Portland General Electric

Distribution Interconnection Handbook

Release / Revision Version: Version 1.2

Release / Revision Date: 3/29/2023

Document Status: Published

Table of Contents

Figures

Tables

1 Purpose and Scope

Portland General Electric Company (PGE) has prepared this document to describe the process and technical requirements for interconnecting distributed energy resources (DERs) to electrical distribution facilities owned by PGE, the PGE system, and PGE's methods for evaluating compliance with the requirements. These requirements apply to:

- New DERs seeking to interconnect with the PGE system
- The ongoing operation of existing DERs on the PGE system
- Existing DERs seeking to make any changes other than minor equipment modifications as defined in OAR 860-082 (small generator).

In this document, DERs are defined as facilities capable of delivering electric power using generators and energy storage technologies that can be connected directly to the PGE system or connected to a host facility within the PGE system.

Facilities that are not covered in this document are those:

- Interconnecting to PGE's high-voltage transmission system and under the jurisdiction and requirements of the Federal Energy Regulatory Commission (FERC).
- Interconnecting to the PGE system but under the jurisdiction and requirements of FERC due to their wholesale market sales of electricity.
- Interconnecting to the PGE system for DERs larger than 10 megawatts (MW) in nameplate capacity and not selling electricity on a wholesale basis. Such DERs follows Oregon Standard Interconnection Procedures and Agreements Adopted for Large Qualifying Facilities (QFs) in State of Oregon Public Utility Commission (OPUC) Order Number 10-132.

Technical requirements stated herein are substantially based on:

- Interconnection standards 1547-2003, 1547.1-2005, and 1547-2018 of the Institute of Electrical and Electronics Engineers, Inc. (IEEE)
- UL 1741; National Fire Protection Association (NFPA)
- National Electrical Code® (for example, NFPA 70®)
- Reliability standards developed by the North American Electric Reliability Council (NERC) and Western Electric Coordinating Council (WECC)
- Western Power Pool (WPP) principles and practices
- Good utility practices

While this document is intended as a helpful review of PGE's technical requirements, it is not a comprehensive guide to all of the complexities that may arise with interconnecting or operating an individual DER on the PGE system.

With regard to IEEE interconnection standards, PGE reserves the right to follow IEEE 1547-2018 (or later) standards where appropriate to protect the safety and reliability of the PGE system consistent with good utility practice. This allows PGE to operate under the most current and advanced standards, irrespective of whether OPUC interconnection rules set forth in Oregon Administrative Rules (OAR) have yet been updated to adopt the IEEE 1547-2018 (or later) standards at the time PGE applies the technical requirements. Oregon Administrative Rules are laws created by state agencies to implement Oregon statutory law. The majority of utility regulation happens under Chapter 860 of the OAR. Within OAR chapters, there are divisions that apply to certain subjects. For interconnection, there are divisions 039, 082, etc.

An "applicant" or "customer" refers to an entity or person that seeks to interconnect a DER to the PGE system. DER applicants are responsible for adhering to all relevant process and technical requirements for DER interconnection and operation included applicable tariffs; federal, state, and local government laws and regulations; utility industry standards; and interconnection-related documents that applicants sign with PGE, regardless of whether such requirements are explicitly contained or referenced in this document. If there are inconsistencies between this document and federal, state, or local government laws or regulations, or between this document and tariffs filed by PGE or agreements signed with PGE, the respective laws, regulations, tariffs, or agreements control, except where PGE is taking action to protect the safety and reliability of the PGE system in accordance with good utility practice.

This document is intended to summarize the processes pertinent to DERs seeking to interconnect to the PGE system, the technical requirements of such interconnections, and PGE's methods for evaluating the DERs compliance with the requirements. OAR 860-082 (small generator) covers small generator interconnection rules, OAR 860-039 (net metering) covers Net Metering rules, and OAR 860-088 (CSP) and PGE Standards for Interconnection of Community Solar Program Projects cover Community Solar Program (CSP) rules. The applicant is required to meet all timelines in the relevant OAR documents unless PGE and the applicant mutually agree on other timelines. This document does not duplicate the full descriptions of pertinent interconnection processes, rules, and timelines in the OAR documents noted above.

1.1 Overview of System Conformity, Limitations, and Upgrade Cost Requirements

PGE interconnection evaluations of proposed DERs are managed in accordance with applicable laws and regulations, IEEE standards, good utility practice, and other requirements. PGE technical screenings and studies consider issues such as short-circuit capabilities, transient voltages, reactive power requirements, stability requirements, harmonics, asset capacities, safety, operations, maintenance, and good utility practice. New facilities and upgrades are identified in the studies to maintain system design standards and safely accommodate the DER.

Proposed DERs are evaluated to determine effects on the associated PGE feeder, substation, and the connected transmission system, as well as on any affected utility system other than PGE's. The proposed DERs must conform to the existing system limitations based on PGE's power quality and other guidelines. If PGE's interconnection evaluation determines that the proposed DERs impose safety, reliability and power quality risks on PGE's system, the applicant is responsible for the cost of PGE designing and constructing any new mitigating facilities and system upgrades.

The applicant is also responsible for the cost of maintaining and repairing any interconnection-related equipment between its DER and the point of interconnection (POI) for small generator and CSP applications or point of common coupling (PCC) for net metering applications. This includes, but is not limited to, all necessary distribution system and equipment upgrades to accommodate the proposed interconnection, as well as any corresponding communication facilities.

1.2 Overview of Applicant Responsibility for Liability, Insurance, and Easements/Rights of Way

The applicant is liable for any loss, cost claim, injury, or expense arising from any act or omission related to the performance of its interconnected DER. In addition, a small generator or CSP applicant with a DER having nameplate capacity above 200 kW must obtain prudent amounts of general liability insurance in relation to the interconnection at its own expense sufficient to protect PGE or any other party that may be affected by the DER interconnection. That insurance must be maintained over the entire course of the DER interconnection agreement with PGE, and documentation of the insurance coverage must be provided annually to PGE unless otherwise specified in the interconnection agreement.

The applicant is responsible, without cost to PGE, for all easements, rights of way, and permits required for the installation and maintenance of its own DER. These may include easements for above-ground or underground PGE distribution line extensions to the DER. The applicant must acquire a permit from the Authority Having Jurisdiction (AHJ) before its own DER work in the right of way may be performed.

When an easement or right of way is required for the interconnection of the applicant's DER to the PGE system, the applicant must obtain the easement or right of way, whether that easement or right of way is on property owned by the applicant or on property owned by an outside party and to which the applicant has rights through a lease or other legal arrangement.

1.3 Overview of Applicant Responsibility for its DER Equipment

The applicant is responsible for the proper installation, operation, and maintenance of its DER equipment. A certificate of completion from PGE is not an endorsement of applicant-owned facilities nor a guarantee of performance, but only a finding that the DER can safely and reliably interconnect with the PGE system at the time the certificate of completion is issued and under the test conditions and settings in place at that time.

Moreover, the applicant is responsible for ensuring that its protection scheme is adequately protective of its DER equipment. The requirements described in this document, and the example single-line (also called "one-line") diagrams in Section 12, are intended only to show interconnection relays that protect the PGE system, not the DER equipment itself.

More information on applicant responsibilities for its own equipment is provided in later sections of this document.

1.4 Applicable Facility Types

The types of DERs eligible to interconnect to the PGE system are solely based on FERC rules, OPUC rules, and PGE tariffs.

1.4.1 Inverter-Based Facilities

Inverter-based facilities include any direct current (DC) power supply facility that requires alternating current (AC) conversion. These include, but are not limited to, solar photovoltaic (PV) or energy storage facilities. Inverter-based facilities utilizing UL 1741 SB smart inverters are able to provide multiple functions such as connecting to and from the grid, generation limiting, power factor control, voltage regulation (volt var, volt watt, power factor, etc.), frequency response, price/temperature driven functions, ride-through functions, and load and generation following functions.

DER projects may have multiple inverters. The sum of the inverter nameplate capacity ratings is used in rounding calculations with voltage at the location where the ground reference will be attached. For DERs interconnecting at secondary voltage, a single ground referencing device may prove sufficient for the combined DER nameplate capacity.

1.4.2 Machine-Based Facilities

Machine-based facilities are used to convert mechanical energy into electrical power. These sources include, but are not limited to, synchronous generators and induction generators.

A. Synchronous Generators

Synchronous generators can be used to produce electrical energy and provide frequency response. These generators require a DC power source for startup.

B. Induction Generators

Induction (asynchronous) generators produce electrical energy when rotor rotation exceeds synchronous speed. To start, these generators need to draw energy from an external source. With the absence of an external energy source or a reactive supply, these generators do not possess the ability to restore electrical power to a disconnected and de-energized part of an electrical grid. These generators can be coupled with wind or small hydro turbines to produce electrical power.

1.5 Overview of Interconnection Process

This section summarizes process requirements for DERs interconnecting to the PGE system. The major steps for DERs to be successfully interconnected include:

- Application
- Assignment of Queue Position
- Technical Screening and/or Study
- Interconnection Agreement
- Design, Procurement, and Construction

- Commissioning, Inspections, and Witness Testing
- Operation and Maintenance

These steps are described in turn in this document.

1.5.1 Level of Service Offered for Interconnection on the Distribution System

PGE offers four options for customers interested in installing DERs that are not under FERC jurisdiction. The options are typically based on interconnection type and DER nameplate capacity, but they also can be differentiated by compensation method and are briefly described below.

A. Net Metering

PGE offers net metering to applicants interested in offsetting their electricity consumption as an existing retail service customer of PGE. Under net metering, customers are compensated based on energy measured in kilowatt-hours (kWh) provided to the PGE system during a given billing period. The energy provided is deducted from the customer consumption prior to billing.

With net metering, residential customers can install up to 25 kW of DER. Non-residential customers can install up to 2 MW of DER. Only certain technology types qualify for net metering. They are solar, wind, fuel cell, hydroelectric, landfill gas, digester gas, waste, dedicated energy crops available on a renewable basis, or low-emission, nontoxic biomass based on solid organic fuels from wood, forest, or field residues.

Schedule 203 and other materials on PGE's website define net metering service in greater detail.

B. Small Generator Interconnection

Customers interested in installing a generating facility for the purpose of selling energy to PGE may qualify for a small generator interconnection. Under the small generator interconnection rules, customers can install DERs up to 10 MW of capacity.

If the small generator applicant wishes to sell power to PGE on an avoided-cost basis as a Qualifying Facility (QF), it must execute a power purchase agreement (PPA) with PGE subject to Schedule 201, which is provided on PGE's website. The PPA may contain provisions relating to DER interconnection.

The OAR-defined small generator program described above does not apply to interconnection requests that are FERC-jurisdictional. DER applicants of small-generator-scale projects that are FERC-jurisdictional must follow applicable FERC interconnection standards. FERC-jurisdictional DER projects interconnected at the utility distribution system level are defined as those making wholesale market sales of electricity. In addition, all interconnections for new or expanded capacity for generation and energy storage projects interconnected at the transmission system level are

FERC-jurisdictional, though such projects by definition are not DERs.

C. Community Solar Program

Customers seeking to install solar DERs to sell power to PGE end-user subscribers within the Community Solar Program (CSP) may apply for interconnection of DERs up to 3 MW in capacity. The interconnection requirements for CSP DERs are similar to small generator requirements, though they differ in some respects such as the possibility of joint study for applications in limited circumstances. CSP applicants must adhere exactly to PGE's CSP interconnection requirements. Each CSP applicant must also execute a Community Solar Program Purchase Agreement with PGE.

D. Large Generator, Non-FERC Jurisdictional Interconnection

Customers seeking to install DERs larger than 10 MW and up to 20 MW that are not under FERC jurisdiction may qualify for a large generator interconnection to the PGE system on the same basis as DERs larger than 20 MW. Such customers should expect to follow Oregon Standard

Interconnection Procedures and Agreements Adopted for Large Qualifying Facilities in OPUC Order Number 10-132. DER interconnection requests that are FERC-jurisdictional must follow applicable FERC interconnection standards.

Large generator interconnection requirements are not otherwise described in this document.

2 Application Submission and Initial Review

This section summarizes the process from prior to interconnection application submission through the stage at which the application is judged to have the necessary information and fees to be placed in a queue for technical review by PGE.

2.1 Pre-Application Report

Potential DER interconnection applicants, or other interested parties such as DER project developers that are evaluating the installation of a small generator or CSP interconnection, can request a Pre-Application Report from PGE. The report is based on the proposed POI on the PGE system and contains relevant information that may be used to understand the feasibility of interconnecting a DER at the POI. Applicants may be required to sign a confidentiality agreement to obtain their Pre-Application Report depending on the nature of the information in the report.

Consistent with OAR rules stipulating that requestors must reimburse utilities for reasonable costs associated with the reports, there is a pre-application fee of $300 per request. PGE may require up to 30 business days to complete a report. A Pre-Application Request can be made through PGE's PowerClerk.

There is not a pre-application process for net metering. However, Level 3 net metering applicants can request certain information associated with their proposed interconnection location after they submit an application. This information includes available fault current, existing peak loading on PGE distribution lines in the vicinity of their proposed DER, and the configuration of distribution lines at the proposed PCC. PGE will provide such information within three business days of the request.

2.2 Interconnection Type and Level/Tier

The interconnection type (net metering, small generator, and CSP) and DER nameplate capacity dictate which interconnection application is needed. Table 1 below maps the level or tier of application needed by interconnection type and DER capacity. The net metering categories are termed “levels”, while the small generator, and CSP categories are termed “tiers.”

Each progressively higher level or tier involves more detailed technical screens or detailed studies to assess DER requirements and impacts on the PGE system and as needed, to identify new PGE facilities and system upgrades that would allow the DER to safely and reliably interconnect. At the highest level (Level 3) for a net metering applicant, an impact study by PGE is required if the DER interconnection application is to advance. A facilities study may also be required. At the highest tier

(Tier 4) for a small generator or CSP applicant, a combination of a feasibility study, system impact study, and/or facilities study may be required.

Table 1: Levels/Tiers of Interconnection-Based on Interconnection Type and DER Nameplate Capacity

Net Metering	
Level 1	Inverter-based and less than or equal to 25 kW in nameplate capacity
Level 2	Less than or equal to 25 kW and does not meet Level 1 screening requirements in Section 3.2, but does meet Level 2 requirements *OR* Between 25 kW and 2,000 kW and meets Level 2 requirements
Level 3	Less than or equal to 25 kW and does not meet Level 1 and Level 2 screening requirements; or, between 25 kW and 2,000 kW and does not meet Level 2 requirements
Small Generator	
Tier 1	Inverter based and less than or equal to 25 kW in nameplate capacity with lab-tested interconnection equipment
Tier 2	Less than or equal to 25 kW and does not meet Tier 1 screening requirements in Section 3.3, but does meet Tier 2 requirements or Between 25 kW and 2,000 kW and meets Tier 2 requirements Also, in all cases, must: Use lab-tested or field-tested interconnection equipment Be seeking interconnection to either a radial distribution circuit or a spot network distribution circuit limited to serving one customer Not be a synchronous machine to the extent that PGE is using high-speed reclosing with less than two seconds of interruption

Tier 3	Less than or equal to 25 kW and does not meet Tier 1 or 2 screening requirements, but does meet Tier 3 requirements or Between 25 kW and 2,000 kW and does not meet Tier 1 or 2 screening requirements, but does meet Tier 3 requirements or More than 2,000 kW but no more than 10,000 kW and meets Tier 3 screening requirements Also, in all cases, must not be a synchronous machine to the extent that PGE is using high-speed reclosing with less than two seconds of interruption
Tier 4	Less than or equal to 25 kW and does not meet Tier 1, Tier 2, or Tier 3 screening requirements or Between 25 kW and 2,000 kW and does not meet Tier 1, 2, or 3 screening requirements or More than 2,000 kW but no more than 10,000 kW and does not meet Tier 3 screening requirements
Community Solar Program	
Tier 2	Less than or equal to 2,000 kW and meets Tier 2 screening requirements
Tier 4	Less than or equal to 2,000 kW and does not meet Tier 2 screening requirements or is greater than 2,000 kW but no more than 3,000 kW

NOTE: There is no Tier 1 or Tier 3 screening for CSP applicants. The lack of Tier 3 screening is because CSP DERs, by program definition, export to the PGE system and are not eligible for the non-exporting DER reviews that are defined for Tier 3.

2.3 Application Requirements

Application requirements are based on the relevant OAR. Applications are web forms in the respective net metering, small generator, and CSP PowerClerk software systems that are accessed through PGE's website.

2.3.1 Application Review

The review of an interconnection application by PGE cannot begin unless the application is satisfactorily completed. For an application to be considered completed (considered "pending completed" per OAR), the application must have all applicable fields filled out accurately and all application fees must be paid. Applications include information such as

DER location; existing electric service at the location; DER equipment data such as nameplate capacity rating, energy resource, prime mover technology, inverter and customer-owned transformer descriptions; and contact information for the applicant and the DER installation contractor.

In addition to completing the application, the applicant must provide required supporting documentation relevant to its particular level or tier, such as a single-line diagram; site plan; and generating, energy storage, and inverter device specification sheets. If the DER is a QF, then the FERC "Notice of Self Certification" must be submitted with the application. For a CSP DER, the project must be pre-certified in that program in accordance with OAR 860-088-0040 and the CSP Program Implementation Manual.

2.3.2 Site Plans

Site plans should show the location of the DER along with the location of the utility meter(s) and AC disconnect(s) when required.

2.3.3 Site Control

A small generator or CSP applicant must demonstrate that it has control of the proposed DER site through ownership, a leasehold interest, or an option or other right to develop its DER at the site. An application can satisfy this requirement by using various types of documentation described in OAR 860-082-0025.

2.3.4 Fee Structure

Application fees are based on the level or tier of an application and the nameplate capacity of the DER. Table 2 below summarizes the appropriate application fees.

Table 2: Application Fee Structure Based on Interconnection Type, Level, and Tier

Net Metering	
Level 1	No fee
Level 2	$50, plus $1 per kW of nameplate capacity
Level 3	$100, plus $2 per kW of nameplate capacity
Small Generator	
Tier 1	$100
Tier 2	$500
Tier 3	$1,000

Tier 4	$1,000
Community Solar Program	
Tier 2	$500
Tier 4	$1,000

There are additional costs to the applicant for studies, if they are required, to assess the DER. Those costs and the associated study agreements are described later in this section.

2.3.5 Initial Review Timelines

Table 3 describes the timing for PGE's review of the completeness of DER interconnection applications.

Table 3: **Application Review Timeline Based on Interconnection Type, Level, and Tier**

Net Metering	
Level 1	3 business days of receipt
Level 2	3 business days of receipt
Level 3	3 business days of receipt
Small Generator	
Tier 1	10 business days of receipt
Tier 2	10 business days of receipt
Tier 3	10 business days of receipt
Tier 4	10 business days of receipt
Community Solar Program	
Tier 2	10 business days of receipt
Tier 4	10 business days of receipt

If the application is deemed "pending completed", it is considered complete by PGE and enters the utility's interconnection queue (See Section 2.4.).

If the application is found by PGE to be incomplete, the utility will send a list of information needed to the applicant to complete the application. For a small generator or CSP DER, the applicant has 10 business days from receipt of the note of deficiencies to provide the required information. If the applicant does not meet that timeline, the application is withdrawn by PGE. For a net metering DERs, the applicant is expected to provide the required, additional information within 10 business days.

Per the OAR, an applicant with a "pending completed" application for a small generator or CSP DER must submit a new application if the applicant proposes to make any change to the small generator DER, including changes to the DER's proposed POI or to its nameplate capacity, other than a minor equipment modification (as defined in the OAR and reprinted in the Glossary).

2.4 Interconnection Queue

As noted above, an application enters the interconnection queue when the application is deemed "pending completed". The queue is ranked based on the date and time that PGE receives the completed application. An application is not considered complete until the application fee has been paid.

Once an application has entered the queue, any changes to the DER other than minor equipment modifications require the submission of a new application, thus relinquishing the current queue position. The new application will enter the queue based on the date and time it is deemed "pending completed."

A small generator or CSP application retains its original interconnection queue position if the application is resubmitted at a higher tier of screening within 15 business days of the date when the applicant receives PGE's denial of the application at a lower tier of screening. If the applicant meets that timeline, the original application fees can be used to offset the cost of the higher-tier application.

A small generator application relinquishes its small generator queue position if it subsequently applies as a CSP DER. Per regulatory requirements, PGE maintains separate queues for small generator and CSP applications.

A net metering application retains its queue position if the applicant resubmits the application within 30 business days of PGE's denial of its application at a lower level of screening. If a Level 2 net metering application must be re-submitted to Level 3, fees previously paid are applied to the Level 3 screening of the application.

3 Interconnection Technical Screenings and Studies

This section describes technical requirements for DER interconnecting to the PGE system and PGE's methods for evaluating the DER compliance with the requirements. The requirements are the same for small generator, CSP, and net metering applicants, unless otherwise noted. The requirements listed herein provide a means to interconnect DERs to the PGE system while ensuring the safety, reliability, and power quality of the PGE system.

An interconnection application at Level 3 for net metering applicants or Tier 4 for small generator or CSP applicants may require one or more types of studies. Screening requirements are determined by PGE personnel based on the tier (for small generator and CSP applications) or level (for net metering applications) of the interconnection application, as well as PGE's analysis of the proposed DER at its proposed POI or PCC on the PGE system.

Interconnection applications at lower levels (Levels 1 and 2) or tiers (Tiers 1, 2, and 3) are typically evaluated through the use of structured technical screening processes that do not require full studies. If an application fails one or more technical screens at a given level or tier of screening, it is required to be re-submitted at the next higher level or tier by the applicant. If the application is submitted at the higher level or tier with the necessary information and any additional fees required within the OAR-prescribed timeline, the application maintains its queue position and PGE reviews the application based on the requirements of the higher level or tier. If the applicant chooses not to re-submit at the higher level or tier or fails to provide necessary information or fees within the prescribed timelines, the application is withdrawn.

3.1 Technical Screening Summary List

The technical screens generally applied for each level and tier of interconnection are listed in Section 3.2 and Section 3.3. These lists are being provided for convenience and should not be relied upon as full depictions of technical screens. These lists, where "aggregate generation capacity" impacts are identified, include existing DER capacity plus the capacity of the applicant's DER. For more detailed and comprehensive descriptions of applicable technical screens, see OAR 860-039 (net metering), OAR 860-082 (small generator), and OAR 860-088 (CSP).

The lists in Section 3.2 do not duplicate the eligibility requirements for review under various interconnection application levels and tiers, which are summarized in Table 1 of this document.

Because net metering Level 3 screenings typically consist of detailed studies by PGE rather than technical screens, no Level 3 screens are listed in relevant OAR documents or in Section 3.2.1. Similarly, small generator and CSP Tier 4 screenings typically consist of detailed studies and do not have provisions for technical screens in relevant OAR documents. As a result, Tier 4 is not included in Section 3.3. CSP DERs are not eligible for Tier 1 or Tier 3 screening. Therefore, only the Tier 2 section of Section 3.3 is applicable to CSP DER.

3.2 Technical Screening of Net Metering Applicants

In accordance to Oregon Public Utility Commission rules set forth in OAR 860-039 (net metering), PGE screens each net metering application to ensure adherence to the rules. The following are the screening requirements for DERs interconnecting to the PGE system and PGE's methods for evaluating the DERs compliance with the requirements:

3.2.1 Level 1

A. Aggregate generation capacity on the circuit to which the DER seeks interconnection shall not contribute more than 10% of the circuit's maximum fault current.

B. The DER's PCC shall not be on a transmission line, spot network, or area network.

C. If the DER is to be connected to a radial distribution circuit, aggregate generation capacity on the circuit shall not exceed 15% of the circuit's annual peak load for solar electric DERs or not exceed 10% of the circuit's annual peak load for other DER technologies.

D. If the DER is to be connected to a single-phase shared secondary line, aggregate generation capacity on the shared secondary shall not exceed 20 kVA.

E. If a single-phase DER is to be connected to a transformer center tap neutral of a 240 V service, the DER shall not create a current imbalance exceeding 20% of the transformer nameplate rating.

3.2.2 Level 2

A. Aggregate generation capacity on the circuit to which the DER seeks interconnection shall not cause any distribution protective equipment or customer equipment on the PGE system to exceed 90% of the short circuit interrupting capability of the equipment.

B. If there are posted transient stability limits in the vicinity of the PCC, the aggregate generation capacity connected to the low voltage side of the substation transformer on the circuit containing the PCC shall not exceed 10 MW.

C. Aggregate generation capacity on the circuit to which the DER seeks interconnection shall not contribute more than 10% of the circuit's maximum fault current at the nearest primary voltage location on the PGE system.

D. If the DER is to be connected to a radial distribution circuit, aggregate generation capacity on the circuit from non-public utility sources shall not exceed 15% of the circuit's annual peak load for solar electric DERs or not exceed 10% of the circuit's annual peak load for other DER technologies.

E. If the DER is to be connected to a three-phase, three-wire primary PGE distribution line, a three-phase or single-phase DER shall be connected phase-to-phase.

F. If the DER is to be connected to a three-phase, four-wire primary PGE distribution line, a three-phase or single-phase DER shall be connected line-to-neutral and effectively grounded.

G. If the DER is to be connected to a single-phase shared secondary line, aggregate generation capacity on the shared secondary shall not exceed 20 kVA.

H. If a single-phase DER is to be connected to a transformer center tap neutral of a 240 V service, the DER shall not create a current imbalance exceeding 20% of the transformer nameplate rating.

I. The DER's PCC shall not be on a transmission line.

J. If the DER's PCC is on a spot network, aggregate generation capacity on the network shall not exceed 5% of the network's maximum load.

K. If a DER with inverter-based protective functions has its PCC on an area network, the aggregate generation capacity on the network shall not exceed the lesser of:

- 10% of minimum annual load on the network or
- 500 kW for this screen, minimum annual load is determined from off-peak daylight periods.

L. For a DER without inverter-based protective functions, or a DER with inverter-based protective functions that do not meet the requirements of the two previous rows in this list that has its PCC on a spot network or an area network, the DER shall use low-forward power relays or other protective devices to ensure no power is exported from the DER that could adversely affect protective devices on the network.

3.3 Technical Screening for Small Generator and CSP Applicants

In accordance to Oregon Public Utility Commission rules set forth in OAR 860-082 (small generator), PGE screens each Small Generator and CSP application to ensure adherence to the rules. Following are the screening requirements for DERs interconnecting to the PGE system and PGE's methods for evaluating the DERs compliance with the requirements:

3.3.1 Tier 1

A. The DER interconnection must use existing public utility facilities.

B. If the DER is to be connected to a radial distribution circuit, aggregate generation capacity on the circuit shall not exceed 15% of the circuit line section's annual peak load.

C. If the DER's POI is on the load side of spot network protectors, aggregate generation capacity on the load side of the protectors shall not exceed the lesser of

- 5% of the network's maximum load
- 50 kW.

D. If the DER is to be connected to a single-phase shared secondary line, aggregate generation capacity on the shared secondary shall not exceed 20 kW.

E. If a single-phase DER is to be connected to a transformer center tap neutral of a 240 V service, the DER shall not create a current imbalance exceeding 20% of the transformer nameplate rating.

3.3.2 Tier 2

A. If the DER is to be connected to a radial distribution circuit, aggregate generation capacity on the circuit shall not exceed 15% of the circuit line section's annual peak load.

B. If the DER's POI is on the load side of spot network protectors, aggregate generation capacity on the load side of the protectors shall not exceed the lesser of 5% of the network's maximum load or 50 kW.

C. Aggregate generation capacity on the circuit to which the DER seeks interconnection shall not contribute more than 10% of the circuit's maximum fault current at the nearest primary voltage location on the PGE system.

D. Aggregate generation capacity on the circuit to which the DER seeks interconnection shall not cause any distribution protective equipment or customer equipment on PGE's distribution or transmission systems to exceed 90% of the short circuit interrupting capability of the equipment.

E. If there are known or posted transient stability limits in the vicinity of the POI, the aggregate generation capacity connected on the distribution side of the substation transformer on the circuit containing the POI shall not exceed 10 MW.

F. If the DER is three-phase or single-phase and is to be connected to a three-phase, three-wire primary PGE distribution line, the DER shall be connected phase-to-phase.

G. If the DER is three-phase or single-phase and is to be connected to a three-phase, four-wire primary PGE distribution line, the DER shall be connected line-to-neutral and effectively grounded.

H. If the DER is to be connected to a single-phase shared secondary distribution or transmission line, aggregate generation capacity on the shared secondary shall not exceed 20 kW.

I. If a single-phase DER is to be connected to a transformer center tap neutral of a 240 V service, the DER shall not create a current imbalance exceeding 20% of the transformer nameplate rating.

J. Aggregate generation capacity where the DER seeks to interconnect shall not cause the associated transmission system circuit to exceed its design capacity

K. Interconnection of the DER does not require PGE system upgrades or new facilities beyond minor equipment modifications as defined in OAR 860-082 (small generator).

3.3.3 Tier 3

A. The DER must meet all Tier 2 technical screens described above.

B. The DER shall not export power beyond the POI.

C. The DER shall not use low forward power relays or other protection functions that prevent power flow onto the area network.

D. If the DER's POI is on an area network, the DER shall use lab-tested, inverter-based interconnection equipment; shall have nameplate capacity that does not exceed 50 kW; and shall not cause aggregate generation capacity to exceed the lesser of 5% of the network maximum load or 50 kW.

E. If the DER's POI is not on a spot network or an area network, the POI shall be on a radial distribution circuit, the DER shall have nameplate capacity that does not exceed 10 MW, the aggregate generation capacity on the circuit shall not exceed 10 MW, and the DER shall not be served by a shared transformer.

3.4 Study Types

Depending on the level and tier of the interconnection application, the DER's interconnection applications may be reviewed under any or all three of the progressively more detailed study types described below.

- Feasibility Study (not applicable to CSP applications)
- System Impact Study (terminology for small generator and CSP applications) or Impact Study (terminology for net metering applications)
- Facilities Study

For each study that is required, PGE notifies the applicant and provides a study agreement. The agreement outlines what information is reviewed and the cost of the study. The study fees are based on the number of engineering hours PGE estimates are needed to conduct the study. When studies are required, the applicant must sign a study agreement before a study can be completed and its application can advance. An applicant wishing to withdraw its application can decline to sign a study agreement.

Each study can take a considerable amount of time and effort depending on the type of interconnection, the queue position of the proposed DER in relation to other DER at similar locations on the PGE system, DER capacity, and the extent and complexity of potential impacts on the PGE system and any affected systems.

At the conclusion of each study, PGE issues a report to the applicant outlining the results. The report may contain a summary of the study scope, study assumptions, requirements (for example, protection enhancements), PGE system modifications necessary for interconnection, the applicant's and PGE's respective responsibilities for implementing the requirements and modifications, estimated applicant costs for the requirements and modifications, and an estimated schedule for the design, procurement, and construction of the requirements and modifications.

When conducting studies, PGE considers all existing energized DERs, as well as DERs ahead of the applicant's project in queue at the feeder and substation associated with the applicant's planned POI or PCC. DERs interconnected with affected systems of other utilities are also considered if they may impact the applicant's interconnection request. Doing so allows PGE to model system impacts in a comprehensive manner accounting for the cumulative impacts of DERs on relevant portions of the PGE system.

PGE studies DERs serially at each POI or PCC (feeder or substation). There is currently no joint (or group) study process for net metering or small generator applicants. This means that each DER incurs the PGE interconnection facilities and system upgrade costs necessary for the safe and reliable integration and operation of the DER, regardless of the effects of those costs on other DERs with a lower queue position at the same POI or PCC. There is a joint study process for CSP applications submitted by the same organization that are back-to-back in the queue on the same feeder, whereby each CSP DER project is allocated the interconnection costs for system upgrades based on its proportional capacity.

Timing related to each study type is listed below. Applicants should note that there are no OAR-prescribed timelines for PGE's completion of the studies themselves, except for the net metering impact study. However, there are prescribed timelines in several instances for the utility to provide study agreements (contracts authorizing the utility to perform the study) to applicants and for applicants to return signed study agreements to the utility. If applicants do not meet timelines for returning signed study agreements, their applications are withdrawn.

For small generator and CSP applications, there is an option for a scoping meeting between PGE and the applicant to determine the types of studies that may be required for the application. The applicant and PGE can jointly decide to forego the scoping meeting so that the application can proceed directly and more quickly to PGE's review. Small generator applicants whose DER does not pass technical screens should expect that the study process will begin with the feasibility study. CSP applicants whose DER does not pass technical screens should expect that the study process will begin with the system impact study.

Following are the Study Types and a description for each interconnection program.

- Net Metering
  - Impact Study
    - Within 7 business days of completion of the application, PGE provides the applicant with the study agreement.
    - Within 30 calendar days of receiving a signed study agreement and payment of the good-faith estimated study cost, PGE determines if only minor modifications are needed to accommodate interconnection of the DER, or if substantial modifications are needed and if systems of other utilities will be affected.
  - Facilities Study
    - There are no OAR-prescribed timelines.
- Small Generator and CSP
  - Feasibility Study (not applicable to CSP DER).
    - Within 5 business days of a scoping meeting, PGE provides study agreement to the applicant.
    - Within 15 business days of receipt of the agreement, the applicant signs.
    - Within 60 days of agreement execution and study deposit being received, PGE provides the study to the applicant.
  - System Impact Study
    - Within 5 business days of the scoping meeting (CSP DER) or the latter of a scoping meeting or completion of a feasibility study for the DER (small generator DER), PGE provides the applicant with the study agreement.
    - Within 15 business days of receipt, the applicant signs the agreement.
    - Within 5 business days of completion, PGE provides the applicant with the study.

- Facilities Study
    - Within 5 business days of the latter of a scoping meeting or completion of a system impact study for the DER, PGE provides the applicant with the study agreement.
    - Within 15 business days of receipt, the applicant signs the agreement.

PGE's ability to deliver study results on a timely basis is dependent on applicants providing accurate, timely information and responses to questions that may arise from PGE during the course of conducting studies. Additionally, PGE studies DERs in a serial manner. With that said, when a delay occurs during the study process for a DER higher in the queue at a given feeder or substation, the delay could potentially have downstream delays of studies and results for a DER lower in the queue at the same location on PGE's system. Also, when higher-queued projects are withdrawn, there can be down-queue impacts necessitating another study and causing additional delays.

The study costs are based upon:

- The scope of work in the respective study agreements
- PGE's estimate of the number of engineering hours needed to complete the study
- Consistency with the OAR maximum hourly utility labor cost

In some cases, additional studies are necessary if the proposed DER may affect distribution or transmission systems of utilities other than PGE.

Additional information on study requirements for each interconnection level and tier is provided below and in OAR 860-039 (net metering), OAR 860-082 (small generator).

3.4.1 Feasibility Study

This type of study is only applicable to small generator DER applications. There is no feasibility study in the OAR for net metering applications or CSP applications.

The feasibility study provides an initial review of potential adverse impacts of interconnecting the proposed DER on the PGE system or other affected utility systems. As a result, the feasibility study provides the customer with baseline requirements needed for interconnection of the DER as well as non-binding, initial cost estimates and timelines for implementing that scope.

Due to the preliminary nature of the feasibility study, the band of uncertainty on cost and schedule estimates may be wide. The timeline may provide basic information regarding design, procurement, and construction.

If PGE concludes that neither a system impact study nor a facilities study is required, the utility will provide an interconnection agreement for the applicant's review and signature within 15 business days of completing the feasibility study as long as the application meets other OAR interconnection review criteria, and no new interconnection facilities or system upgrades are needed beyond those identified on the DER application. If PGE identifies only minor equipment modifications (facilities or upgrades) are needed to safely and reliably interconnect the proposed DER, but neither system impact nor facilities studies are needed, the utility will provide an interconnection agreement for the applicant's review and signature within 15 business days of the applicant's agreement to pay for minor modifications identified.

3.4.2 Impact Study or System Impact Study

If any adverse system impacts are found from the feasibility study (or if the applicant moves directly from the scoping meeting to a system impact study), then a system impact study for a small generator or CSP DER must be conducted to identify and detail impacts associated with the POI designated by the applicant. The system impact study builds upon PGE's feasibility study analysis and evaluates adverse impacts to the PGE system and any other affected utility systems. This study reviews possible impacts through analyses including, but not limited to:

- Short Circuit
- Stability
- Power flow
- Voltage drop and flicker
- Protection and set point coordination
- Grounding

The system impact study may also document fault-interrupting equipment with short circuit capability limits that may be exceeded as a result of interconnecting the proposed DER.

The system impact study will contain a good-faith, non-binding estimate of the costs that the applicant must pay for new interconnection facilities and system upgrades needed to safely and reliably accommodate the DER on the PGE system as well as a good-faith, non-binding estimate of the timeline for designing, procuring, and constructing the necessary facilities and upgrades.

If PGE concludes that no new facilities nor system upgrades are required, the utility will provide an interconnection agreement for the applicant's review and signature within 15 business days of completing the system impact study as long as the application meets other OAR interconnection review criteria and no new interconnection facilities, or system upgrades are needed beyond those identified on the DER application. However, if PGE identifies that only minor equipment modifications (facilities or upgrades) are needed to safely and reliably interconnect the proposed DER, and a facilities study is not needed, the utility will provide an interconnection agreement for the applicant's review and signature within 15 business days of the applicant's agreement to pay for the minor modifications.

The impact study for net metering applicants is similar in scope and purpose to the system impact study described above and emphasizes power flows, utility protective devices, and control requirements. Within seven business days after receiving a complete Level 3 application, PGE will provide an impact study agreement to the applicant. After the applicant signs the impact study agreement and pays the utility's good-faith estimate of the study cost, PGE will notify the applicant within 30 calendar days of whether only minor modifications are needed to accommodate the applicant's DER or whether substantial modifications are needed, and if any other utility's systems may be affected by the new DER.

If substantial modifications are identified by PGE during the impact study process, the utility will provide a non-binding, good faith estimate of those modification costs and offer to conduct a facilities study (at the applicant's additional expense) to identify specific equipment that comprise the substantial modifications. More information on the impact study is available in OAR 860-039-0040.

3.4.3 Facilities Study

For small generator or CSP applicants, if PGE determines a new interconnection facilities or system upgrades beyond minor equipment modifications are necessary, or if the applicant moves directly from the scoping meeting to a facilities study, then a Facilities Study must be performed.

The facilities study builds upon prior studies and provides more precise identification of the new interconnection facilities and system upgrades needed to accommodate the DER interconnection based on further analysis and preliminary design activities and often involves a visit by PGE staff to the proposed DER site. The facilities study may also contain a delineation of applicant versus PGE roles and responsibilities with regard to new facilities and system upgrades. Since the facilities study is a thorough review, PGE may identify new requirements or modified requirements compared to earlier studies of the DER.

Like the system impact study, the facilities study contains good-faith, non-binding estimates of interconnection costs and the timeline for designing, procuring, and constructing the necessary facilities and upgrades. Those costs and schedules are more refined estimates than in the system impact study.

The applicant has 15 business days from its receipt of the facilities study to agree to pay the costs identified within the study. If the applicant agrees, it will receive an interconnection agreement for review and signature within 5 business days of agreeing to pay the costs.

For net metering applicants, the facilities study is similar in scope and purpose to the requirements described above. Applicants must execute the facilities study agreement and pay the estimated cost of the study before PGE commences its facilities analysis. More information on the facilities study for net metering applicants is available in OAR 860-039-0040.

3.4.4 Studies Required for Affected Systems

If the proposed DER interconnection may affect other utility systems, the affected utilities may require their own studies beyond those described above before the DER can advance in the PGE interconnection process. PGE will coordinate with other utilities so that they may perform such studies; however, PGE is not responsible for the cost, timing, or the work necessary for affected utilities to perform their studies. The applicant must contract with any Affected Systems to perform such studies and agree to pay associated costs before the studies are initiated. An Applicant’s ability to successfully interconnect to PGE requires successful demonstration that all issues identified as “Affected Systems” have been successfully mitigated or otherwise addressed to the satisfaction of the Affected System.

3.5 Overarching Interconnection Study Concepts

This section describes four concepts that PGE applies across its interconnection studies of DER. This information is provided for applicants and other interested parties can gain insights into PGE's methods to better prepare their applications and understand the rationale for decisions made by PGE to preserve the safety and reliability of the PGE system. However, this document is not a comprehensive description of PGE's study methods.

PGE may modify its modeling and analysis methods for studies without notice as long as they remain consistent with relevant OAR documents, IEEE standards, or good utility practice. Additional information on PGE's study methods for small generators can be found in the "Small Generator Interconnection Program, Interconnection Technical Requirements" document on PGE's website.

Depending on the interconnection level and tier of the proposed DER as well as the studies the DER undergoes, some of the methodologies described below may not apply to a specific DER. However, the general methodologies apply to the majority of small generator and CSP interconnection applications, and to aspects of Level 2 and Level 3 net metering applications.

3.5.1 Additional DERs Associated with the POI or PCC

PGE models its electrical distribution system with the presence of the applicant's proposed DER in addition to:

- Existing DERs (possessing certificates of completion) at the same feeder or substation location as the proposed DER.
- Proposed DERs higher in the interconnection queue at the same feeder or substation as the applicant's proposed DER (for example, DERs that have not yet received a certificate of completion but have completed interconnection applications before the proposed DER application was complete).
- DERs on any affected systems of other utilities. These include both inverter-based and machine-based DER.

3.5.2 Peak (or Heavy) Load

A peak load condition is defined as the highest coincidental hourly load condition for a group of feeders served from the same substation transformer during a season when load is at its highest level. PGE's peak load typically occurs during the summer. Load conditions are limited to daytime hours for studying DER that are strictly solar photovoltaic.

PGE uses hourly circuit data recorded through Supervisory Control And Data Acquisition (SCADA) systems to determine the applicable peak load for its interconnection studies. For peak load conditions, the highest coincidental system load is selected and compared to corresponding weather conditions and system configuration. For this reason, 18 to 24 months of feeder load data may be evaluated to avoid anomalies in a single year's load data due to potential abnormal circuit configurations or atypical seasonal peak loads. Peak load scenarios are finalized after weather conditions and system configuration are reviewed. PGE then applies the selected feeder loads for study of the proposed DER.

3.5.3 Minimum (or Light) Load

A minimum load condition is defined as the lowest coincidental hourly load condition for a grouping of feeders served from the same substation transformer during a season when load is at its lowest level. Minimum load typically occurs during the spring on the PGE system. Load conditions are limited to daytime hours for studying DER that are strictly solar photovoltaic.

PGE uses hourly circuit data recorded through SCADA to determine the applicable minimum load (for example, May 7, 2017, from 13:00 to 14:00) for its interconnection studies. For minimum load conditions, the lowest coincidental system load is selected and compared to corresponding weather conditions and system configuration. For this reason, 18 to 24 months of feeder load data may be evaluated to avoid anomalies in a single year's load data due to potential abnormal circuit configurations or atypical seasonal light loads.

Light load scenarios are finalized after weather conditions and system configuration are reviewed. PGE then applies the selected feeder loads for study of the proposed DER. Note that during DER studies, PGE uses a reduced minimum load value to determine distribution equipment/conductor limitations (equipment/conductor outside the substation). The reduced minimum load is determined by disaggregating the measured minimum load into two parts: generation and load, where the disaggregated load is reduced to 50%. The purpose of the reduction in load is to provide a safety factor to account for a lost load scenario: if a fault happens on a feeder and a protective device (fuse, recloser, etc.) opens, this results in lost load. If generation is still online (upstream of the protective device), reverse power flow from the generation would suddenly increase (since it is no longer offset by the lost load), and this could result in an overload condition if the lost load scenario is not accounted for during the study.

3.6 Interconnection Study Methodologies and Requirements

PGE applies both "base case" and "system upgrade" scenarios in its study process. The "base case" scenarios below refer to the PGE system as presently configured, with the addition of higher-queued DER and their associated upgrades implemented. The "system upgrades" scenarios include the new interconnection facility and system upgrades needed to accommodate the proposed DER on the feeder and substation portions of the PGE system.

PGE analyzes DER impacts at times of peak loading and minimum loading on the PGE feeders served by substations associated with the proposed DERs per Section 3.5.

The specific scenarios analyzed include:

- Peak Loading Period
  - Base case with the proposed DERs offline (for example, due to unavailability)
  - Base case with the proposed DERs in service (for example, online)
  - New interconnection facilities and system upgrades with the proposed DERs offline
  - New interconnection facilities and system upgrades with the proposed DERs in service
- Light Loading Period
  - Base case with the proposed DERs offline
  - Base case with the proposed DERs in service
  - New interconnection facilities and system upgrades with the proposed DERs offline
  - New interconnection facilities and system upgrades with the proposed DERs in service

For study purposes, the proposed DERs are simulated with a default unity power factor and operating at full nameplate capacity in conjunction with all additional DERs associated with the POI or PCC per Section 3.5.1. Alternate power factors can be modeled if mutually agreed upon by PGE and the applicant.

The following are monitored iteratively during the interconnection studies:

- Equipment and Conductor Loading – Conductor loading is evaluated to ensure that (mainline) feeder load does not exceed 80% of conductor and associated equipment normal load level ampacity ratings, which are based on peak loading conditions. The analysis simulates all DERs associated with the POI or PCC per Section 3.5.1.
- Fault Current – A fault current profile is simulated to ensure that the withstand ratings of distribution equipment, including but not limited to: feeder breakers, reclosers, regulators, switches, and fuses are not exceeded. The analysis is completed such that all installed and proposed DERs on the feeders served from the same substation, and any DERs on affected systems of other utilities, come in service and go offline in sync and are evaluated at equipment locations up to and including the corresponding feeder breaker. Fault current is evaluated at the POI or PCC and at equipment locations up to and including the corresponding feeder breaker.
- Reverse Flow – Backfeed from the proposed DER into the PGE system is simulated for peak and light loading conditions to ensure compliance with voltage and protection equipment requirements.
- Voltage Flicker – According to IEEE 1547-2003, DER shall not create objectionable flicker for other customers.
- Voltage Imbalance – Phase voltages are monitored to ensure that there is no risk of impending energy management system alarms or nuisance tripping at the feeder breaker level due to phase imbalance. The steady-state voltage imbalance shall not exceed 3.0%, consistent with American National Standards

Institute (ANSI) C84.1-2016 (Electric Power Systems and Equipment - Voltage Ranges [60 Hz]).

- Voltage Profile – A voltage profile provides measurements of voltage at every location on the interconnected feeder and is used to ensure that the proposed DER does not violate any voltage or any power quality requirements per ANSI C84.1-2016 Range A.

If one or more power system criteria violations exist in the study modeling, PGE will attempt to mitigate the system violations without requiring that the proposed DER curtails its active power output.

3.6.1 Power Flow and Voltage Stability

Absolute voltage levels and/or voltage imbalances may require upgrades to conductors, modifications to the PGE system single-phase or two-phase taplines (with load balance considerations), and/or the addition of voltage regulators or capacitors.

PGE analyzes potential voltage and loading on the PGE system due to impacts from the proposed DER. PGE’s simulation analysis includes multiple scenarios to ensure that the proposed DER does not pose any violations to the PGE system. PGE’s power quality guidelines for proposed DERs are established in PGE design standards, ANSI C84.1-2016, and the most recent versions of IEEE 141 (Recommended Practice for Electric Power Distribution for Industrial Plants), IEEE 519 (Recommended Practice and Requirements for Harmonic Control in Electric Power Systems), and IEEE1453 (Recommended Practice for the Analysis of Fluctuating Installations on Power Systems).

If the proposed DER causes reverse power flow through any existing voltage regulation bank and the appropriate voltage regulator controls are not capable of accommodating this reverse power flow, then the voltage regulator controls shall be replaced with new microprocessor controls capable of bidirectional and co-generation settings. All new voltage regulator banks will have microprocessor controls capable of bidirectional and co-generation settings.

The requirement to include bidirectional and co-generation settings on voltage regulator equipment is necessary to ensure that neighboring customers' service voltage does not stray from the acceptable +/- 5% voltage range under steady-state conditions, per ANSI C84.1-2016. Voltage sensing and time delay relays may also be required to prevent excessive voltage regulator operations due to temporary voltage swings caused by the DER. The requirement to prevent excessive operations due to temporary voltage swings is largely driven by the need to reduce potential impacts to equipment life as a result of more frequent mechanical operations and subsequent wear and tear under the presence of local intermittent DER output. These concerns with equipment life extend to both mid-line voltage regulation equipment and upstream equipment, such as substation load tap changers (LTCs) or substation feeder regulators.

3.6.2 Conductor Capabilities

To ensure that no system equipment is damaged, PGE evaluates interconnecting DERs at full capacity while the surrounding load is modeled according to minimum load data (daytime for strictly PV systems). Some generation and load scenarios can create significant current flow onto the PGE system. This current flow can, in some cases, exceed 80% of the rating of existing conductors, requiring a primary feeder reconductor. PGE reviews such potential conductor or equipment overloads accordingly.

Appropriate conductor and equipment upgrades are identified and quantified. For conductors and other equipment, the size, length, type, and thermal rating of the proposed upgraded materials is determined by PGE. Any additional actions that are necessary to accommodate conductor or other equipment upgrades (such as easements for anchors or pole relocations, or the need to upgrade from a single-phase or open-delta service to a three-phase service) are also identified.

3.6.3 Distribution Protection Requirements

PGE reviews the proposed DER's impact on existing protection equipment (including breakers, fuses, and reclosers) as part of the study process. In the event of a fault or service interruption on the PGE system, a circuit breaker, fuse, or recloser operates, opens, and isolates the fault to prevent and limit the damage to both PGE-owned and customer-owned equipment.

A. Hot Line Indication (for Hot Line Blocking)

PGE performs a high-level review of feeder and substation loading to determine the protection requirements based on the following guidelines using aggregate DERs on the associated feeder.

For inverter-based DERs:

- Up to 90%* minimum load requires no extra protection.
- Above 90%* minimum load requires hot line indication. On feeders with reclosing, the hot-line indication is used to do hot-line blocking.
  - A single feeder transformer up to 80% minimum load requires no extra protection. Above 80%, minimum load hot line indication is required.

For machine-based DERs, hot-line indication is always used. On feeders with reclosing, hot-line indication is used to do hot-line blocking. Additionally, transfer trip is needed if either:

- The station does not have SCADA, and aggregate machine-based DERs exceed 1/6 of the minimum load on the feeder.
- Aggregate machine-based DERs exceed 1/3 of the minimum load on the feeder.

If the DER capacity can exceed loading of the station transformer (can backfeed onto the PGE transmission system) for inverter- or machine-based DERs, additional analysis is performed by PGE.

B. Circuit Reclosers

An electronic recloser, instead of a fuse, may be required by PGE to allow for effective coordination with other protective devices to more effectively isolate the PGE system during unplanned power quality or reliability events, and speed up restoration of service. On the PGE system, fuses are limited to tapline/service transformer load sizes and do not have voltage sensing capability.

If a recloser is required, it must meet all these conditions:

- Be independently pole-mounted
- Have the ability to operate as a recloser, as a switch, or as a sectionalizer, and automatically change between these three functions

- Work remotely
- Be capable of both three-phase and single-phase tripping and lockout
- Be capable of hot line indication
- Be capable of Mirrored Bits Transfer Trip (MBTT)

If a recloser is not present, a PGE line crew may be required to manually close the breaker or fuse to restore power flow. If a recloser is present and the event triggering the fault or service interruption is temporary, the recloser closes after a set time delay and remains closed. As a result, inverter-based DERs can often come back online much more quickly with a recloser present than without one.

Based on the coordination analysis that PGE uses to analyze and identify overloaded protective devices, the sizes of fuses and reclosers may need to be increased, and the devices may need to be relocated to prevent overload and maintain reliability. If recloser changes are warranted, PGE's practice is to replace a recloser that does not meet its current standards rather than retrofitting the recloser. That is because it would be cost-prohibitive to retrofit existing reclosers to meet PGE distribution design standards requiring voltage sensing equipment on both the line and load sides of the recloser to allow for synchronizing capability.

As an example, hydraulic reclosers typically must be replaced with electronic reclosers. That is because hydraulic reclosers on the PGE system:

- Do not have the voltage sensing, relaying, and communications capabilities required by standards
- Have lower ampacity ratings than new electronic reclosers
- Have higher maintenance needs and costs than new electronic reclosers.

If an electronic recloser is required, current transformers (CTs) must be integral to the recloser and have a ratio of 1000:1 or 500:1. Internal voltage sensors must also be provided on the source side of each recloser pole. The voltage sensors must have a magnitude accuracy of 2% or better, and a phase degree accuracy of ±1.5 degrees. Load-side voltage sensors must be provided for sensing voltage on all three phases of the recloser with the same or better accuracy as the source-side internal voltage sensors.

C. Circuit Breakers

If a change to the feeder circuit breaker is required as a result of the studied DER project, PGE may determine that the replacement of the circuit breaker is necessary due to the characteristics of the existing circuit breaker. For example, if new protective relays are required, installing new protective relays in some existing circuit breakers can be more complex and time-intensive than installing a new circuit breaker with relays already installed and pre-wired.

D. Distribution Line Fusing and Coordination

Output from the proposed DER may result in equipment desensitization and coordination. PGE studies these issues as necessary to ensure fault clearing devices are adequately sized to isolate the fault and can do so under acceptable limits.

3.6.4 Substation Requirements

Step-down transformers that reside in substations designated to serve PGE customers are often referred to as distribution power transformers. Although from site to site these transformers vary in size and voltage, a standard installation for PGE is a 16.8/22.4/28 MVA nameplate transformer with 120:13.2 kV stepdown voltages. These transformers have an LTC at the low voltage terminals used to regulate or control voltage within operational limits. For distribution power transformers that are sized smaller than 15 MVA, separate voltage regulators are utilized in lieu of the LTC.

Under certain conditions, such as light loading, DERs have the capability of introducing current through substation equipment and onto PGE’s transmission system. This is commonly referred to as backfeed. Backfeed is limited based on when current begins to flow in reverse through the substation transformer. In the event when backfeed is at risk of occurring, PGE substation impacts are explicitly analyzed. The following are six types of substation requirements.

A. Voltage Stability Requirements and Harmonic Distortion Limits

Traditionally, utility facilities were designed for unidirectional power flow. With the addition of DERs, two-way flows on the PGE system are possible at any time. Due to this, DER penetration on distribution feeders may have an adverse system impact on PGE's electrical distribution or transmission systems.

The addition of DERs requiring inverters may introduce harmonics to the PGE system. These harmonics can potentially distort the voltage and contribute to equipment heating, damage, and loss of life. Also, harmonics can cause protective relay misoperations and, in some circumstances, may affect revenue metering accuracy.

The total harmonic distortion shall not exceed 5% on the PGE system. PGE's harmonic distortion requirements are based on the stricter of the most recent version of IEEE 519 ("Recommended Practice and Requirements for Harmonic Control in Electric Power Systems") or PGE's internal requirements.

If an applicant is negligent in correcting a harmonic distortion problem that is adversely affecting electrical service to other customers, PGE reserves the right to consider refusing service, discontinuing service, or regulating hours of service to the non-compliant applicant.

B. Hot Line Indication

PGE reviews the relays installed on the feeder associated with the potential DER. If the relays are not capable of hot line indication (and transfer trip, if needed), PGE specifies the need to replace the existing relay per PGE's current standard. If hot line indication/hot line blocking is required, then a sensing potential transformer (PT) is required.

C. Preferred Substation Relaying

PGE exclusively uses Schweitzer Engineering Laboratories (SEL) microprocessor-based protective relays. PGE has standardized the SEL-487E Transformer Protection Relay for transformer protection. This relay has the functionality for DER interconnection protection (3V0 detection) required by PGE design standards. Other SEL relays are used for feeder protection, including hot line blocking and transfer trip.

D. Conditions Requiring Transfer Trip

PGE requires transfer trip with hot line indication/blocking if the total DER capacity on the bus can exceed 80% of the minimum load of the substation transformer.

Transfer trip is a practice used in the utility industry to prevent unintentional islanding by DERs. Unintentional islanding can compromise the operation of utility equipment such as reclosers and switchgears as well as damaging the applicant's DER and the equipment of other PGE customers connected to the island.

Installing transfer trip will also take the DER offline for reliability events that the DER cannot detect (for example, due to the DER not being inverter-based or the DER having a multi-inverter configuration) and is used to remove the DER from the PGE system when switching or other system work is required.

If PGE determines that transfer trip is required, the applicant must install a relay or ancillary device that uses SEL Mirrored Bits and the SEL Mirrored Bits Transfer Trip protocol (MBTT). The SEL-751 and SEL-351 relays are both capable of MBTT. The applicant must also install a device capable of communicating via SEL Mirrored Bits.

PGE is currently reviewing the safety and reliability impacts and operational requirements of equipment alternatives to transfer trip for new or modified DER. This is an evolving area of the utility industry in part due to changes in inverter standards and testing. Pending the outcomes of PGE's review, PGE may revise its requirements for substation backfeed protection.

If transfer trip is required, 3V0 protection on the high side of the substation transformer may also be required. More information on the rationale and requirements for 3V0 protection are provided in Overvoltage (3V0) Protection. Additional information on the equipment required to address communications with transfer trip is provided in Communications.

E. Overvoltage (3V0) Protection

When there is ground fault on the high side of a tapped substation transformer or a transformer at a line control station, the line relays trip the line breakers leaving the substation primary without a ground reference. The DER capacity beyond 80% of the transformer load creates an overvoltage condition on the unfaulted phases of up to 173% of normal phase-ground voltage. Until the fault is cleared and the DER separated, the arresters on the unfaulted phases are exposed to this overvoltage and continuously conduct, leading to thermal runaway and arrester failure. The overvoltage condition can also damage the transformer and the line insulators. At low DER penetration, the relatively large, stranded load facilitates rapid cessation of the DER. At higher penetration levels, the DER removes itself increasingly slowly.

PGE follows one of two approaches to address this fault-induced overvoltage condition:

- Prevent the overvoltage condition by making the substation transformer appear to the PGE transmission system as an effectively grounded source. This requires replacement of the substation transformer with a different configuration or the installation of a grounding bank.
- Rapidly detect the overvoltage condition and remove the transformer as a source. This is referred to as 3V0 sensing (or 59N protection).

Once the DER is separated from the transmission system for fault-induced overvoltage, it is essential that the DER also be tripped to allow PGE's transmission system to reenergize PGE's distribution system without risk of closing in out-of-phase to still-energized portions of PGE's distribution system.

The equipment required to rapidly detect the fault-induced overvoltage condition, remove the transformer as a source, and trip the DER is:

- Three-phase PT on the high side of the substation transformer
- Circuit switcher or circuit breaker on the high side of the substation transformer
- Dual SEL-487E relays to detect overvoltage and for overall transformer protection
- Transfer trip to the DER via SEL Mirrored Bits

F. Communications

If transfer trip is required, then communications between the applicant's equipment and a PGE-owned communicating device is needed. PGE's current standard is to use fiber communication for transfer trip schemes. Fiber deployment is PGE's standard due to its low level of ongoing maintenance, long cable life, low security risk, resistance to interference, easy accommodation of different technology platforms, and PGE's experience outside and inside plant fiber networks. PGE has not installed a new power line carrier for telecommunications in many years due to concerns regarding speed, maintenance, and reliability, therefore power line carrier is not allowed for any interconnections.

PGE does not currently have the infrastructure for a radio solution that is smaller and less expensive to deploy than a large backbone microwave radio system, or one that provides the required level of reliability and low latency needs. Limitations to radio communication also include distance, line of sight between the applicant's and PGE's existing communicating devices, frequency coordination, potential interference, and regular radio infrastructure maintenance. Additional engineering, towers, and path analysis is also necessary to determine if these radios could be used for any particular transfer trip scheme.

3.6.5 Transmission System Requirements

Additional requirements that a proposed DER may have related to PGE's high-voltage transmission system are not a subject of this document.

3.6.6 Ownership of New Facilities and System Upgrades

For secondary-metered DER, PGE will own facilities up to the termination of our cable/conductor.

Due to the highly specialized and critical nature of communications equipment, when communications infrastructure is required, PGE will own all necessary communication equipment up to the fiber termination junction at the applicant site. This is to ensure safety, reliability, and security of both the applicant's DER and the PGE system.

Depending on the size and type of DER installation on the PGE system, substation upgrades may be required. These upgrades may include, but are not limited to, new feeder installation; transformer protection upgrades (for example, transfer trip, 3V0) or telemetry upgrades; unidirectional equipment upgrades; and upgrades to feeder protection schemes.

As noted in Section 1.1, the applicant is solely responsible for the cost of PGE designing and constructing any new facilities and system upgrades required to safely and reliably accommodate the proposed DER, as well as the cost of maintaining and repairing the new facilities and system upgrades.

4 Interconnection Agreement

An interconnection agreement must be signed by PGE and the applicant for every DER prior to the operation of the DER on the PGE system. Additionally, any payment schedules in the interconnection agreement must be met by the applicant before PGE initiates its design, procurement, and construction activities to accommodate the DER. An example of the standard form of the net metering interconnection agreement is available on PGE's website. Also, below provides additional information:

- For DERs requiring studies, the interconnection agreement is typically presented to the applicant after the final study of the DER is complete. The agreement will contain the estimated interconnection cost and schedule based on the last study. Execution of the interconnection agreement and payment of a specified portion of the estimated costs must be made before PGE begins its design, procurement, and construction activities. All estimated costs must be paid before the DER can be energized on the PGE system.
- For DERs not requiring studies (for example, that qualify for and pass level or tier technical screenings not requiring studies), the applicant may be able to sign a standard utility interconnection agreement at the time of its application or thereafter. PGE will include minor equipment modification costs in the agreement where appropriate and provisions for payment of those costs before the DER is energized.

Overall, interconnection agreements often contain elements such as responsibilities and requirements for operation; maintenance; monitoring; metering; testing; inspection; access; recordkeeping; disconnection and restoration of interconnection service; cost responsibilities and billing; insurance requirements; descriptions of required facilities and system upgrades to accommodate the DER; estimated applicant interconnection costs; estimated schedule covering design, procurement, and construction of those facilities and upgrades; and various other legal terms and conditions. PGE requirements for some of those contract elements are highlighted in subsequent sections of this document.

A small generator applicant connecting a DER as a QF will also sign a PPA with PGE. Such an applicant must also abide by interconnection-related requirements in the PPA. A CSP applicant will also sign a Community Solar Program Purchase Agreement and must abide by any interconnection-related requirements therein.

5 Design, Procurement, and Construction

Depending on the technical screening and study results as reflected in the applicant's interconnection agreement, a DER interconnection may require construction at the PGE distribution system, substation level, and transmission system. The major utility activities that precede construction of new interconnection facilities and system upgrades are completion of design and procurement of required materials.

The applicant bears the costs pertaining to distribution facilities, substation facilities, transmission facilities, communication facilities, and system upgrades related to its new or modified DER. As PGE experiences higher volumes of DER penetration at individual feeders and substations, the cost, complexity, and timeline for interconnecting DERs can increase at those system locations, and adverse substation and transmission impacts are likely to occur more frequently than in the past.

While PGE endeavors to complete its design, procurement, and construction activities efficiently and place the new or modified DER in-service according to the schedule in the interconnection agreement, the schedule is not guaranteed because there are many factors, including those outside of the utility's control that can affect the schedule. These factors include the interconnection progress of DERs ahead in queue, construction resource availability, equipment and material availability as well as delivery, extreme weather events or other causes of outages and construction delays, AHJ delays in approvals, seasonal system reliability impacts (for example, if a delay causes construction to be pushed into a time of year that we perform a construction task), and applicant delays in responding to information requests. Additionally, if milestone payments or other required deliverables (such as schedules, engineering designs, equipment information, etc.) are not received before or during the cure period for a given milestone, PGE reserves the right to discontinue work on the project until such time as payments or other deliverable, as identified in the Interconnection Agreement, for system upgrade work have been received by PGE.

6 Commissioning, Inspecting, and Witness Testing

PGE does not commission an applicant's DER. The applicant is required to provide paperwork indicating all required inspections by non-utility parties have been completed and all required permits have been obtained. PGE may require its presence for commissioning tests.

6.1 Commissioning Technical Tests

The applicant is responsible for commissioning the DER in compliance with the IEEE 1547-2003 technical requirements and employing equipment that has been tested according to UL 1741SB standards. Per IEEE 1547-2003, the applicant's commissioning process shall include tests of DER response to abnormal voltage and frequency, synchronization, interconnect integrity, unintentional islanding, limitation of DC injection, and harmonics. With regard to commissioning, PGE reserves the right to require the applicant follow IEEE 1547-2018 (or later) standards where appropriate to protect the safety and reliability of the PGE system, consistent with good utility practice.

6.1.1 Additional Requirements for Transfer Trip Protection Testing

If transfer trip is required, PGE will perform end-to-end testing prior to interconnection of the DER. The applicant must provide relay settings (or drawings if using an auxiliary device; for example, SEL-2505) before testing can occur. A PGE relay/meter technician will witness the tripping and relay operation at the applicant's DER site during the testing.

6.2 Authority Having Jurisdiction Inspections and Permits

Before the applicant's DER can be commissioned, it must meet all relevant requirements of government AHJs. This includes passing all relevant inspections and obtaining all relevant permits including those related to construction, electrical, and safety codes.

6.3 Metering Commissioning

Each new DER interconnection requires testing and verification by PGE of the applicant's revenue grade metering prior to granting a certificate of completion. PGE will coordinate with the applicant to schedule a date for commissioning and witness testing as PGE requires the applicant be present during the metering commissioning.

For inverter-based DERs, PGE will verify inverters are capable of generating, the PGE-installed meter, and any additional PGE equipment is working properly during testing. For testing of machine-based DER, PGE will verify proper operation of PGE-installed metering and any other equipment. The metering tests are conducted and recorded per PGE's testing and maintenance standards.

6.4 Witness Testing

In addition to metering commissioning, PGE conducts, as appropriate, onsite witness tests (for example, visual verification) of DERs before new or modified DERs are energized to check the DER complies with all relevant interconnection safety and reliability requirements. For applicant interconnection equipment that does not meet the definition of lab-tested equipment, the witness test may, at PGE's discretion, also include a system design and production evaluation according to IEEE 1547-2003.

The overall scope of the witness test may include but not be limited to communications verification, points list verification, verification of normal operations, and verification of critical functions (for example, loss of communication circuits, transfer trip, transfer trip disabled, breaker operations). Additionally, the PGE team performing the witness test reserves the right to check nameplate capacities on the facilities inverters.

A witness test checklist applicable to small generator DERs, including a list of documents that must be provided by the applicant, is provided in Section 15.

7 Operation and Maintenance of Customer Facilities

The interconnection standards of PGE do not end when the DER is energized. They must be adhered to for the full duration of the interconnection agreement, whether or not the DER ceases producing electricity. For a small generator that is a QF, there may be additional operational requirements in an applicant's power purchase agreement (PPA) with PGE. Some key operations and maintenance requirements are summarized below.

7.1 Overall Operation and Maintenance Standards

Per OAR 860-082 (small generator) and OAR 860-039 (net metering), the applicant must operate and maintain its DER and associated interconnection equipment in compliance, at all times, with applicable federal, state, and local government laws and regulations, IEEE standards, good utility practice, its interconnection agreement, and, as applicable, the PPA with PGE.

Changes to DER operating or maintenance practices that conflict with federal, state, or local government laws and regulations, IEEE standards, good utility practice, the interconnection agreement, or the PPA are not allowed without PGE review and approval. Any changes other than minor equipment modifications as defined by OAR 860-082 (small generator) or OAR 860-039 (net metering) made by the applicant without prior PGE approval may cause PGE to temporarily disconnect the DER from the PGE system. Certain modifications may necessitate a new interconnection application.

7.2 General Safety Requirements

The DER is required to cease to energize when there is a fault on the feeder to which it is connected and shall not energize the feeder when the feeder is de-energized. This also limits the applicant's DER from receiving electricity from an alternate source during a loss of service unless otherwise and explicitly stated in its interconnection agreement

7.3 Islanding

The applicant's DER must isolate itself from the PGE system in the event of a loss of service from PGE's source. The applicant's DER must also ensure it is incapable of

re-energizing the PGE system after a loss of service, creating an unintentional island. Per IEEE 1547-2003, for an unintentional island in which the DER energizes a portion of the PGE system, the DER shall locate the island and cease to energize the PGE system within two seconds of the formation of an island. Following an event, the islanded applicant may reconnect to PGE via closed transition with prior consent from PGE. The role of and rationale for transfer trips in preventing unintentional islanding under specific circumstances is described in Section 3.6.4 D. Communication requirements to support transfer trip are described in Section 3.6.4 F.

Intentional islanding is not covered in this document because it is not within the scope of IEEE 1547-2003 and 1547.1-2005, which are the IEEE DER interconnection standards referenced in State rules OAR 860-039 (net metering) and OAR 860-082 (small generator).

7.4 Temporary Disconnection

PGE or the applicant may temporarily disconnect the DER as long as necessary. PGE and the applicant must cooperate to restore normal operations for the DER as soon as practical following a temporary disconnection.

Events causing temporary disconnection include those listed immediately below. These events apply equally to all applicants except the forced-outage requirement which pertains only to small generator and CSP applicants.

- ➢ Emergency Conditions – In emergencies, PGE or the applicant may immediately disconnect the DER with no prior notice. The party disconnecting the service must notify the other party promptly and provide available information on the causes and expected impacts, duration, and corrective actions needed.

- Routine Maintenance – PGE or the applicant must make an effort to provide notice to the other party of at least 5 business days before it conducts maintenance, repair, or construction on the DER or PGE system that requires disconnection.
- Forced Outage – When the utility makes repairs to the PGE system requiring a forced outage, PGE will use reasonable efforts to provide notice to the applicant prior to the disconnection. If prior notice is not given, PGE will document the circumstances of the disconnection.
- Disruption or Deterioration of Service – If PGE determines that continued operation of the applicant's DER will likely cause either disruption or deterioration of utility service to other PGE customers, or damage to the PGE system, PGE may disconnect the DER and provide relevant documentation of its decision to the applicant, upon request. In emergencies, no prior notice is required for such disconnections. In non-emergencies, PGE allows the small generator or CSP applicant 5 business days to remedy the DER's condition before disconnection.
- DER Changes other than Minor Equipment Modifications – If such modifications are made by the applicant prior to the changes being approved in writing by PGE, the utility may disconnect service.

In addition to the temporary disconnection provisions noted above, PGE may require an annual test in which a Net Meeting, CSP, or an inverter-based small generator DER is disconnected from the PGE system to ensure that the DER's inverter stops delivering power to the utility grid.

7.5 Labeling

All DER systems are required to follow the labeling requirements as outlined by the National

Electrical Code, National Electrical Safety Code, Occupational Safety and Health Administration, the AHJ(s), the State of Oregon, and their agreements with PGE. Labeling should be made of an engraved metal or plastic. It must be permanently affixed to the meter base, AC disconnect (when one is required), or switchgear.

If the AC disconnect is more than 10 feet from the meter, then a permanent placard must be posted at the meter indicating the location of the switch. The labeling must be approved by PGE prior to posting.

PGE will install labeling on customer switchgear indicating the location of the PTs and CTs to aid with switching during emergencies

7.6 Special Access Issues for Isolation Devices

The applicant may request approval from PGE to provide access to an isolation device that is contained in a building or area that may be unoccupied, locked, or otherwise not readily accessible to outside parties. If a request to PGE is made and approved, the applicant must provide a lockbox capable of accepting a lock provided by PGE that provides ready access to the isolation device. The applicant must install the lockbox in a location that is readily accessible by PGE and must affix a placard in a location acceptable to PGE that provides clear instructions on how to access the isolation device. PGE must review and approve the placard design and language prior to its placement.

7.7 Frequency Stability

PGE is responsible for maintaining system frequency at 60 Hertz (Hz) across its service territory per standard system requirements across the United States electric grid. PGE requires that all DER operate in sync with PGE's 60 Hz system frequency. Unless otherwise noted as part of a frequency response program, PGE requires that the DERs be able to immediately disconnect itself from the PGE system and cease operations once its output frequency strays from the allowable limits set by IEEE 1547, Clause 6. DERs must also be capable of high and low frequency ride through according to the same standard. Furthermore, DER must be capable of operating in droop control according to the requirements of that standard. PGE will coordinate with the applicant on specific design requirements to support frequency response program participation as needed.

7.8 Record-Keeping and Retention

When a DER undergoes maintenance or testing in compliance with the OAR 860-082 (small generator) or OAR 860-039 (net metering), the applicant must retain written records documenting the maintenance and the results of testing for at least seven years. The applicant must provide copies of these records to PGE upon request.

7.9 Special Issues Related to Energy Storage

Energy storage (ES DER), having unique capabilities as both a source and a load must only be operated in modes consistent with the project's interconnection application materials submitted to PGE, approved by PGE, and the interconnection agreement. If an energy storage DER is expected to change its operating modes outside those that PGE approved, PGE must be contacted to determine if further review is required.

8 Customer Equipment Requirements

Small generator applicants must meet all requirements in OAR 860-082 (small generator). Net Metering applicants must meet all requirements in OAR 860-039 (net metering). CSP applicants must meet all requirements in OAR 860-088 (CSP). DER and related customer equipment must also meet standards as designated by PGE and local electrical and building codes. Descriptions of certain equipment requirements are summarized below.

8.1 Inverters

Inverters must be UL 1741-tested and compliant. Non-UL 1741 inverters will not be considered. Any material modifications to the inverter's standard settings must be noted with the interconnection application materials. These may include, but are not limited to, static or dynamic power factor adjustments, use of smart inverter functionality, and permanent curtailment of the maximum inverter output compared to its AC nameplate capacity provided by the inverter manufacturer.

8.2 Supervisory Control and Data Acquisition

PGE offers direction to applicants on Supervisory Control and Data Acquisition (SCADA) requirements for their DER on an individual project basis. An example SCADA schematic is provided in Figure 1 below. That schematic represents a general cable and conduit design. Applicants' individual site requirements may alter the design, and applicants must coordinate with PGE on any changes to the design.

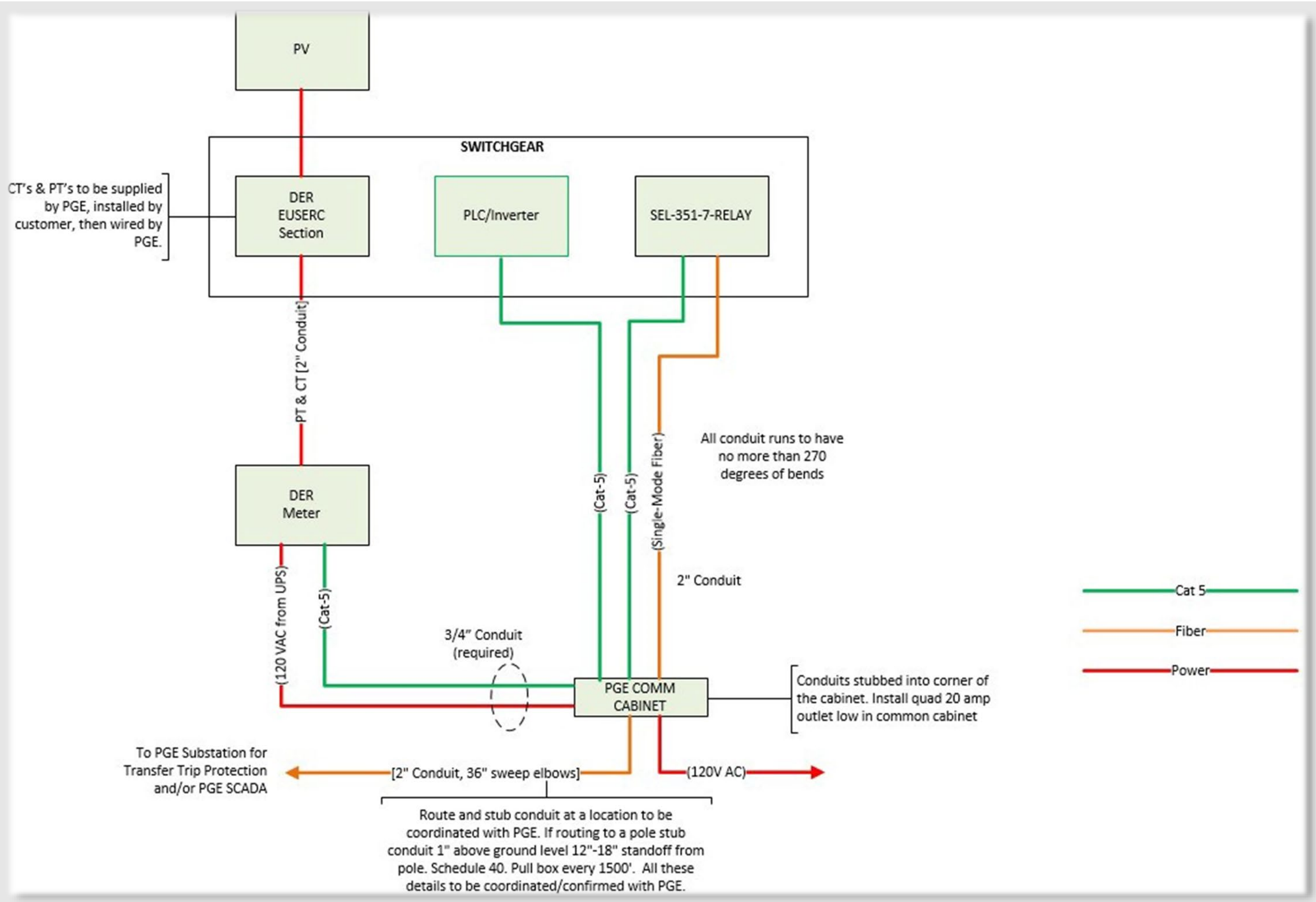


Figure 1: Example Schematic of SCADA Cable and Conduit Requirements for DER

Metering requirements as they relate to SCADA are described in Section 9.

8.3 Effective Grounding

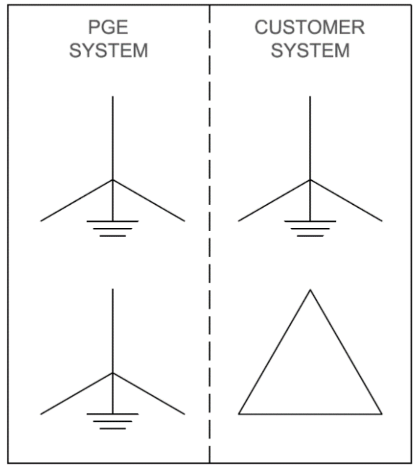
Grounding and bonding are critical for safety and electrical reliability. The applicant is responsible for ensuring the DER's electrical wiring and service equipment is grounded and bonded in accordance with applicable National Electrical Code requirements.

The DER must also provide the same level of effective grounding as the PGE system to avoid an adverse impact on the PGE system. Maintaining effective grounding is critical to protecting equipment of PGE and its customers. PGE system grounding is designed to provide a path of least resistance for potentially damaging electrical current following a surge or fault on the PGE system.

As noted in Overvoltage (3V0) Protection, faults on the PGE system may create an overvoltage condition as high as 173% of the nominal voltage in the absence of effective grounding. Requiring effective grounding ensures potentially damaging, temporary overvoltages remain in the tolerable limits of 125% – 138% of nominal voltage. More information on acceptable transformer configurations and grounding requirements can be found in Section 8.4.

8.4 Electric Service Requirements

PGE's Electric Service Requirements (ESR) are to be followed in full. The latest version of the ESR is available on PGE's website. Within the ESR, guidance (in Section 3.10.4 of the ESR) on customer-owned transformers beyond the point of delivery must be followed, if applicable. See Figure 2 below.



ACCEPTABLE INTERCONNECTION CONFIGURATIONS

Figure 2 STD-D-6901: Interconnection Configurations Acceptable

8.5 Disconnecting Devices

For secondary voltage connections of parallel operations, a lockable AC disconnect switch is required (with very limited exceptions per OAR 860-082-0030(4)(b)). This switch must be within 10 feet of the interconnection meter unless another location has been approved by PGE.

For primary voltage connections, lockable switching equipment (disconnect switch, breaker, or recloser) with a visible break to isolate the DER from the PGE system is required.

8.5.1 Plot Plan

If an AC disconnect switch or switching equipment is required, then a single-line diagram and site plan must be included in the interconnection application. The single-line diagram must show the complete circuit between the DER and the proposed POI or PCC, including all protective devices and transformers. The site plan must show the DER location and the accessibility of the disconnect switch. Example single-line diagrams can be found in Section 12.

8.6 Protection Devices (Relays)

The applicant is responsible for the protection of its DER. For primary voltage interconnections, the applicant is required to have overcurrent protection to isolate PGE from a disturbance on the DER. For proposed three-phase DER interconnections, overvoltage and undervoltage relaying must be included on each phase, and overfrequency and underfrequency must be included on at least one phase. Three-phase systems must also be gang operated if any single phase of the protection devices detect a power quality violation. More information on the exact relay types and settings that comply with PGE protection standards can be found in Relay Types and Settings on the next page.

As explained in Section 3.6.4 D, if PGE determines that transfer trip is required, the applicant must install a relay or ancillary device that uses SEL Mirrored Bits. Under this configuration, the applicant is expected to need an SEL transceiver and fiber optic jumper to connect to PGE's patch panel.

8.6.1 Relay Types and Settings

The settings required by PGE for each relay type correspond to the default settings in IEEE 1547-2003. Settings within the ranges provided by IEEE 1547-2003 for each relay type, along with brief descriptions of the purpose of each relay type, are provided for reference in Table 4 below. All relay types may not be applicable to a particular DER.

Table 4: Settings and Descriptions of Relays

Related Type	Trip Setting	Purpose
Undervoltage with time delay	70% of nominal voltage with a 2.0 second time delay	Detect undervoltage conditions as a result of unintentional islands or other abnormal operations
Overvoltage with time delay	120% of nominal voltage with a 0.16 second time delay	Detect overvoltage conditions as a result of unintentional islands or other abnormal operations
Overfrequency with time delay	62.0 Hz with a 0.16 second delay	Detect overfrequency conditions as a result of unintentional islands or other abnormal operations
Underfrequency with time delay	56.5 Hz with a 0.16 second delay	Detect underfrequency conditions as a result of unintentional islands or other abnormal operations
Distance Relaying	Set by PGE	Detect faults on the transmission system and isolate the DER to remove any additional generation to the fault contribution
Negative Sequence Overcurrent / Overvoltage	Set by the applicant and approved by PGE	Detect upstream protection device operations to improve fault sensitivity
Synchronism Check	Set by the applicant and approved by PGE	Ensure synchronous operations of the DER

8.7 Ancillary Devices

If the applicant is installing relays incapable of sending/receiving Mirrored Bits, then an ancillary device can be used to translate Mirrored Bits to the relay. This device will have hard-wired inputs and outputs as well as a fiber connection for the Mirrored Bits. Typical devices are the SEL-2505 and SEL-2506. Check with PGE on Fiber Type needed.

8.8 Surge Arresters

Voltage surges and transients are considered temporary overvoltages of various levels, durations, frequencies, and repetition. Such occurrences can overheat arresters and cause failure. If the voltage surges and transients as a result of the proposed DER cannot be mitigated through other means, the applicant's installation of additional surge arresters or surge arresters with higher maximum continuous operating voltage ratings may be required. PGE's surge arrester requirements related to DER are based on IEEE standards C37.90.1-2002 and C62.41.2-2002, as well as good utility practice.

8.9 Paralleling Devices

When a DER is generating for a duration of 100 milliseconds (ms) or more while connected to the PGE system, the DER is considered to be in parallel operation. Per IEEE 1547-2003, the paralleling device shall be capable of withstanding 220% of the interconnection system rated voltage.

8.9.1 Secondary Service

PGE provides the following secondary voltages (underground/overhead):

- Single-phase, 120/240 V, three-wire, grounded
- Single-phase, 240/480 V, three-wire, grounded
- Three-phase, 208Y/120 V, four-wire, grounded, wye
- Three-phase, 480Y/277 V, four-wire, grounded, wye

8.9.2 Medium Voltage Service

PGE's medium voltage system has a nominal operating voltage of 12.47 kV, with a maximum design voltage of 15.5 kV. High-voltage instrument transformers and transformer-rated meters are required for applicants taking service at medium voltage. PGE's Medium Voltage Requirements are to be followed in full. The latest version of the Medium Voltage Requirements book is available on PGE's website.

PGE will provide medium voltage delivery to qualified applicants directly, without transformation, from the medium voltage electrical distribution facilities (standard for the location in which service is requested) if the following conditions apply:

- The service at medium voltage will not, in the judgment of PGE, adversely affect the operation of the PGE system or service to other customers.
- The service supplied is distributed in a safe and reliable manner.
- The applicant provides switching devices with appropriate overcurrent protection to isolate the PGE system from disturbance on the applicant-owned primary facility.
- The applicant is responsible for the operation and maintenance of all applicant-owned equipment. PGE does not provide replacement parts for applicant-owned equipment. PGE will not energize applicant-owned facilities beyond the point of delivery.
- As stated in Section 3.6.4 F and Section 8.6, the applicant is responsible for all communications equipment (for example, fiber jumpers, transceivers) behind the terminating fiber optic patch panel at the applicant site. This is typical for sites requiring transfer trip. However, this demarcation point may be further downstream for sites without direct transfer trip.

9 Metering Requirements

The applicant is responsible for all costs associated with the metering and data acquisition equipment as outlined in this section. PGE and the applicant must have unrestricted access to metering and data acquisition equipment to conduct routine business or respond to an emergency. This section summarizes PGE's interconnection service voltages and associated metering equipment.

9.1 Secondary Service (up to 600 V)

PGE's ESR provides interconnection and equipment requirements for relocated, rewired, and new services. Refer to Section 3 of the ESR for general service requirements.

For single-phase services over 320 A or three-phase services over 200 A, the applicant must submit a drawing package for PGE review. The package must contain a site plan, electrical one-line, electrical room layout (if applicable), working clearances, and manufacturer drawings with EUSERC references. The applicant must receive confirmation that equipment meets PGE requirements from PGE Meter Engineering prior to installation.

Refer to PGE's ESR Section 10 for commercial, industrial, and large residential service entrance ratings of 800 A or lower.

Refer to PGE's ESR Section 11 for commercial, industrial, and large residential service entrance ratings of 801 A or greater.

9.2 Medium Voltage Service (greater than 600 V)

The applicant must consult with PGE regarding services greater than 600 V prior to construction. PGE's Medium Voltage requirements are available in the Medium Voltage book. The applicant must apply for service and obtain an approved job sketch before construction. The Switchboards must meet EUSERC Section 400 requirements for service voltages of 12.47 kV. The metering equipment must be located within 100 feet of the POI. Consult with PGE regarding equipment requirements for service voltage of 34.5 kV.

The applicant must submit drawings of metering equipment to PGE for review. Information required in the drawing package is provided in PGE's Medium Voltage Example Drawing Package. The applicant must receive the Medium Voltage Service Review Complete letter that includes engineering technical review feedback before ordering equipment. Drawings must include the company name, job address, contact address, and phone number of the manufacturer's representative.

The applicant must install an AC disconnect on load-side, or down-stream of PGE metering equipment to separate the applicant's DER from the PGE system. The AC disconnect switch is intended for PGE use only. The AC disconnect separates the applicant's equipment from the PGE system to provide a visible open for PGE personnel. The AC disconnect requirement is in addition to any disconnecting means, overcurrent protective devices, or switching equipment provided by the applicant. Please note that in some cases, PGE may require a line side disconnection in addition to the load side disconnect.

IMPORTANT: PGE personnel will not close the AC disconnect. Closing the AC disconnect to energize the service, or pick up load, is the responsibility of the applicant. PGE personnel will not close any equipment owned and operated by PGE that will result in energization of applicant equipment, or picking up load; such equipment includes, but is not limited to cables, breakers, or arresters.

Microgrid projects are not applicable to this document and will be evaluated on an individual basis.

9.2.1 Switchgear Enclosure Customer Requirements

The applicant must provide and install:

- All necessary hardware per EUSERC Section 400
- Load side disconnect switch
- Clear workspace 78-inches high, 48-inches deep, and as wide as the PGE metering equipment
- Concrete mounting vault (with a minimum 4-inch-thick concrete pad) for the switchgear metering enclosure when necessary

9.2.2 Switchboard Enclosure PGE Requirements

PGE will provide the following:

- Meter
- Meter test switch
- Instrument CTs and PTs and secondary metering wiring
- The primary disconnecting means

9.3 Instrumentation

The applicant must consult PGE for specifications on instrument transformers, the meter test switch, and secondary wiring of instrument transformers prior to ordering the meter enclosure. Enclosure drawings with a site plan and electrical room detail must be provided to PGE for approval prior to installation.

PGE will specify and purchase all revenue metering instrument transformers (CTs and PTs). PGE will provide the instrument transformers to the applicant for applicable switchboard and primary services for the applicant to install. PGE will install the test switch and all secondary meter wiring. All instrument transformers must meet IEEE C57.13-2016 revenue metering requirements and will only be used for PGE revenue metering devices.

9.4 End-Use Customer Switchboard Requirements

All commercial, industrial, and large residential electricity customers of PGE must coordinate their service requirements with PGE. They must provide factory-produced submittal drawings of metering equipment before purchase and installation. Single residential services over 320-amp continuous and all three-phase residential services are considered large residential services.

For commercial, industrial, and large residential service entrance ratings of 800 amps or lower:

- Single-phase services over 320 amps continuous, and three-phase services over 200 amps, require CT metering except as referenced in Section 10.3 of the ESR.
- Refer to Section 10 of the ESR for comprehensive service requirements.

For commercial, industrial, and large residential service entrance ratings of 801 amps or greater:

- An EUSERC-approved switchboard metering section is required.
- The switchboard metering section may be used for three-phase services over 200 amps and single-phase service over 320 amps.
- The metering will be located in the CT section of the cabinet/compartment. The exact location and cabinet requirements are determined by PGE during the metering review.
- The meter and test switch may be mounted on the cover of the hinged compartment or located remotely.

- The area below the barrier in this compartment may be used as a main switch (or breaker) compartment, a load distribution compartment, or a bottom-fed terminating pull section.
- The metering compartment shall be on the supply side of the main switch.
- The mounting pad for all switchboard metering enclosures will be a minimum 4-inch-thick concrete pad.

Refer to Section 11 of the ESR for comprehensive service requirements

9.5 Metering Considerations with Energy Storage

Similar to other DER, appropriate revenue grade metering shall be installed and owned by PGE. Additional behind-the-meter telemetry may be required at the discretion of PGE to distinguish between net and gross electricity consumption at the customer premises for PGE operational or planning purposes

9.6 Telemetry

Consistent with OAR 860-082 (small generator) and IEEE 1547-2003, PGE requires monitoring of connection status, real power output, reactive power output, and voltage at the point of connection for interconnections of small generator and CSP DERs with capacity of 3 MW and larger.

More specifically, the following data points represent the minimum required data points to be provided to PGE by way of an ethernet connection to PGE's communications rack installed at the DER location. These points are in addition to any data communications that may be required if the DER location requires transfer trip protection:

- Net real power flowing out or into the small generator facility (analog).
- Net reactive power flowing out or into the small generator facility (analog).
- Bus bar voltage at the POI (analog).
- Communications heartbeat (used to validate the communications path functionality). The logic for the heartbeat is based on both ends of the communications path incrementing the value received and sending the new value out. When the value received reaches a prescribed value, the value is reset. Applicants must coordinate with PGE to ensure compatible logic is used, which requires sending and receiving analog values.

- Online or offline prime mover status (digital). The applicant must coordinate with PGE in the event of multiple prime movers (for example, generation or energy storage technologies).

If an applicant operates equipment associated with a high-voltage switchyard interconnecting the DER to the PGE system and is required to provide monitoring and telemetry, then the applicant must provide the following data to PGE in addition to the data above:

- Switchyard line and transformer MW and MVA values
- Switchyard bus voltage
- Switching device status

The communication must take place via a private network link using a device and protocol deemed suitable by PGE (for example, a remote terminal unit provided by a Distributed Network Protocol (DNP)3 Level 2 compliant outstation). The DNP3 device profile from the outstation vendor must also be provided to PGE.

PGE requires the following from the DNP3 device:

- Specified DNP3 object types and variations for statuses and analogs
- Statuses included in Polling Class 0 (static value or current state) and Polling Class 1 (static events)
- Outstation capable of responding to interval event polling and interval integrity polling

9.7 SCADA Metering

For SCADA-connected DER, the metering will be consistent with the schematic in Figure 3. That schematic represents a general wall-mounted, remote meter base design. An applicant's individual site requirements may alter the design, and the applicant must coordinate with PGE on any changes to the design.

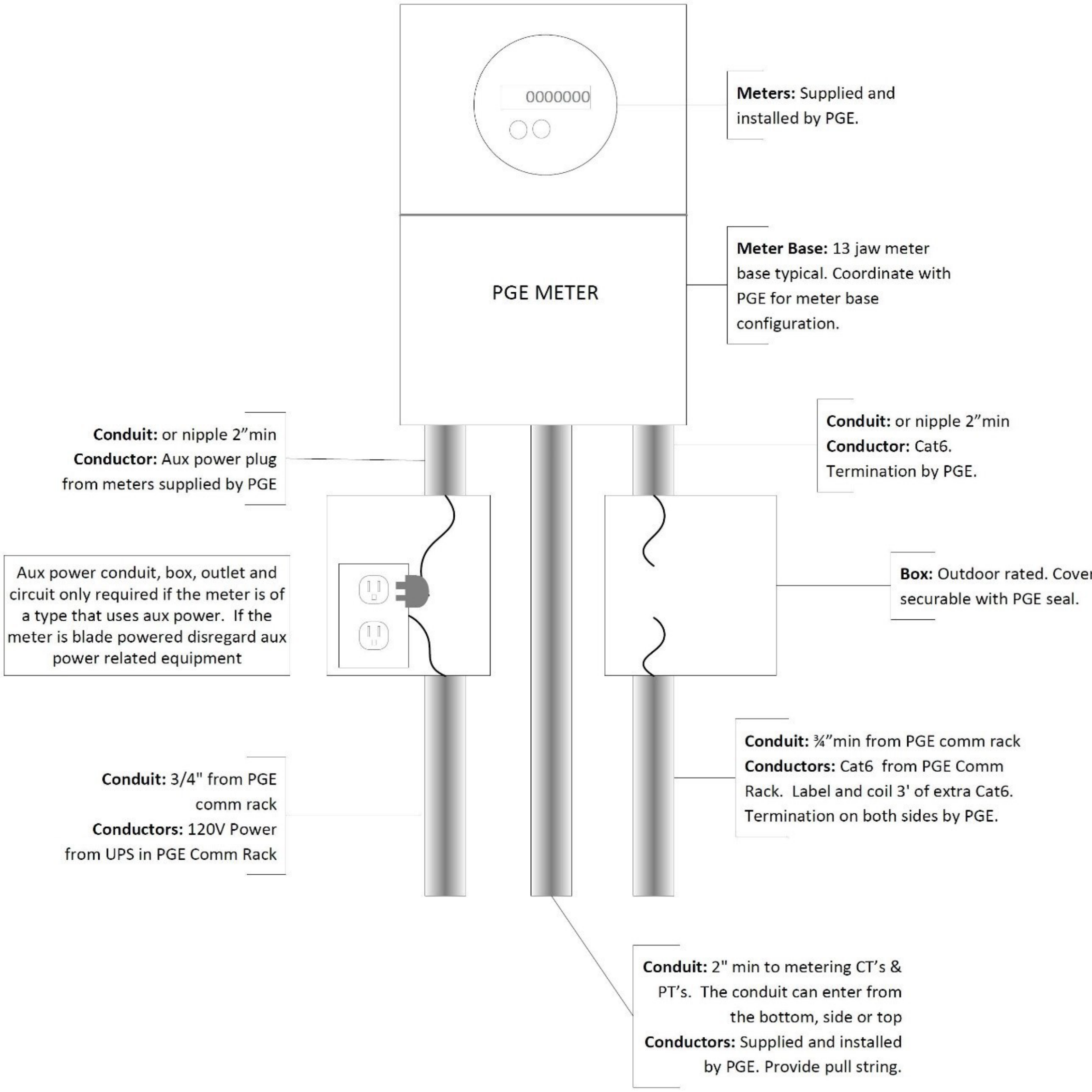


Figure 3: SCADA Remote Meter Base Configuration for DER

9.8 Interoperability

PGE expects to address interoperability in future versions of this document, after pertinent

OAR documents adopt recent IEEE standards. The IEEE standard upon which pertinent OAR documents are currently based does not address interoperability.

10 Additional Technical Requirements for Parallel Operations on Secondary Networks

By definition, when a DER is serving as a source of electric power for greater than 100 ms while connected to the PGE system, the DER is in parallel operations. Interconnection to a secondary network system for parallel operations is limited due to PGE system risks related to cycling network protectors and potential islanding of customers. Although common rules exist for the general network system, there are additional interconnection rules when addressing grid or spot networks.

10.1 Secondary Grid Network Interconnection

For interconnection to a secondary grid network (also called an area network), PGE can accommodate new or modified DER up to an aggregate DER capacity not exceeding the lesser of 5% of the associated network system's peak load, 10% of the minimum load for Net Metering interconnections, or 50 kilowatts (kW). If either of these thresholds are met, no additional DER can be added to the network system.

There are no additional provisions for connecting to secondary grid networks.

10.2 Spot Network Interconnection

For interconnection to a spot network, PGE can accommodate new or modified DER if aggregate DER capacity does not exceed the lesser of 5% of the spot network's peak load, 10% of the minimum load for Net Metering interconnections, or 50 kW. If either of these thresholds are met, no additional DER can be added to the network system. Additional rules, per IEEE 1547-2003, are:

- Network protectors shall not be used to separate, switch, perform breaker failure back up, or isolate a network or network primary feeder to which the DER is connected from the remainder of the spot network.
- The DER shall not cause operation or prevent reclosing of any network protectors on the spot network. This coordination shall be accomplished without requiring any changes to prevailing network protector clearing time practice at PGE.

- Connection of the DER to the spot network is only allowed if the network bus is already energized by more than 50% of the installed network protectors.
- The DER output shall not cause any cycling of network protectors.
- The network equipment loading and fault interrupting capacity shall not be exceeded with the addition or modification of the DER.
- DER installations on a spot network, using an automatic transfer scheme in which load is transferred between the DER and PGE in a momentary make-before-break (closed transition) operation, shall meet the above requirements regardless of the duration of paralleling.

11 As-Built Documentation and Interconnection Checklist

Complete the following tables and submit to PGE two weeks prior to energizing of the facility. Enter as much information as possible. Return the completed tables to PGE via e-mail to Small.PowerProduction@pgn.com

11.1 DER Facility Information

Interconnection Queue Number	
Facility Name	
Facility Location	
Type of Facility	
Total AC Nameplate Rating	
Interconnection Voltage (kV)	

11.2 Nameplate Information

Inverter Manufacturer	
Inverter Model	
Inverter Nameplate Rating	
Number of Inverters	

11.3 Set Up Transformer Information

Transformer Manufacturer			
Single-Phase			
Three-Phase			
Transformer Rated Capacity (MVA)			
Percent Impedance on Transformer Base	Percent Impedance on Transformer Base		
Low Side Voltage	Delta	Wye	Taps
High Voltage Side	Delta	Wye	Taps

11.4 Documentation Checklist

Documents Required	Included
As-Built One-Line	☐
As-Built Site Plan	☐
Inverter Specification Sheet	☐
Step Up Transformer Specification Sheet	☐
Transfer Trip Relay Settings	☐
Operation and Maintenance Contact Information	☐

11.5 Interconnection Commissioning Checklist to be Completed by PGE

Requirements	Completed/Passed
PGE Horseshoe Lock in Place	☐
AC Disconnect in Place	☐
AC Disconnect has Proper Labeling	☐
Inverter(s) Match Commissioning Checklist	☐
Step Up Transformer Match Commissioning Checklist	☐
Requirements	**Completed/Passed**
Inverter Anti-Islanding Test	☐
Emergency Contact Labeling on Gate	☐

12 Example Single-Line Diagrams

Figure 4 below is an example of a single-line diagram for an inverter-based net metering project.

This diagram does not apply to DER implementing a Two-Meter Solution (See Section 8.10.)

Figure 5 is a single-line diagram example for an inverter-based small generator.

The single line for CSP projects is the same as a small generator.

These figures are provided only for illustrative purposes. Applicants must develop single-line diagrams for their applications, as needed, that are consistent with their project specifics and with all PGE technical requirements.

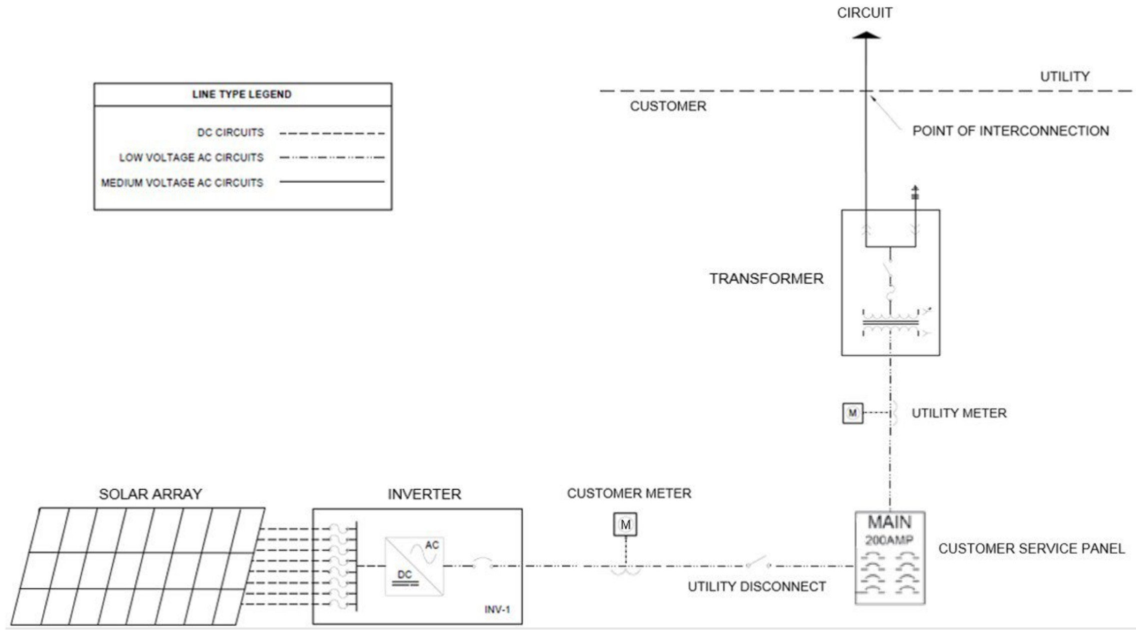


Figure 4: Example Single-Line Diagram for Net Metering Inverter-Based Project

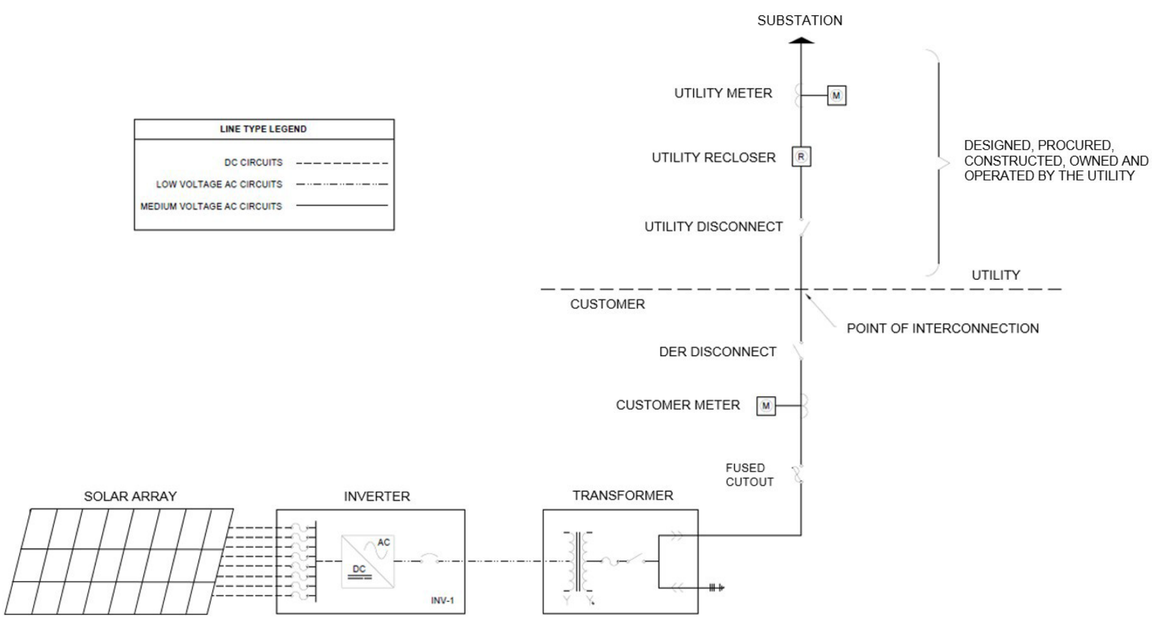


Figure 5: Example of Single-Line Diagram for Small Generator Inverter-Based Project

13 QF Energization Checklist

	Item	Task	Completion Date (mm/dd/yyyy)	Completed By
☐	13-1	PGE drawing review complete.		
☐	13-2	PGE settings review complete (if Transfer Trip is required)		
☐	13-3	Electrical inspection complete (Green Tag)		
☐	13-4	PGE system upgrades complete (Compile task list for each project/DOR)		
☐	13-5	PGE mapping changes		
☐	13-6	Customer equipment one-lines input to MyWorld		
☐	13-7	Meter Enclosure		
☐		Verify installed equipment matches drawings and meter gear review.		

	Item	Task	Completion Date (mm/dd/yyyy)	Completed By
☐	13-8	PGE Instrument Transformers		
☐		Verify three CTs and three PTs installed		
☐		Inspect CT and PT mounting, polarity, and nameplate		
☐		Inspect CT and PT secondary wiring meter		
☐		Verify PT fuses and fuse clip assembly		
☐	13-9	PGE Meter		
☐		Meter numbers		
☐		Verify meter meets accuracy requirements		
☐		Verify meter communication with MV90		
☐		Greater than 3 MW		
☐		Verified Schneider Electric ION meter installed		
☐	13-10	PGE Operations Approval for Energization		
☐		Distribution Operations Engineer approval		
☐		Grid Operations approval		

14 PGE Witness Testing Prerequisites Checklist

These are the prerequisites for the witness testing of the site. Once all the steps below are completed the developer will be allowed to generate power for testing purposes.

	Item	Task	Completion Date (mm/dd/yyyy)	Completed By
☐	14-1	PGE to run approved switching sheet		
☐	14-2	Site protection system in-service		
☐	14-3	Transfer trip verified complete by PGE		
☐	14-4	Communications from PGE relay to developer device is functional		
☐	14-5	Developer device trips the proper protective device		
☐	14-6	SCADA system in service (if QF site generating more than 3 MW)		
☐	14-7	Final as-left relay settings provided to PGE (.rdb)		
☐	14-8	Meter approved for Generation		
☐	14-9	PGE Operations approval for generation		
☐	14-10	Distribution Operations Engineer approval		
☐	14-11	Grid Operations approval		
☐	14-12	PPA owner approval		

15 PGE Witness Testing Checklist

	Item	Task	Completion Date (mm/dd/yyyy)	Completed By
☐	15-1	As-built drawings provided (.pdf)		
☐	15-2	Proper signs are installed on the gate and switchgear		
☐	15-3	PGE locks are installed on all equipment and gates		
☐	15-4	Anti-islanding test is performed (Meterman to check COMM after test completed)		
☐	15-5	PGE Operations approval for Permission to Operate		
☐	15-6	Distribution Operations Engineer approval		
☐	15-7	Grid Operations Approval		
☐	15-8	PPA Owner approval		
☐	15-9	Permission to Operate letter sent.		

16 Appendix

16.1 Overview of Steps for Small Group Interconnections

The flow chart below, Figure 6, provides a basic sequencing of steps involved in the interconnection of small generator DER on the PGE system. This chart begins with submission of the interconnection application by the applicant to PGE's secure, web-based PowerClerk portal. The chart is provided for illustrative purposes only. small generator applicants must follow the interconnection procedures described in OAR 860-082 (small generator), as implemented by PGE consistent with pertinent technical standards and good utility practice.

Moreover, the duration and requirements of any individual step in the flow chart can vary widely between applicants based upon their DER nameplate capacity and facility type, application tier, DER design, conditions at the proposed POI, responsiveness to PGE information requests, and other factors.

See Section 2.3.5 and Section 3.4 for descriptions of time requirements for basic steps in the interconnection processes for small generator Tier 1, Tier 2, Tier 3, and Tier 4 DER.

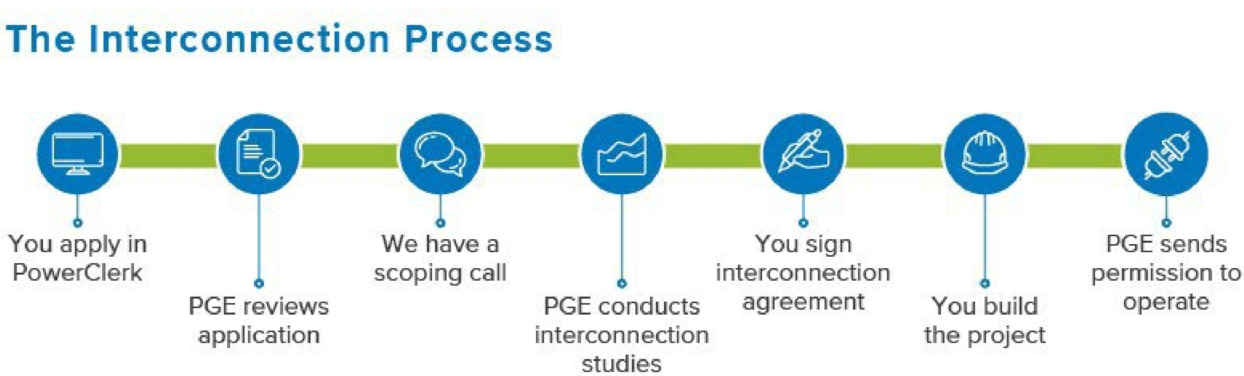


Figure 6: Overview Flow of Small Chart Generator Interconnection Process

16.2 Tables with Timeframes Specific to Small Generator Interconnections

The following 4 tables describe major steps and time requirements in the interconnection of small generator DER. The tables are provided for illustrative purposes only. small generator applicants must follow the interconnection procedures described in OAR 860-082 (small generator) as implemented by PGE consistent with pertinent technical standards and good utility practice.

Table 5: Summary of Interconnection Steps and Timing Specific to Tier 1 Small Generator Applications

General Process Overview for Small Generator Interconnection – Tier 1	
Application	PGE to give notice to the applicant within 10 business days of whether the application is complete. If the application is incomplete, PGE to provide list of information needed to complete the application. Applicant to provide the requested information within 10 business days of receipt of the PGE list or the application is withdrawn.
Interconnection Studies	PGE to analyze the interconnection request based on the criteria listed in OAR 860-082-0045 and good utility practice. If a small generator facility is not approved under the Tier 1 interconnection screening procedure, the applicant may submit a new application under the Tier 2, Tier 3, or Tier 4 screening procedures. At an applicant's request, PGE will provide a written explanation of the reasons for denial within 5 business days of receipt of the request.
Interconnection Agreement	PGE to deliver an executable interconnection agreement to the applicant within 5 business days after approval of an interconnection application. Applicant to execute the interconnection agreement within 15 business days of receipt or the application is withdrawn.
Commissioning	Applicant to provide PGE written notice at least 20 business days before the planned commissioning for the small generator facility. PGE has the option of conducting a witness test at a mutually agreeable time within 10 business days of the scheduled commissioning.

General Process Overview for Small Generator Interconnection – Tier 1	
	PGE to provide written notice to the applicant indicating whether PGE plans to conduct a witness test or waive the witness test. If PGE notifies the applicant that it plans to conduct a witness test but fails to conduct the witness test within 10 business days of the scheduled commissioning date or within a time otherwise agreed upon by applicant and PGE, the witness test is waived. If the witness test is conducted and is not acceptable to PGE, PGE to provide written notice to the applicant describing the deficiencies within 5 business days of conducting the witness test. PGE to provide the applicant 20 business days from the date of the applicant's receipt of the notice to resolve the deficiencies. If the applicant fails to resolve the deficiencies to the satisfaction of PGE within 20 business days, the application is withdrawn.

Table 6: Summary of Interconnection Steps and Timing Specific to Tier 2 Small Generator Applications

General Process Overview for Small Generator Interconnection – Tier 2	
Application	PGE to give notice to the applicant within 10 business days of whether the application is complete. If the application is incomplete, PGE to provide list of information needed to complete the application. Applicant to provide the requested information within 10 business days of receipt of the PGE list or the application is withdrawn.
Scoping Meeting	PGE to schedule the scoping meeting within 10 business days of notifying the applicant that the application is complete.
Interconnection Studies	PGE to analyze the interconnection request based on the criteria listed in OAR 860-082-0050 and good utility practice. If a small generator facility is not approved under the Tier 2 interconnection screening procedure, the applicant may submit a new application under the Tier 3 or Tier 4 screening procedures. At applicant's request, PGE to provide a written explanation of the reasons for denial within 5 business days of receipt of the request. When a higher-queued interconnection request withdraws from the queue, PGE reserves the right to restudy a project as the interconnection requirements may have changed.

General Process Overview for Small Generator Interconnection – Tier 2	
Interconnection Agreement	PGE to deliver an executable interconnection agreement to the applicant within 5 business days after approval of an interconnection application. Applicant to execute the interconnection agreement within 15 business days of receipt or its application is withdrawn.
Commissioning	Applicant to provide PGE written notice at least 20 business days before the planned commissioning for the small generator facility. PGE has the option of conducting a witness test at a mutually agreeable time within 10 business days of the scheduled commissioning. PGE to provide written notice to the applicant indicating whether PGE plans to conduct or waive the witness test. If PGE notifies the applicant that it plans to conduct a witness test but fails to conduct the witness test within 10 business days of the scheduled commissioning date or within a time otherwise agreed upon by applicant and PGE, the witness test is waived.

Table 7: Summary of Interconnection Steps and Timing Specific to Tier 3 Small Generator Application

General Process Overview for Small Generator Interconnection – Tier 3	
Application	PGE to give notice to the applicant within 10 business days of whether the application is complete. If the application is incomplete, PGE to provide list of information needed to complete the application. Applicant to provide the requested information within 10 business days of receipt of the PGE list or the application is withdrawn.
Scoping Meeting	PGE to schedule the scoping meeting within 10 business days of notifying the applicant that the application is complete.
Interconnection Studies	PGE to analyze the interconnection request based on the criteria listed in OAR 860-082-0055 and good utility practice. If a small generator facility is not approved under the Tier 3 interconnection screening procedure, applicant may submit a new application under Tier 4 screening procedures.

General Process Overview for Small Generator Interconnection – Tier 3	
	At the applicant's request, PGE to provide a written explanation of the reasons for denial within 5 business days of receipt of the request. When a higher-queued interconnection request withdraws from the queue, PGE reserves the right to restudy a project as the interconnection requirements may have changed.
Interconnection Agreement	PGE to deliver an executable interconnection agreement to the applicant within 5 business days after approval of an interconnection application. Applicant to execute the Interconnection Agreement within 15 business days of receipt or its application is withdrawn.
Commissioning	Applicant to provide PGE written notice at least 20 business days before the planned commissioning for the small generator facility. PGE has the option of conducting a witness test at a mutually agreeable time within 10 business days of the scheduled commissioning. PGE to provide written notice to the applicant indicating whether PGE plans to conduct or waive the witness test. If PGE notifies the applicant that it plans to conduct a witness test but fails to conduct the witness test within 10 business days of the scheduled commissioning date or within a time otherwise agreed upon by applicant and PGE, the witness test is waived. If the witness test is conducted and is not acceptable to PGE, PGE to provide written notice to the applicant describing the deficiencies within 5 business days of conducting the witness test. PGE to provide the applicant 20 business days from the date of the applicant's receipt of the notice to resolve the deficiencies. If the applicant fails to resolve the deficiencies to the reasonable satisfaction of PGE within 20 business days, the application is withdrawn.

Table 8: Summary of Interconnection Steps and Timing Specific to Tier 4 Small Generator Applications

General Process Overview for Small Generator Interconnection – Tier 4	
Application	PGE to give notice to the applicant within 10 business days of whether the application is complete. If the application is incomplete, PGE to provide list of information needed to complete the application. Applicant to provide the requested information within 10 business days of receipt of the PGE list or the application is withdrawn.
Scoping Meeting	PGE to schedule the scoping meeting within 10 business days of notifying the applicant that the application is complete. PGE to give notice of approval of the application to the applicant within 15 business days of scoping meeting if no studies are necessary, no system upgrades or facility modifications are required, and no safety or reliability issues are identified.
Feasibility Study	PGE to deliver the Feasibility Study Agreement to the applicant within 5 business days of the scoping meeting. Applicant to execute the Feasibility Study Agreement within 15 business days or its application is withdrawn. PGE to provide the study results to the applicant within 5 business days of study completion.
System Impact Study	PGE to deliver the System Impact Study Agreement to the applicant within 5 business days of completing the feasibility study or following the scoping meeting date if no feasibility study is required or the need for a feasibility study is waived. Applicant to execute the System Impact Study Agreement within 15 business days of receipt or its application is withdrawn. PGE to give notice of approval of application to the applicant within 15 business days of completion of the system impact study if all criteria are met and no interconnection facilities or system upgrades are required. PGE to provide the study results within 5 business days of study completion.
Facilities Study	PGE to deliver the Facilities Study agreement to the applicant within 5 business days after the scoping meeting if no feasibility study or system impact study is needed. Applicant to execute the Facilities Study Agreement within 15 business days of receipt or its application is withdrawn.

General Process Overview for Small Generator Interconnection – Tier 4	
	PGE to give notice of approval of application within 15 business days after the applicant agrees to pay for the interconnection facilities and system upgrades identified in the facilities study. PGE to provide the study results to the applicant within 5 business days of study completion.
Interconnection Agreement	PGE to deliver an executable interconnection agreement to the applicant within 5 business days after approval of an interconnection application. Applicant to execute the interconnection Agreement within 15 business days of receipt or its application is withdrawn.
Commissioning	Applicant to provide PGE written notice at least 20 business days before the planned commissioning for the small generator facility. PGE has the option of conducting a witness test at a mutually agreeable time within 10 business days of the scheduled commissioning. PGE to provide written notice to the applicant indicating whether PGE plans to conduct a witness test or waive the witness test. If PGE notifies the applicant that it plans to conduct a witness test but fails to conduct the witness test within 10 business days of the scheduled commissioning date or within a time otherwise agreed upon by applicant and PGE, the witness test is waived. If the witness test is conducted and is not acceptable to PGE, PGE to provide written notice to the applicant describing the deficiencies within 5 business days of conducting the witness test. PGE to provide the applicant 20 business days from the date of the applicant's receipt of the notice to resolve the deficiencies. If the applicant fails to resolve the deficiencies to the reasonable satisfaction of PGE within 20 business days, the application is withdrawn.

16.3 DER Transfer Trip Settings

Table 9: **Mirrored Bits Sent from PGE to DER (As seen by the DER)**

Word Bit	PGE Initiating Action	DER Resulting Action	Time Delay on Resulting Action
RMB1A	Feeder Trip	Initiates DTT of DER	0
RMB2A	Feeder 52a	DER must trip if this signal is lost	0.1 seconds
RMB3A	DER TT Enabled	DER must cease generating	60 seconds
RMB4A	DER DTT w/o Feeder Trip	Initiates DTT of DER	0
RMB1A	Feeder Trip	Initiates DTT of DER	0

Table 10: **Mirrored Bits Sent from DER to PGE**

Word Bit	DER Site Initiating Actor	PGE Resulting Action
TMB1A	DER Main Breaker 52a	Status only
TMB2A	Reserved for Second 52a	Status only
TMB3A	DER Online and In Parallel (See Additional Logic section if using current or power supervision)	Block feeder breaker close
TMB4A	Reserved for Second Online and in Parallel	Block feeder breaker close

Table 11: DER Transfer Trip Communications Settings

Setting	Setting Value	Description
RXDFLT	000000X0	RMB2A (52A) defaults to last received value upon loss of communications - all other RMBs default to 0.
SPEED	19200	Communications port baud rate
PROTO	MB8A	Port protocol
RMB1PU	2	RMB1A Pickup Debounce (messages)
RMB1DO	8	RMB1A Dropout Debounce (messages)
RMB2PU	2	RMB2A Pickup Debounce (messages)
RMB2DO	8	RMB2A Dropout Debounce (messages)
RMB3PU	2	RMB3A Pickup Debounce (messages)
RMB3DO	8	RMB3A Dropout Debounce (messages)
RMB4PU	2	RMB4A Pickup Debounce (messages)
RMB4DO	8	RMB4A Dropout Debounce (messages)
RBADPU	60	Mirrored Bits RX Bad Pickup Time (seconds)
CBADPU	1000	Mirrored Bits Channel Bad Pickup (parts per million)

Table 12: DER Transfer Trip Additional Logic

Setting	Setting Value	Description
Loss of Communications	SVn = !ROKA*(CBADA+RBADA)	Channel fail with security restraints. Recommend 30 second pickup and 1 second dropout. Results in soft shutdown if DER is capable of a soft shutdown in under 2 minutes – otherwise results in DER trip.
Relay Fail Alarm	ALARM	Indicates relay has a problem or has powered down. Results in soft shutdown if DER is capable of a soft shutdown in under 2 minutes – otherwise results in DER trip.
Event Trigger	CLOSE+/52A	Relay auto generates event report for Trip, this will also generate an event report for Close or closing the breaker.

Setting	Setting Value	Description
Load Detector	Positive sequence current I1_MAG comparison against current setpoint (SEL-7xx only) or 3-phase directional power element set in direction of power export.	Indicates that the DER is exporting power. 5 second dropout timer. Timer variable supervises TMB3A. Setpoint of power or current supervision equivalent to 250 kW or less.

Table 13: DER Transfer Trip Recommended Display Points

Display Point	Logic	Description
TT Disabled/Enabled	RMB3A	Transfer Trip Enabled
Utility 52A	RMB2A	Utility Breaker closed
DER Online/Parallel	TMB3A	DER running and in parallel
Loss of Comms	!ROKA	Loss of Comms

Table 14: DER Transfer Trip Recommended SER Points

Word Bit	Description
TMB1A	DER Main Breaker 52a
TMB2A	Reserved for Second 52a
TMB3A	DER Online and In Parallel
TMB4A	Reserved for Second Online and in Parallel
RMB1A	Feeder Trip
RMB2A	Feeder 52a
RMB3A	DER TT Enabled
RMB4A	DER DTT w/o Feeder Trip
RBADA	Mirrored Bits RX Bad Pickup Time
CBADA	Mirrored Bits Channel Bad Pickup
SVn	Loss of Communications
DER 52a	DER Main Breaker 52a
TRIP	Relay Trip
Elements in Trip Equation	Under/over voltage, frequency, overcurrent, negative sequence elements
Inputs	Inputs used

Word Bit	Description
Outputs	Outputs used
Close	Relay Close
Elements in Close Equation	Close permissive

NOTE: If the site has alternate service arrangements that allow it to switch on its own, the DER is not allowed to run on the alternate feed unless otherwise agreed to.

NOTE: If there is an intermediate device (for example, PLC) between the relay and the DER that controls the DER, there should be delay in the common fail and relay alarm outputs from the relay to the intermediate device. The delay will prevent unwanted shutdown of the DER when changing settings on the relay.

16.4 Commissioning and Witness Test Checklist for Small Generator Applicants

PGE provides the tables in Section 11 to help applicants assemble required information for the commissioning (or energization) of their DER. The information should be sent to PGE at least two weeks prior to planned commissioning of the DER on the PGE system.

16.5 Glossary

The definitions below define a selection of key terms used in this document and was drawn primarily from OAR 860-082 (small generator) and OAR 860-039 (net metering). This is not a comprehensive glossary. Additional definitions are available in those two OAR documents and in IEEE documents.

Adverse System Impact: A negative effect caused by the interconnection of a DER that may compromise the safety, reliability, or power quality of a distribution or transmission system.

Affected System: A distribution or transmission system, not owned or operated by the interconnecting public utility, which may experience an adverse system impact from the interconnection of a DER.

Applicant or **Customer**: An entity or person that seeks to interconnect a DER to the PGE system.

Area Network: See definition for secondary grid network.

Backfeed: Real power watt flow towards the substation.

Bidirectional: A device is considered to be bidirectional only if the device is capable of operating in two or more directions. For example, if a recloser bank's settings are not set up for bidirectional protective coordination, then the device would be considered unidirectional. In another example, if a voltage regulator bank does not have the appropriate control for bidirectional or co-generation operation, then the voltage regulator bank is considered unidirectional.

Certificate of Completion: A document signed by an applicant and PGE attesting that a DER is complete, meets the applicable requirements of the interconnection rules, and has been inspected, tested, and certified as physically ready for operation on the PGE system. A certificate of completion includes the "as built" specifications and initial settings for the DER and its associated interconnection equipment. This document is also referred to as a "permission to operate."

Distributed Energy Resources (DER): Facilities capable of delivering electric power, including both generators and energy storage technologies, that can be interconnected with the PGE system or connected to a host facility within the PGE system. In contexts other than this document's focus on interconnection, distributed energy resources may include additional technologies that customers may implement on the PGE system such as electric vehicles, controllable loads, and energy efficiency measures.

Electric Service Requirements (ESR): PGE book of requirements for obtaining electric service. This book applies to new service, relocated services, rewired services, and temporary services.

Fault Current: An electrical current that flows through a circuit during a fault condition. A fault condition occurs when one or more electrical conductors contact ground or each other. Types of faults include phase to ground, double-phase to ground, three-phase to ground, phase to phase, and three-phase. PGE uses the term "fault current" interchangeably with "short-circuit current."

Good Utility Practice: A practice, method, policy, or action engaged in or accepted by a significant portion of the electric industry in a region, which a reasonable utility official would expect, in light of the facts reasonably discernable at the time, to accomplish the desired result reliably, safely, and expeditiously.

Interconnection Agreement (IA): A contract between an applicant and PGE governing the interconnection of a DER to the PGE system and the ongoing operation of the DER after it is energized on the PGE system.

Interconnection Facilities: The facilities and equipment required by PGE to accommodate the interconnection of a DER to the PGE system and used exclusively for that interconnection. These facilities do not include "system upgrades."

Large Generator Applicant: A proposed DER facility that is above 10 MW in nameplate capacity, seeks to interconnect to the PGE system, and is not under FERC jurisdiction. Such applicants are subject to PGE's large generator interconnection requirements.

Minor Equipment Modification: A change to a small generator or CSP DER or its associated interconnection equipment that:

Does not affect the application of the Tier 1, 2, or 3 (small generator) or Tier 2 (CSP) approval requirements

Does not, in PGE's reasonable opinion, have a material impact on the safety or reliability of its distribution or transmission system or an "affected system"; and

Does not affect the nameplate capacity of the DER.

For small generator and CSP DER, minor equipment modifications also cannot exceed $10,000.

For net metering DER, there is an analogous concept of Minor Modification, but it is not specifically defined in the manner of small generator minor equipment modifications nor does it have a specific dollar cap.

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

Net Metering Applicant: A proposed DER facility that seeks to be directly interconnected to a PGE end-use electricity customer's premises, is intended primarily to offset part or all of that customer's electricity requirements from PGE and can operate in parallel with the PGE system. A fuller definition of "net metering" is available in Oregon Revised Statutes 757.300. Net metering DER projects are limited to a capacity of 25 kW or less in nameplate capacity for residential customers and 2 MW or less in nameplate capacity for non-residential customers.

Parallel Operations*:* Occurs when a DER is serving as a source of electric power for greater than 100 milliseconds while connected to the PGE system.

Permission to Operate*:* See definition for Certificate of Completion.

PGE System***:*** Electrical distribution facilities owned by PGE. These facilities can deliver electricity from either transformation points on the transmission system or electricity directly injected into the distribution facilities to points of connection on an end-use customer's premises.

Point of Common Coupling (PCC)*:* The point beyond a net metering DER's meter where the DER connects with the PGE system.

Point of Interconnection (POI): The point where a small generator or CSP DER is electrically connected to the PGE system. This term has the same meaning as "point of common coupling" as defined in Section 3.1.13 of IEEE 1547-2003. This term does not, however, have the same meaning as "point of common coupling" as defined in OAR 860-039-0005 for net metering DERs.

Queue Position: The rank of an interconnection application determined by PGE to have complete information, relative to all other applications determined by PGE to be complete at a given location on the PGE system. Queue position is established based on the date and time that PGE receives the completed applications, including application fees.

Secondary Grid Network: A type of distribution system served by multiple transformers interconnected in an electrical network circuit to provide high reliability of service.

Small Generator Applicant: A proposed DER facility of up to 10 MW in nameplate capacity seeking to interconnect to the PGE system that does not meet the standards for a net metering applicant and is not under FERC jurisdiction.

Spot Network: A type of distribution or transmission system that uses two or more intertied transformers protected by network protectors to supply an electrical network circuit. A spot network may be used to supply power to a single customer or a small group of customers.

System Upgrade: An addition or modification to PGE's distribution or transmission system or to an "affected system" of another public utility that is required to accommodate the interconnection of a DER.

16.6 Acronyms

Acronyms used in this document are defined below.

AC: Alternating Current

AHJ: Authority Having Jurisdiction

ANSI: American National Standards Institute

CSP: Community Solar Program

CT: Current Transformer

DC: Direct Current

DER: Distributed Energy Resources

DNP: Distributed Network Protocol

ESR: Electric Service Requirements

EUSERC: Electric Utility Service Equipment Requirements Committee

FERC: Federal Energy Regulatory Commission

IEEE: Institute of Electrical and Electronics Engineers, Inc. kV: Kilovolt(s) kVA: Kilovolt-amps kW: Kilowatt(s) kWh: Kilowatt-hour(s)

LTC: Load Tap Changer

MBTT: Mirrored Bits Protocol for Transfer Trip

ms: Milliseconds

MVA: Megavolt amps

MW: Megawatt(s)

NERC: North American Electric Reliability Council

NFPA: National Fire Protection Association

NWPP: Northwest Power Pool

OAR: Oregon Administrative Rules

OPUC: State of Oregon Public Utility Commission

PCC: Point of Common Coupling

PGE: Portland General Electric Company

POI: Point of Interconnection

PPA: Power Purchase Agreement

PT: Potential Transformer

PV: Photovoltaic

QF: Qualifying Facility

SCADA: Supervisory Control and Data Acquisition

SEL: Schweitzer Engineering Laboratories

V: Volt

WECC: Western Electric Coordinating Council

16.7 References

The external sources referenced in this document are listed below, with their URLs. The URLs represented the web locations of the references at the time PGE completed this edition of its interconnection standards, but the URLs may have changed since the time this document was completed.

ANSI C84.1-2016 (Electric Power Systems and Equipment - Voltage Ratings [60 Hz]): https://webstore.ansi.org/Standards/NEMA/ANSIC842016 (available for subscription)

IEEE 141-1993 (Recommended Practice for Electric Power Distribution for Industrial Plants): https://standards.ieee.org/standard/141-1993.html (available for purchase or subscription)

IEEE 519-2014 (Recommended Practice and Requirements for Harmonic Control in Electric Power Systems): https://standards.ieee.org/standard/519-2014.html (available for purchase or subscription)

IEEE 1453-2015 (Recommended Practice for the Analysis of Fluctuating Installations on Power Systems): https://standards.ieee.org/standard/1453-2015.html (available for purchase or subscription)

IEEE 1547-2003 (Standard for Interconnecting Distributed Resources with Electric Power Systems): https://standards.ieee.org/standard/1547-2003.html (available for purchase or subscription)

IEEE 1547.1-2005 (Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems): https://standards.ieee.org/standard/1547_1-2005.html (available for purchase or subscription)

IEEE 1547-2018 (Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces): https://standards.ieee.org/standard/1547-2018.html (available for purchase or subscription)

IEEE C37.90.1-2002 (Standard Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus): https://standards.ieee.org/standard/C37_90_1-2002.html (available for purchase or subscription)

IEEE C57.13-2016 (Standard Requirements for Instrument Transformers): https://standards.ieee.org/standard/C57_13-2016.html (available for purchase or subscription)

IEEE C62.41.2-2002 (Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and less) AC Power Circuits): https://standards.ieee.org/standard/C62_41_2-2002.html (available for purchase or subscription)

NFPA 70® (National Electrical Code®): https://www.nfpa.org/nec

OPUC OAR 860-039 (net metering rules): https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=4053

OPUC OAR 860-082 (small generator interconnection rules): https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=4084

OPUC OAR 860-088 (Community Solar Program Rules): https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=4090

OPUC Order Number 10-132 (Oregon Standard Interconnection Procedures and Agreements Adopted for Large Qualifying Facilities): https://apps.puc.state.or.us/orders/2010ords/10-132.pdf

PGE Electric Service Requirements, January 2020: https://www.portlandgeneral.com/construction/electric-service-requirements

Small Generator Interconnection Program Interconnection Technical Requirements: https://www.portlandgeneral.com/PGE_Small_Gen_Interconnection_FAQs_2023.pdf

PGE Community Solar Program website:
https://portlandgeneral.com/energy-choices/generate-power/community-solar/

UL 1741 (Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources):
https://standardscatalog.ul.com/standards/en/standard_1741_2 (available for purchase)

17 Revision Table

Review this document no later than three (3) years of the effective date, as required by the Document Governance.

Rev. No.	Revision Date	Reason for Revision	Affected Pages
0	7/1/2017	Initial release	
1	9/24/2021	Bring up to current standard. Setup online navigation	ALL
1.1	11/4/2021	Added fillable fields and hyperlinks to pdf	ALL

PGE