collected.

4.4 *Automatic Reclosing*

4.4.1 Hot Line Block

To restore service after a temporary fault, fault circuit reclosing is enabled after the trip. For the automatic reclosing to be successful, all sources of power must be disconnected from the circuit before the circuit is re-energized.
Hot line block is used to delay the reclose of the fault interrupting device. Hot line block must be installed on circuits when:

- The aggregated photovoltaic IBR DER systems are greater than 90% of the circuit's minimum daytime load and high-speed reclosing is being implemented.
- The aggregated rotating-based DER systems are greater than 33% of the circuit's minimum load.
- The aggregated combined photovoltaic-based DER systems and rotating-based DER systems exceeds 33% of the circuit's minimum load.

4.4.2 Direct Transfer Trip

When aggregated IBR on the area EPS exceeds 80% of the substation transformer minimum loading, a direct transfer-trip (DTT) scheme shall be required for all interconnected IBR with a total aggregate nameplate capacity of 500 kW or greater. Non-IBR shall be required to install DTT when the aggregate generation on the area EPS exceeds 80% of the substation transformer minimum loading.. The transfer-trip scheme will operate between the substation and the DER facility, and may be required between any upstream automatic reclosing device and the DER facility.

The requirement for DTT from the substation or upstream automatic reclosing device such as a line recloser to the Interconnection Customer's fault-interrupting device will be studied on a case-by-case basis. A reliable, high-speed communication system will be required to support the transfer trip circuit. This communication circuit will be over fiber optic or microwave radio system, or by an agreed upon means between the applicant and Pacific Power. The following are some of the situations that dictate the requirements for the transfer trip:

- The circuit's minimum load is less than the potential generation and high-speed reclosing is being implemented.
- The aggregate DER exceeds the substation transformer minimum load.The transfer trip will be keyed for detection of transformer faults.
- The aggregate DER exceeds 80% of the substation minimum load.

5 Smart Inverter Performance Requirements

This section of the Handbook summarizes the requirements for inverter-based DER as stated in the IEEE 1547-2018 standard. The IEEE standard was updated to allow changes for voltage regulation, voltage and frequency response to normal and abnormal conditions among other performance categories. Pacific Power has incorporated IEEE 1547-2018 compatible smart inverter settings and has posted the recommended settings on the company's website and are available for download. Unless explicitly stated by Pacific Power,

all inverter-based DER connecting to the distribution system in Oregon must implement the recommended smart inverter settings.

5.1 *Enter Service Criteria*

Requirements are specified in IEEE 1547-2018 Clause 4.10. These include the allowable voltage and frequency ranges, and performance during entering service. Settings include required capabilities such as active power requirements and delays to enter service. The DER shall enable the permit service settings consistent with the default voltage and frequency settings listed in Table 2 below, unless otherwise specified by Pacific Power.

Enter Service Criteria		**Default Settings**
Permit Service		**Enabled**
Applicable Voltage within Range	Minimum Value	≥ 0.917 p.u.
	Maximum Value	≤ 1.05 p.u.
Frequency within Range	Minimum Value	≥ 59.5 Hz
	Maximum Value	≤ 60.1 Hz

Table 2: Enter Service Criteria

The DER shall delay entry into service by a default minimum of 300 seconds. This requirement shall apply for returning to service after a DER disconnects due to intentional or unintentional tripping.

5.2 *Ramp Rate*

Unless explicitly stated by Pacific Power, the DER shall ramp the active power output with a linear ramp of 300 seconds. See IEEE 1547-2018 Clause 4.10.3(c).

5.3 *Synchronization*

The DER shall parallel and synchronize with Pacific Power in accordance with IEEE 1547-2018 Clause 4.10.4. These requirements provide maximum voltage step changes when synchronizing and synchronization parameter limits.

Aggregate rating of DER units (kVA)	Frequency difference (Δf, Hz)	Voltage difference (ΔV, %)	Phase angle difference ($\Delta\Phi$, °)
0-500	0.3	10	20
>500-1500	0.2	5	15
>1500	0.1	3	10

Table 3: Synchronization parameter limits for synchronous interconnection to an EPS, or an energized Local EPS to an energized Area EPS (IEEE 1547-2018 Table 5)

5.4 *Performance Categories*

The IEEE 1547-2018 standard provides a technology-neutral approach in which performance categories are assigned to specify required capability for reactive power performance, voltage regulation performance, and response to abnormal conditions. Performance categories describe minimum equipment capability and the required ranges of allowable settings. The next two subsections, Normal Operating Conditions and Abnormal Operating Conditions, contain the Oregon and Pacific Power specific application requirements based on the available performance categories defined in IEEE 1547-2018 standard.

5.4.1 Normal Operating Conditions

For categories related to reactive power capability and voltage regulation performance requirements (IEEE 1547-2018 Clause 5):

Category A covers minimum performance capabilities needed for Area EPS voltage regulation and are reasonably attainable by all DER technologies as of the publication of this standard. This level of performance is deemed adequate for applications where the DER penetration in the distribution system is lower, and where the overall DER power output is not subject to frequent large variations.

Category B covers all requirements within Category A and specifies supplemental capabilities needed to adequately integrate DERs in local Area EPSs where the aggregated DER penetration is higher or where the overall DER power output is subject to frequent large variations.

Unless explicitly stated by Pacific Power, all inverter-based generation shall select Category B and all synchronous generation shall select Category A.

5.4.2 Abnormal Operating Conditions

For categories related to response to Area EPS abnormal conditions (IEEE 1547-2018 Clause 6):

Categories I, II, and III differentiate performance requirements for DER response to abnormal conditions.

Category I – Based on essential bulk power system (BPS) stability needs and reasonably attainable by all DER technologies that are in use today.

Category II – Covers all BPS stability/reliability needs and is coordinated with existing reliability standards to avoid tripping for a wider range of disturbances of concern to BPS stability.

Category III – is based on both BPS stability/reliability and distribution system reliability/power quality needs and is coordinated with existing interconnection requirements for very high DER penetration.

Unless explicitly stated by Pacific Power, all inverter-based DER shall select Category III and synchronous generation shall select Category I.

5.5 *Reactive Power Capability and Voltage/Power Control Requirements*

DER causing fluctuating and elevated voltages on the Area EPS beyond the acceptable ANSI C84.1 Range A levels must be mitigated. To assist in mitigation, reactive and active power control functions will be used.

5.5.1 Reactive Power Capability

DER reactive power capability shall be available for use by Pacific Power and compliant with IEEE 1547-2018 Section 5.2 for the applicable performance

category for the specific DER type. Figure H.4 of IEEE 1547-2018 is applicable (Figure 1).

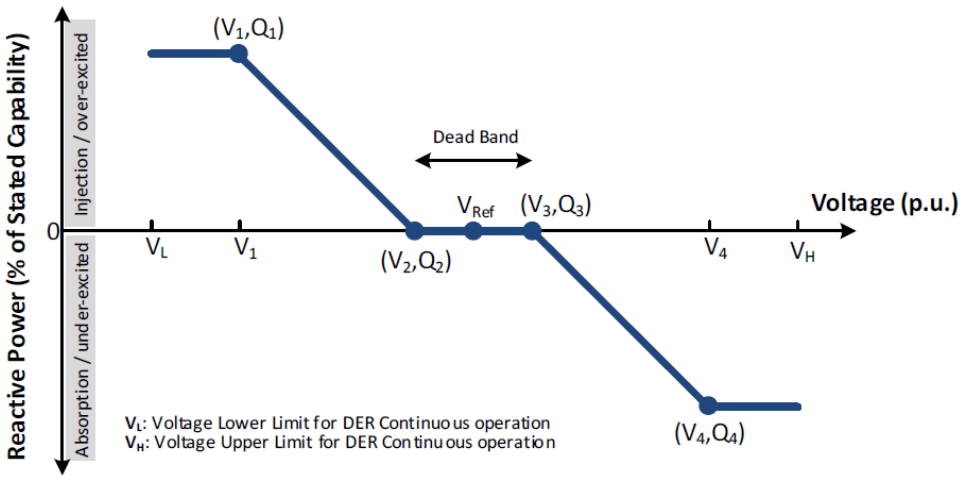


Figure 1: Example voltage-reactive power characteristic

5.5.2 Constant Power Factor

Unless explicitly stated by Pacific Power, the settings for constant power factor (PF) shall be disabled.

5.5.3 Voltage – Reactive Power Control (Volt/Var)

The Voltage-Reactive Power Control shall be enabled, unless otherwise specified in the Interconnection Agreement. The Voltage-Reactive Power mode settings differ slightly for Pacific Power (Figure 2) than the default settings in IEEE 1547-2018 due to substation voltage settings. The Pacific Power volt/var settings will

allow for the DER to delay the regulation while also getting to full regulation at a faster rate.

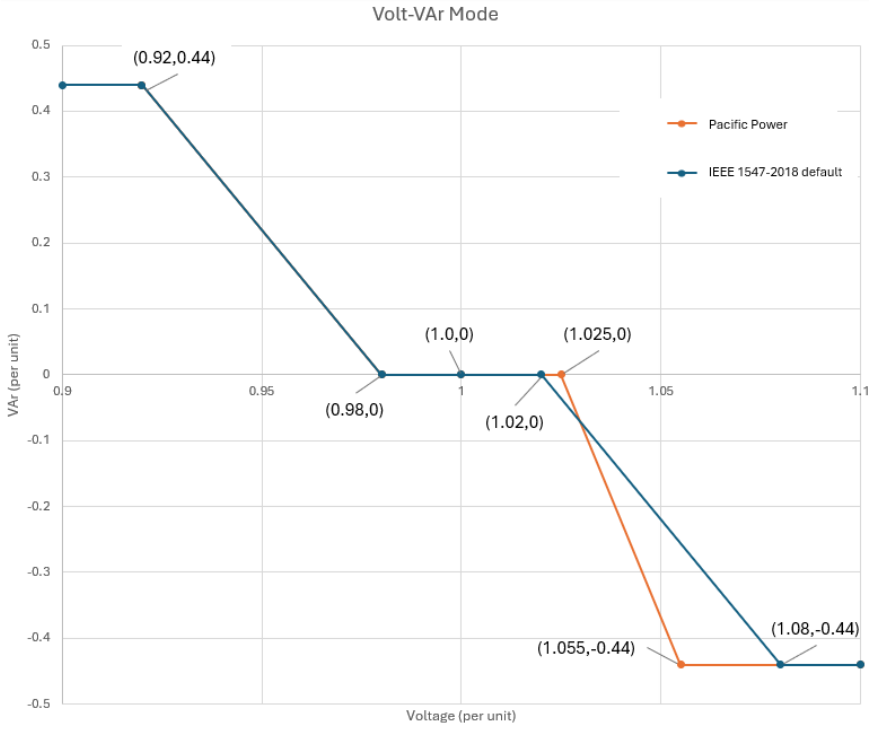


Figure 2: Pacific Power Volt-Var regulation settings

5.5.4 Voltage – Active Power Control (Volt/Watt)

The Voltage-Watt Power Control shall be enabled with the default settings in IEEE 1547 Table 10 (Table 4), unless otherwise specified in the Interconnection Agreement.

Voltage-active power parameters	Default settings	Ranges of allowable settings	
		Minimum	Maximum
V_1	1.06 V_N	1.05 V_N	1.09 V_N
P_1	P_{rated}	N/A	N/A
V_2	1.1 V_N	V_1 + 0.01 V_N	1.10 V_N
P_2 (*applicable to DER that can only generate active power*)	The lesser of 0.2 P_{rated} or P_{min}[a]	P_{min}	P_{rated}
P'_2 (*applicable to DER that can generate and absorb active power*)	0[b]	0	P'_{rated}
Open Loop Response Time	10 s[c]	0.5 s	60 s

[a] P_{min} is the minimum active power output in p.u. of the DER rating (i.e., 1.0 p.u.).
[b] P'_{rated} is the maximum amount of active power that can be absorbed by the DER. ESS operating in the negative real power half plane, through charging, shall follow this curve as long as available energy storage capacity permits this operation.
[c] Any settings for the open loop response time of less than 3 s shall be approved by the Area EPS operator with due consideration of system dynamic oscillatory behavior.

Table 4: Voltage-active power settings for Category A and Category B DER

5.5.5 Active - Reactive Power Control (Watt/Var)

Unless explicitly stated by Pacific Power, the settings for reactive power control (watt/var) shall be disabled.

5.5.6 Constant Reactive Power Control

Unless explicitly stated by Pacific Power, the settings for constant reactive power control shall be disabled.

5.6 *Response to Abnormal Conditions*

Abnormal conditions can arise on Pacific Power's system to which the DER shall appropriately respond. The DER's response contributes to the stability of the system, safety of utility maintenance personnel and the general public, as well as the avoidance of damage to connected equipment, including the DER. IEEE 1547-2018 default settings should be implemented unless otherwise specified by Pacific Power. Tables 4 and 5 show the default voltage settings and Table 5 shows the default frequency settings.

5.6.1 Voltage Trip Settings and Ride-through

Shall-Trip Category I		
Shall Trip Function	**Default Settings**	
	Voltage (p.u. of nominal voltage)	**Clearing Time (s)**
OV2	1.20	0.16
OV1	1.10	2.0
UV1	0.70	2.0
UV2	0.45	0.16

Table 5: Synchronous machines voltage trip settings
(IEEE 1547-2018 Table 11)

Shall-Trip Category III		
Shall Trip Function	**Default Settings**	
	Voltage (p.u. of nominal voltage)	**Clearing Time (s)**
OV2	1.20	0.16
OV1	1.10	2.0
UV1	0.70	2.0
UV2	0.45	0.16

Table 6: Inverter-based voltage trip settings

5.6.2 Frequency Trip Settings and Ride-through

Frequency Trip Settings		
Shall Trip Function	Frequency (Hz)	Clearing Time (s)
OF2	62.0	0.16
OF1	61.0	180
UF1	59.0	180
UF2	57.0	0.16

Table 7: Synchronous & Inverter-based frequency trip settings

Inverter based DER shall comply with the Rate of Change of Frequency (ROCOF) ride-through performance requirements per IEEE 1547-2018 Section 6.5.2.5.

5.7 *Frequency Droop Settings*

The DER shall comply with the frequency-droop requirements for the applicable Abnormal Operating Performance Categories. See IEEE 1547-2018 Table 24 for the default settings.

Parameter	Default settings[a]			Ranges of allowable settings[b]		
	Category I	Category II	Category III	Category I	Category II	Category III
db_{OF}, db_{UF} (Hz)	0.036	0.036	0.036	0.017[c]–1.0	0.017[c]–1.0	0.017[c]–1.0
k_{OF}, k_{UF}	0.05	0.05	0.05	0.03–0.05	0.03–0.05	0.02–0.05
$T_{response}$ (small-signal) (s)	5	5	5	1–10	1–10	0.2–10

[a]Adjustments shall be permitted in coordination with the Area EPS operator.

[b]For the single-sided deadband values (db_{OF}, db_{UF}) ranges, both the lower value and the upper value is a minimum requirement (wider settings shall be allowed). For the frequency droop values (k_{OF}, k_{UF}) ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set to greater values). For the open-loop response time, $T_{response\ (small\text{-}signal)}$, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values). Any settings different from the default settings in Table 24 shall be approved by the *regional reliability coordinator* with due consideration of system dynamic oscillatory behavior.

[c]A deadband of less than 0.017 Hz shall be permitted.

Table 8: Parameters of frequency-droop (frequency power) operation for DER of abnormal operating performance Category I, Category II, and Category III

5.8 *Dynamic Voltage Support*

Unless explicitly stated by Pacific Power, dynamic voltage support shall be disabled. See IEEE 1547-2018 6.4.2.6 for reference.

5.9 *Interoperability Requirements*

Section 10 of IEEE 1547-2018 states that the following is applicable to communications interoperability functions:

DER shall have provisions for a local DER interface capable of communicating (local DER communication interface) to support the information exchange requirements specified in the IEEE 1547–2018 standard for all applicable functions that are supported in the DER.

Under mutual agreement between Pacific Power and DER operator, additional communication capabilities are allowed. The decision to use the local DER communication interface or to deploy a communication system shall be determined by Pacific Power.

Emergency and standby DER are exempt as specified in Section 4.13 in the IEEE 1547-2018 standard.

The application of these requirements will be determined by Pacific Power.

Appendix A – Handbook Notification List

Pacific Power is sending this notice to the service lists for AR 659 and UM 2111. Pacific Power is also sending this notice to the installers pulled from PowerClerk from June 2021 to June 2024. Parties on the notification list will be notified via email of any updates to this Handbook. PacifiCorp's OASIS website will also have information on any updates. The notification list can be updated periodically as a part of the handbook update process. If you would like to opt in and be added to the notification list please send an email with your contact information to the following email: Handbookopt-ins@pacificorp.com

Appendix B – Net Metering Solar and ESS Disconnect Requirements

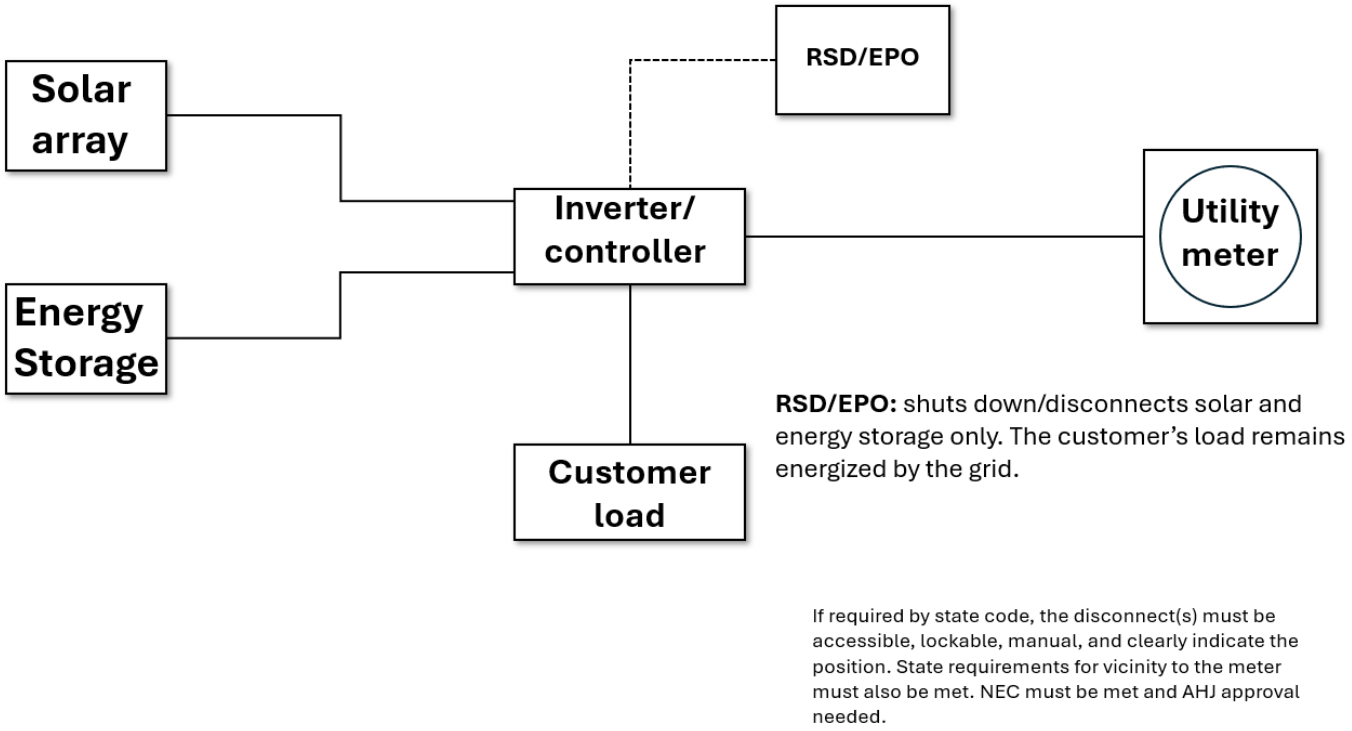


Figure B1 – RSD/EPO Disconnect

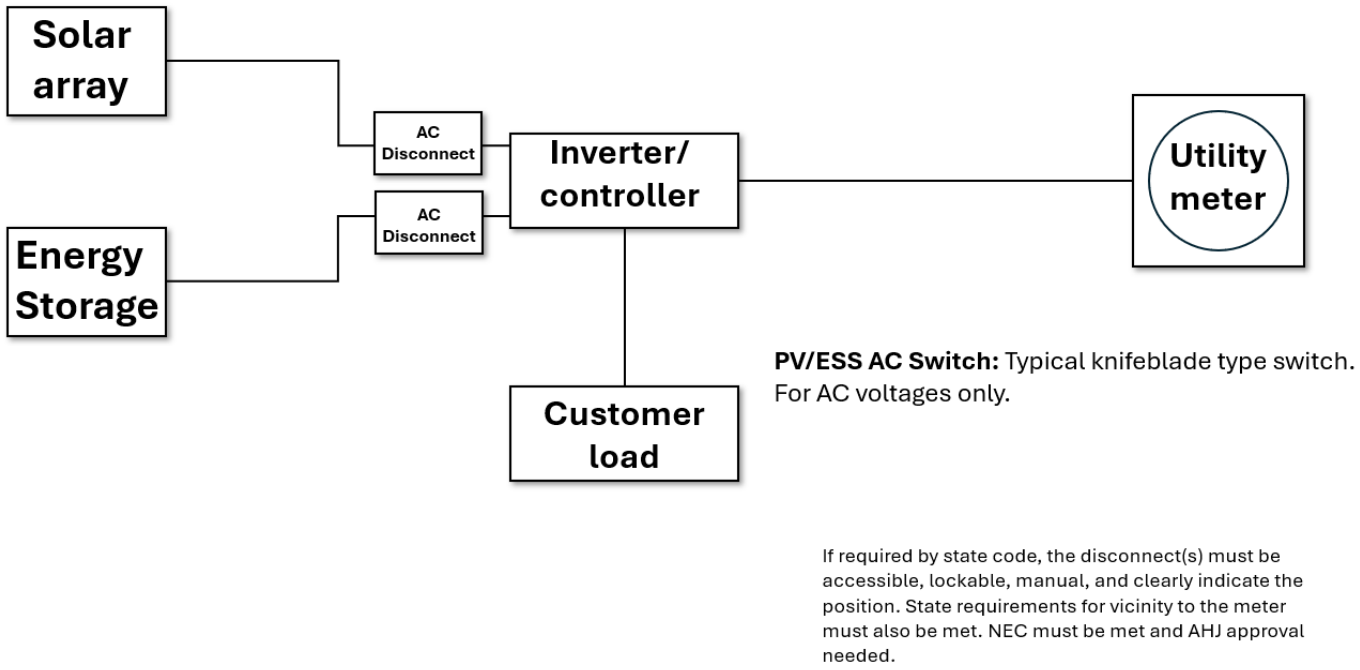


Figure B2 – PV/ESS AC Disconnect